ORIGINAL

BEFORE THE PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida And Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	)	**DOCKET NO. 981042-EM** December 14, 1998

NOTICE OF FILING REQUEST FOR OFFICIAL NOTICE

Florida Power Corporation requests that the Commission take judicial notice of the following item in opposition to the Joint Petition for Determination of Need in the above-referenced docket.

1. Petition to Determine Need for Electrical Power Plant, filed in In re: Petition of City of Tallahasee to Determine Need for Proposed Electrical Power Plant in St. Marks, Wakulla County, Florida, Docket No. 96-1512 (December 20, 1996).

Respectfully submitted,

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 1
COMPANY/ WITNESS: FPC
DATE: 12-2-98

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FPSC-RECORDS/REPORTING

DOCUMENT NO. DATE
14742-98 12/31/1998
FPSC - COMMISSION CLERK

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing has been furnished by U.S. Mail this 14th day of December 1998, to counsel of record as follows:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition of City of Tallahassee to Determine Need for Proposed Electrical Power Plant in St. Marks, Wakulla County, Florida	Docket No. 961512 Filed: December 20, 1996

PETITION TO DETERMINE NEED FOR ELECTRICAL POWER PLANT

CITY OF TALLAHASSEE ("City"), by and through its undersigned attorneys, hereby petitions the Florida Public Service Commission ("Commission") pursuant to Section 403.519, Florida Statutes, and Rule 25-22.081, Florida Administrative Code, to determine the need for the proposed electrical power plant described herein, and to file its order making that determination with the Department of Environmental Protection ("DEP") pursuant to Section 403.507(2)(a)2., F.S. In support thereof, City states:

1. City's full name and business address is:

City of Tallahassee
City Hall
Tallahassee, Florida 32301

2. The name and address of City's representatives to receive communications regarding this docket are:

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Jonathan T. Johnson
Hopping Green Sams & Smith, P.A.
P.O. Box 6526
Tallahassee, Florida 32314

with copies to:

Patrick E. Hurley
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City Hall
Tallahassee, Florida 32301

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3. City is a municipal corporation which provides retail electric service to approximately 88,000 customers located within the municipal limits of the City of Tallahassee and portions of the surrounding area.

4. City meets its power supply needs through a combination of City-owned generation and wholesale power purchases from the Southern Company and Entergy, Inc. City's power purchase contract for 75 MW from Southern Company terminates on May 31, 2000. When coupled with load growth between now and the year 2000, the City requires an additional 88 MW of generation by May, 2000 in order to continue to meet its power supply obligations at an acceptable level of reliability. This amount continues to increase with future load growth and with the expiration on March 31, 2002 of the City's power purchase contract for 25 MW from Entergy.

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5. City employed a competitive request for proposal (RFP) process, in combination with an evaluation of City-owned generation options, to choose the most cost-effective alternative to meet that need. That process identified a 250 MW combined cycle generating facility, to be constructed for City under an engineering, procurement and construction (EPC) contract with Raytheon, Inc. as the most cost-effective alternative. The new unit will be constructed at the existing Purdom generating plant site located in St. Marks, Wakulla County, Florida. The new unit, to be known as Purdom Unit 8, consists of an "F" frame advanced combustion turbine/generator and a heat recovery steam generator that will drive a steam turbine generator.

6. The construction and operation of Purdom Unit 8 will replace power currently obtained under the City's contract with Southern Company; will allow the City to retire two smaller, less efficient units at the Purdom site; and will displace generation from other less efficient units in the City's existing generating portfolio. Because Purdom Unit 8 is a highly efficient combined cycle generator, the average energy cost for the City's electric system is projected to decrease by approximately 11% in the unit's first full year of commercial operation.

7. The Purdom Unit 8 project is the most cost-effective option to meet the City's generating needs. Under base case planning assumptions, compared to the lowest-cost project submitted to the City in response to its RFP, the Purdom Unit 8 project saves approximately $91 million (1996$) in cumulative

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present worth of revenue requirements (PWRR) over the 20-year period 1995-2014.

8. Pursuant to the Florida Electrical Power Plant Siting Act, Section 403.519, F.S., and Rules 25-22.080 to 25-22.081, F.A.C., the Commission has jurisdiction to determine the need for the proposed electrical power plant, applying the standards set forth in Section 403.519, F.S.

9. As authorized by Rule 25-22.080(1), F.A.C., City has elected to commence this proceeding for a determination of need prior to the filing with DEP of a Site Certification Application (SCA) for the proposed electrical power plant.

10. The information supporting this petition is contained in City's Need Determination Study (the "Need Study") which is attached as an exhibit to this petition and incorporated herein by reference. The Need Study contains City's analysis of the need for the proposed electrical power plant and includes the information required by Rule 25-22.081, F.A.C.

11. The accompanying information demonstrates the need for the proposed electrical power plant in the proposed time frame as the most cost-effective alternative available, taking into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and other relevant matters.

(a) By providing sufficient resources for City to meet its reliability requirements upon termination of the contract with Southern Company, the proposed plant will contribute to the

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reliability of the City's system. By locating additional generation resources within the City's service territory, the availability of transmission capacity to support the City's system during an unplanned outage of one of the City's units is enhanced. The unit's location at the Purdom Generating Station also allows the unit to provide voltage support for the southeast area of the City's system at low cost.

(b) The proposed unit will ensure that City has an adequate supply of power to serve its customers' needs at a reasonable cost. Due to the retirement of older units and the displacement of generation from other less efficient units, the total cost of generation after the installation of Purdom Unit 8 will be lower than current costs.

(c) The proposed unit is the most cost-effective alternative available for meeting this increment of capacity, saving approximately $91 million PWRR (1996$) over a 20-year period compared to the least cost alternative identified through the City's competitive RFP process.

(d) The City has implemented demand-side management programs which are cost-effective based on the results of its integrated resource planning process. Even with the demand and energy reductions from those programs, Purdom Unit 8 is required to enable City to reliably meet its customers' power supply needs.

12. As set forth in more detail in the Need Study, the Purdom Unit 8 project has a number of advantageous features, including the following:

(a) The facility will be located at the existing Purdom site which is presently connected to the City's load center by 115 kV transmission lines into which the new unit will connect. No additional off-site transmission will be required to integrate the unit into the electric grid, although some existing transmission lines will need to be reconductored to handle increased power flows.

(b) The EPC contractual arrangement will minimize the project-related risks to City by placing the burden on the contractor to ensure a timely commercial operation date and to guarantee output and heat rate levels.

(c) The project will minimize environmental impacts by utilizing clean burning natural gas as the primary fuel, utilizing low sulfur diesel for back-up fuel, utilizing the latest dry low NOx combustor technology to achieve a NOx emission rate lower than that of other recently licensed projects, and utilizing a zero water discharge design which also eliminates groundwater withdrawals for the entire Purdom facility and reuses treated effluent from St. Marks sewage treatment facility (which is currently discharged to the St. Marks River).

13. City has coordinated with the Commission staff to arrange a schedule which calls for the need determination hearing to commence on April 3, 1997, and for a final Commission vote on

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(P) RECEIVED

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	)	DOCKET NO. 981042-EM DATED: NOVEMBER 19, 1998

PETITIONERS' RESPONSE TO FLORIDA POWER & LIGHT COMPANY'S FIRST REQUESTS FOR ADMISSIONS TO DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P. AND UTILITIES COMMISSION, NEW SMYRNA BEACH

The Utilities Commission, City of New Smyrna Beach, Florida ("Utilities Commission") and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. ("Duke New Smyrna"), collectively referred to as Petitioners, pursuant to Uniform Rule 28-106.206, Florida Administrative Code, hereby respond to Florida Power & Light Company's ("FPL") First Requests for Admissions.

A. The numbered paragraphs below repeat FPL's requests for admissions. Petitioners' response to each request follows the numbered paragraph.

1. Duke New Smyrna has no final purchased power contract for any of the output from its proposed Project.

Admitted.

2. Duke New Smyrna has not provided in either its Joint Petition and Exhibits or its direct testimony and exhibits the terms and conditions pursuant to which it will sell the output of its Project to Florida utilities.

Denied.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 2
COMPANY/ WITNESS: FPL
DATE: 12-2-98

3. Duke New Smyrna has not identified in either its Joint Petition and Exhibits or its direct testimony and exhibits any individual Florida utility other than the Utilities Commission, New Smyrna Beach, to which it intends to sell the output of its Project.

Admitted.

4. Duke New Smyrna has not identified in either its Joint Petition and Exhibit or its direct testimony and exhibits any individual Florida utilities, other than the Utilities Commission, New Smyrna Beach, which have a need for the output of the Project.

Admitted.

5. Duke New Smyrna has not proposed any reliability criteria appropriate for determining either Peninsular Florida's or any individual peninsular Florida utility's need for capacity.

Admitted.

6. Duke New Smyrna has not demonstrated in its Joint Petition and Exhibit or in its direct testimony and exhibits that the uncommitted merchant plant capacity of its Project is needed for an individual Florida utility to have adequate electricity at a reasonable cost.

Denied.

7. Duke New Smyrna has not demonstrated in its Joint Petition and Exhibit or in its direct testimony and exhibits that the uncommitted merchant plant capacity of its Project is the most cost-effective alternative for any individual Florida utility.

Denied.

8. Duke New Smyrna has not demonstrated in its Joint Petition and Exhibit or in its direct testimony and exhibits that any individual Florida utility to which it might sell the output of its Project, other than the Utilities Commission, New Smyrna Beach, does not have conservation measures reasonably available which would mitigate the need for the Project.

Admitted.

9. Electric system reliability and integrity are appropriately measured through the use of reliability criteria.

Admitted.

10. In its Joint Petition and Exhibit and its direct testimony and exhibits Duke New Smyrna relies upon the 1998 Regional Load and Resource Plan dated July, 1998 and prepared by the Florida Reliability Coordinating Council ("FRCC").

Denied.

11. The 1998 Regional Load and Resource Plan shows that both summer and winter reserve margins for Peninsular Florida will meet or exceed 15% for the years 1998 through the winter of 2007/2008.

Denied.

12. The 1998 Regional Load and Resource Plan does not include the Duke New Smyrna Project.

Admitted.

13. The 1998 Regional Load and Resource Plan prepared by the FRCC and relied upon by Duke New Smyrna in its Joint Petition and Exhibit and direct testimony exhibits shows that Peninsular Florida will achieve or exceed its reserve margin criteria of 15% for 1998 through summer 2007 without the Duke New Smyrna Project.

Denied.

14. The 1998 Reliability Assessment, dated August, 1998 and prepared by the Florida Regional Coordinating Council examined Peninsular Florida's bulk reliability reflected in the 1998 Regional Load and Resource Plan.

Admitted that page 6 of the 1998 Reliability Assessment states that the "FRCC's 1998 Reliability Assessment Study examines peninsular Florida's bulk reliability, reflected in [the utility companies' resource plans]". The 1998 Reliability Assessment speaks for itself. Duke New Smyrna did not prepare the 1998 Reliability Assessment and thus is without knowledge as to the accuracy of the statement.

15. The FRCC's 1998 Reliability Assessment concludes "that the peninsular Florida electric system is reliable through the ten year planning period and that the FRCC 1998 Load and Resource Plan is suitable.

Admitted that page 50 of the 1998 Reliability Assessment states that "the FRCC concludes that the peninsular Florida electric system is reliable through the ten year planning period and that the FRCC 1998 Load and Resource Plan is suitable." The 1998 Reliability Assessment speaks for itself. Duke New Smyrna did not prepare the 1998 Reliability Assessment, thus it is without knowledge as to the accuracy of this statement.

16. The FRCC's 1998 Reliability Assessment contains a reserve margin standard of 15% for both summer and winter peaks.

Admitted that the 1998 Reliability Assessment contains within it a reserve margin standard of 15% for both summer and winter peaks. The 1998 Reliability Assessment speaks for itself. Duke New Smyrna did not prepare the 1998 Reliability Assessment, thus it is without knowledge as to the accuracy of this statement.

17. The FRCC's 1998 Reliability Assessment states that the "reserve margin analysis indicates that peninsular Florida maintains summer and winter reserve levels in excess of 15% throughout the entire ten-year planning period. This level is considered to provide adequate levels of reserve margin for reliable service."

Admitted that page 50 of the 1998 Reliability Assessment states that the "reserve margin analysis indicates that peninsular Florida maintains summer and winter reserve levels in excess of 15% throughout the entire ten-year planning period. This level is considered to provide adequate levels of reserve margin for reliable service." The 1998 Reliability Assessment speaks for itself. Duke New Smyrna did not prepare the 1998 Reliability Assessment, thus it is without knowledge as to the accuracy of this statement.

18. The FRCC's 1998 Reliability Assessment recommends that "the 15% reserve margin criterion be retained for reliability analyses of peninsular Florida.

Admitted that page 16 of Exhibit 2 to the 1998 Reliability Assessment states that the FRCC Resource Working Group "recommends that the 15% reserve margin criterion be retained for reliability analyses of peninsular Florida." The 1998 Reliability Assessment speaks for itself. Duke New Smyrna did not prepare the 1998 Reliability Assessment, thus it is without knowledge as to the accuracy of this statement.

19. Duke New Smyrna intends to sell the output of its Project outside of Florida when market conditions warrant such sales.

Denied.

20. Duke New Smyrna has not committed to sell the output of its Project solely to Florida utilities.

Admitted.

21. Duke New Smyrna has not committed to sell the output of its Project to any peninsular Florida utility other than the Utilities Commission, New Smyrna Beach.

Admitted.

22. Table 8 of the Joint Petition Exhibit and Exhibit ___ RLV-7, Page 1 of 2, show that peninsular Florida will achieve the FRCC's reserve margin criteria of 15% for every year in the horizon shown without the Duke New Smyrna Project.

Admitted that the subject tables show that peninsular Florida is projected to have summer reserve margins greater than 15% for each year of the horizon.

23. Table 8 of the Joint Petition Exhibit and Exhibit ____ RLV-7, Page 2 of 2, show that without the Duke New Smyrna Project peninsular Florida will achieve or exceed FRCC's winter reserve margin criteria of 15% for every winter from 1998/99 through 2006/07.

Denied.

24. Neither Duke New Smyrna nor the Utilities Commission, New Smyrna Beach have sought or been granted a waiver of or exemption from Florida Administrative Code Rule 25-22.081.

Admitted.

25. The Pahokee Power Partners II Project for which ARK Energy, Inc. and CSW Development-I, Inc. sought a determination of need in FPSC Docket No. 920761-EQ was an independent power project and not a cogeneration, small power production, or qualifying facility.

Denied.

26. The petition for a determination of need for the Pahokee Power Partners II Project was dismissed by the Florida Public Service Commission because the petitioners were found not to be "proper applicants for need determination proceeding under Section 403.519, Florida Statutes."

Admitted that Order No. PSC-92-1210-FOF-EQ at page 10:644, states "we find the petitions should be dismissed because Nassau and Ark are not proper applicants for a need determination proceeding under Section 403.519, Florida Statutes." Denied that this quoted language has any relevance to this proceeding.

27. The Pahokee Power Partners II Limited Partnership which would have owned the Pahokee Power Partners II Project could have met eligibility requirements for Exempt Wholesale Generation status.

Denied.

28. The Pahokee Power Partners II Limited Partnership did not have an executed final purchased power contract for the output of its Project.

Admitted.

29. Duke New Smyrna and the Utilities Commission New Smyrna Beach have not and will not jointly finance the Project.

Denied.

30. Duke New Smyrna and the Utilities Commission New Smyrna Beach have not and will not jointly acquire the Project.

Denied.

31. Duke New Smyrna and the Utilities Commission New Smyrna Beach have not and will not jointly construct the Project.

Denied.

32. Duke New Smyrna and the Utilities Commission New Smyrna Beach have not and will not jointly manage the Project.

Denied.

33. Duke New Smyrna and the Utilities Commission New Smyrna Beach have not and will not jointly operate the Project.

Denied.

34. Duke New Smyrna and the Utilities Commission New Smyrna Beach have not and will not jointly own the Project.

Denied.

35. The utilities which will be primarily affected by the Project include the peninsular Florida utilities to whom Duke New Smyrna will sell the output of the Project.

Denied.

36. The terms and conditions pursuant to which Duke New Smyrna will sell the output of the merchant capacity of its proposed plant have not been established.

Admitted that not all terms and conditions have been established.

37. The Pahokee Power Partners II Project, as an independent power project, would have been a public utility under the Federal Power Act.

Denied.

38. In Order No. PSC-92-1210-FOF-EQ, the Pahokee Power Partners II Project was characterized by the Commission as owned by "Ark" and Ark was characterized as a "non-utility generator."

Denied that Order No. PSC-92-1210-FOF-EQ states that Ark "owned" the Pahokee Power Partners II Project. Admitted that Order No. PSC-92-1210-FOF-EQ at page 10:645 stated "[n]on-utility generators...such as Ark..." Denied that this statement is relevant to this proceeding.

39. As to its merchant plant capacity, Duke New Smyrna has no customers.

Admitted that at this time, Duke New Smryna has no customers other than the UCNSB.

40. As to its merchant plant capacity, Duke New Smyrna is not obligated to serve customers.

Admitted at this time. Denied to the extent that when Duke New Smyrna has customers it will be contractually obligated to serve them.

41. The Commission has previously held in Order No. PSC-92-1210-FOF-EQ that it is "need, resulting from a duty to serve customers, which the need determination proceeding is designed to examine."

Admitted that Order No. PSC-92-1210-FOF-EQ at page 10:645 states that "[i]t is this need, resulting from a duty to serve customers, which the need determination proceeding is designed to examine." Denied that this is the holding of this case or that the statement is relevant to this proceeding.

42. As to its merchant plant capacity, Duke New Smyrna has no need since it is not required to serve customers.

Denied.

43. Duke New Smyrna has not made an offer to sell capacity from its Project to any Peninsular Florida utility other than the 30MW committed to the Utilities Commission, New Smyrna Beach.

Admitted that Duke New Smyrna has not made a specific offer, including price, duration, and all terms and conditions, to any Peninsular Florida utility other than the UCNSB. Otherwise denied. Duke New Smyrna has generally offered to sell capacity from its Project to any interested utility in Peninsular Florida.

44. No Florida utility, other than the Utilities Commission, New Smyrna Beach, alleges that the Duke New Smyrna Project is needed for electric system reliability and integrity.

Duke New Smyrna is without knowledge. Duke New Smyrna has made reasonable inquiry and absent polling <u>all</u> Florida utilities, the information known or readily attainable by Duke New Smyrna is insufficient to allow Duke New Smyrna to admit or deny this request.

45. No Florida utility, other than the Utilities Commission, New Smyrna Beach, alleges that the Duke New Smyrna Project is needed for adequate electricity at a reasonable cost.

Duke New Smyrna is without knowledge. Duke New Smyrna has made reasonable inquiry and absent polling all Florida utilities, the information known or readily attainable by Duke New Smyrna is insufficient to allow Duke New Smyrna to admit or deny this request.

46. No Florida utility, other than the Utilities Commission, New Smyrna Beach, alleges that the Duke New Smyrna Project is the most cost-effective alternative available.

Duke New Smyrna is without knowledge. Duke New Smyrna has made reasonable inquiry and absent polling all Florida utilities, the information known or readily attainable by Duke New Smyrna is insufficient to allow Duke New Smyrna to admit or deny this request.

47. Duke New Smyrna has not demonstrated in its Joint Petition and Exhibit or in its direct testimony and exhibits that the uncommitted merchant plant capacity of its Project is needed for electric system reliability and integrity by any individual Florida utility.

Denied.

B. Each of the following documents exhibited with this request is a true copy of the original and is genuine.

48. 1998 Reliability Assessment, August - 1998, prepared by the Florida Reliability Coordinating Council (Exhibit A)

Admitted.

49. 1998 Regional Load & Resource Plan, July, 1998, prepared by the Florida Reliability Coordinating Council (Exhibit B)

Admitted.

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and

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

1998

Regional

Load & Resource

Plan

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 3
COMPANY/ WITNESS: FPL
DATE: 12-2-98

July, 1998

FLORIDA RELIABILITY COORDINATING COUNCIL

1998

LOAD AND RESOURCE PLAN

FLORIDA RELIABILITY COORDINATING COUNCIL

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

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1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

HISTORY AND FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	SUMMER PEAK DEMAND - (MW)					WINTER PEAK DEMAND - (MW)					ENERGY	
YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
1988	24819				1988 / 89	26800				1988	131143	58.47%
1989	26608				1989 / 90	29170				1989	141021	60.07%
1990	27238				1990 / 91	24978				1990	142490	55.76%
1991	27662				1991 / 92	28179				1991	146786	60.58%
1992	28930				1992 / 93	27215				1992	147728	58.29%
1993	29748				1993 / 94	28149				1993	153269	58.82%
1994	29321				1994 / 95	32618				1994	159353	62.04%
1995	31801				1995 / 96	34552				1995	168982	59.14%
1996	32315				1996 / 97	34762				1996	173327	57.26%
1997	32924				1997 / 98	30932				1997	175534	57.64%

YEAR	TOTAL (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET DEMAND (MW)	YEAR	TOTAL (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	NET DEMAND (MW)	YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
1998	35633	1106	1670	32857	1998 / 99	39450	1182	2602	35666	1998	182222	63.31%
1999	36628	1242	1769	33617	1999 / 00	40383	1221	2729	36433	1999	188257	60.26%
2000	37410	1277	1853	34280	2000 / 01	41395	1229	2849	37317	2000	193353	60.58%
2001	38220	1286	1941	34993	2001 / 02	42219	1193	2960	38066	2001	198102	60.60%
2002	38844	1234	2022	35588	2002 / 03	42998	1165	3067	38766	2002	202477	60.72%
2003	39395	1220	2097	36078	2003 / 04	43925	1159	3148	39618	2003	206108	60.69%
2004	40227	1214	2142	36871	2004 / 05	44895	1152	3183	40560	2004	210841	60.75%
2005	41112	1209	2170	37733	2005 / 06	45896	1148	3217	41531	2005	215677	60.70%
2006	41998	1205	2200	38593	2006 / 07	46879	1141	3251	42487	2006	220692	60.66%
2007	42885	1203	2231	39451	2007 / 08	47902	1145	3270	43487	2007	225697	60.64%

NOTE: FORECASTED SUMMER AND WINTER DEMANDS ARE NON-COINCIDENT.

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

HISTORY AND FORECAST
ENERGY USE BY CUSTOMER TYPE - GWH
AS OF JANUARY 1, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	RURAL & RESIDENTIAL			COMMERCIAL			INDUSTRIAL								
YEAR	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	STREET & HIGHWAY LIGHTING GWH	OTHER SALES GWH	TOTAL SALES GWH	RESALE GWH	UTILITY USE & LOSSES GWH	NEL GWH
1988	58379	5008214	11657	40328	595369	67736	16230	26741	606926	485	3245	118666	0	12477	131143
1989	62263	5191812	11993	43237	618010	69962	16633	26681	623384	501	3503	126137	0	14884	141021
1990	65022	5354736	12143	44819	633799	70715	16676	26065	639761	508	3576	130600	0	11890	142490
1991	66787	5484780	12177	45796	645580	70938	16650	25020	665471	538	3736	133508	0	13278	146786
1992	67008	5584026	12000	45888	660642	69459	16646	24690	674190	552	3796	133890	0	13838	147728
1993	70488	5709685	12345	48080	676150	71109	16524	24962	661962	535	3877	139503	0	13766	153269
1994	74128	5833171	12708	50454	691625	72951	17025	25964	655718	582	4007	146177	0	13176	159353
1995	78667	5955574	13209	52100	705921	73804	17687	25660	689299	586	4165	153205	0	15777	168982
1996	81047	6066709	13359	53086	720371	73693	18338	25523	718516	600	4278	157349	0	15978	173327
1997	80727	6185747	13051	55643	737205	75478	18707	25936	721263	620	4536	160233	0	15301	175534
88-'97 % AAGR	3.67%	2.37%	1.26%	3.64%	2.40%	1.21%	1.59%	-0.34%	1.94%	2.77%	3.79%	3.39%	0.00%	2.29%	3.29%
1998	84576	6304392	13415	56905	753603	75491	18940	26188	723234	634	4603	165658	0	16564	182222
1999	87435	6433162	13591	58777	770187	76316	19673	26577	740226	651	4749	171284	0	16973	188257
2000	90030	6560221	13724	60606	788400	77068	20367	26893	757334	669	4902	176574	0	16779	193353
2001	92426	6682834	13830	62281	801915	77665	20898	27160	769465	685	5054	181345	0	16757	198102
2002	94594	6802878	13905	63850	816890	78163	21294	27388	777496	703	5205	185647	0	16830	202477
2003	96847	6922167	13991	65478	831777	78721	21566	27615	780954	715	5348	189954	0	16154	206108
2004	99217	7041885	14090	67130	846659	79288	21988	27832	790028	728	5492	194556	0	16285	210841
2005	101520	7161969	14175	68799	861783	79833	22410	28028	799530	740	5633	199101	0	16576	215677
2006	103906	7282895	14267	70463	877079	80338	22841	28223	809321	752	5762	203725	0	16967	220692
2007	106254	7404768	14349	72169	892691	80845	23300	28419	819869	765	5890	208379	0	17318	225697
98-'2007 % AAGR	2.57%	1.80%	0.75%	2.68%	1.90%	0.76%	2.33%	0.91%	1.40%	2.12%	2.78%	2.58%	0.00%	0.50%	2.41%

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF LOAD MANAGEMENT / INTERRUPTIBLE LOAD - MW

SUMMER

YEAR	FKE	FMPA		FPC		FPL		JEA		KEY	KUA	LAK		NSB	OEU	OUC		SEC		TEC		TOTAL (LM / INT)	
1998	4	5	0	683	272	660	438	0	85	0	12	21	5	6	2	0	1	126	88	151	217	1,670	1,106
1999	4	6	0	708	331	709	458	0	121	0	12	22	5	6	2	0	1	131	93	169	233	1,769	1,242
2000	4	6	0	726	345	752	479	0	121	0	12	22	5	6	2	0	1	136	96	187	230	1,853	1,277
2001	5	7	0	748	350	792	482	0	121	0	12	23	5	6	2	0	1	140	99	206	228	1,941	1,286
2002	5	8	0	762	295	833	485	0	121	0	12	23	5	6	2	0	1	145	102	226	225	2,022	1,234
2003	5	8	0	771	278	873	488	0	121	0	12	24	5	6	3	0	1	149	105	246	222	2,097	1,220
2004	6	9	0	774	271	887	489	0	121	0	13	25	5	6	3	0	1	153	108	266	219	2,142	1,214
2005	6	10	0	776	265	887	489	0	121	0	13	25	5	6	3	0	1	158	111	287	217	2,170	1,209
2006	6	10	0	779	258	887	489	0	121	0	13	26	6	6	3	0	1	162	115	308	215	2,200	1,205
2007	6	11	0	782	256	887	489	0	121	0	13	26	6	6	3	0	1	167	118	330	212	2,231	1,203

WINTER

YEAR	FKE	FMPA		FPC		FPL		JEA		KEY	KUA	LAK		NSB	OEU	OUC		SEC		TEC		TOTAL (LM / INT)	
1998 / 99	0	6	0	1,175	318	866	448	0	108	0	12	51	5	8	3	0	1	185	91	296	211	2,602	1,182
1999 / 00	0	7	0	1,213	340	925	464	0	108	0	12	52	5	8	3	0	1	192	94	317	209	2,729	1,221
2000 / 01	0	7	0	1,251	348	976	464	0	108	0	12	53	5	8	4	0	1	199	96	339	207	2,849	1,229
2001 / 02	0	7	0	1,281	312	1,028	464	0	108	0	12	54	5	8	4	0	1	205	99	361	204	2,960	1,193
2002 / 03	0	8	0	1,306	282	1,079	464	0	108	0	12	55	5	8	4	0	1	212	102	383	203	3,067	1,165
2003 / 04	0	8	0	1,309	275	1,127	464	0	108	0	12	57	5	8	4	0	1	218	105	405	201	3,148	1,159
2004 / 05	0	9	0	1,312	268	1,127	464	0	108	0	13	58	5	8	4	0	1	224	108	428	198	3,183	1,152
2005 / 06	0	9	0	1,315	262	1,127	464	0	108	0	13	59	5	8	4	0	1	231	112	451	196	3,217	1,148
2006 / 07	0	9	0	1,318	255	1,127	464	0	108	0	13	60	5	9	5	0	1	237	115	474	193	3,251	1,141
2007 / 08	0	9	0	1,322	257	1,127	464	0	108	0	13	61	5	9	5	0	1	243	118	482	192	3,270	1,145

NOTE: A SINGLE NUMBER DENOTES LOAD MANAGEMENT.

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF EXISTING CAPACITY
AS OF JANUARY 1, 1998

	NET CAPABILITY - MW	
UTILITY	SUMMER	WINTER
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOCIATION, INC.	22	22
FLORIDA MUNICIPAL POWER AGENCY	453	478
FLORIDA POWER CORPORATION	6,962	7,717
FLORIDA POWER & LIGHT COMPANY	16,420	17,258
FORT PIERCE UTILITIES AUTHORITY	109	109
GAINESVILLE REGIONAL UTILITIES	550	563
CITY OF HOMESTEAD	52	52
JACKSONVILLE ELECTRIC AUTHORITY	2,649	2,716
UTILITY BOARD OF THE CITY OF KEY WEST	53	56
KISSIMMEE UTILITY AUTHORITY	172	189
CITY OF LAKELAND	597	642
CITY OF LAKE WORTH UTILITIES	95	105
UTILITIES COMMISSION OF NEW SMYRNA BEACH	24	24
OCALA ELECTRIC UTILITY	11	11
ORLANDO UTILITIES COMMISSION	1,631	1,688
REEDY CREEK IMPROVEMENT DISTRICT	35	40
SEMINOLE ELECTRIC COOPERATIVE, INC.	1,291	1,369
CITY OF ST. CLOUD	27	27
CITY OF TALLAHASSEE	490	508
TAMPA ELECTRIC COMPANY	3,493	3,615
CITY OF VERO BEACH	154	162
TOTALS:		
FRCC REGION:	35,290	37,351
NON-UTILITY GENERATING FACILITIES:	2,220	2,240
TOTAL FRCC REGION:	**37,510**	**39,591**

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	OWNERSHIP (U,J, or N)
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOCIATION, INC.																
MARATHON	8	MONROE	D	LO	TK	HO	TK	6	1988	---	---	2,000	2	2		U
MARATHON	9	MONROE	D	LO	TK	HO	TK	6	1988	---	---	2,000	2	2		U
MARATHON	3	MONROE	D	LO	TK	HO	TK	6	1955	---	---	3,000	3	3		U
MARATHON	4	MONROE	D	LO	TK	HO	TK	6	1957	---	---	3,000	3	3		U
MARATHON	5	MONROE	D	LO	TK	HO	TK	6	1959	---	---	3,000	3	3		U
MARATHON	6	MONROE	D	LO	TK	HO	TK	6	1973	---	---	2,500	3	3		U
MARATHON	7	MONROE	D	LO	TK	HO	TK	6	1973	---	---	2,500	3	3		U
MARATHON	10	MONROE	D	LO	TK	HO	TK	1	1998	---	---	3,500	3	3		U
TOTAL:													22	22		
FLORIDA MUNICIPAL POWER AGENCY																
ST. LUCIE (839/853)	2	ST. LUCIE	N	N	TK	--	--	8	1983	---	---	839,000	74	75		J
STANTON ENERGY CENTER (441/443)	1	ORANGE	FS	C	RR	--	--	7	1987	---	---	464,580	115	115		J
STANTON ENERGY CENTER (444/444)	2	ORANGE	FS	C	RR	--	--	7	1987	---	---	464,580	122	122		J
INDIAN RIVER(74/96) CT	A,B	BREVARD	GT	NG	PL	LO	TK	7	1989	---	---	82,800	29	37		J
INDIAN RIVER(216/254) CT	C,D	BREVARD	GT	NG	PL	LO	TK	8	1992	---	---	224,080	44	54		J
CANE ISLAND(30/40)	1	OSCEOLA	GT	NG	PL	LO	TK	11	1994	---	---	42,000	15	15		J
CANE ISLAND(68/80)	2	OSCEOLA	CCT	NG	PL	LO	TK	6	1995	---	---	80,000	34	40		J
CANE ISLAND(40/40)	2	OSCEOLA	CCW	NG	PL	LO	TK	6	1995	---	---	40,000	20	20		J
TOTAL:													453	478		
FLORIDA POWER CORPORATION																
AVON PARK	P1	HIGHLANDS	GT	LO	TK	NG	PL	12	1968	12	2004	33,790	29	32		U
AVON PARK	P2	HIGHLANDS	GT	LO	TK	---	---	12	1968	12	2004	33,790	29	32		U
BAYBORO	P1	PINELLAS	GT	LO	WA,TK	---	---	4	1973	---	---	56,700	47	58		U
BAYBORO	P2	PINELLAS	GT	LO	WA,TK	---	---	4	1973	---	---	56,700	47	58		U
BAYBORO	P3	PINELLAS	GT	LO	WA,TK	---	---	4	1973	---	---	56,700	47	58		U
BAYBORO	P4	PINELLAS	GT	LO	WA,TK	---	---	4	1973	---	---	56,700	47	58		U
CRYSTAL RIVER	1	CITRUS	FS	C	WA,RR	---	---	10	1966	---	---	440,550	369	373		U
CRYSTAL RIVER	2	CITRUS	FS	C	WA,RR	---	---	11	1969	---	---	523,800	464	469		U
CRYSTAL RIVER(812/835)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	734	755		J
CRYSTAL RIVER	4	CITRUS	FS	C	WA,RR	---	---	12	1982	---	---	739,260	697	717		U
CRYSTAL RIVER	5	CITRUS	FS	C	WA,RR	---	---	10	1984	---	---	739,260	697	717		U
TURNER	P1	VOLUSIA	GT	LO	TK	---	---	10	1970	12	2004	19,290	15	18		U
TURNER	P2	VOLUSIA	GT	LO	TK	---	---	10	1970	12	2004	19,290	15	18		U

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			OWNERSHIP
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	(U,J, or N)
TURNER	P3	VOLUSIA	GT	LO	TK	---	---	8	1974	---	---	71,200	65	82		U
TURNER	P4	VOLUSIA	GT	LO	TK	---	---	8	1974	---	---	71,200	65	82		U
HIGGINS	P1	PINELLAS	GT	LO	TK	NG	PL	3	1969	12	2003	33,790	29	32		U
HIGGINS	P2	PINELLAS	GT	LO	TK	NG	PL	4	1969	12	2003	33,790	29	32		U
HIGGINS	P3	PINELLAS	GT	LO	TK	NG	PL	12	1970	12	2003	42,925	35	42		U
HIGGINS	P4	PINELLAS	GT	LO	TK	NG	PL	1	1971	12	2003	42,925	35	42		U
BARTOW	1	PINELLAS	FS	HO	WA	---	---	9	1958	---	---	127,500	115	117		U
BARTOW	2	PINELLAS	FS	HO	WA	---	---	8	1961	---	---	127,500	117	119		U
BARTOW	3	PINELLAS	FS	HO	WA	NG	PL	7	1963	---	---	239,360	208	213		U
BARTOW	P1	PINELLAS	GT	LO	WA	---	---	5	1972	---	---	55,700	46	53		U
BARTOW	P2	PINELLAS	GT	LO	WA	NG	PL	6	1972	---	---	55,700	46	53		U
BARTOW	P3	PINELLAS	GT	LO	WA	---	---	6	1972	---	---	55,700	46	53		U
BARTOW	P4	PINELLAS	GT	LO	WA	NG	PL	6	1972	---	---	55,700	49	58		U
RIO PINAR	P1	ORANGE	GT	LO	TK	---	---	11	1970	12	2003	19,280	15	18		U
SUWANNEE RIVER	1	SUWANNEE	FS	HO	TK	NG	PL	11	1953	4	2000	34,500	33	34		U
SUWANNEE RIVER	2	SUWANNEE	FS	HO	TK	NG	PL	11	1954	4	2000	37,500	32	33		U
SUWANNEE RIVER	3	SUWANNEE	FS	HO	TK	NG	PL	10	1956	4	2000	75,000	80	80		U
SUWANNEE RIVER	P1	SUWANNEE	GT	LO	TK	NG	PL	10	1980	---	---	61,200	54	67		U
SUWANNEE RIVER	P2	SUWANNEE	GT	LO	TK	---	---	10	1980	---	---	61,200	54	67		U
SUWANNEE RIVER	P3	SUWANNEE	GT	LO	TK	---	---	11	1980	---	---	61,200	54	67		U
DEBARY	P1	VOLUSIA	GT	LO	TK,RR	---	---	2	1976	---	---	66,870	54	65		U
DEBARY	P2	VOLUSIA	GT	LO	TK,RR	---	---	3	1976	---	---	66,870	54	65		U
DEBARY	P3	VOLUSIA	GT	LO	TK,RR	---	---	12	1975	---	---	66,870	54	65		U
DEBARY	P4	VOLUSIA	GT	LO	TK,RR	---	---	4	1976	---	---	66,870	54	65		U
DEBARY	P5	VOLUSIA	GT	LO	TK,RR	---	---	12	1975	---	---	66,870	54	65		U
DEBARY	P6	VOLUSIA	GT	LO	TK,RR	---	---	4	1976	---	---	66,870	54	65		U
DEBARY	P7	VOLUSIA	GT	LO	TK,RR	---	---	10	1992	---	---	115,000	83	99		U
DEBARY	P8	VOLUSIA	GT	LO	TK,RR	---	---	10	1992	---	---	115,000	83	99		U
DEBARY	P9	VOLUSIA	GT	LO	TK,RR	---	---	10	1992	---	---	115,000	83	99		U
DEBARY	P10	VOLUSIA	GT	LO	TK,RR	---	---	10	1992	---	---	115,000	83	99		U
UNIV. OF FLORIDA	P1	ALACHUA	GT	NG	PL	---	---	1	1994	---	---	43,000	36	42		U
ANCLOTE	1	PASCO	FS	HO	PL	---	---	10	1974	---	---	556,200	503	517		U
ANCLOTE	2	PASCO	FS	HO	PL	---	---	10	1978	---	---	556,200	503	517		U
INTERCESSION	P1	OSCEOLA	GT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58		U
INTERCESSION	P2	OSCEOLA	GT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58		U
INTERCESSION	P3	OSCEOLA	GT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58		U
INTERCESSION	P4	OSCEOLA	GT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58		U
INTERCESSION	P5	OSCEOLA	GT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58		U
INTERCESSION	P6	OSCEOLA	GT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58		U
INTERCESSION	P7	OSCEOLA	GT	LO	PL	NG	PL	10	1993	---	---	115,000	83	99		U
INTERCESSION	P8	OSCEOLA	GT	LO	PL	NG	PL	10	1993	---	---	115,000	83	99		U
INTERCESSION	P9	OSCEOLA	GT	LO	PL	NG	PL	10	1993	---	---	115,000	83	99		U

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	OWNERSHIP (U,J, or N)
INTERCESSION	P10	OSCEOLA	GT	LO	PL	NG	PL	10	1993	---	---	115,000	83	99		U
INTERCESSION	P11	OSCEOLA	GT	LO	PL,TK	---	---	1	1997	---	---	165,000	0	168		J
TIGER BAY	1	POLK	CC	NG	PL	---	---	8	1997	---	---	233,000	206	236		U
TOTAL:													6,962	7,717		
FLORIDA POWER & LIGHT COMPANY																
TURKEY POINT	ST1	DADE	FS	HO	WA	NG	PL	4	1967	---	---	402,050	410	411		U
TURKEY POINT	ST2	DADE	FS	HO	WA	NG	PL	4	1968	---	---	402,050	400	403		U
TURKEY POINT	3	DADE	N	N	TK	---	---	12	1972	---	---	760,000	693	717		U
TURKEY POINT	4	DADE	N	N	TK	---	---	9	1973	---	---	760,000	693	717		U
TURKEY POINT	IC1	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	3	3		U
TURKEY POINT	IC2	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	3	3		U
TURKEY POINT	IC3	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	2	2		U
TURKEY POINT	IC4	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	2	2		U
TURKEY POINT	5	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	2	2		U
CUTLER	5	DADE	FS	NG	PL	---	---	11	1954	---	---	745,000	71	72		U
CUTLER	6	DADE	FS	NG	PL	---	---	7	1955	---	---	162,000	144	145		U
LAUDERDALE	4ST	BROWARD	CCW	WH	---	---	---	10	1957	---	---	151,250	430	475		U
LAUDERDALE	4CT1	BROWARD	CCT	NG	PL	LO	TK	5	1993	---	---	185,000				U
LAUDERDALE	4CT2	BROWARD	CCT	NG	PL	LO	TK	5	1993	---	---	185,000				U
LAUDERDALE	5ST	BROWARD	CCW	WH	---	---	---	4	1958	---	---	151,250	430	475		U
LAUDERDALE	5CT1	BROWARD	CCT	NG	PL	LO	TK	6	1993	---	---	185,000				U
LAUDERDALE	5CT2	BROWARD	CCT	NG	PL	LO	TK	6	1993	---	---	185,000				U
LAUDERDALE	1	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	2	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	3	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	GT4	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	GT5	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	6	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	7	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	8	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	9	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	10	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	11	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	12	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	13	BROWARD	GT	NG	PL	LO	TK	8	1970	---	---	34,228	37	43		U
LAUDERDALE	14	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	15	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	16	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	17	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			OWNERSHIP
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	(U,J, or N)
LAUDERDALE	18	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	19	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	20	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	21	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	22	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	23	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
LAUDERDALE	24	BROWARD	GT	NG	PL	LO	TK	8	1972	---	---	34,228	37	43		U
PORT EVERGLADES	ST1	BROWARD	FS	HO	WA	NG	PL	6	1960	---	---	225,250	221	222		U
PORT EVERGLADES	ST2	BROWARD	FS	HO	WA	NG	PL	4	1961	---	---	225,250	222	223		U
PORT EVERGLADES	ST3	BROWARD	FS	HO	WA	NG	PL	7	1964	---	---	402,050	389	391		U
PORT EVERGLADES	ST4	BROWARD	FS	HO	WA	NG	PL	4	1965	---	---	402,050	395	397		U
PORT EVERGLADES	GT1	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	GT2	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	GT3	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	GT4	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	GT5	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	6	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	7	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	8	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	9	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	10	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	11	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
PORT EVERGLADES	12	BROWARD	GT	NG	PL	LO	WA	8	1971	---	---	34,228	36	43		U
RIVIERA	3	PALM BEACH	FS	HO	WA	NG	PL	6	1962	---	---	310,420	290	292		U
RIVIERA	4	PALM BEACH	FS	HO	WA	NG	PL	3	1963	---	---	310,420	290	292		U
MARTIN	1	MARTIN	FS	NG	PL	HO	PL	12	1980	---	---	863,300	814	821		U
MARTIN	2	MARTIN	FS	NG	PL	HO	PL	6	1981	---	---	863,300	816	833		U
MARTIN	3ST	MARTIN	CCW	WH	---	---	---	2	1994	---	---	204,000	430	490		U
MARTIN	3CT1	MARTIN	CCT	NG	PL	LO	TK	2	1994	---	---	204,000				U
MARTIN	3CT2	MARTIN	CCT	NG	PL	LO	TK	2	1994	---	---	204,000				U
MARTIN	4ST	MARTIN	CCW	WH	---	---	---	4	1994	---	---	204,000	430	490		U
MARTIN	4CT1	MARTIN	CCT	NG	PL	LO	TK	4	1994	---	---	204,000				U
MARTIN	4CT2	MARTIN	CCT	NG	PL	LO	TK	4	1994	---	---	204,000				U
ST. LUCIE	1	ST. LUCIE	N	N	TK	---	---	5	1976	---	---	850,000	839	853		U
ST. LUCIE (839/853)	2	ST. LUCIE	N	N	TK	---	---	6	1983	---	---	839,000	714	726		J
CAPE CANAVERAL	1	BREVARD	FS	HO	WA	NG	PL	4	1965	---	---	402,050	405	408		U
CAPE CANAVERAL	2	BREVARD	FS	HO	WA	NG	PL	5	1969	---	---	402,050	405	408		U
SANFORD	3	VOLUSIA	FS	HO	WA	NG	PL	5	1959	---	---	156,250	153	155		U
SANFORD	4	VOLUSIA	FS	HO	WA	NG	PL	7	1969	---	---	436,100	383	387		U
SANFORD	5	VOLUSIA	FS	HO	WA	NG	PL	5	1974	---	---	436,100	390	394		U
SCHERER	4	MONROE, GA.	FS	C	RR	---	---	7	1991	---	---	891,000	667	667		J

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	KW	SUMMER	WINTER	STATUS	OWNERSHIP (U,J, or N)
ST. JOHNS RIVER (624/626)	1	DUVAL	FS	LO	PL	C	CV	3	1986	---	---	679,600	130	130		J
ST. JOHNS RIVER (624/626)	2	DUVAL	FS	LO	PL	C	CV	5	1988	---	---	679,600	130	130		J
PUTNAM	1ST	PUTNAM	CCW	WH	---	NG	PL	4	1978	---	---	120,000	249	297		U
PUTNAM	1GT1	PUTNAM	CCT	NG	PL	LO	WA	4	1978	---	---	85,000				U
PUTNAM	1GT2	PUTNAM	CCT	NG	PL	LO	WA	4	1978	---	---	85,000				U
PUTNAM	2ST	PUTNAM	CCW	WH	---	NG	PL	8	1977	---	---	120,000	249	297		U
PUTNAM	2GT1	PUTNAM	CCT	NG	PL	LO	WA	8	1977	---	---	85,000				U
PUTNAM	2GT2	PUTNAM	CCT	NG	PL	LO	WA	8	1977	---	---	85,000				U
FT. MYERS	ST1	LEE	FS	HO	WA	---	---	11	1958	---	---	156,250	147	148		U
FT. MYERS	ST2	LEE	FS	HO	WA	---	---	7	1969	---	---	402,050	397	400		U
FT. MYERS	GT1	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT2	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT3	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT4	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT5	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT6	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT7	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT8	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT9	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT10	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT11	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
FT. MYERS	GT12	LEE	GT	LO	WA	---	---	5	1974	---	---	62,000	52	65		U
MANATEE	1	MANATEE	FS	HO	WA	---	---	10	1976	---	---	863,300	819	826		U
MANATEE	2	MANATEE	FS	HO	WA	---	---	12	1977	---	---	863,300	819	826		U
TOTAL:													16,420	17,258		
FORT PIERCE UTILITIES AUTHORITY																
H. D. KING	5	ST. LUCIE	CCW	WH	---	---	---	1	1953	---	---	8,375	8	8		U
H. D. KING	6	ST. LUCIE	FS	NG	PL	HO	TK	12	1958	---	---	16,500	17	17	M	U
H. D. KING	7	ST. LUCIE	FS	NG	PL	HO	TK	1	1964	---	---	33,000	33	33		U
H. D. KING	8	ST. LUCIE	FS	NG	PL	HO	TK	5	1976	---	---	56,116	56	56		U
H. D. KING	9	ST. LUCIE	CCT	NG	PL	LO	TK	5	1990	---	---	22,620	23	23		U
H. D. KING	D1	ST. LUCIE	D	LO	TK	---	---	4	1970	---	---	2,750	3	3		U
H. D. KING	D2	ST. LUCIE	D	LO	TK	---	---	4	1970	---	---	2,750	3	3		U
TOTAL:													109	109		

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	OWNERSHIP (U,J, or N)
GAINESVILLE REGIONAL UTILITIES																
CRYSTAL RIVER(812/835)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	11	11		J
DEERHAVEN	1	ALACHUA	FS	NG	PL	HO	TK	8	1972	---	---	75,000	85	85		U
DEERHAVEN	2	ALACHUA	FS	C	RR	---	---	10	1981	---	---	250,750	228	228		U
DEERHAVEN	GT1	ALACHUA	GT	NG	PL	LO	TK	7	1976	---	---	24,600	18	20		U
DEERHAVEN	GT2	ALACHUA	GT	NG	PL	LO	TK	8	1976	---	---	24,600	18	20		U
DEERHAVEN	GT3	ALACHUA	GT	NG	PL	LO	TK	1	1996	---	---	98,140	75	81		U
J. R. KELLY	6	ALACHUA	FS	NG	PL	HO	TK	3	1958	---	---	18,750	15	15	M	U
J. R. KELLY	7	ALACHUA	FS	NG	PL	HO	TK	8	1961	---	---	25,000	23	23		U
J. R. KELLY	8	ALACHUA	FS	NG	PL	HO	TK	4	1965	---	---	50,000	50	50		U
J. R. KELLY	GT1	ALACHUA	GT	NG	PL	LO	TK	2	1968	---	---	16,320	14	15		U
J. R. KELLY	GT2	ALACHUA	GT	NG	PL	LO	TK	2	1968	---	---	16,320	14	15		U
J. R. KELLY	GT3	ALACHUA	GT	NG	PL	LO	TK	2	1969	---	---	16,320	14	15		U
TOTAL:													550	563		
CITY OF HOMESTEAD																
G. W. IVEY	6	DADE	D	NG	PL	LO	TK	1	1954	1	2008	2,500	2	2		U
G. W. IVEY	2-3	DADE	D	NG	PL	LO	TK	3	1970	---	---	4,140	4	4		U
G. W. IVEY	9-10	DADE	D	NG	PL	LO	TK	1	1958	1	2008	5,000	4	4		U
G. W. IVEY	11-12	DADE	D	NG	PL	LO	TK	1	1965	1	2008	6,540	6	6		U
G. W. IVEY	13-17	DADE	D	NG	PL	LO	TK	11	1972	---	---	10,350	9	9		U
G. W. IVEY	18-19	DADE	D	NG	PL	LO	TK	4	1975	---	---	15,000	15	15		U
G. W. IVEY	20-21	DADE	D	NG	PL	LO	TK	5	1981	---	---	12,970	12	12		U
TOTAL:													52	52		
JACKSONVILLE ELECTRIC AUTHORITY																
ST. JOHNS RIVER (638/638)	1	DUVAL	FS	C	RR/WA	---	---	3	1987	3	2027	679,600	499	499		J
ST. JOHNS RIVER (638/638)	2	DUVAL	FS	C	RR/WA	---	---	5	1988	5	2028	679,600	499	499		J
SCHERER	4	MONROE, GA.	FS	C	RR	---	---	7	1991	2	2029	416,000	200	200		J
KENNEDY	8	DUVAL	FS	HO	PL	HO	PL	7	1955	---	---	50,000	43	43	M	U
KENNEDY	9	DUVAL	FS	HO	PL	HO	PL	1	1958	---	---	50,000	43	43	M	U
KENNEDY	10	DUVAL	FS	HO	PL	NG	PL	12	1961	10	2000	149,600	102	102	D	U
KENNEDY	3	DUVAL	GT	LO	PL	LO	PL	5	1973	---	---	56,200	54	63		U
KENNEDY	4	DUVAL	GT	LO	PL	LO	PL	8	1973	---	---	56,200	54	63		U
KENNEDY	5	DUVAL	GT	LO	PL	LO	PL	7	1973	---	---	56,200	54	63		U
NORTHSIDE	1	DUVAL	FS	HO	PL	NG	PL	11	1966	---	---	297,500	262	262		U

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	OWNERSHIP (U,J, or N)
NORTHSIDE	2	DUVAL	FS	HO	PL	HO	PL	3	1972	---	---	297,500	262	262	M	U
NORTHSIDE	3	DUVAL	FS	HO	PL	NG	PL	6	1977	---	---	563,700	505	505		U
NORTHSIDE	3	DUVAL	GT	LO	PL	LO	PL	2	1975	---	---	62,100	52	62		U
NORTHSIDE	4	DUVAL	GT	LO	PL	LO	PL	1	1975	---	---	62,100	52	62		U
NORTHSIDE	5	DUVAL	GT	LO	PL	LO	PL	12	1974	---	---	62,100	52	62		U
NORTHSIDE	6	DUVAL	GT	LO	PL	LO	PL	12	1974	---	---	62,100	52	62		U
SOUTHSIDE	3	DUVAL	FS	HO	PL	HO	PL	1	1955	---	---	50,000	44	46	M	U
SOUTHSIDE	4	DUVAL	FS	HO	PL	NG	PL	11	1958	10	2000	75,000	67	67		U
SOUTHSIDE	5	DUVAL	FS	HO	PL	NG	PL	9	1964	10	2003	156,600	142	142		U
GIRVIN LANDFILL	1-4	DUVAL	GT	NG	PL	---	---	6	1997	---	---	3,200	3	3		U
TOTAL:													2,649	2,716		
KEY WEST UTILITY BOARD																
BIG PINE	1	MONROE	D	LO	TK	---	---	2	1969	---	---	2,750	3	3		U
CUDJOE	2	MONROE	D	LO	TK	---	---	8	1968	---	---	2,750	3	3		U
CUDJOE	3	MONROE	D	LO	TK	---	---	8	1968	---	---	2,300	2	2		U
KEY WEST	GT1	MONROE	GT	LO	WA	---	---	11	1976	---	---	23,450	21	24		U
STOCK ISLAND	IC1	MONROE	D	LO	WA	---	---	1	1965	---	---	2,500	2	2		U
STOCK ISLAND	IC2	MONROE	D	LO	WA	---	---	1	1965	---	---	2,500	2	2		U
STOCK ISLAND	IC3	MONROE	D	LO	WA	---	---	1	1965	---	---	2,500	2	2		U
MEDIUM SPEED DIESEL	IC4	MONROE	D	LO	WA	---	---	6	1991	---	---	9,600	9	9		U
MEDIUM SPEED DIESEL	IC5	MONROE	D	LO	WA	---	---	6	1991	---	---	9,600	9	9		U
TOTAL:													53	56		
KISSIMMEE UTILITY AUTHORITY																
CRYSTAL RIVER(812/635)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	6	6		J
CANE ISLAND(30/40)	1	OSCEOLA	GT	NG	PL	LO	TK	11	1994	---	---	42,000	15	20		J
CANE ISLAND(68/80)	2	OSCEOLA	CCT	NG	PL	LO	TK	6	1995	---	---	80,000	34	40		J
CANE ISLAND(40/40)	2	OSCEOLA	CCW	NG	PL	LO	TK	6	1995	---	---	40,000	20	20		J
HANSEL	8	OSCEOLA	D	NG	PL	LO	TK	2	1959	1	1998	3,000	3	3		U
HANSEL	14	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2		U
HANSEL	15	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2		U
HANSEL	16	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2		U
HANSEL	17	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2		U
HANSEL	18	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2		U
HANSEL	19	OSCEOLA	D	LO	TK	---	---	2	1983	1	2013	2,500	3	3		U
HANSEL	20	OSCEOLA	D	LO	TK	---	---	2	1983	1	2013	2,500	3	3		U

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	OWNERSHIP (U,J, or N)
HANSEL	21	OSCEOLA	CCT	NG	PL	LO	TK	2	1983	1	2013	35,000	28	32		U
HANSEL	22	OSCEOLA	CCW	WH	---	---	---	11	1983	1	2013	10,000	10	10		U
HANSEL	23	OSCEOLA	CCW	WH	---	---	---	11	1983	1	2013	10,000	10	10		U
INDIAN RIVER(74/96) CT	A,B	BREVARD	GT	NG	PL	LO	TK	7	1988	---	---	82,800	9	11		J
STANTON ENERGY CENTER (441/443)	1	ORANGE	FS	C	RR	---	---	7	1987	---	---	464,580	21	21		J
TOTAL:													172	189		
CITY OF LAKELAND																
LARSEN	1	POLK	GT	NG	PL	LO	TK	10	1962	6	1999	11,250	10	14		U
LARSEN	2	POLK	GT	NG	PL	LO	TK	11	1962	---	---	11,250	10	14		U
LARSEN	3	POLK	GT	NG	PL	LO	TK	12	1962	---	---	11,250	10	14		U
LARSEN	5	POLK	CCW	WH	---	---	---	4	1956	---	---	25,000	29	31		U
LARSEN	7	POLK	FS	NG	PL	HO	TK	2	1966	6	1999	44,000	42	42		U
LARSEN	8	POLK	CC	NG	PL	LO	TK	7	1992	---	---	101,520	73	93		U
MCINTOSH(333/442)	3	POLK	FS	C	RR	REF	TK	9	1982	---	---	363,870	198	205		J
MCINTOSH	GT1	POLK	GT	NG	PL	LO	TK	---	1973	---	---	26,640	19	23		U
MCINTOSH	IC1	POLK	D	LO	TK	---	---	---	1970	---	---	2,500	3	3		U
MCINTOSH	IC2	POLK	D	NG	PL	---	---	---	1970	---	---	2,500	3	3		U
MCINTOSH	ST1	POLK	FS	NG	PL	HO	TK	2	1971	---	---	103,500	92	92		U
MCINTOSH	ST2	POLK	FS	NG	PL	HO	TK	6	1976	---	---	126,000	108	108		U
TOTAL:													597	642		
CITY OF LAKE WORTH UTILITIES																
TOM G. SMITH	S-1	PALM BEACH	FS	NG	PL	HO	TK	1	1961	---	---	7,500	7	8		U
TOM G. SMITH	S-3	PALM BEACH	FS	NG	PL	HO	TK	11	1967	---	---	26,500	22	24		U
TOM G. SMITH	S-4	PALM BEACH	FS	NG	PL	HO	TK	8	1971	---	---	32,580	32	33	M	U
TOM G. SMITH	MU1	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2		U
TOM G. SMITH	MU2	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2		U
TOM G. SMITH	MU3	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2		U
TOM G. SMITH	MU4	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2		U
TOM G. SMITH	MU5	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2		U
TOM G. SMITH	GT-1	PALM BEACH	GT	LO	TK	---	---	12	1976	---	---	30,800	26	31		U
TOM G. SMITH	GT-2	PALM BEACH	CCT	NG	PL	LO	TK	3	1978	---	---	21,410	21	23		U
TOM G. SMITH	S-5	PALM BEACH	CCW	WH		---	---	3	1978	---	---	10,000	9	9		U
TOTAL:													95	105		

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	OWNERSHIP (U,J, or N)
UTILITIES COMMISSION OF NEW SMYRNA BEACH																
CRYSTAL RIVER(812/835)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	4	4		J
GLENCOE	1	VOLUSIA	D	LO	TK	---	---	2	1982	---	---	750	1	1		U
NORTH CAUSEWAY	1	VOLUSIA	D	LO	TK	---	---	7	1981	---	---	750	1	1		U
SMITH	3	VOLUSIA	D	LO	TK	---	---	1	1946	---	---	840	1	1		U
SMITH	4	VOLUSIA	D	LO	TK	---	---	1	1950	---	---	1,000	1	1		U
SMITH	6	VOLUSIA	D	LO	TK	---	---	1	1955	---	---	1,800	2	2		U
SMITH	7	VOLUSIA	D	LO	TK	---	---	1	1956	---	---	1,800	2	2		U
SMITH	8	VOLUSIA	D	LO	TK	---	---	1	1960	---	---	1,100	1	1		U
SMITH	9	VOLUSIA	D	LO	TK	---	---	1	1967	---	---	2,000	2	2		U
SMITH	10	VOLUSIA	D	LO	TK	---	---	1	1967	---	---	2,000	2	2		U
SMITH	11	VOLUSIA	D	LO	TK	---	---	1	1967	---	---	2,000	2	2		U
SWOOPE STATION	2	VOLUSIA	D	NG	PL	LO	TK	11	1981	---	---	810	1	1		U
SWOOPE STATION	3	VOLUSIA	D	NG	PL	LO	TK	12	1982	---	---	2,050	2	2		U
SWOOPE STATION	4	VOLUSIA	D	NG	PL	LO	TK	12	1982	---	---	2,275	2	2		U
TOTAL:													24	24		
OCALA ELECTRIC UTILITY																
CRYSTAL RIVER(812/835)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	11	11		J
ORLANDO UTILITIES COMMISSION																
CRYSTAL RIVER(812/835)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	13	13		J
INDIAN RIVER	1	BREVARD	FS	NG	PL	HO	WA	2	1960	---	---	86,700	88	90		U
INDIAN RIVER	2	BREVARD	FS	NG	PL	HO	WA	12	1964	---	---	207,600	201	205		U
INDIAN RIVER	3	BREVARD	FS	NG	PL	HO	WA	2	1974	---	---	344,500	319	324		U
INDIAN RIVER(74/98) CT	A,B	BREVARD	GT	NG	PL	LO	TK	7	1989	---	---	82,800	36	46		J
INDIAN RIVER(216/254) CT	C,D	BREVARD	GT	NG	PL	LO	TK	8	1992	---	---	224,080	170	200		J
MCINTOSH(333/442)	3	POLK	FS	C	RR	REF	TK	9	1982	---	---	363,870	133	136		J
ST. LUCIE (839/853)	2	ST. LUCIE	N	N	TK	---	---	6	1983	---	---	839,000	51	52		J
STANTON ENERGY CENTER (441/443)	1	ORANGE	FS	C	RR	---	---	7	1987	---	---	464,580	302	304		J
STANTON ENERGY CENTER (444/444)	2	ORANGE	FS	C	RR	---	---	6	1996	---	---	464,580	318	318		J
TOTAL:													1,631	1,666		

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			OWNERSHIP
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	(U,J, or N)
REEDY CREEK IMPROVEMENT DISTRICT																
CENTRAL ENERGY PLANT	1	ORANGE	OT	NG	PL	---	---	1	1968	1	2018	43,000	35	40		U
SEMINOLE ELECTRIC COOPERATIVE, INC.																
CRYSTAL RIVER(812/835)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	15	15		J
SEMINOLE	1	PUTNAM	FS	C	WA	---	---	2	1984	---	---	714,600	638	677		U
SEMINOLE	2	PUTNAM	FS	C	WA	---	---	1	1985	---	---	714,600	638	677		U
TOTAL:													1,291	1,369		
CITY OF ST. CLOUD																
ST. CLOUD	1	OSCEOLA	D	LO	TK	---	---	7	1982	---	---	2,000	2	2		U
ST. CLOUD	2	OSCEOLA	D	LO	TK	---	---	12	1974	---	---	5,850	5	5		U
ST. CLOUD	3	OSCEOLA	D	LO	TK	---	---	9	1982	---	---	2,000	2	2		U
ST. CLOUD	4	OSCEOLA	D	LO	TK	---	---	8	1981	---	---	3,750	3	3		U
ST. CLOUD	6	OSCEOLA	D	LO	TK	---	---	3	1987	---	---	3,750	3	3		U
ST. CLOUD	7	OSCEOLA	D	LO	TK	---	---	9	1982	---	---	6,300	6	6		U
ST. CLOUD	8	OSCEOLA	D	LO	TK	---	---	4	1977	---	---	6,445	6	6		U
TOTAL:													27	27		
CITY OF TALLAHASSEE																
CRYSTAL RIVER(812/835)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	11	11		J
HOPKINS	1	LEON	FS	NG	PL	HO	TK	5	1971	3	2016	75,000	76	80		U
HOPKINS	2	LEON	FS	NG	PL	HO	TK	10	1977	3	2022	259,250	238	248		U
HOPKINS	GT1	LEON	GT	NG	PL	LO	TK	2	1970	3	2015	16,320	12	14		U
HOPKINS	GT2	LEON	GT	NG	PL	LO	TK	9	1972	3	2017	27,000	24	26		U
PURDOM	5	WAKULLA	FS	NG	PL	HO	WA	4	1958	9	1999	25,000	24	24		U
PURDOM	6	WAKULLA	FS	NG	PL	HO	WA	1	1961	9	1999	25,000	24	24		U
PURDOM	7	WAKULLA	FS	NG	PL	HO	WA	6	1966	3	2011	50,000	50	50		U
PURDOM	GT1	WAKULLA	GT	NG	PL	LO	TK	12	1963	3	2008	15,000	10	10		U
PURDOM	GT2	WAKULLA	GT	NG	PL	LO	TK	5	1964	3	2009	15,000	10	10		U
C. H. CORN HYDRO	1	LEON/	HY	WAT	WA	---	---	9	1985	---	---	4,000	4	4		U
C. H. CORN HYDRO	2	GADSEN/	HY	WAT	WA	---	---	8	1985	---	---	4,000	4	4		U
C. H. CORN HYDRO	3	LIBERTY	HY	WAT	WA	---	---	1	1986	---	---	3,000	3	3		U
TOTAL:													490	508		

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)	(15)
				PRIMARY FUEL		ALTERNATE FUEL		COM'L IN-SERVICE		EXPTD RTRMNT		GEN MAX NAMEPLATE	NET CAPABILITY - MW			
PLANT NAME AND UNIT NO.		LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	MO.	YEAR	MO.	YEAR	kW	SUMMER	WINTER	STATUS	OWNERSHIP (U,J, or N)
TAMPA ELECTRIC COMPANY																
BIG BEND	ST1	HILLSBOROUGH	FS	C	WA	---		10	1970	---	---	445,500	421	431		U
BIG BEND	GT1	HILLSBOROUGH	GT	LO	WA	---	TK	2	1969	---	---	18,000	15	17		U
BIG BEND	GT2	HILLSBOROUGH	GT	LO	WA	---	TK	11	1974	---	---	78,750	65	80		U
BIG BEND	GT3	HILLSBOROUGH	GT	LO	WA	---	TK	11	1974	---	---	78,750	65	80		U
BIG BEND	ST2	HILLSBOROUGH	FS	C	WA	---	---	4	1973	---	---	445,500	416	426		U
BIG BEND	ST3	HILLSBOROUGH	FS	C	WA	---	---	5	1976	---	---	445,500	428	438		U
BIG BEND	ST4	HILLSBOROUGH	FS	C	WA	---	---	2	1985	---	---	486,000	442	447		U
GANNON	1	HILLSBOROUGH	FS	C	WA	---	RR	9	1957	---	---	125,000	114	114		U
GANNON	2	HILLSBOROUGH	FS	C	WA	---	RR	11	1958	---	---	125,000	108	108		U
GANNON	3	HILLSBOROUGH	FS	C	WA	---	RR	10	1960	---	---	179,520	155	155		U
GANNON	4	HILLSBOROUGH	FS	C	WA	---	RR	11	1963	---	---	187,500	169	179		U
GANNON	5	HILLSBOROUGH	FS	C	WA	---	RR	11	1965	---	---	239,360	227	232		U
GANNON	6	HILLSBOROUGH	FS	C	WA	---	RR	10	1967	---	---	445,500	362	392		U
GANNON	GT1	HILLSBOROUGH	GT	LO	WA	---	TK	3	1969	---	---	18,000	15	17		U
HOOKERS POINT	1	HILLSBOROUGH	FS	HO	WA	---	---	7	1948	1	2003	33,000	32	34		U
HOOKERS POINT	2	HILLSBOROUGH	FS	HO	WA	---	---	6	1950	1	2003	34,500	32	34		U
HOOKERS POINT	3	HILLSBOROUGH	FS	HO	WA	---	---	8	1950	1	2003	34,500	32	34		U
HOOKERS POINT	4	HILLSBOROUGH	FS	HO	WA	---	---	10	1953	1	2003	49,000	41	43		U
HOOKERS POINT	5	HILLSBOROUGH	FS	HO	WA	---	---	5	1955	1	2003	81,600	70	70		U
DINNER LAKE	1	HIGHLANDS	FS	NG	PL	HO	TK	12	1966	---	---	12,650	11	11	M	U
PHILLIPS PLANT	3	HIGHLANDS	HRSG	WH	---	---	---	6	1983	---	---	3,600	3	3	M	U
PHILLIPS PLANT	IC1	HIGHLANDS	D	HO	TK	LO	---	6	1983	---	---	19,215	17	17		U
PHILLIPS PLANT	IC2	HIGHLANDS	D	HO	TK	LO	---	6	1983	---	---	19,215	17	17		U
POLK	1	POLK	IGCC	C	TK	LO	---	9	1996	---	---	326,299	250	250		U
TOTAL:													3,493	3,615		
CITY OF VERO BEACH																
MUNICIPAL PLANT	1	INDIAN RIVER	FS	NG	PL	HO	TK	11	1961	---	---	12,500	13	13		U
MUNICIPAL PLANT	2	INDIAN RIVER	CCW	NG	PL	HO	TK	8	1964	---	---	16,500	17	17		U
MUNICIPAL PLANT	3	INDIAN RIVER	FS	NG	PL	HO	TK	9	1971	---	---	33,000	33	33		U
MUNICIPAL PLANT	4	INDIAN RIVER	FS	NG	PL	HO	TK	8	1976	---	---	55,000	56	56		U
MUNICIPAL PLANT	5	INDIAN RIVER	CCT	NG	PL	LO	TK	12	1992	---	---	41,400	35	43		U
TOTAL:													154	162		
												FRCC TOTAL:	**35,290**	**37,351**		

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FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES, AND REMOVALS
(JANUARY 1,1998 THROUGH DECEMBER 31, 2007)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					FUEL		FUEL TRANSPORTATION			GENERATOR MAXIMUM	NET CAPABILITY (MW)		
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALTERNATE	PRIMARY	ALTERNATE	COMMERCIAL IN-SERVICE (MO/YR)	NAMEPLATE kW	SUMMER	WINTER	STATUS
	1998												
FPL	FT. MYERS	ST1	LEE	FS	HO		WA		1 / 1998	156,250	(4)	0	D
FPL	FT. MYERS	ST2	LEE	FS	HO		WA		1 / 1998	402,050	15	15	A
FPL	MARTIN	2	MARTIN	FS	HO		WA		1 / 1998	883,300	31	11	A
FPL	MARTIN	3	MARTIN	CCW	NG	LO	PL	TK	1 / 1998	204,000	48	12	A
FPL	MARTIN	4	MARTIN	CCW	NG	LO	PL	TK	1 / 1998	204,000	48	12	A
FPL	PORT EVERGLADES	3	BROWARD	FS	HO	NG	WA	PL	1 / 1998	402,050	14	15	A
FPL	PORT EVERGLADES	4	BROWARD	FS	HO	NG	WA	PL	1 / 1998	402,050	13	14	A
FPL	PUTNAM	1	PUTNAM	CCW	NG	LO	PL	WA	1 / 1998	290,000	14	0	A
FPL	PUTNAM	2	PUTNAM	CCW	NG	LO	PL	WA	1 / 1998	290,000	15	0	A
FPL	SANFORD	4	VOLUSIA	FS	HO	NG	WA	PL	1 / 1998	436,100	(7)	(7)	D
KUA	HANSEL	8	OSCEOLA	IC	NG	LO	PL	TK	1 / 1998	3,000	(3)	(3)	R
FPC	CRYSTAL RIVER	3	CITRUS	N	UR		TK		2 / 1998	890,460	11	12	A
FMPA	STOCK ISLAND	CT2	MONROE	GT	LO		WA		6 / 1998	19,770	18	18	U
FMPA	STOCK ISLAND	CT3	MONROE	GT	LO		WA		6 / 1998	19,770	18	18	U
FPC	SUWANNEE RIVER	P3	SUWANNEE	GT	LO	NG	TK	PL	6 / 1998	61,200	0	0	CA
FPC	ANCLOTE	2	PASCO	FS	HO	NG	PL	PL	11 / 1998	556,200	0	0	CA
FPC	HINES ENERGY COMPLEX	1	POLK	CC	NG	LO	PL	TK	11 / 1998		470	505	V
	1999												
FPL	CAPE CANAVERAL	2	BREVARD	FS	HO	NG	WA	PL	1 / 1999	402,050	3	3	A
FPL	SCHERER	4	MONROE, GA.	FS	C		RR		1 / 1999		35	35	A
FPL	MARTIN	3	MARTIN	CCW	NG	LO	PL	TK	1 / 1999	204,000	13	13	A
FPL	MARTIN	4	MARTIN	CCW	NG	LO	PL	TK	1 / 1999	204,000	13	13	A
FPL	FT. MYERS GT's		LEE	GT	LO		WA		1 / 1999		41	0	A
FPC	ANCLOTE	1	PASCO	FS	HO	NG	PL	PL	5 / 1999	556,200	0	0	CA
FPC	CRYSTAL RIVER	5	CITRUS	FS	C		WA,RR		5 / 1999	739,260	16	16	A
LAK	LARSEN	CT1	POLK	GT	NG	LO	PL	TK	6 / 1999	11,500	(10)	(14)	R
LAK	LARSEN	ST7	POLK	FS	NG	HO	PL	TK	6 / 1999	50,000	(42)	(42)	R
LAK	MCINTOSH	5	POLK	GT	NG	LO	PL	TK	6 / 1999	292,500	198	254	P
TAL	PURDOM	5	WAKULLA	FS	NG	HO	PL	TK	9 / 1999	25,000	(24)	(24)	R
TAL	PURDOM	6	WAKULLA	FS	NG	HO	PL	TK	9 / 1999	25,000	(24)	(24)	R
JEA	KENNEDY	GT37	DUVAL	GT	NG	LO	PL	PL	11 / 1999		143	177	P
FPC	CRYSTAL RIVER	1	CITRUS	FS	C		WA,RR		12 / 1999	440,550	12	12	A
	2000												
FPL	FT. MYERS GT's		LEE	GT	LO		WA		1 / 2000		31	30	A
FPL	LAUDERDALE	4	BROWARD	CCW	NG	LO	PL	TK	1 / 2000	151,250	10	10	A
FPL	LAUDERDALE	5	BROWARD	CCW	NG	LO	PL	TK	1 / 2000	151,250	10	10	A
FPL	MANATEE	2	MANATEE	FS	ORI	HO	WA	WA	1 / 2000	883,000	(99)	(100)	CA,D
FPL	MARTIN	3	MARTIN	CCW	NG	LO	PL	TK	1 / 2000	204,000	10	30	A
FPL	MARTIN	4	MARTIN	CCW	NG	LO	PL	TK	1 / 2000	204,000	10	30	A

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(JANUARY 1,1998 THROUGH DECEMBER 31, 2007)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					FUEL		FUEL TRANSPORTATION			GENERATOR MAXIMUM	NET CAPABILITY (MW)		
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALTERNATE	PRIMARY	ALTERNATE	COMMERCIAL IN-SERVICE (MO/YR)	NAMEPLATE kW	SUMMER	WINTER	STATUS
FPC	SUWANNEE RIVER	1	SUWANNEE	FS	HO	NG	TK	PL	4 / 2000	34,500	(33)	(34)	R
FPC	SUWANNEE RIVER	2	SUWANNEE	FS	HO	NG	TK	PL	4 / 2000	37,500	(32)	(33)	R
FPC	SUWANNEE RIVER	3	SUWANNEE	FS	HO	NG	TK	PL	4 / 2000	75,000	(80)	(80)	R
FPC	CRYSTAL RIVER	4	CITRUS	FS	C		WA,RR		4 / 2000	739,260	16	16	A
FPC	CRYSTAL RIVER	2	CITRUS	FS	C		WA,RR		5 / 2000	523,800	16	16	A
TAL	PURDOM	8	WAKULLA	CC	NG	LO	PL	TK	5 / 2000	259,800	233	260	P
FPL	MANATEE	1	MANATEE	FS	ORI	HO	WA	WA	6 / 2000	883,000	(99)	(100)	CA,D
JEA	KENNEDY	10	DUVAL	FS	HO	NG	WA	PL	10 / 2000	149,800	(102)	(102)	R
JEA	SOUTHSIDE	4	DUVAL	FS	HO	NG	WA	PL	10 / 2000	75,000	(67)	(67)	R
JEA	JEA CT	1	DUVAL	GT	NG	LO	PL	PL	11 / 2000		143	177	P
JEA	JEA CT	2	DUVAL	GT	NG	LO	PL	PL	11 / 2000		143	177	P
JEA	JEA CT	3	DUVAL	GT	NG	LO	PL	PL	11 / 2000		143	177	P
	2001												
FMPA	CANE ISLAND (250/250)	3	OSCEOLA	CC	NG	LO	PL	TK	6 / 2001	250,000	125	125	P
KUA	CANE ISLAND (250/250)	3	OSCEOLA	CC	NG	LO	PL	TK	6 / 2001	250,000	125	125	P
SEC	HARDEE POWER STATION		HARDEE	CC	NG	LO	PL	TK	11 / 2001	612,112	451	527	T
	2002												
FPL	FT. MYERS REPOWERING		UNKNOWN	CCW	NG	LO	PL		1 / 2002		837	1,062	P,RP
KUA	HANSEL	14	OSCEOLA	IC	NG	LO	PL	TK	1 / 2002	2,070	(2)	(2)	R
KUA	HANSEL	15	OSCEOLA	IC	NG	LO	PL	TK	1 / 2002	2,070	(2)	(2)	R
KUA	HANSEL	16	OSCEOLA	IC	NG	LO	PL	TK	1 / 2002	2,070	(2)	(2)	R
KUA	HANSEL	17	OSCEOLA	IC	NG	LO	PL	TK	1 / 2002	2,070	(2)	(2)	R
KUA	HANSEL	18	OSCEOLA	IC	NG	LO	PL	TK	1 / 2002	2,070	(2)	(2)	R
JEA	NORTHSIDE	2	DUVAL	FS	PET		WA	RR	4 / 2002	297,500	262	262	RP
SEC	UNKNOWN	GT1	UNKNOWN	GT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
SEC	UNKNOWN	GT2	UNKNOWN	GT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
SEC	UNKNOWN	GT3	UNKNOWN	GT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
SEC	UNKNOWN	GT4	UNKNOWN	GT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
SEC	UNKNOWN	GT5	UNKNOWN	GT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
SEC	UNKNOWN	GT6	UNKNOWN	GT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
TEC	POLK	2	POLK	GT	NG	LO	PL	TK	11 / 2002		148	180	P
	2003												
TEC	HOOKERS POINT	1	HILLSBOROUGH	FS	HO		WA		4 / 2003	33,000	(32)	(34)	R
TEC	HOOKERS POINT	2	HILLSBOROUGH	FS	HO		WA		4 / 2003	34,500	(32)	(34)	R
TEC	HOOKERS POINT	3	HILLSBOROUGH	FS	HO		WA		4 / 2003	34,500	(32)	(34)	R
TEC	HOOKERS POINT	4	HILLSBOROUGH	FS	HO		WA		4 / 2003	49,000	(41)	(43)	R
TEC	HOOKERS POINT	5	HILLSBOROUGH	FS	HO		WA		4 / 2003	61,600	(70)	(70)	R
LAK	MCINTOSH	4	POLK	PB	COL		RR		5 / 2003	183,000	183	183	P

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES, AND REMOVALS
(JANUARY 1,1998 THROUGH DECEMBER 31, 2007)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					FUEL		FUEL TRANSPORTATION				NET CAPABILITY (MW)		
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALTERNATE	PRIMARY	ALTERNATE	COMMERCIAL IN-SERVICE (MO/YR)	GENERATOR MAXIMUM NAMEPLATE kW	SUMMER	WINTER	STATUS
JEA	SOUTHSIDE	5	DUVAL	FS	HO	NG	WA	PL	10 / 2003	156,600	(142)	(142)	R
JEA	JEA CT	4	DUVAL	GT	NG	LO	PL	PL	11 / 2003		143	177	P
TEC	POLK	3	POLK	GT	NG	LO	PL	TK	11 / 2003		148	180	P
FPC	HIGGINS	P1	PINELLAS	GT	LO	NG	TK	PL	12 / 2003	33,790	(29)	(32)	R
FPC	HIGGINS	P2	PINELLAS	GT	LO	NG	TK	PL	12 / 2003	33,790	(29)	(32)	R
FPC	HIGGINS	P3	PINELLAS	GT	LO	NG	TK	PL	12 / 2003	42,925	(35)	(42)	R
FPC	HIGGINS	P4	PINELLAS	GT	LO	NG	TK	PL	12 / 2003	42,925	(35)	(42)	R
FPC	RIO PINAR	P1	ORANGE	GT	LO		TK		12 / 2003	19,290	(15)	(18)	R
	2004												
FPL	SANFORD REPOWERING		UNKNOWN	CCW	NG	LO	PL	TK	1 / 2004		914	1,076	P,RP
SEC	UNKNOWN	GT7	UNKNOWN	GT	NG	LO	PL	TK	5 / 2004	180,000	150	150	P
FPC	HINES ENERGY COMPLEX	2	POLK	CC	NG	LO	PL	TK	11 / 2004		470	505	P
JEA	JEA CT	5	DUVAL	GT	NG	LO	PL	PL	11 / 2004		143	177	P
SEC	UNKNOWN	GT8	UNKNOWN	GT	NG	LO	PL	TK	11 / 2004	180,000	150	150	P
SEC	UNKNOWN	GT9	UNKNOWN	GT	NG	LO	PL	TK	11 / 2004	180,000	150	150	P
FPC	AVON PARK	P1	HIGHLANDS	GT	LO	NG	TK	PL	12 / 2004	33,790	(29)	(32)	R
FPC	AVON PARK	P2	HIGHLANDS	GT	LO		TK		12 / 2004	33,790	(29)	(32)	R
FPC	TURNER	P1	VOLUSIA	GT	LO		TK		12 / 2004	19,290	(15)	(18)	R
FPC	TURNER	P2	VOLUSIA	GT	LO		TK		12 / 2004	19,290	(15)	(18)	R
	2005												
FPL	MARTIN	5	MARTIN	CCW	NG	LO	PL	TK	11 / 2005		419	448	P
SEC	UNKNOWN	GT10	UNKNOWN	GT	NG	LO	PL	TK	11 / 2005	180,000	150	150	P
TEC	POLK	4	POLK	GT	NG	LO	PL	TK	11 / 2005		148	180	P
	2006												
FPC	HINES ENERGY COMPLEX	3	POLK	CC	NG	LO	PL	TK	11 / 2006		470	505	P
FPL	MARTIN	6	MARTIN	CCW	NG	LO	PL	TK	11 / 2006		419	448	P
	2007												
FMPA	CANE ISLAND	4	OSCEOLA	GT	NG	LO	PL	TK	1 / 2007	80,000	80	80	P
GRU	DEERHAVEN	FS03	ALACHUA	UNK	NG	LO	PL	TK	6 / 2007	60,000	60	60	P
FPL	UNCITED		UNKNOWN	UNK	NG		PL		11 / 2007	100,000	100	100	P
									FRCC FUTURE TOTAL:		7,885	8,725	

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
YEAR	INSTALLED CAPACITY (MW)	NET CONTRACTED FIRM INTERCHANGE (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT. (MW)	% OF PEAK	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT. (MW)	% OF PEAK
1998	35485	1412	2220	39117	35633	3484	10%	32857	6260	19%
1999	36112	1702	2220	40034	36628	3406	9%	33617	6417	19%
2000	36356	1852	2220	40428	37410	3018	8%	34280	6148	18%
2001	36866	1766	2295	40927	38220	2707	7%	34993	5934	17%
2002	38406	1704	2286	42396	38844	3552	9%	35588	6808	19%
2003	39430	1623	2286	43339	39395	3944	10%	36078	7261	20%
2004	40500	1633	2286	44419	40227	4192	10%	36871	7548	20%
2005	41325	1644	2276	45245	41112	4133	10%	37733	7512	20%
2006	42042	1630	2143	45815	41998	3817	9%	38593	7222	19%
2007	43096	1755	2143	46994	42885	4109	10%	39451	7543	19%

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
YEAR	INSTALLED CAPACITY (MW)	NET CONTRACTED FIRM INTERCHANGE (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT. (MW)	% OF PEAK	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT. (MW)	% OF PEAK
1998 / 99	38037	1939	2240	42216	39450	2766	7%	35668	6550	18%
1999 / 00	38402	1918	2240	42558	40383	2175	5%	36433	6125	17%
2000 / 01	38809	1691	2240	42740	41395	1345	3%	37317	5423	15%
2001 / 02	40638	1705	2315	44658	42219	2439	6%	38066	6592	17%
2002 / 03	41980	1612	2306	45898	42998	2900	7%	38766	7132	18%
2003 / 04	43073	1623	2306	47002	43925	3077	7%	39618	7384	19%
2004 / 05	44105	1633	2296	48034	44895	3139	7%	40560	7474	18%
2005 / 06	44883	1555	2163	48601	45896	2705	6%	41531	7070	17%
2006 / 07	45916	1630	2163	49709	46879	2830	6%	42487	7222	17%
2007 / 08	46076	1555	2163	49794	47902	1892	4%	43487	6307	15%

NOTE: COLUMN 9: "FIRM PEAK DEMAND" = TOTAL PEAK DEMAND - INTERRUPTIBLE LOAD - LOAD MANAGEMENT.

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SCHEDULE OF CONTRACTED IMPORTS BY UTILITY - MW

	SUMMER						
	FIRM						IMPORT
YEAR	FPC	FPL	GRU	JEA	TAL	TOTAL	TOTAL
1998	441	914	31	286	102	1774	1774
1999	441	914	32	438	102	1927	1927
2000	441	914	33	439	25	1852	1852
2001	441	914	45	341	25	1766	1766
2002	441	914	57	292	0	1704	1704
2003	441	914	68	200	0	1623	1623
2004	441	914	78	200	0	1633	1633
2005	441	914	89	200	0	1644	1644
2006	441	914	0	275	0	1630	1630
2007	441	914	0	400	0	1755	1755

	WINTER						
	FIRM						IMPORT
YEAR	FPC	FPL	GRU	JEA	TAL	TOTAL	TOTAL
1998/99	441	914	31	451	102	1939	1939
1999/00	441	914	32	427	102	1916	1916
2000/01	441	914	33	278	25	1691	1691
2001/02	441	914	45	280	25	1705	1705
2002/03	441	914	57	200	0	1612	1612
2003/04	441	914	68	200	0	1623	1623
2004/05	441	914	78	200	0	1633	1633
2005/06	441	914	0	200	0	1555	1555
2006/07	441	914	0	275	0	1630	1630
2007/08	441	914	0	200	0	1555	1555

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SCHEDULE OF CONTRACTED EXPORTS BY UTILITY - MW

	SUMMER						
	FIRM						EXPORT
YEAR	FPC	FPL	GRU	JEA	TAL	TOTAL	TOTAL
1998	362	0	0	0	0	362	362
1999	225	0	0	0	0	225	225
2000	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0

	WINTER						
	FIRM						EXPORT
YEAR	FPC	FPL	GRU	JEA	TAL	TOTAL	TOTAL
1998/99	0	0	0	0	0	0	0
1999/00	0	0	0	0	0	0	0
2000/01	0	0	0	0	0	0	0
2001/02	0	0	0	0	0	0	0
2002/03	0	0	0	0	0	0	0
2003/04	0	0	0	0	0	0	0
2004/05	0	0	0	0	0	0	0
2005/06	0	0	0	0	0	0	0
2006/07	0	0	0	0	0	0	0
2007/08	0	0	0	0	0	0	0

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

EXISTING NON-UTILITY GENERATING FACILITIES AS OF JANUARY 1, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							POTENTIAL EXPORT TO GRID AT TIME OF PEAK - MW				QF LOAD SERVED BY QF GENERATION (MW)		MAXIMUM NORMAL GENERATOR OUTPUT (MW)		
				FUEL TYPE			FIRM		AS-AVAILABLE						
UTIL / FACILITY NAME	UNIT NO.	LOCATION	TYPE	PRI	ALT	COMMERCIAL IN-SERVICE (MO/YR)	SUM	WIN	SUM	WIN	SUM	WIN	SUM	WIN	STATUS
FLORIDA MUNICIPAL POWER AGENCY															
CUTRALE		LAKE	COG	NG	---	12/87	0.0	0.0	0.0	0.0	0.0	3.9	4.6	4.6	NC
US SUGUR CORP.		HENDRY	SPP	BIO	---	02/84	0.0	0.0	0.0	0.0	0.0	17.0	19.5	19.5	NC
TOTAL:							0.0	0.0	0.0	0.0					
FLORIDA POWER CORPORATION															
BAY COUNTY RES. RECOV.	1	BAY	SPP	REF	---	04/88	11.0	11.0	0.0	0.0	0.0	0.0	11.0	11.0	C
BEN HILL GRIFFIN	1	POLK	COG	NG	HO	11/81	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	NC
CARGILL	2	POLK	COG	WH	NG	10/92	16.0	16.0	0.0	0.0	0.0	0.0	15.0	15.0	C
CFR-BIOGEN	1	POLK	COG	NG	---	06/95	74.0	74.0	0.0	0.0	0.0	0.0	75.0	75.0	C
CITRUS WORLD	1	POLK	COG	NG	HO	11/79	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	NC
CITRUS WORLD	4	POLK	COG	NG	LO	12/87	0.0	0.0	0.0	0.0	4.0	4.0	4.0	4.0	NC
DADE COUNTY RES. RECOV.	1	DADE	SPP	REF	---	11/91	43.0	43.0	0.0	0.0	0.0	0.0	43.0	43.0	C
EL DORADO	1	POLK	COG	NG	LO	08/94	114.2	114.2	18.8	18.8	0.0	0.0	133.0	133.0	C
FLORIDA CRUSHED STONE /1 /2	1	HERNANDO	COG	C	---	03/88	0.0	0.0	0.0	0.0	0.0	0.0	133.0	133.0	NC
LAKE COGEN	1	LAKE	COG	NG	LO	07/93	110.0	110.0	0.0	0.0	0.0	0.0	111.0	111.0	C
LAKE COUNTY RES. RECOV.	1	LAKE	SPP	REF	---	09/90	12.8	12.8	0.0	0.0	0.0	0.0	14.8	14.8	C
LFC JEFFERSON	1	POLK	COG	NG	LO	01/95	8.5	8.5	0.0	0.0	0.0	0.0	8.5	8.5	C
LFC MADISON	1	POLK	COG	NG	LO	01/95	8.5	8.5	0.0	0.0	0.0	0.0	8.5	8.5	C
MULBERRY /3	1	POLK	COG	NG	LO	08/94	79.2	79.2	0.0	0.0	0.0	0.0	80.2	80.2	C
OCCIDENTAL CHEMICAL /1	1	HAMILTON	COG	WH	---	01/80	0.0	0.0	1.0	1.0	14.0	14.0	16.2	16.2	NC
OCCIDENTAL CHEMICAL /1	2	HAMILTON	COG	WH	---	05/86	0.0	0.0	0.2	0.2	26.8	26.8	28.0	28.0	NC
ORLANDO COGEN /4	1	ORANGE	COG	NG	---	10/93	79.2	79.2	0.0	0.0	0.0	0.0	115.2	115.2	C
PASCO COGEN	1	PASCO	COG	NG	LO	07/93	109.0	109.0	0.0	0.0	0.0	0.0	110.0	110.0	C
PASCO COUNTY RES. RECOV.	1	PASCO	SPP	REF	---	03/91	23.0	23.0	0.0	0.0	0.0	0.0	28.0	28.0	C
PINELLAS COUNTY RES. RECOV.	1	PINELLAS	SPP	REF	---	04/83	40.0	40.0	0.0	0.0	0.0	0.0	44.6	44.6	C
PINELLAS COUNTY RES. RECOV.	2	PINELLAS	SPP	REF	---	06/86	14.8	14.8	0.0	0.0	0.0	0.0	17.1	17.1	C
PROCTOR & GAMBLE (BUCKEYE)	1-4	TAYLOR	COG	WD	---	01/54	0.0	0.0	0.0	0.0	38.0	38.0	38.0	38.0	NC
RIDGE GENERATING STATION	1	POLK	SPP	WD	NG	08/94	39.6	39.6	0.0	0.0	0.0	0.0	39.6	39.6	C
ROYSTER	1	POLK	COG	NG	LO	08/94	30.8	30.8	0.0	0.0	0.0	0.0	30.8	30.8	C
ST. JOE FOREST PRODUCTS	1-6	GULF	COG	WD	---	01/37	0.0	0.0	3.0	3.0	42.0	42.0	45.0	45.0	NC
TIMBER ENERGY	1	LIBERTY	SPP	BIO	---	07/86	12.8	12.8	0.0	0.0	0.0	0.0	13.8	13.8	C
US AGRICHEM	1	POLK	COG	WH	---	10/82	6.6	6.6	10.0	10.0	28.5	28.5	44.1	44.1	C
TOTAL:							831.0	831.0	33.0	33.0					
FLORIDA POWER & LIGHT COMPANY															
BIO-ENERGY PARTNERS	1	BROWARD	SPP	LG	---	05/89	10.0	10.0	---	---	N/A	N/A	15.9	15.9	C
BROWARD RES. REC. - NORTH	1	BROWARD	SPP	MSW	---	04/92	56.0	56.0	---	---	N/A	N/A	59.5	59.5	C
BROWARD RES. REC. - SOUTH	1	BROWARD	SPP	MSW	---	04/91	54.1	54.1	---	---	N/A	N/A	64.1	64.1	C
DADE CO. GOVT. CENTER /5	1	DADE	COG	NG	LO	07/86	---	---	---	---	N/A	N/A	0.0	0.0	AA
FLORIDA CRUSHED STONE	1	HERNANDO	COG	C	---	04/92	133.0	133.0	---	---	N/A	N/A	150.0	150.0	C
NAPLES BEACH HOTEL	1	COLLIER	COG	PG	---	01/85	---	---	---	---	0.1	0.1	0.1	0.1	NC
ROYSTER CO. - MULBERRY	1	POLK	COG	WH	---	04/92	9.0	9.0	---	---	N/A	N/A	21.0	21.0	C
PALM BEACH SOLID WASTE	1	PALM BEACH	SPP	MSW	---	04/92	42.0	42.0	---	---	N/A	N/A	65.0	65.0	C
TROPICANA PRODUCTS	1	MANATEE	COG	NG	---	02/90	---	---	11.0	11.0	45.1	45.1	46.8	46.8	AA
U. S. SUGUR - BRYANT /6	1	PALM BEACH	SPP	BIO	HO	02/80	---	---	---	13.0	N/A	N/A	17.5	17.5	AA
U. S. SUGUR - CLEWISTON /6	1	HENDRY	SPP	BIO	HO	02/84	---	---	---	6.0	N/A	N/A	N/A	N/A	AA
GEORGIA PACIFIC	1	PUTNAM	COG	BL	NG	02/93	---	---	3.0	5.0	55.8	55.8	61.5	61.5	AA
MERRITT SQUARE MALL	1	BREVARD	COG	NG	---	N/A	---	---	---	---	3.0	1.0	4.9	4.9	NC
CEDAR BAY	1	DUVAL	COG	C	NG	01/94	250.0	250.0	---	---	N/A	N/A	285.0	285.0	C
LEE COUNTY RES. REC.	1	LEE	SPP	MSW	---	08/94	---	---	34.0	34.0	N/A	N/A	39.7	39.7	AA
INDIANTOWN COGEN. LTD.	1	MARTIN	COG	C	---	12/95	330.0	330.0	---	---	N/A	N/A	360.0	360.0	C
OKEELANTA /7	1	PALM BEACH	COG	BIO	---	01/97	70.0	70.0	---	---	N/A	N/A	74.9	74.9	C
OSCEOLA FARMS CO. /7	1	PALM BEACH	COG	BIO	---	01/97	55.9	55.9	---	---	N/A	N/A	46.5	46.5	C
TOTAL:							1010.0	1010.0	48.0	69.0					

1998
. LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

EXISTING NON-UTILITY GENERATING FACILITIES AS OF JANUARY 1, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							POTENTIAL EXPORT TO GRID AT TIME OF PEAK - MW				QF LOAD SERVED BY QF GENERATION (MW)		MAXIMUM NORMAL GENERATOR OUTPUT (MW)		
				FUEL TYPE			FIRM		AS-AVAILABLE						
UTIL FACILITY NAME	UNIT NO.	LOCATION	TYPE	PRI	ALT	COMMERCIAL IN-SERVICE (MO/YR)	SUM	WIN	SUM	WIN	SUM	WIN	SUM	WIN	STATUS
JACKSONVILLE ELECTRIC AUTHORITY															
ANHEUSER BUSCH		DUVAL	COG	NG	--	04/88	0.0	0.0	0.0	0.0	7.2	9.4	8.0	9.0	C
BAPTIST HOSPITAL		DUVAL	COG	NG	--	10/82	0.0	0.0	0.0	1.0	6.2	6.2	7.0	8.0	C
FIRST UNION		DUVAL	COG	NG	--	10/82	0.0	0.0	0.0	0.0	1.2	1.2	1.0	1.0	C
JEFFERSON SMURFITT		DUVAL	COG	NG	--	04/83	0.0	0.0	8.0	8.0	25.0	25.0	33.0	33.0	C
RING POWER LANDFILL		DUVAL	COG	NG	--	04/92	0.0	0.0	1.0	1.0	0.8	0.0	1.0	1.0	C
ST. VINCENTS HOSPITAL		DUVAL	COG	NG	--	12/91	0.0	0.0	0.0	0.0	0.4	1.3	1.0	1.0	C
TOTAL:							0.0	0.0	9.0	10.0					
UTILITY BOARD OF THE CITY OF KEY WEST															
METRO	1	MONROE	COG	SW	--	10/86	0.0	0.0	1.6	1.5	0.4	0.4	1.6	1.5	C
SEMINOLE ELECTRIC COOPERATIVE, INC.															
HARDEE POWER STATION /8	1	HARDEE	CC	NG	LO	01/93	238.0	269.0	0.0	0.0	0.0	0.0	224.0	269.0	C
HARDEE POWER STATION /8	2	HARDEE	GT	NG	LO	01/93	80.0	93.0	0.0	0.0	0.0	0.0	74.0	93.0	C
TOTAL:							318.0	362.0	0.0	0.0					
TAMPA ELECTRIC COMPANY															
C. F. INDUSTRIES	1	HILLSBOROUGH	COG	WH	--	12/88	0.0	0.0	1.8	1.8	28.4	28.4	30.2	30.2	NC
CITY OF TAMPA REFUSE	1	HILLSBOROUGH	SPP	REF	--	06/85	12.7	12.7	0.0	0.0	2.9	2.9	15.6	15.6	C
CITY OF TAMPA SEWAGE	1-5	HILLSBOROUGH	SPP	BG	--	07/89	0.0	0.0	0.0	0.0	1.5	1.5	1.5	1.5	NC
COCA-COLA	1-3	POLK	COG	NG/WH	LO	12/87	0.0	0.0	0.0	0.0	5.2	5.2	5.2	5.2	NC
FARMLAND HYDRO	1	POLK	COG	WH	--	10/90	0.0	0.0	0.8	1.5	14.3	26.8	15.1	28.3	NC
HILLS. COUNTY REFUSE	1	HILLSBOROUGH	SPP	REF	--	04/87	26.6	2.6	0.0	0.0	3.1	0.3	29.7	2.9	C
IMC-AGRICO NEW WALES	1-2	POLK	COG	WH	--	12/84	0.0	0.0	0.1	0.1	54.1	54.1	54.2	54.2	NC
IMC-AGRICO NICHOLES	1	POLK	COG	WH	--	12/82	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NC
IMC-AGRICO SOUTH PIERCE	1-2	POLK	COG	WH	--	09/92	0.0	0.0	1.1	1.1	34.9	34.9	36.0	36.0	NC
NITRAM	1	HILLSBOROUGH	COG	WH	--	04/85	0.0	0.0	0.0	0.0	1.3	1.3	1.3	1.3	NC
ORANGE COGEN. LP	NA	POLK	COG	NG	--	01/95	21.4	21.4	0.0	0.0	NA	NA	21.4	21.4	C
ST. JOSEPH'S HOSPITAL	1	HILLSBOROUGH	COG	NG	--	04/93	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	NC
TOTAL:							60.7	36.7	3.8	4.6					
FRCC REGION TOTAL:							2219.7	2239.7	85.4	118.0					

NOTES:

/1 INTERRUPTIBLE QF.
/2 133 MW WHEELED TO FPL.
/3 23 MW WHEELED TO TEC.
/4 35 MW WHEELED TO RCI.
/5 NO LONGER OPERATIONAL.
/6 SELLS AS-AVAILABLE ENERGY DURING THE SUGAR CANE GRINDING SEASON (NOVEMBER-MARCH).
/7 FPL HAS FILED SUIT AGAINST THE OKEELANTA AND OSCEOLA PARTNERSHIPS IN PALM BEACH COUNTY CIRCUIT COURT. THE LAWSUIT SEEKS A DECLARATORY JUDGEMENT THAT THE PARTNERSHIPS FAILED TO ACCOMPLISH COMMERCIAL OPERATIONS BY JANUARY 1, 1997, AS REQUIRED BY THE POWER PURCHASE CONTRACTS WITH THE PARTNERSHIPS, AND, AS A RESULT, FPL IS RELIEVED OF ALL FURTHER OBLIGATIONS, INCLUDING CAPACITY PAYMENTS, UNDER THE CONTRACTS. FPL HAS PROPOSED TO PAY INTO A COURT-AUTHORIZED ESCROW ACCOUNT THE DISPUTED CAPACITY PAYMENTS PENDING A FINAL DETERMINATION BY THE COURT. IN ADDITION, THE AMOUNT OF CAPACITY WHICH THE OSCEOLA PARTNERSHIP HAS ATTEMPTED TO DECLARE REMAINS SUBJECT TO DISPUTE.
/8 THIS CAPACITY IS AVAILABLE ON A FIRST-CALL BASIS TO BACK UP SEMINOLE UNITS 1 & 2 AND CRYSTAL RIVER 3 FOR THE FIRST 1240 MW OF LOAD OBLIGATION, AND IS LIMITED BY CONTRACT TO A LESSER PRIORITY FOR OTHER USES.

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
PLANNED AND PROPOSED NON-UTILITY GENERATING FACILITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
							POTENTIAL EXPORT TO GRID AT TIME OF PEAK - MW				QF LOAD SERVED BY QF GENERATION (MW)		
				FUEL TYPE		COMMERCIAL	FIRM		AS-AVAILABLE				
UTIL FACILITY NAME	UNIT NO.	LOCATION	TYPE	PRI.	ALT.	IN-SERVICE (MO/YR)	SUM	WIN	SUM	WIN	SUM	WIN	STATUS
1998													
1999													
2000													
2001													
FPC PANDA KATHLEEN	1	POLK	COG	NG	LO	01/01	74.9	74.9	0.0	0.0	0.0	0.0	C
TEC FARMLAND LP GREENBAY	1	POLK	COG	WH	---	01/01	0.0	0.0	12.4	12.4	2.7	2.7	NC
2002													
FPL ROYSTER CO. - MULBERRY	1	POLK	COG	WH	---	04/02	(9.0)	(9.0)	0.0	0.0	0.0	0.0	NC
2003													
2004													
FPL BIO-ENERGY PARTNERS	1	BROWARD	SPP	LG	---	12/04	(10.0)	(10.0)	0.0	0.0	0.0	0.0	NC
2005													
FPL FLORIDA CRUSHED STONE	1	HERNANDO	COG	C	---	11/05	(133.0)	(133.0)	0.0	0.0	0.0	0.0	NC
2006													
2007													

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
NON-UTILITY GENERATING FACILITIES SUMMARY

	SUMMER			WINTER	
YEAR	FIRM NET TO GRID (MW)	AS AVAILABLE NET TO GRID (MW)	YEAR	FIRM NET TO GRID (MW)	AS AVAILABLE NET TO GRID (MW)
1998	2,219.7	95.4	1998/99	2,239.7	118.0
1999	2,219.7	95.4	1999/00	2,239.7	118.0
2000	2,219.7	95.4	2000/01	2,239.7	118.0
2001	2,294.6	107.8	2001/02	2,314.6	130.4
2002	2,285.6	107.8	2002/03	2,305.6	130.4
2003	2,285.6	107.8	2003/04	2,305.6	130.4
2004	2,285.6	107.8	2004/05	2,295.6	130.4
2005	2,275.6	107.8	2005/06	2,162.6	130.4
2006	2,142.6	107.8	2006/07	2,162.6	130.4
2007	2,142.6	107.8	2007/08	2,162.6	130.4

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		CONTRACT TERM		NET CAPABILITY - MW		
PURCHASING UTILITY	SELLING UTILITY	FROM (MO/YR)	TO (MO/YR)	SUMMER	WINTER	DESCRIPTION
ENRON						
	OUC	06/96	12/00	10	25	SCHEDULE D
FLORIDA KEYS ELECTRIC COOPERATIVE, INC.						
	FPL /1	05/92	05/13	PEAK REQUIREMENTS	PEAK REQUIREMENTS	SCHEDULE D
FLORIDA MUNICIPAL POWER AGENCY						
	FPC	01/98	12/98	100	100	PARTIAL REQUIREMENTS
	FPC	01/99	12/99	120	120	PARTIAL REQUIREMENTS
	FPC	01/00	12/00	80	80	PARTIAL REQUIREMENTS
	FPC	01/01	12/01	40	40	PARTIAL REQUIREMENTS
	FPC	01/02	12/02	2	2	PARTIAL REQUIREMENTS
	FPL	06/97	06/98	10	10	PARTIAL REQUIREMENTS
	FPL	06/98	12/98	9	9	PARTIAL REQUIREMENTS
	OUC	05/86	12/01	130	130	UPS
	OUC	01/02	12/02	108	108	UPS
	OUC	01/03	12/03	87	87	UPS
	OUC	01/04	12/04	65	65	UPS
	OUC	01/05	12/05	43	43	UPS
	OUC	01/06	12/06	22	22	UPS
	OUC	01/89	12/03	20	20	SCHEDULE D
	LWU	01/99	12/00	15	15	SCHEDULE D
	LWU	01/01	12/01	10	10	SCHEDULE D
	TEC	12/97	12/98	85	85	SCHEDULE D
	TEC	12/98	12/99	105	105	SCHEDULE D
	TEC	12/99	03/01	150	150	SCHEDULE D
	GRU	01/98	12/98	20	20	SCHEDULE D
	GRU	10/97	03/03	3	3	SCHEDULE D
	GRU	01/99	12/99	10	10	SCHEDULE D
	VER	06/97	------	150	155	EXISTING UNIT PURCHASE
	FTP	06/98	------	118	118	EXISTING UNIT PURCHASE
	LWU	01/99	------	87	97	EXISTING UNIT PURCHASE
	KEY	04/98	------	50	50	EXISTING UNIT PURCHASE

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		CONTRACT TERM		NET CAPABILITY - MW		
PURCHASING UTILITY	SELLING UTILITY	FROM (MO/YR)	TO (MO/YR)	SUMMER	WINTER	DESCRIPTION
FLORIDA POWER CORPORATION						
	TEC	06/93	01/99	50	50	RATE SCHEDULE AR-1
	TEC	01/99	01/05	60	60	RATE SCHEDULE AR-1
	TEC	01/05	03/11	70	70	RATE SCHEDULE AR-1
	SEPA	01/98	12/10	36	36	
	SOU	01/94	06/10	202	202	UPS #1
	SOU	01/95	06/10	203	203	UPS #2
FLORIDA POWER & LIGHT COMPANY						
	SOU /2	06/93	05/10	914	914	UPS
	JEA /3	03/87	09/21	383	383	UPS
CITY OF FT. MEADE						
	TEC	03/93	12/98	5	5	SCHEDULE D
	TEC	01/97	12/13	4-12	5-13	PARTIAL REQUIREMENTS
FT. PIERCE UTILITIES AUTHORITY						
	FMPA	08/83	UNK	11	11	ST. LUCIE
	FMPA	07/87	UNK	20	20	STANTON 1
	FMPA	06/96	UNK	16	16	STANTON 2
GAINESVILLE REGIONAL UTILITIES						
	LG&E POWER MARKETING	03/98	03/99	31	31	SCHEDULE D
	LG&E POWER MARKETING	03/99	03/00	32	32	SCHEDULE D
	LG&E POWER MARKETING	03/00	03/01	33	33	SCHEDULE D
	LG&E POWER MARKETING	03/01	03/02	45	45	SCHEDULE D
	LG&E POWER MARKETING	03/02	03/03	57	57	SCHEDULE D
	LG&E POWER MARKETING	03/03	03/04	68	68	SCHEDULE D
	LG&E POWER MARKETING	03/04	03/05	78	78	SCHEDULE D
	LG&E POWER MARKETING	03/05	03/06	89	0	SCHEDULE D
GEORGIA POWER COMPANY						
	FPC	01/98	12/99	150	150	FIRM

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		CONTRACT TERM		NET CAPABILITY - MW		
PURCHASING UTILITY	SELLING UTILITY	FROM (MO/YR)	TO (MO/YR)	SUMMER	WINTER	DESCRIPTION
JACKSONVILLE ELECTRIC AUTHORITY						
	SOU	06/95	06/10	200	200	UPS
	PECO	06/98	09/98	40	0	FIRM
	PECO	06/99	09/99	50	0	FIRM
	ENRON	01/98	12/98	86	74	FIRM
	ENRON	01/99	12/99	88	76	FIRM
	ENRON	01/00	12/00	89	77	FIRM
	ENRON	01/01	12/01	91	78	FIRM
	ENRON	01/02	12/02	92	80	FIRM
	UNSPECIFIED	01/99	12/99	100	175	FIRM OUT-OF-STATE
	UNSPECIFIED	01/00	12/00	150	150	FIRM OUT-OF-STATE
	UNSPECIFIED	06/01	09/01	50	0	FIRM OUT-OF-STATE
	UNSPECIFIED	06/06	03/07	75	75	FIRM OUT-OF-STATE
	UNSPECIFIED	06/07	09/07	200	0	FIRM OUT-OF-STATE
UTILITY BOARD OF THE CITY OF KEY WEST	FMPA	03/85	ONGOING	12	12	UPS, STANTON #1
	FMPA	06/96	ONGOING	9	9	UPS, STANTON #2
	FPL	06/93	05/13	45	45	LONG TERM FIRM
KISSIMMEE UTILITY AUTHORITY						
	FMPA	06/82	On Going	7	7	UPS, ST. LUCIE
	FMPA	06/96	On Going	41	41	UPS, STANTON #2
	OUC	01/89	12/03	20	20	SCHEDULE D
	OUC	01/98	12/99	30	30	UNIT PURCHASE
	OUC	01/00	12/00	40	40	UNIT PURCHASE
CITY OF LAKELAND						
	TEC	11/96	09/06	10	10	SCHEDULE D
	ENRON	07/96	12/01	20	20	SCHEDULE D
CITY OF LAKE WORTH UTILITIES						
	FPL	LIFE TIME OF UNIT		17	18	UPS, ST. LUCIE
	OUC	LIFE TIME OF UNIT		10	10	UPS, STANTON #1
MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA						
	FPC	01/98	12/99	75		FIRM

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		CONTRACT TERM		NET CAPABILITY - MW		
PURCHASING UTILITY	SELLING UTILITY	FROM (MO/YR)	TO (MO/YR)	SUMMER	WINTER	DESCRIPTION
UTILITIES COMMISSION OF NEW SMYRNA BEACH	TEC	03/96	02/00	16-19	10-14	SCHEDULE D
	FPC	03/96	12/02	24	24	PARTIAL REQUIREMENTS
	FPC	03/96	12/02	6	6	STRATIFIED PEAKING SERVICE
	ENRON	06/96	05/00	10	25	SCHEDULE ST
OGLETHORPE POWER CORPORATION	FPC	01/98	12/98	137	0	FIRM
PECO ENERGY	GRU	06/98	09/98	50	0	SCHEDULE D
	GRU	06/99	09/99	47	0	SCHEDULE D
	OUC	06/96	12/99	100	100	50% STANTON; 50% INDIAN RIVER
REEDY CREEK IMPROVEMENT DISTRICT	OUC	01/91	12/99	15	15	SCHEDULE D
	OUC	01/00	12/00	10	10	SCHEDULE D
	OUC	01/01	12/01	5	5	SCHEDULE D
	OUC	01/91	12/01	6	6	BACKUP POWER
	OUC	01/98	12/98	15	15	UPS, STANTON #1
	OUC	01/99	12/00	12	12	UPS, STANTON #1
	TEC	01/92	12/99	15-30	15-30	SCHEDULE D
	TEC	06/95	12/17	10-40	10-40	CONTRACT SALE
SEMINOLE ELECTRIC COOPERATIVE, INC.	TECO POWER SERVICES/4	01/93	12/02	145	145	UPS - TEC BIG BEND #4
	JEA	01/95	05/04	53	63	CAPACITY PURCHASE OF CTs
	OUC	01/96	12/04	75	75	UNIT POWER PURCHASE
	OUC	01/97	12/00	50	50	UNIT POWER PURCHASE
	FPC	01/99	12/01	300	300	STRUCTURED SYS. CAP. PURCH
	FPC	01/99	12/01	155	155	SYSTEM PEAKING PURCHASE
	FPC	01/99	12/13	150	150	SYS. INTERMEDIATE CAP. PURCH.
	FPC	01/00	12/02	150	150	SYSTEM PEAKING CAP. PURCHASE
	FPC	01/01	12/02	150	150	

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		CONTRACT TERM		NET CAPABILITY - MW		
PURCHASING UTILITY	SELLING UTILITY	FROM (MO/YR)	TO (MO/YR)	SUMMER	WINTER	DESCRIPTION
CITY OF ST. CLOUD						
	FPC	01/98	12/98	5	5	
	OUC	01/98	12/98	17	33	OUC PORTION OF CITY OF ST. CLOUD
	OUC	01/99	12/99	31	36	SYSTEM REQUIREMENTS
	OUC	01/00	12/00	35	40	
	OUC	01/01	12/01	39	43	
	OUC	01/02	12/02	43	46	
	OUC	01/03	12/03	47	49	
	OUC	01/04	12/04	51	52	
	OUC	01/05	12/05	55	54	
	OUC	01/06	12/06	58	56	
	OUC	01/07	12/07	61	58	
	TEC	01/97	12/13	5-15	5-15	TECO PR
	TEC	01/98	12/98	10	10	
	TEC	01/99	12/12	15	15	
SOUTHERN COMPANY						
	FPC	06/98	09/98	362	0	
	FPC	06/99	09/99	225	0	
CITY OF STARKE						
	GRU	01/94	01/04	3	3	SCHEDULE D
CITY OF TALLAHASSEE						
	SOU	10/96	05/00	77	77	UPS
	ENTERGY	03/96	03/02	25	25	FIRM CAP. & ENERGY
TAMPA ELECTRIC COMPANY						
	TECO POWER SERVICES /4	01/93	12/12	318	362	HARDEE STATION POWER SALE
TECO POWER SERVICES						
	TEC	01/93	12/02	145	145	BIG BEND 4 UNIT SALE

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		CONTRACT TERM		NET CAPABILITY - MW		
PURCHASING UTILITY	SELLING UTILITY	FROM (MO/YR)	TO (MO/YR)	SUMMER	WINTER	DESCRIPTION
CITY OF VERO BEACH						
	FMPA	06/97	UNK	21	21	STANTON #1
	FMPA	06/97	UNK	17	17	STANTON #2
CITY OF WAUCHULA						
	TEC	01/97	12/98	5	5	STATION POWER SALE
	TEC	01/97	12/13	7-17	8-20	PARTIAL REQUIREMENTS

NOTES:

1) FIRM CAPACITY CAN CHANGE FROM YEAR TO YEAR IN RESPONSE TO CHANGES IN FKEC SYSTEM PEAK DEMAND AND FKEC GENERATING RESOURCES.

2) THE AMOUNT OF CAPACITY PURCHASED VARIES OVER THE LIFE OF THE CONTRACT. THE AMOUNT SHOWN IS THE MAXIMUM NOMINAL AMOUNT PURCHASED. THE ACTUAL CAPACITY PURCHASED VARIES FROM THE NOMINAL CAPACITY SHOWN DUE TO THE DEMONSTRATED CAPABILITY OF THE UNITS VARYING FROM THE EXPECTED CAPACITY.

3) THIS CONTRACT TERMINATES 9/21 OR UPON THE RETIREMENT OR DECOMMISSIONING OF THE ST. JOHNS RIVER POWER PARK, WHICHEVER OCCURS FIRST.

4) TAMPA ELECTRIC WILL PURCHASE CAPACITY FROM PHASE 1 OF THE PURCHASE AGREEMENT WITH TECO POWER SERVICES. AVAILABILITY OF THIS CAPACITY IS SUBJECT TO THE BACK-UP REQUIREMENTS OF SEMINOLE ELECTRIC COOPERATIVE. DURING THE SAME PERIOD, TAMPA ELECTRIC COMPANY WILL SELL 145 MW OF BIG BEND 4 TO TECO POWER SERVICES, ON A LIMITED ENERGY BASIS, FOR USE BY SEMINOLE ELECTRIC COOPERATIVE. AVAILABILITY OF THIS CAPACITY IS SUBJECT TO THE BACK-UP REQUIREMENTS FOR SEMINOLE ELECTRIC COOPERATIVE.

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

HISTORY AND FORECAST: INTERCHANGE AND GENERATION BY FUEL TYPE - GWH

		ACTUAL											
TYPE		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
INTERCHANGE	GWH	15,084	11,739	18,287	20,613	22,977	21,999	21,161	19,629	20,066	20,886	22,030	22,680
NUCLEAR	GWH	25,428	23,426	30,438	29,964	30,444	29,452	30,518	29,505	29,933	30,016	29,995	29,391
COAL	GWH	65,197	68,819	67,379	67,881	76,039	77,700	79,779	82,737	83,552	83,887	84,114	85,021
OIL - TOT	GWH	22,530	24,001	22,963	20,897	14,627	15,777	15,905	23,335	22,747	21,805	24,076	25,218
STEAM	GWH	21,987	23,451	22,669	20,580	14,266	15,290	15,450	22,832	22,136	21,345	23,469	24,708
CC	GWH	53	53	28	30	38	58	72	85	97	103	108	114
CT	GWH	490	497	266	287	323	429	383	418	514	357	499	396
NG - TOT	GWH	30,594	33,556	27,824	33,720	34,426	37,116	39,197	34,932	38,541	43,160	44,409	47,093
STEAM	GWH	12,561	13,748	8,462	11,502	11,841	10,831	10,016	4,764	4,312	3,812	3,639	3,653
CC	GWH	17,222	18,316	17,983	20,340	20,631	24,473	27,608	27,497	31,210	36,463	37,148	39,658
CT	GWH	811	1,492	1,379	1,878	1,954	1,812	1,573	2,671	3,019	2,885	3,622	3,782
HYDRO	GWH	22	29	25	25	25	25	25	25	25	25	25	25
NUG	GWH	14,472	13,964	15,306	15,157	14,815	16,033	15,892	15,945	15,977	15,898	16,043	16,269
NEL	GWH	173,327	175,534	182,222	188,257	193,353	198,102	202,477	206,108	210,841	215,677	220,692	225,697

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

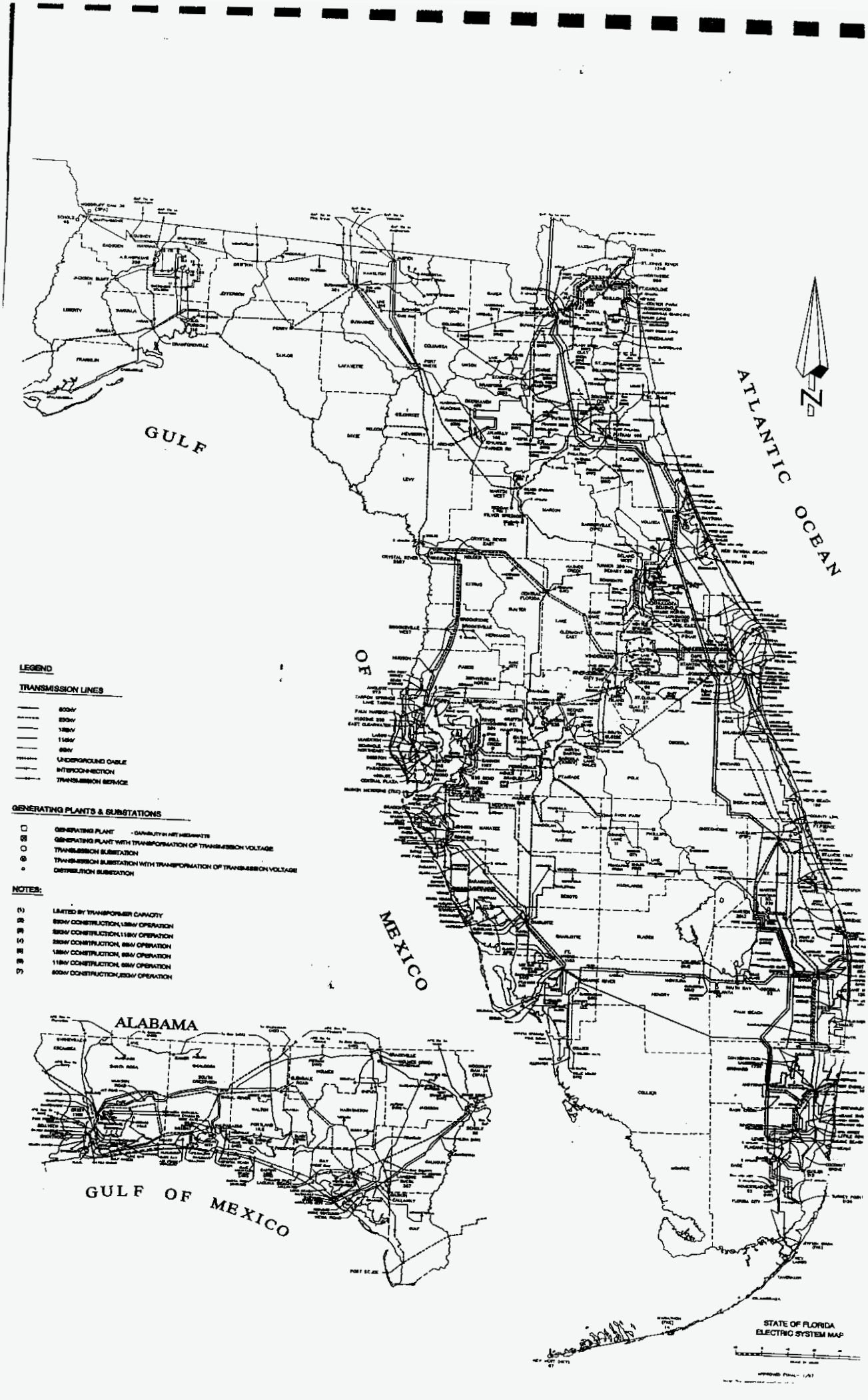
HISTORY AND FORECAST: INTERCHANGE AND GENERATION BY FUEL TYPE - % GWH

		ACTUAL											
TYPE		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
INTERCHANGE	%	8.7%	6.7%	10.0%	10.9%	11.9%	11.1%	10.5%	9.5%	9.5%	9.7%	10.0%	10.0%
NUCLEAR	%	14.7%	13.3%	16.7%	15.9%	15.7%	14.9%	15.1%	14.3%	14.2%	13.9%	13.6%	13.0%
COAL	%	37.6%	39.2%	37.0%	36.1%	39.3%	39.2%	39.4%	40.1%	39.6%	38.9%	38.1%	37.7%
OIL - TOT	%	13.0%	13.7%	12.6%	11.1%	7.6%	8.0%	7.9%	11.3%	10.8%	10.1%	10.9%	11.2%
STEAM	%	12.7%	13.4%	12.4%	10.9%	7.4%	7.7%	7.6%	11.1%	10.5%	9.9%	10.6%	10.9%
CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
CT	%	0.3%	0.3%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
NG - TOT	%	17.7%	19.1%	15.3%	17.9%	17.8%	18.7%	19.4%	16.9%	18.3%	20.0%	20.1%	20.9%
STEAM	%	7.2%	7.8%	4.6%	6.1%	6.1%	5.5%	4.9%	2.3%	2.0%	1.6%	1.6%	1.6%
CC	%	9.9%	10.4%	9.9%	10.8%	10.7%	12.4%	13.6%	13.3%	14.8%	16.9%	16.8%	17.6%
CT	%	0.5%	0.8%	0.8%	1.0%	1.0%	0.9%	0.8%	1.3%	1.4%	1.3%	1.6%	1.7%
HYDRO	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NUG	%	8.3%	8.0%	8.4%	8.1%	7.7%	8.1%	7.8%	7.7%	7.6%	7.4%	7.3%	7.2%
NEL	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

HISTORY AND FORECAST: FUEL REQUIREMENTS

TYPE		ACTUAL 1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
NUCLEAR	10E12 BTU	267	246	320	315	320	309	320	310	314	315	315	309
COAL	10E3 TON	24,915	26,045	25,678	25,744	25,696	26,116	26,339	27,186	26,944	27,324	27,348	22,247
OIL - TOT	10E3 BBL	36,891	39,097	37,860	34,857	25,089	27,050	27,261	38,544	38,012	35,871	39,509	41,469
STEAM	10E3 BBL	35,313	36,817	36,223	33,079	23,242	24,874	25,309	36,270	35,263	34,191	37,346	39,403
CC	10E3 BBL	86	338	264	309	314	344	366	387	409	418	429	443
CT	10E3 BBL	1,492	1,942	1,373	1,469	1,533	1,832	1,586	1,887	2,340	1,262	1,734	1,623
NG - TOT	10E6 CF	281,012	291,086	250,612	305,464	311,333	325,501	337,376	293,203	307,531	337,589	349,255	369,916
STEAM	10E6 CF	136,152	136,390	88,588	120,309	123,659	113,226	105,332	51,150	36,218	30,546	27,872	29,026
CC	10E6 CF	135,116	135,278	145,236	163,105	164,193	189,386	211,888	209,299	236,675	274,708	280,799	298,996
CT	10E6 CF	9,744	19,418	16,788	22,050	23,481	22,889	20,156	32,754	34,638	32,335	40,584	41,894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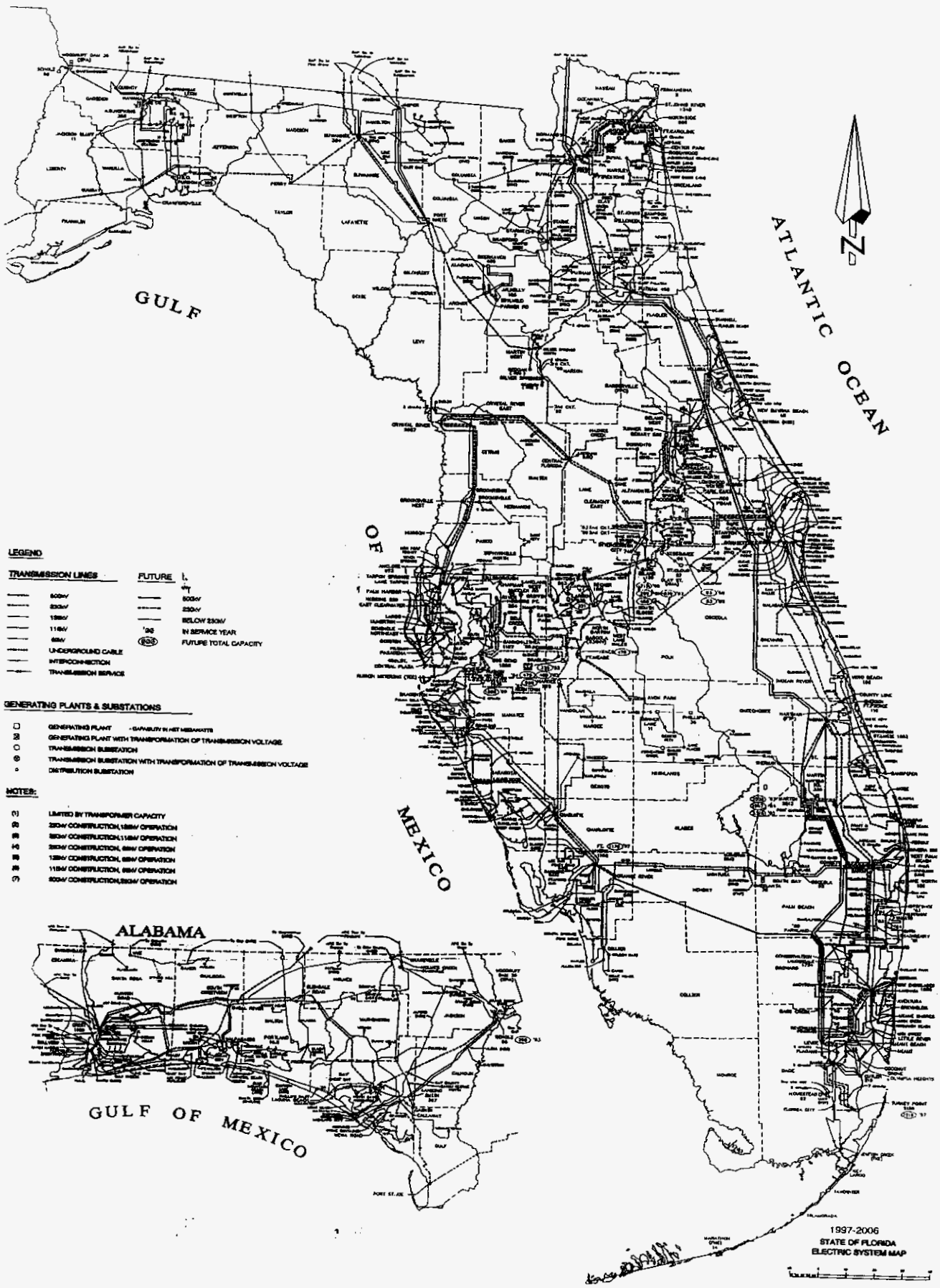
INTERCONNECTION
TRANSMISSION SERVICE
GENERATING PLANTS & SUBSTATIONS
GENERATING PLANT - CAPABILITY IN NET MEGAWATTS
GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION
TRANSMISSION SUBSTATION WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
DISTRIBUTION SUBSTATION
NOTES:
(1) LIMITED BY TRANSFORMER CAPACITY
(2) 500kV CONSTRUCTION, 138kV OPERATION
(3) 500kV CONSTRUCTION, 115kV OPERATION
(4) 230kV CONSTRUCTION, 69kV OPERATION
(5) 138kV CONSTRUCTION, 69kV OPERATION
(6) 115kV CONSTRUCTION, 69kV OPERATION
(7) 500kV CONSTRUCTION, 230kV OPERATION
ALABAMA
GULF OF MEXICO
STATE OF FLORIDA
ELECTRIC SYSTEM MAP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115kV
69kV
UNDERGROUND CABLE
INTERCONNECTION
TRANSMISSION SERVICE
BELOW 230kV
'96
IN SERVICE YEAR
(804)
FUTURE TOTAL CAPACITY
GENERATING PLANTS & SUBSTATIONS
GENERATING PLANT - CAPABILITY IN NET MEGAWATTS
GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION
TRANSMISSION SUBSTATION WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
DISTRIBUTION SUBSTATION
NOTES:
(1) LIMITED BY TRANSFORMER CAPACITY
(2) 230kV CONSTRUCTION,115kV OPERATION
(3) 500kV CONSTRUCTION,115kV OPERATION
(4) 230kV CONSTRUCTION, 69kV OPERATION
(5) 138kV CONSTRUCTION, 69kV OPERATION
(6) 115kV CONSTRUCTION, 69kV OPERATION
(7) 500kV CONSTRUCTION,230kV OPERATION
1997-2006
STATE OF FLORIDA
ELECTRIC SYSTEM MAP

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

ABBREVIATIONS

ELECTRIC MARKET PARTICIPANTS

ENR	-	Enron Power Marketing
ENT	-	Entergy Power Marketing Corp.
FKE	-	Florida Keys Electric Cooperative Association, Inc.
FMP	-	Florida Municipal Power Agency
FPC	-	Florida Power Corporation
FPL	-	Florida Power & Light
FMD	-	Ft. Meade, City of
FTP	-	Ft. Pierce Utilities Authority
GRU	-	Gainesville Regional Utilities
HST	-	Homestead, City of
JEA	-	Jacksonville Electric Authority
KEY	-	Key West, City of
KUA	-	Kissimmee Utility Authority
LAK	-	Lakeland, City of
LWU	-	Lake Worth Utilities, City of
NSB	-	Utilities Commission of New Smyrna Beach
OEU	-	Ocala Electric Utility
OUC	-	Orlando Utilities Commission
PEC	-	PECO Energy Company
RCI	-	Reedy Creek Improvement District
STC	-	St. Cloud, City of
SEC	-	Seminole Electric Cooperative, Inc.
SOU	-	Southern Company
TAL	-	Tallahassee, City of
TEC	-	Tampa Electric Company
VER	-	Vero Beach, City of
WAU	-	Wauchula, City of

OTHER

FRCC	-	Florida Reliability Coordinating Council

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

GENERATION TERMS

Fuel Transportation Method

PL	--	Pipeline
RR	--	Railroad
TK	--	Truck
WA	--	Water

Power and Energy

KW	--	Kilowatt
KWh	--	Kilowatt-hour
MW	--	Megawatt (1000 KW)
MWh	--	Megawatt-hour (1000 KWh)
GW	--	Gigawatt (1000 MW)
GWh	--	Gigawatt-hour (1000 MWh)

Status of Generation Facilities

A	--	Capability increase
C	--	Conversion from oil to coal
CA	--	Conversion to alternate fuel
CG	--	Conversion to gas
D	--	Capability decrease
L	--	Regulatory approval pending; not under construction
M	--	Cold standby, reserve shutdown
P	--	Planned
R	--	To be retired
RP	--	Repowering
S	--	Returned from cold standby or reserve shutdown
T	--	Regulatory approval received or not required; not under construction
U	--	Under construction; less than 50% completed
V	--	Under construction; more than 50% completed

Types of Fuel

ALT	--	Alternate Fuel
C	--	Coal
SUB	--	Subbituminous coal
ORI	--	Orimulsion
LO	--	No. 2 Fuel Oil (Distillate)
HO	--	No. 6 Fuel Oil (Heavy)
NG	--	Natural Gas
N	--	Nuclear
PET	--	Petroleum Coke
SW	--	Solid Waste
UN	--	Unknown
WAT	--	Water
WH	--	Waste Heat

Types of Generation Units

CC	--	Combined Cycle
CCT	--	Combined Cycle, Combustion Turbine
CCW	--	Combined Cycle, Waste Heat
CT	--	Combustion Turbine
D	--	Diesel
FC	--	Fuel Cell
FS	--	Fossil Steam
HRSG	--	Heat Recovery Steam Generator
HY	--	Hydro
OT	--	Other
IGCC	--	Integrated Coal Gasification Combined Cycle
UN	--	Unknown
PC	--	Pulverized Coal
N	--	Nuclear
IC	--	Internal Combustion

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
GENERATION TERMS

Type of Non-Utility Generator Facility

COG	--	Cogenerator
IPP	--	Independent Power Producer
SPP	--	Small Power Producer
SSG	--	Self Service Generation

Qualifying Facility Fuel Type

BG	--	Biogas
BIO	--	Biomass
BL	--	Black Liquor
C	--	Coal
HY	--	Hydro
LG	--	Landfill Gas
MG	--	Methane Gas
NG	--	Natural Gas
OTH	--	Other
PG	--	Propane Gas
PT	--	Peat
SW	--	Solid Waste
WD	--	Wood
WH	--	Waste Heat
MSW	--	Municipal Solid Waste

Qualifying Facility Status

C	--	Under contract for the delivery of energy and/or capacity to the utility.
NC	--	Not under contract for the delivery of energy and/or capacity to the utility.
AA	--	As-Available

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

INTERCHANGE TERMS

FR	--	Full requirement service agreement
PR	--	Partial requirement service agreement
Schd D	--	Long term firm capacity and energy interchange agreement
Schd E	--	Non-Firm capacity and energy interchange agreement
Schd F	--	Long term non-firm capacity and energy interchange agreement
Schd G	--	Back-up reserve service
Schd J	--	Contract which the terms and conditions are negotiated yearly
UPS	--	Unit Power Sale

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

DEFINITIONS

AAGR
- Average Annual Growth Rate, usually expressed as a percent.

INTERRUPTIBLE LOAD
- Load which may be disconnected at the supplier's discretion.

LOAD FACTOR
- A percent which is the calculation of NEL/(annual peak demand * the number of hours in the year).

NET CAPABILITY OR NET CAPACITY
- The continous gross capacity, less the power required by all auxillaries associated with the unit.

NET ENERGY FOR LOAD (NEL)
- The net system generation PLUS interchange received MINUS interchange delivered.

PEAK DEMAND OR PEAK LOAD
- The net 60-minute integrated demand, actual or adjusted. Forecasted loads assume normal weather conditions.

PENINSULAR FLORIDA
- Geographically, those Florida utilities located east of the Apalachicola River.

QUALIFYING FACILITY (QF)
- The cogenerator or small power producer which meets FERC criteria for a qualifying facility.

SALES FOR RESALE
- Energy sales to other electric utilities.

STATE OF FLORIDA
- Utilities in Peninsular Florida plus Gulf Power Company, West Florida Electric Cooperative, Choctawhatchee Electric Cooperative, Escambia River Electric Cooperative, Gulf Coast Electric Cooperative, and Alabama Electric Cooperative.

SUMMER
- June 1 through September 30 of each year being studied.

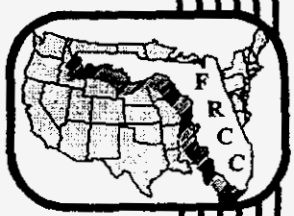
WINTER
- December of the previous year through March 31 of the year being studied.

YEAR
- The calendar year, January 1, through December 31. Unless otherwise indicated, this is the year used for historical and forecast data.

1998
Reliability Assessment

August – 1998

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 4
COMPANY/ WITNESS: FPL
DATE: 12-2-98



FLORIDA RELIABILITY COORDINATING COUNCIL

1998
Reliability Assessment

Prepared By:
The Resource Working Group

FLORIDA RELIABILITY COORDINATING COUNCIL

August – 1998

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Executive Summary

This report contains a description of the peninsular Florida reliability assessment study that was conducted by the Florida Reliability Coordinating Council (FRCC) during 1998.

This assessment was based on two reliability studies:

- Adequacy of planned reserve margins to meet (or exceed) the 15% standard at the time of peak demand (the suitability of the 15% standard was verified in a separate study, which is attached as Exhibit II in this report), and

- The ability to maintain 0.1 day/year or lower loss-of-load-probability (LOLP).

The study concludes that the FRCC's existing and planned resources will reliably meet the expected needs of the state's electricity consumers over the study period, 1998 to 2007.

The resources relied upon and the projected demands are described in the FRCC's Load and Resource Plan which was submitted to the Florida Public Service Commission on July 1, 1998.

Introduction

The Florida Reliability Coordinating Council (FRCC) is one of the ten regions of the North American Electric Reliability Council (NERC). The purpose of the FRCC is to promote the reliability and adequacy of the bulk electric power supply in peninsular Florida. To this end, the FRCC's Reliability Working Group (RWG) conducted the 1998 Reliability Assessment Study. This study is also intended to meet the NERC Planning Standards (Section I-B, System Adequacy and Security/Reliability Assessment[1]). Furthermore, it is being provided as a reference document to the FPSC and its staff.

On July 1, 1998, the FRCC submitted to the Florida Public Service Commission (FPSC) its Load and Resource Plan for 1998-2007. That report contains an aggregated summary of the utility companies' resource plans and demand forecasts for peninsular Florida. The FRCC's 1998 Reliability Assessment study examines peninsular Florida's bulk reliability reflected in those resource plans.

The Reliability Assessment study will be submitted to the FPSC on August 1, 1998. Two public workshops in Tallahassee are currently scheduled later in the year to review this study.

[1] This standard is available on the internet at WWW.NERC.COM

1.1. Scope of Reliability Assessment Study

The purpose of this study was to make an assessment of the reliability adequacy which is reflected in the FRCC utilities' aggregate of existing and planned resources. The following measures of reliability were used:

- Reserve margins at time of summer and winter FRCC non-coincident peak demands as they appear in the FRCC's 1998 Load and Resource Plan.

  A separate study was undertaken to establish the benchmark level of reserve margin which would be deemed to be adequate. It was based on an analysis of the historically required reserves which would have been adequate to cover the unexpected deviations in demand and in the availability of key resources (installed generation, purchases and load management). This analysis concluded that a reserve margin of 15% would provide an adequate level of reliability to meet peak demands during summer and winter.

- Loss-of-load-probability (LOLP) of less than 0.1 day per year resulting from matching the expected daily FRCC resources to the expected daily peak loads during the ten year period, 1998 to 2007. The LOLP analysis was performed by utilizing the TIGER computer model.

In addition, a comprehensive range of sensitivities were run from the LOLP reference case:

- A generation expansion sensitivity case consisting of only existing and certified units
- Three forced outage rate sensitivities
- Two sensitivities on limiting the operation of load management/interruptible loads

- Three sensitivities on the availability of peninsular Florida's import tie line assistance, and
- A load forecast sensitivity

In addition, the system's LOLP was tested under further severe conditions by employing combinations of sensitivities:

- Two cases combining the load forecast sensitivity with the forced outage rate sensitivities, and
- A case combining the load forecast sensitivity with a limited tie line assistance sensitivity.

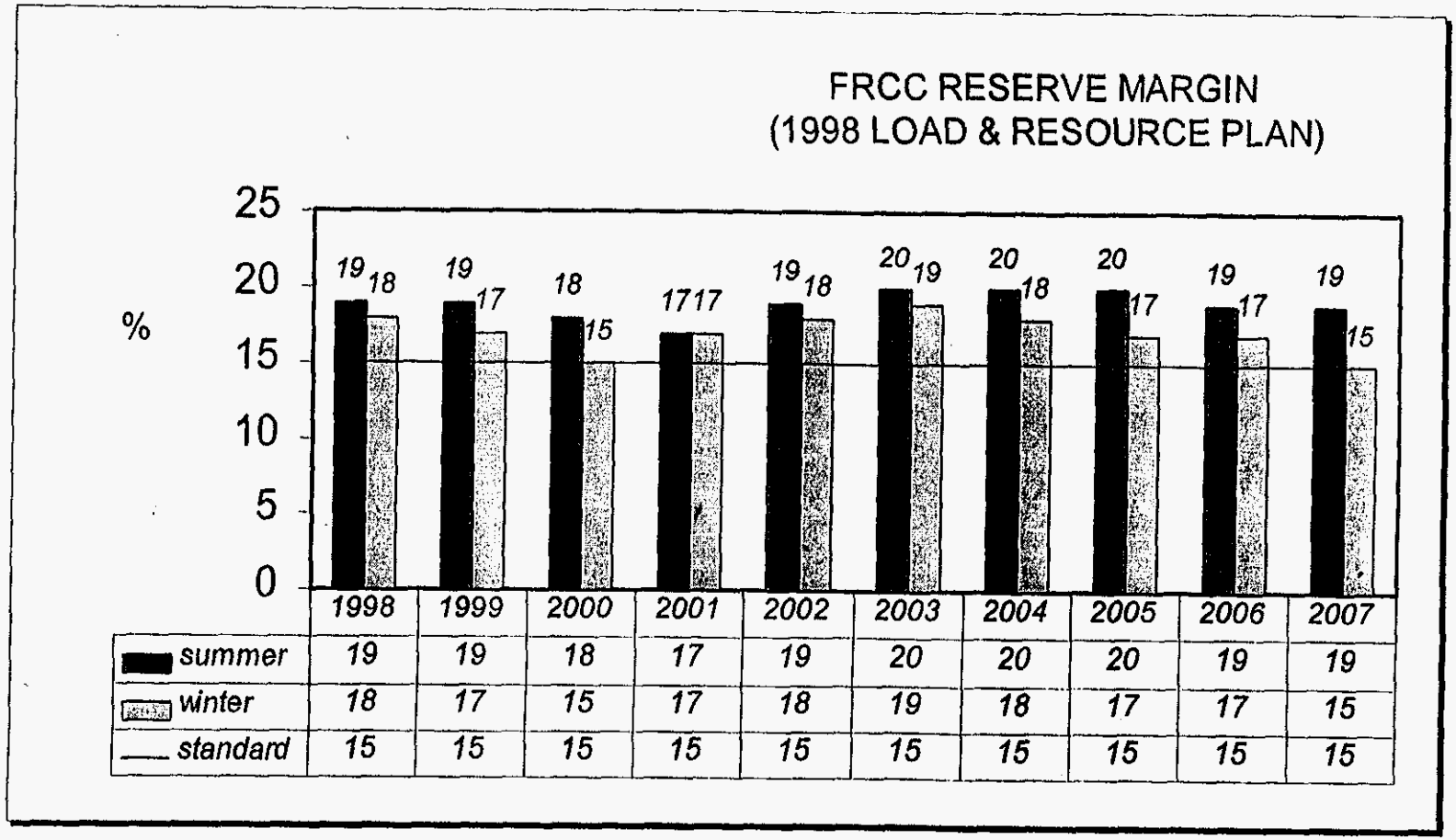
The study also includes an assessment by the Florida Gas Transmission (FGT) of its ability to expand its pipeline capacity in support of the FRCC generation expansion plan.

1.2 Summary of Results

1.2.1. Reserve Margin Analysis

The analysis is based on the data contained in the FRCC Load and Resource Plan which was submitted to the FPSC on July 1, 1998.

The table on the next page summarizes the resulting projected summer and winter reserve margins versus the reserve margin standard of 15%.



	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
summer	19	19	18	17	19	20	20	20	19	19
winter	18	17	15	17	18	19	18	17	17	15
standard	15	15	15	15	15	15	15	15	15	15

1.2.2 LOLP Analysis

The table below presents the results of the reference case analysis.

1998 FRCC RELIABILITY ASSESSMENT

LOLP ANALYSIS
(Days/year)

Year	Reference Case	LOLP Standard
1998	0.000002	0.100000
1999	0.000001	0.100000
2000	0.000033	0.100000
2001	0.000876	0.100000
2002	0.000099	0.100000
2003	0.000047	0.100000
2004	0.000093	0.100000
2005	0.000148	0.100000
2006	0.000610	0.100000
2007	0.000477	0.100000

Some of the sensitivity cases resulted in violations of the LOLP criterion in some of the study years. The sensitivities reflect conditions that might occur if the tested variables are "moved" from their reference case values without a commensurate compensating action by the FRCC utilities. They are discussed in detail in Section 3, "Assessment and Results".

1.3 Conclusions

The reserve margin analysis indicates that peninsular Florida maintains summer and winter reserve levels at or in excess of 15% throughout the entire ten-year planning period. This level is considered to provide adequate levels of reserve margin for reliable service.

Furthermore, with the "most likely" assumptions the peninsula electric system does not exceed the 0.1 days per year LOLP criterion in any year of the ten-year planning horizon. Some sensitivity analyses run indicated LOLP violations. However, the cases examined either represent an unlikely scenario of occurrence or else utilities have existing processes in place to effectively deal with them.

Therefore, based on the results of the 1998 Reliability Assessment, the FRCC concludes that the peninsular Florida electric system is reliable through the ten year planning period and that the FRCC 1998 Load and Resource Plan is suitable.

2. Methodologies and Assumptions

The 1998 Reliability Assessment includes three major activities or analyses. The first is a reliability analysis which utilizes both probabilistic and deterministic methods (i.e., Loss-Of-Load-Probability and Reserve Margin). The second is an analysis of the suitability of a 15% reserve margin standard for peninsular Florida. Finally, an evaluation of future natural gas transmission capability to meet the projected natural gas requirements for planned electric generation in peninsular Florida was performed.

The 1998 Reliability Assessment assumes that all of peninsular Florida operates as a single entity. This is a reasonable assumption based on the high degree of inter-utility operational coordination. This is accomplished by aggregating all of the individual utility non-coincident system demand and energy projections, power supply resources, and energy management resources.

The FPSC Staff has participated as an observer in all phases of this study and was kept apprised of the FRCC's Resource Working Group (RWG) activities on a regular basis. Staff representatives participated in several RWG conference calls and meetings.

2.1 Reliability Modeling and Analysis

The energy resources of an electric system are planned to exceed the system peak demand if the system is to reliably meet customer energy requirements. These resources include the generating unit capacity owned by utilities, non-utility generating capacity, capacity available

to the system from assistance areas and direct customer load control capability. The amount by which the resources exceed the system firm peak demand is referred to as reserve capacity. Adequate reserve capacity allows for unplanned outages or regular maintenance of generating units. Adequate reserve capacity also protects against capacity shortfalls in the event of higher than anticipated system peak load due to short-term temperature fluctuations. If system reliability were the only concern, electric utilities would plan their system with very high reserve capacity. However, the cost to maintain reserves must also be considered. Therefore, reliability and cost must be balanced. In long-range planning studies, some measure must be employed to determine the appropriate level of reserve capacity.

2.1.1 Measures of Reliability

Probabilistic methods are employed by many utilities as part of their evaluation of generation adequacy. The most commonly used is the Loss-Of-Load-Probability (LOLP). This represents the projected equivalent number of days per year that the capacity resources may be insufficient to serve the daily peak.

Deterministic methods are relatively easier to calculate than probabilistic methods. The 1998 Reliability Assessment uses reserve margin relative to the system seasonal firm peak to measure reliability deterministically.

2.1.2 LOLP Analysis Modeling

The LOLP method combines the probabilities of unplanned outages, planned maintenance and seasonal capabilities of both generation equipment and load control programs with the system

coincident firm peak loads. A table of all the possible capacity combinations is made for all the generating units not on scheduled maintenance. This table determines the discrete and cumulative probability that the generating system will not be able to meet each possible load level. The annual LOLP is calculated by summing the daily LOLP values for every day of the year.

The Tie Line and Generation Reliability (TIGER) model was selected by the RWG to calculate LOLP values for the ten year planning horizon. TIGER is a probabilistic computer model which accounts for system characteristics on demand and energy requirements, generating unit capacity and availability, energy management resources, firm transactions and emergency assistance from interconnected systems. Although TIGER is considered suitable for the assessment of peninsular Florida reliability, the model does not factor in the effects of intrastate transmission and short-term operational capabilities that may occur in real-time system operations.

The TIGER model can provide calculations of LOLP as well as loss of load hours (LOLH) and expected unserved energy (EUE). TIGER can be used as a single- or dual-area model allowing for the representation of both primary and assistance areas. The FRCC's 1998 Reliability Assessment is based on a single area model that includes the equivalent assistance from the Southeastern Electric Reliability Council (SERC) region through the transmission interconnections. This equivalent assistance is represented as a generating resource within the FRCC region.

In March 1991, the Florida Electric Power Coordinating Group (FCG) evaluated the TIGER program by confirming the IEEE benchmark case. As in the IEEE test case verification process, the FCG manually verified several of the calculations performed by the program. This process confirmed the correct treatment of the conditions modeled and verified the accuracy of the calculations by the program. Within the current methodology, the FCG found that TIGER was suitable for peninsular Florida reliability assessment.

2.1.3 Reserve Margin Analysis

Reserve margin is calculated by subtracting the system non-coincident firm peak load from available firm capacity resources. The resulting difference is expressed in MW or as a percentage of the firm load. The system firm load is determined for the annual or seasonal non-coincident peak by subtracting the demand reduction effects of conservation, interruptible load, and load management programs from the projected total load. The firm available capacity includes the installed generation, reflecting the appropriate seasonally adjusted capability ratings of utility generators and firm Qualifying Facilities, as well as the firm net purchases and sales relative to peninsular Florida.

The RWG calculated reserve margins for both the winter and summer projected hourly integrated non-coincident firm peaks for peninsular Florida. These winter and summer peaks are assumed to occur during the months of January and August, respectively, for planning purposes. The firm system load accounts for the cumulative load-reduction effects of existing and future conservation programs that have reduced both the system demand and energy requirements in the FRCC region. Load management and interruptible loads are modeled as

dispatchable resources assumed to be available during the peak to further reduce the system load. While load management and interruptible load contribute to reserve margin, the frequency of utilization of these resources is dependent on the availability of supply side resources and temporary fluctuations in load. Frequency of use of these resources is not reflected in reserve margin calculations, but is addressed in LOLP analysis.

The firm available capacity is estimated by adding the seasonally adjusted capability of the existing units and the firm purchases and subtracting firm sales, at the time of the system peak. All generating units are assumed to be available at time of system peak (i.e., their capability is not adjusted for forced outages and scheduled maintenance is not planned for seasonal peaks). All firm purchased power transactions from non-utility generators within the state are included in the reserve margin calculation. The net firm interchange, external to the FRCC region via the electric interconnections, is included in the reserve margin calculation. Potential as-available purchases or economy purchases are not included in reserve margin calculations.

2.1.4 Suitability of the 15% Reserve Margin Standard

In 1998, the FRCC was charged with the task of developing a methodology and procedures for assessing resource adequacy. In Florida, the dual reliability criteria of reserve margin and Loss-of-Load-Probability (LOLP) are commonly used. Because, in 1997, extensive analyses of LOLP were conducted, the decision was made to also focus in 1998 on the suitability of a reserve margin standard. Because several utilities currently use a 15% reserve margin criterion, the suitability of utilizing the 15% value as a planning standard was analyzed.

The analysis started by recognizing that reserve margin calculations consist of the following 5 components:

1) forecasted loads at peak hours;
2) availability of utilities' own generation at peak hours;
3) availability of firm imports at peak hours;
4) availability of firm Qualifying Facility (QF) power at peak hours; and,
5) availability of load management at peak hours.

Reserve margin projections essentially assume, as a starting point, that each of these 5 components are accurate (i.e., are forecasted with 100% accuracy). The projections are then used with the understanding that an inaccurate forecast in one or more of these components will occur (for example, a peak load will be somewhat different than projected, generating unit(s) may be unavailable at the peak hour, etc.). The starting reserve margin value then changes as inaccuracies in the component forecasts are accounted for. In theory, the starting reserve margin value will be large enough to ensure that generation still meets or exceeds load after these adjustments are accounted for.

In order to test that the projected reserve margins for the peninsula are adequate, the FRCC looked back at the last 5 years (1993-1997) of actual data for these reserve margin components in order to see how the projections for those same 5 years matched up with the actual data. In this way, the FRCC determined the historic accuracy of the utilities' ability to forecast values for each of the five reserve margin components.

The historic accuracy levels (expressed in terms of a % of the forecasted values) were then applied to the FRCC's current projections of annual reserve margins for the peninsula. These "starting point" reserve margin projections were thus revised by applying the historic accuracy "adjustment factors".

The suitability of the FRCC's "starting point" reserve margin projections were then judged by the following guidelines:

a) If the revised reserve margins are greater than or equal to zero, then the starting point reserve margins are suitable for maintaining electric reliability.
b) However, if the revised reserve margins are less than zero, then the starting point reserve margins are not suitable for maintaining electric reliability.

In addition, the suitability of the 15% reserve margin standard was then judged by the following guidelines:

a) If the difference between the starting point and the revised reserve margin values is less than or equal to 15%, then the 15% reserve margin standard is suitable for maintaining electric reliability.
b) However, if the difference between the starting point and revised reserve margin values is greater than 15%, then the 15% reserve margin standard is not suitable for maintaining electric reliability.

The FRCC's analysis showed that both the "starting point" reserve margins projected by the utilities, and the 15% reserve margin standard, are suitable. Exhibit II is a summary of the suitability study. It includes a description of the methodology and the detailed results of the study which confirm the 15% standard.

Currently, the FRCC is considering the application of this methodology and this standard as an additional basis for determining adequacy of resources. Adoption of this standard requires action by the FRCC Board. If adopted, the FRCC would conduct on an annual basis an assessment of resource adequacy for the FRCC region as a whole.

2.2 Key Assumptions

2.2.1. Peninsular Florida Demand and Energy Forecast

The development of a long-term demand and energy forecast for peninsular Florida involved aggregating the individual utility projections from the 1998 EIA-411 and 1998 Ten Year Site Plan filings. The aggregation process was completed by the FRCC and combined data for 59 utilities in the FRCC region. In certain cases, utilities from within the region provided either partial or full requirements power to other utilities. With two exceptions, the energy requirements of these partial and full requirements purchasing utilities were aggregated into the regional forecast based upon projections provided by the utilities supplying the power. Those exceptions were the forecasts of energy requirements for Seminole Electric Cooperative, Inc. (SEC) and Florida Municipal Power Agency (FMPA). SEC and FMPA both provided aggregate forecasts representing their member utilities.

In compiling the data, the process was carefully checked to eliminate double counting of the partial or full requirement loads. In addition, the forecasts from the larger utilities were also checked against their individual company 1998 Ten Year Site Plans.

Seasonal demand forecasts provided by each utility are not assumed to be coincident with respect to the occurrence of the maximum electricity demand experienced by peninsular Florida. Therefore for purposes of the LOLP analysis, where monthly data is required, monthly demand diversity factors were used to develop coincident peak demands. A detailed discussion of how these factors were developed is discussed later in this section of the report.

Once the data compilation was completed, the RWG examined the forecast for reasonability. As part of this process, the trends embodied in the aggregated peninsular Florida demand and energy forecast were compared to the population projections from the University of Florida's Bureau of Economic and Business Research. The reason for utilizing the state population forecast to examine utility forecast reasonability was the fact that for most utilities, the service area population projection drives the residential customer forecast, which, in turn, impacts the load projection. This is because population trends correlate with residential electric sales patterns. In addition, population and residential customer growth has a strong influence on local commercial and public authority electricity sales since these sectors provide services to the local population.

The projections for Florida population provided by the University of Florida indicate that moderation in growth is expected in the FRCC region. That is, Florida population is expected to increase at an annual rate of 1.6% between 1998 and 2007, a reduction from the 2.0% pace of the previous ten years. In addition, the annual number of new state inhabitants is also projected to decrease from 265,000 per year between 1988-1997 to 248,000 per year in the coming decade.

The peninsular Florida demand and energy forecast shows similar trends to those projected for population. The annual percent growth for summer and winter peak demand is expected to moderate between 1998-2007 from the pace experienced between 1988-1997. In addition, average annual energy requirements over the next ten years are also projected to decline. For 1998-2007, summer firm peak is projected to increase by 773 MW per year, below the 900 MW annual increase experienced between 1988-1997. For winter firm peak, annual average additions are projected to be 869 MW, compared to the 995 MW annual average gain reported over the past ten years. However, it is notable that the average winter temperatures for the past ten years have been moderately higher than the long term (50 year) average. Finally, average annual energy increases for the 1998-2007 period are expected to slow to 4,831 GWH from 4,932 GWH.

2.2.1.1 Hourly Load Shape

The objective of producing a "seed year" load shape is to provide an 8,760 hourly representation of a typical load profile year for peninsular Florida. In previous studies, the hourly annual load profile was created from aggregated utility load data for the 1980 to 1989

period. From this data, the most representative example for each of the twelve months was chosen from the 1980 to 1989 data based on weather conditions and load factor.

Since hourly load data for the state has not been collected and aggregated since the early 1990's, a new approach was needed to develop an updated "seed year" load profile. In the 1997 RWG study a new load profile was generated by aggregating projected hourly data from the individual utilities. This new method was believed to be an improvement over using the historic data because each of the hourly forecasts provided by the utilities were weather normalized, a necessary adjustment which could not be done with the same precision in the original approach.

It is important to note that the resulting 1997 hourly load shape, despite being constructed from a more preferred methodology, required further refinement in its aggregation of individual utilities loads for the 1998 study. This methodology is further detailed later on in this section of the report.

2.2.1.2 Monthly Energy Allocation Factors

The energy allocation factors represent the portion of annual net energy for load that falls within each month of the year. In previous studies, these factors were developed by taking the average of each month's contribution over a period of past years. For this year's study, the monthly energy allocation factors are the energy factors obtained from the seed year load shape. The aggregated 8,760 hourly load profile used to devélop the "seed year" load shape

was summarized for each month, and each month's contribution became the monthly energy allocation factors, as shown below:

MONTHLY ENERGY ALLOCATION FACTORS

JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
0.0776	0.0713	0.0732	0.0734	0.0865	0.0918	0.1003	0.0995	0.0924	0.0831	0.0733	0.0776

The energy allocation resulting from the 8,760 hourly load shape methodology is an improvement over the previous method of using historical data because the forecast information has already been weather normalized. In the 1997 study it was determined that the load shape-derived allocation factors were similar to the historical allocation factors. This is also the case for the 1998 study, where the allocation factors derived from the load shape and the historical allocation factors indicate a similar profile.

2.2.1.3 Monthly Peak Demand Diversity Factors

As previously mentioned, the aggregated forecast of seasonal peak demands represents a non-coincident peak for peninsular Florida. In order to determine what the level of seasonal peak demands would be given a coincident occurrence, it is necessary to examine the relationship between the peninsular peaks and non-coincident demand. The factors that represent the relationship or ratio between the monthly coincident peak and the non-coincident seasonal peaks are called the monthly peak demand diversity factors.

In previous studies, the monthly peak demand diversity factors were developed from past data, just like the hourly load profile and the monthly energy allocation factors. As stated before, however, this historic information has not been collected since the early 1990's.

In the 1997 study, the coincident monthly peaks from the aggregated 8,760 hourly load profile were compared to the non-coincident seasonal peaks. November through March represented the winter period and April through October represented the summer period. The results showed a sharp differential when compared to the historic diversity factors which were used in the prior planning study. The reason was that while individual utility monthly peak projections were expected to occur during a weekday, each company would have to choose the specific day within the month subjectively. In doing this, the projected individual utility peaks did not usually match up on the same day in each month. Of course, in actual experience utility peaks normally occur around the same day. Because of this, the diversity factors from the historic data were considerably higher than those from the non-aligned forecast profile. To remedy this limitation, the monthly utility peak projections were aligned so that they corresponded to the same day in each month.

In this year's study, the aggregation is done on the basis of aligning each week and each month, instead of just aligning the peak day after the hourly loads have been aggregated chronologically. To align each utility's load a given utility's load shape had to be selected with which all other utilities load could be aligned. Given that FPL's load represents close to 48% of the total load for the state and because the state usually peaks on the same day FPL

peaks, this utility's load shape was chosen to serve as the basis to which the other utilities in the state could be aligned.

When diversity factors are calculated on the basis of the coincident peaks derived from the new hourly load seed shape, compared to the aggregated non-coincident peak, the resulting diversity factors are very similar to the historic diversity factors. This result suggested that the seed year together with the diversity factors for monthly peak demands could be used in the 1998 Reliability Assessment study. The monthly diversity factors which were used in this study are shown below:

MONTHLY DIVERSITY FACTORS											
JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
0.9750	0.9148	0.7986	0.7512	0.8535	0.9406	0.9587	0.9778	0.9481	0.8341	0.6857	0.8339

2.2.2 Generating Unit Operating Characteristics

In this study, the assumptions for peninsular Florida included the existing capacity, certified capacity and all planned and proposed capacity additions. Although the individual utility plans are based on the 1998 FRCC Load and Resource Plan, additional data was needed for accurate modeling. Data supplied by the utilities included summer and winter capacity ratings, forced outage rates, planned maintenance periods, as well as in-service and retirement dates. This data was requested and carefully reviewed by the RWG.

2.2.3 Energy Management Resources

The individual utilities have identified energy management resources to help meet future demand and energy requirements. The utilities of peninsular Florida have implemented a variety of demand-side management programs measures including various energy conservation programs, load management programs, interruptible load rates, and self-service generation to reduce the system demand and energy requirements. The projected impacts of these efforts were accounted for in the RWG work.

2.2.4 Qualifying Facilities

Individual utilities provided data on the existing, contracted, and proposed non-utility generators (NUG) used in the 1998 Reliability Assessment. The availability of existing NUG capacity was based on minimum contractual requirements. Only firm, contracted capacity was included in the 1998 Reliability Assessment

2.2.5 SERC Assistance and Firm Interstate Transactions

The SERC assistance includes firm and non-firm capacity assistance from Southern Company and other energy resources within the SERC region. The Georgia Integrated Transmission System (GITS) to Florida import interface is rated at 3,600 MW and represents the maximum assistance available from SERC. Firm unit power sale contracts and the Scherer Unit 4 capacity represent approximately 2,700 MW of import allocation. The balance of the firm transmission capability of 900 MW is assumed to be available for emergency assistance and is modeled as a single generating unit with high availability.

2.3 Generic Unit Capacity Modeling

The study assumed that any future new unit additions would be dual fuel technologies utilizing natural gas and distillate oil (gasified coal can also be used). The two generating technologies considered were (1) simple cycle, combustion turbine and (2) combined cycle units.

The capital investment of a combined cycle is higher than that of a combustion turbine but is still substantially less than that of a coal-fired unit. Because of the modular configuration of combustion turbines and heat recovery/steam turbines, combined cycle units may also be operated as simple cycle combustion turbines, increasing dispatch flexibility and yielding high unit availabilities.

2.3.1 Operating Characteristics

Simple cycle combustion turbines are characterized by short construction times, lower installed and fixed operating costs, but relatively lower efficiency, making them suitable for peaking operation. Simple cycle turbines can also be designed and constructed so that they constitute the first phase of a phased combined cycle construction strategy, and become available to serve the load several months to a year before the second phase or steam cycle is completed.

Combined cycle technology, which is more suited to intermediate and base load operations has been evolving since the installation of the first General Electric and Westinghouse "F" type units. The "F" combustion turbines are characterized by a higher firing temperature, resulting in a much lower overall combined cycle heat rate. The next generation of advanced

combustion turbines is designated as the "G" type turbine. These turbines are currently available and form the bases for the technologies selected for this study. The operating characteristics of the "G" combustion turbine and combined cycle technologies are shown in the figure below:

ALTERNATIVE TECHNOLOGIES
OPERATIONAL CHARACTERISTICS AND FUEL REQUIREMENTS

	Simple Cycle Combustion Turbine		Combined Cycle "G" Technology
Capacity, MW			
Winter (35 deg.F)	242		363
ISO (59 deg. F)	230		346
Summer (95 deg.F)	200		310
Heat Rate, (Btu/kWh, HHV)			
100%	9,955		6,600
75%	10,801		6,768
50%	12,344		7,389
Unit Availability			
Equivalent Planned Outage (%)	0.96		2.87
Equivalent Planned Outage (wks/y)	0.50		1.50
Equivalent Unplanned Outage (%)	1.00		1.00
Equivalent Availability (%)	98		96
Capacity Factor,%	5	5	96
Primary Fuel Type	Natural Gas	No. 2 Oil	Natural Gas
Fuel Requirements			
Winter - Million SCF/day	3		55
BBL/day		497	
Summer - Million SCF/day	2		47
BBL/day		411	
Annual - Million SCF/yr	1,003		19,235
BBL/yr			

This data is being provided for references purposes. While generally accurate, specific unit planned additions will reflect the characteristics of the individual manufacturer's designs.

2.3.2 Timeline for Bidding, Permitting and Constructing New Generating Unit Capacity

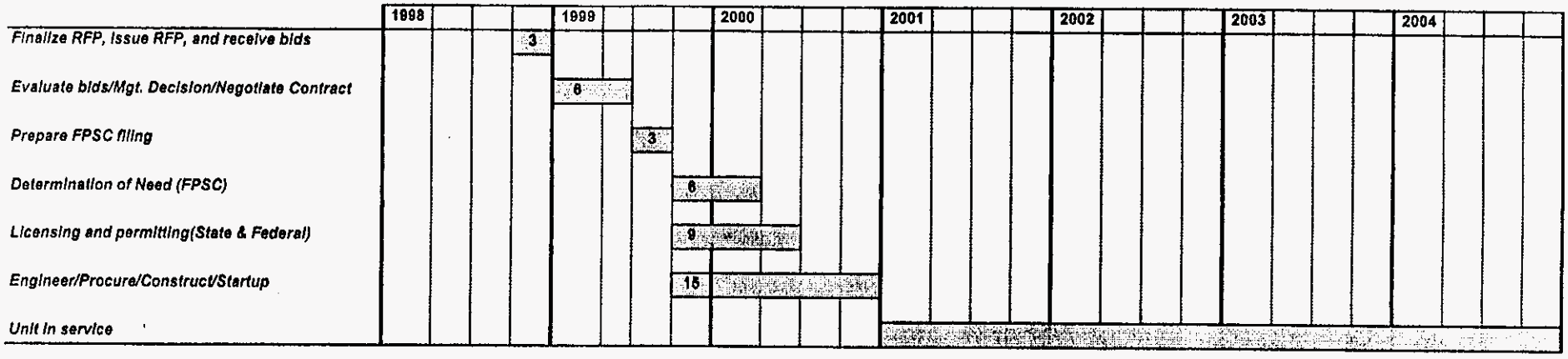
Two project timelines of activities and durations necessary to support the construction of a simple cycle combustion turbine and a combined cycle unit were developed as part of this study. It was assumed that these units would be constructed at an existing site since there are sufficient available sites identified in individual ten-year site plans. Generally, the major activities required to develop a typical generation project are: Determination of Need, licensing and permitting, engineering and design, equipment procurement, construction and start-up.

Some of these activities are necessarily concurrent. For example, a certain amount of engineering and design are required in order to develop a cost estimate for economic justification during the Determination of Need. Additional engineering and design are required during the licensing and permitting phase to identify emissions, water requirements, etc.

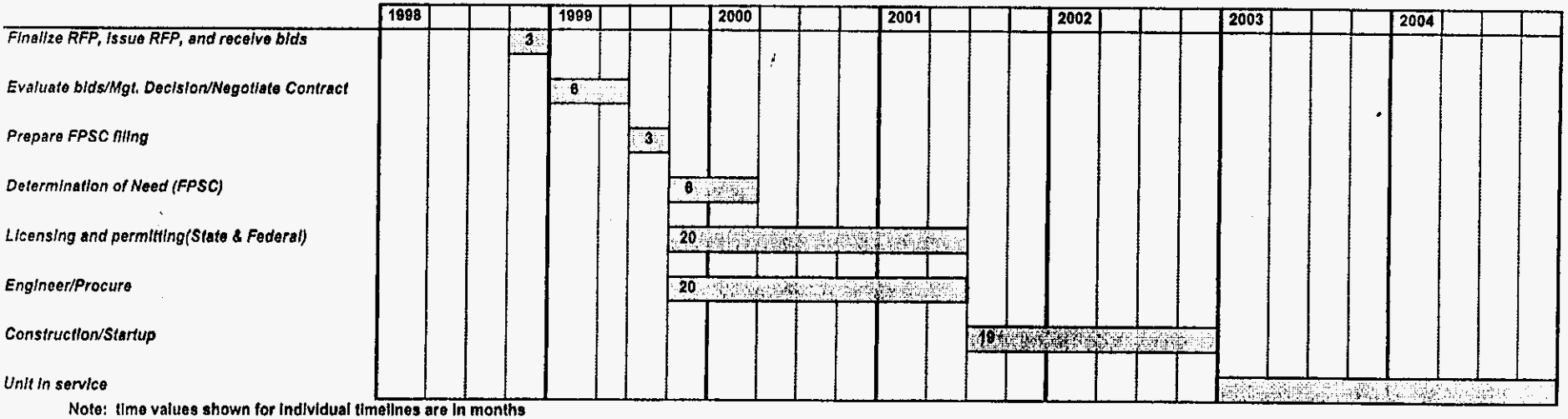
In addition, twelve months were allocated in both timelines to allow for capacity bidding and the negotiation of a power sales agreement, if necessary. The total project time, for the combustion turbine and combined cycle technologies are 27 months and 51 months respectively as shown below:

TIMELINE OF ACTIVITIES NEEDED FOR NEW CAPACITY ADDITIONS AND NATURAL GAS DELIVERY EXPANSION

Unit: 230 MW CT ("G" Technology)



Unit: 346 MW CC ("G" Technology)



Note: time values shown for individual timelines are in months

2.4 Natural Gas Transmission Capability

Supply assumptions for natural gas are based on the Florida Gas Transmission (FGT) expansion capabilities of the interstate pipeline system. The current, firm average delivery capability is estimated at 1,455 million cubic feet per day of firm capacity. The FGT seasonal load profile is the opposite of most interstate pipelines in that its sustained system peak load is in the summer. The electric generation customers in Florida account for approximately 80% of the throughput on the FGT system. They have a seasonal load pattern characterized by higher summer demands due to their air conditioning load requirements. FGT also transports gas for Florida local distribution companies that have a seasonal load pattern characterized by high demands during the winter due to heating requirements of their residential and small commercial customers. FGT also serves industrial customers in Florida that take gas at fairly constant rates during the year, as well as industrial customers in Florida that take gas on a seasonal basis. In addition, natural gas supply restrictions, which may exist in certain geographical regions of peninsular Florida, were not considered in the 1998 Reliability Assessment.

2.4.1 Determination of Future Natural Gas Requirements

The gas requirements for future combined cycle capacity additions were estimated from Section II of the FRCC 1998 Load and Resource Plan. The total combined cycle capacity projected to be in service through 2007 is approximately 6,000 MW. Assuming an average full load, higher heating value, heat rate of approximately 6,600 Btu/kWh (i.e., available from the current advanced combustion turbine technology), approximately 960 million cubic feet per day (mcf/day) of additional gas transportation capacity will be required.

Currently, the state electric utilities can utilize about 410 mcf/day for use in dual fueled (#6 fuel oil and natural gas) which could be committed towards the incremental need of 960 mcf/day. This would leave a net increase of 550 mcf/day over the next 10 years. As explained by FGT in Exhibit I, this transportation capability can be achieved by adding compression and pipeline looping.

2.4.2 Timeline for Permitting and Constructing Natural Gas Transmission Capacity

Once the projected natural gas requirements were developed, the RWG worked with Florida Gas Transmission Company (FGT) to develop a reasonable timeline for expansion of the natural gas transmission facilities. Those requirements point to a need for expansion as early as the fall of 2000. FGT anticipates that in order to meet this schedule it will be filing an expansion project petition with the Federal Energy Regulatory Commission by year end 1998. See Exhibit I, FGT memorandum.

3. Reliability Assessment and Results

3.1 Reliability of Peninsular Florida

3.1.1 Reserve Margin Analysis

The reserve margin analysis indicated that the peninsular Florida electric system maintains summer and winter firm reserves that exceed 15% through the entire ten-year planning period. The projected reserve margins are shown on page 19 of the "1998 Load and Resource Plan, Florida Reliability Coordinating Council".

3.1.2 Assisted LOLP Analysis

Annual assisted LOLP values were developed for two scenarios: existing and certified units, only; and existing, certified, planned and proposed capacity additions. The second scenario became the Reference Case. In the two scenarios, the annual frequency of interruptible load and load management resource usage were limited to 10 and 25 days, respectively.

The LOLP analysis indicated that the reference case for the Peninsular Florida Electric system does not exceed 0.1 days per year for the ten year planning period (see table below).

1998 FRCC Reliability Assessment

RWG Reliability Review

LOLP ANALYSIS (Reference Criterion = 0.1)

(DAYS PER YEAR)

Reference Case

YEAR	EXISTING AND CERTIFIED	SUMMER RESERVE MARGIN (%)	WINTER RESERVE MARGIN (%)	EXISTING, CERTIFIED, PLANNED AND PROPOSED *	SUMMER RESERVE MARGIN (%)	WINTER RESERVE MARGIN (%)
1998	0.000002	19	18	0.000002	19	18
1999	0.000002	19	17	0.000001	19	17
2000	0.000094	18	14	0.000033	18	15
2001	0.015887	16	16	0.000876	17	17
2002	0.004799	18	15	0.000099	19	18
2003	0.044912	16	11	0.000047	20	19
2004	0.139189	12	8	0.000093	20	18
2005	1.029825	10	5	0.000148	20	17
2006	4.325030	7	3	0.000610	19	17
2007	14.550716	5	0	0.000477	19	15

* Reference case: Interruptible load = 10 days, load management = 25 days.

3.1.3 LOLP Sensitivity Analyses

Several LOLP sensitivity analyses were also conducted the 1998 Reliability Assessment:

- Two sensitivities on limiting the operation of load management/interruptible loads
- Three forced outage rate sensitivities
- A load forecast sensitivity
- Three sensitivities on the availability of peninsular Florida's import tie line assistance, and

In addition, the system's LOLP was tested under extreme (pessimistic) assumptions by employing combinations of sensitivities:

- Two cases combining the load forecast sensitivity with the forced outage sensitivities, and
- A case combining the load forecast sensitivity with a limited tie line assistance sensitivity.

3.1.3.1 Frequency of Operation of Load Management and Interruptible Load

The following sensitivities were included to quantify the effects on LOLP of operating load management and interruptible loads at different frequencies of utilization:

1. No load management or interruptible load was operated
2. Only load management was operated (up to 25 times/year). No interruptible load was assumed to be operated

The results of these sensitivities are shown in the table on the next page.

1998 FRCC Reliability Assessment

RWG Reliability Review

LOLP ANALYSIS (Reference Criterion = 0.1)

(DAYS PER YEAR)

Impact of Interruptible Load and Load Management

Sensitivities

YEAR	REFERENCE CASE	TOTAL LOAD CASE *	NO INTR LOAD CASE **
1998	0.000002	0.001310	0.000009
1999	0.000001	0.003348	0.000004
2000	0.000033	0.065367	0.000134
2001	0.000876	0.189506	0.001716
2002	0.000099	0.083615	0.000275
2003	0.000047	0.021429	0.000089
2004	0.000093	0.033980	0.000182
2005	0.000148	0.032854	0.000256
2006	0.000610	0.116251	0.001095
2007	0.000477	0.084130	0.000800

* Total Load Case : Interruptible Load = 0 Days ... Load Management = 0 Days

** No Intr Load Case : Interruptible Load = 0 Days ... Load Management = 25 Days

Compared to the reference case, which assumes 10 and 25 days of interruptible load and load management per year, respectively, the assisted LOLP exceeds 0.1 days per year in 2001 and 2006 for the "Total Load", case. In the second sensitivity, where load management is limited to 25 days per year and interruptible load is not operated, the assisted LOLP criterion of 0.1 days per year is not exceeded.

3.1.3.2 Generating System Availability

Several sensitivities were run to quantify the effect of unit availability on annual net LOLP. First, the equivalent availability of each peninsular Florida unit (i.e., including qualifying facilities and firm purchases) was reduced by 2%[2]. This is the same level which was assumed in last year's study. The results of this sensitivity show that the LOLP criterion is not exceeded in any year.

Additionally, two more sensitivities were run to reflect varying unit availability conditions. These availability degradations were only applied to the steam units. One reflects the average availability of the steam units over the most recent 5 year period of 1993-1997 (2.7% incremental EFOR), and the second reflects the same over the 10 year period of 1988-1997 (5.6% incremental EFOR).

As can be seen in the table on the next page, one sensitivity shows LOLP violations in 2001, 2006, and 2007. The second case shows no LOLP violations.

[2] The equivalent availability of the system was reduced by increasing the equivalent forced outage rate of each resource by 2%. The planned outage rate was held constant. This results in a more severe impact on LOLP since TIGER would, otherwise, be able to move the planned or scheduled maintenance in order to minimize LOLP.

1998 FRCC Reliability Assessment
RWG Reliability Review

LOLP ANALYSIS (Reference Criterion = 0.1)

(DAYS PER YEAR)

Impact of Forced Outage Rate Increases

Sensitivities

YEAR	REFERENCE CASE	2% SYSTEM EFOR INCREASE ***	Approx. NERC GADS 5 Year Avg. (1993-1997) 2.7% STEAM EFOR INCREASE **	Approx. NERC GADS 10 Year Avg. (1988-1997) 5.6% STEAM EFOR INCREASE *
1998	0.000002	0.000472	0.000546	0.004716
1999	0.000001	0.000279	0.000331	0.005370
2000	0.000033	0.002915	0.003038	0.033233
2001	0.000876	0.037724	0.036137	0.212240
2002	0.000099	0.008534	0.008687	0.093176
2003	0.000047	0.005334	0.004961	0.055505
2004	0.000093	0.007601	0.007364	0.073919
2005	0.000148	0.011175	0.010295	0.096959
2006	0.000610	0.031823	0.028665	0.221299
2007	0.000477	0.028468	0.023872	0.188203

* The equivalent forced outage rate (EFOR) was increased by 5.6% on all utility owned and operated steam generating units only.
The sensitivity case level of activation for interruptible load (15 days) and load management (50 days) was assumed in this case.

** The EFOR was increased by 2.7% on all utility owned and operated steam generating units only.
The reference case level of activation for interruptible load (10 days) and load management (25 days) was assumed in this case.

*** The EFOR was increased by 2% on all utility owned and operated generating units and assistance area only.

The reference case level of activation for interruptible load (10 days) and load management (25 days) was assumed in this case.

It should be noted that, in the reference case, the equivalent availability for the peninsular system is 89.6%. When the system-wide equivalent forced outage rate is increased by 2%, the peninsular equivalent availability drops to 87.7%. Finally, raising the equivalent forced outage rate of the steam units by 5.6% reduces the peninsular equivalent availability to 85.7%. This level of unit availability in the state has been exceeded each year since 1993. Furthermore, the increase of 5.6% represents a near 100% increase in the base EFOR of each of the state's nearly two hundred steam units which is very unlikely.

3.1.3.3 Higher Demand and Energy Forecast

In this sensitivity, variations in the load forecast were considered. The load forecast sensitivity assumed 2% higher loads in the first year of the study, with a compounding annual error which resulted in a 10% forecast error by the last year of the study. The results (table below) show that LOLP is exceeded in 2005-2007.

1998 FRCC Reliability Assessment
RWG Reliability Review

LOLP ANALYSIS (Reference Criterion = 0.1)

(DAYS PER YEAR)

Load Forecast Error = 2% to 10% Over Ten Years

Sensitivity

YEAR	REFERENCE CASE	LOAD FORECAST ERROR *	LOAD FORECAST ERROR (%)
1998	0.000002	0.000002	2.00%
1999	0.000001	0.000007	2.89%
2000	0.000033	0.000503	3.78%
2001	0.000876	0.020818	4.67%
2002	0.000099	0.009687	5.56%
2003	0.000047	0.012261	6.44%
2004	0.000093	0.039683	7.33%
2005	0.000148	0.131369	8.22%
2006	0.000610	0.820297	9.11%
2007	0.000477	1.484552	10.00%

* Interruptible Load = 15 Days ... Load Management = 50 Days

The load forecast error was applied to the winter and summer seasonal peak demands each year. The other monthly demands were increased as a percentage of the seasonal peaks. The annual net energy for load was also increased.

This sensitivity makes the assumption that utilities do not react to a constantly increasing peak and energy demand. In reality, the utilities' load forecasting processes are designed to "catch" this persistent increase in demand which will most likely be driven by fundamental market conditions such as population growth or increased economic activity, indicators which are closely followed by the utilities' load forecasters.

3.1.3.4 Reduction in Assistance from SERC Region

The effect of assistance from the SERC region through the Florida/Georgia interface was evaluated in this sensitivity. First, potential assistance was curtailed during the winter peak (i.e., no assistance was made available during the months of December through March). This had virtually no impact on LOLP and the 0.1 days per year criterion was not exceeded in any year.

In the second part of this sensitivity, potential assistance was curtailed during the summer peak (i.e., the month of August). In this case, the impact on LOLP was slightly greater, but still not enough to violate the criterion in any year.

Finally, all assistance was curtailed, year round. Again, LOLP increases slightly, but the criterion is not violated in any year. The results of these runs are shown below:

1998 FRCC Reliability Assessment

RWG Reliability Review

LOLP ANALYSIS (Reference Criterion = 0.1)

(DAYS PER YEAR)

Impact of Reduced Assistance Area Availability

Sensitivities

YEAR	REFERENCE CASE	NO ASSISTANCE IN WINTER *	NO ASSISTANCE IN SUMMER **	NO ASSISTANCE JAN. through DEC.
1998	0.000002	0.000002	0.000038	0.000081
1999	0.000001	0.000001	0.000001	0.000030
2000	0.000033	0.000048	0.000361	0.000672
2001	0.000876	0.001111	0.007355	0.016381
2002	0.000099	0.000162	0.001109	0.002188
2003	0.000047	0.000059	0.000704	0.001370
2004	0.000093	0.000112	0.001007	0.002085
2005	0.000148	0.000169	0.001541	0.003050
2006	0.000610	0.000773	0.005649	0.011189
2007	0.000477	0.000577	0.004796	0.009450

* Assistance Area = 0 in December through March

** Assistance Area = 0 in August

3.1.3.5 Combinations of Sensitivities

There are three parts to this sensitivity. In the first the 2% to 10% load forecast error is combined with no winter assistance. In this case, LOLP is exceeded in 2005-2007 as shown below:

1998 FRCC Reliability Assessment
RWG Reliability Review

LOLP ANALYSIS (Reference Criterion = 0.1)

(DAYS PER YEAR)

Load Forecast Error = 2% to 10% Over Ten Years plus No Winter Assistance

Combination Sensitivity

YEAR	REFERENCE CASE	2% to 10% LOAD FORECAST ERROR and NO WINTER ASSISTANCE *	LOAD FORECAST ERROR (%)
1998	0.000002	0.000002	2.00%
1999	0.000001	0.000012	2.89%
2000	0.000033	0.000980	3.78%
2001	0.000876	0.031755	4.67%
2002	0.000099	0.016068	5.56%
2003	0.000047	0.016354	6.44%
2004	0.000093	0.054545	7.33%
2005	0.000148	0.160786	8.22%
2006	0.000610	1.007119	9.11%
2007	0.000477	1.743676	10.00%

* Interruptible Load = 15 Days ... Load Management = 50 Days

In the second, the 2% to 10% load forecast error is combined with a 2% increase in the system equivalent forced outage rate. In this case, LOLP is exceeded in 2001-2007. Finally, the same load forecast error is combined with a 5.6% increase in the equivalent forced outage rate of the steam units. If this combined sensitivity were to occur, LOLP would be violated in the years 2000-2007.

1998 FRCC Reliability Assessment
RWG Reliability Review

LOLP ANALYSIS (Reference Criterion = 0.1)

(DAYS PER YEAR)

Load Forecast Error = 2% to 10% Over Ten Years plus 2% System EFOR Increase
Load Forecast Error = 2% to 10% Over Ten Years plus 5.6% Steam EFOR Increase

Combination Sensitivities

YEAR	REFERENCE CASE	2% to 10% LOAD FORECAST ERROR * and 2% EFOR INCREASE	2% to 10% LOAD FORECAST ERROR * and 5.6% EFOR INCREASE	LOAD FORECAST ERROR (%)
1998	0.000002	0.000483	0.017203	2.00%
1999	0.000001	0.001082	0.035918	2.89%
2000	0.000033	0.025118	0.347835	3.78%
2001	0.000876	0.435757	2.826477	4.67%
2002	0.000099	0.273135	2.100592	5.56%
2003	0.000047	0.350092	2.421035	6.44%
2004	0.000093	0.730735	4.069841	7.33%
2005	0.000148	1.781390	7.616925	8.22%
2006	0.000610	6.320654	18.573919	9.11%
2007	0.000477	9.743308	24.544994	10.00%

* Interruptible Load = 15 Days ... Load Management = 50 Days

3.1.3.6 Summary of Sensitivity Analyses

Sensitivity analysis is frequently employed in the course of planning studies in order to test the robustness of the proposed plans. Similarly, in this study several sensitivities were performed addressing different variables: non-firm load, generating unit forced outage rates, high demand and energy and reduced tieline assistance from SERC. In addition, combination sensitivities were also run at the request of the FPSC staff. These were: high demand and energy with no winter tieline assistance, and high demand and energy with increased forced outage rates.

These sensitivities showed the following.

- Load management/interruptible load

  Assuming that none of the utilities load management/interruptible load capabilities were to be utilized then the analysis shows small LOLP violations in 2001 and 2006. Load management/interruptible loads represent a long term resource for the utilities of the FRCC which is being continuously monitored by them to verify MW capability. It is considered to be an integral component of the FRCC resource mix and contributes towards meeting its reliability standards. If degradations in capability begin to materialize then proper steps will be taken to restore or replace those capabilities.

- Generating unit EFOR

  This sensitivity shows that a 2% and a 2.7% forced outage rate increase will not cause any violations. However, an increase of 5.6% for an entire class of units will cause several violations.

An increase of 5.6% will nearly double the current FRCC steam units' EFOR. This is a pretty severe assumption which would not be very likely for the entire system given that the increase is so substantial and that the generation system consists of nearly two hundred steam units.

- High demand and energy

  This case assumes that peak demand is increased from 2% to 10% between 1998 and 2007. The shoulder peaks are also increased by their historical relationship to the peaks. This results in not only a high peak demand but also a higher energy growth. The sensitivity shows violations occurring in 2005 and beyond.

  Conditions which lead to persistent energy forecast growth are due to fundamental factors such as demographic shifts and economic activity. These factors are closely monitored by utilities and are included in their load forecasting models. As such, utilities will foresee the shortfall in capacity and will react accordingly. Additionally, these levels of increased demands will also violate reserve margins sooner than the LOLP violations and as such will guide utilities to add capacity.

- Reduced tie-line assistance

  No violations were found.

- Combination sensitivities

  These sensitivities combined conditions that individually are not likely to occur. The probability of a combination of them occurring without an appropriate response from the affected utilities is very low and, as such, very unlikely.

4. Conclusions

The reserve margin analysis indicates that peninsular Florida maintains summer and winter reserve levels in excess of 15% throughout the entire ten-year planning period. This level is considered to provide adequate levels of reserve margin for reliable service.

Furthermore, with most likely assumptions the peninsula electric system does not exceed the 0.1 days per year LOLP criterion in any year of the ten-year planning horizon.

Some sensitivities run indicated LOLP violations, however, the cases examined represent either an unlikely scenario of occurrence or utilities have existing processes in place to effectively deal with them.

Therefore, based on the results of the 1998 Reliability Assessment, the FRCC concludes that the peninsular Florida electric system is reliable through the ten year planning period and that the FRCC 1998 Load and Resource Plan is suitable.

Florida Gas Transmission Company

R. L. (Bob) Hayes, Jr.
Vice President
Marketing

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[illegible], Texas 77251-1188
713 853-3152
Fax 713 [illegible]

June 30, 1998

Bobby Adjemian
Florida Reliability Coordinating Council
9250 West Flagler Street
Miami, FL 33174

Dear Mr Adjemian

Florida Gas Transmission Company is pleased to provide the following information regarding the availability and deliverability of natural gas for electric generation requirements for the period 1998 through 2007

Our response is provided in five parts. (a) a discussion of the projected market and firm transportation capacity for the year 2007, (b) a discussion of the expandability of the FGT pipeline system into Florida, (c) information on the gas supply, (d) information on the open season FGT recently conducted, and (e) concluding remarks

FIRM GAS TRANSPORTATION CAPACITY FOR THE YEAR 2007

Florida Gas Transmission Company (FGT) is an open access interstate pipeline company that transports natural gas for third parties from Nueces County, Texas to a point near Miami, Florida with deliveries primarily to the State of Florida. FGT's pipeline system was originally constructed in 1959 FGT has periodically expanded its system capacity to keep pace with the growth in demand for natural gas in Florida In July 1987 FGT placed its Phase I Expansion in service, increasing its firm average delivery capacity from 725 BBtu/day to 825 BBtu/day. In December 1991, FGT placed its Phase II Expansion in service, increasing its firm average delivery capacity by 100 BBtu/day to 925 BBtu/day. In March 1995, with the start-up of FGT's Phase III Expansion, FGT increased its firm average delivery capacity by approximately 530 BBtu/day to a total of about 1,455 BBtu/day.

FGT's seasonal load profile is the opposite of most interstate pipelines in that its sustained system peak load is in the summer. The electric generation customers in Florida account for approximately 80% of the throughput on FGT's system. They have a seasonal load pattern characterized by higher summer demands due to their air-conditioning load requirements FGT also transports gas for Florida local distribution companies that have a seasonal load pattern characterized by high demands during the winter due to heating

requirements of their residential and small commercial customers. FGT also serves industrial customers in Florida that take gas at fairly constant rates during the year, as well as industrials that take gas on a seasonal basis.

There is about 16,000 MW of gas fired capacity in Florida of which only about 220 MW does not have dual fuel capability. FGT estimates that, of the 1,455 BBtu/day total FGT firm transportation capacity into Florida, the electric customers have about 1,170 BBtu/day in the summer season. The total daily gas capacity held by electric customers which have gas fired generation facilities with either no alternate fuel or only No. 2 fuel oil as the alternate fuel are about 760 BBtu/day. The remaining capacity held by electric customers, 410 BBtu/day, is used primarily for generating plants with No. 6 oil as the alternate fuel.

The 1998 Florida Reliability Coordinating Council (FRCC) Ten-Year Plan shows that about 6,000 MW of gas fired combined cycle units will be installed from 1999 through 2007. (Combined cycle units planned for 1998 will not require FGT system expansion.) Assuming a heat rate of 6,600 Btu/kWh, the firm gas transportation capacity needed for the new combined cycle units will be about 960 BBtu/day. As the electric customers install new efficient gas fired combined cycle units, the older and less efficient gas and No. 6 oil dual fueled units will become intermediate loaded units. The firm gas transportation capacity, 410 BBtu/day, currently used for the gas and No. 6 dual fueled units, will be used for the new base loaded combined cycle units. The net increase in firm gas transportation capacity required for power generation will be 550 BBtu/day.

Based on historical demand data and Florida population projections by the University of Florida, Bureau of Economic and Business Research, FGT estimates that there will be an additional 45 BBtu/day demand from the residential, commercial and industrial sectors by the year 2007. With this estimate, the total expansion requirements for FGT by 2007 will be 595 BBtu/day.

EXPANDABILITY OF FLORIDA GAS TRANSMISSION SYSTEM

As a general rule, it is cheaper to expand a gas pipeline by adding compression than by building new pipeline. In addition, the capacity of a given size pipeline increases as the operating pressure is increased. The last expansion of the FGT system was completed in February 1995. In that expansion, a continuous 350-mile, 36-inch pipeline was built from Citronelle, Alabama to Branford, Florida and a new 165-mile, 30-inch line (the "West Leg") was built from Branford, Florida to Tampa, Florida. These new pipelines were designed to operate at 1200 psig as compared to 975 psig for the pre-expansion system. Economics dictated that this part of the system be continuous to take full advantage of the higher operating pressure. The result was that the current mainline system from Citronelle has expandability which can be gained by adding only compression. If fully powered by compression, the capacity of the 36-inch mainline could be increased by over 500 BBtu/day before any new pipeline would have to be constructed. Fully powering the 30-inch West Leg would increase capacity by 250 BBtu/day.

A combination of pipeline looping and compression would be required to expand the capacity of other parts of the system. By constructing only 18 miles of 36" line west of Citronelle, access could be gained to 500 BBtu/day of new supply from the planned Destin Pipeline in George County, Mississippi. The Destin pipeline, extending from offshore fields in the Gulf of Mexico, is scheduled to be completed this summer.

Expansion of the rest of FGT's system in Florida can be tailored to meet any size market by partial looping or extending existing loops and adding compression. This is an advantage that the existing FGT system has over a new grassroots system. Obviously, some new lateral pipelines will be required to access market areas not now served by the FGT system, and loops or partial loops will be required to serve expanded loads at existing locations.

As far as the timing for the construction of pipeline expansion facilities, FGT would estimate eighteen to thirty-six months to obtain all permits, environmental and regulatory approvals, and to complete construction of any pipeline and compression facilities required.

GAS SUPPLY

The future gas supply outlook is very positive. The estimates of the Gulf's resources range from 155 Tcf (Potential Gas Committee) to 162 Tcf (Minerals Management Service). The Department of Energy in its "Annual Energy Outlook 1998" forecasts that offshore production in the Gulf of Mexico will increase from the current production levels of about 5 Tcf per year to 6.8 Tcf in 2010 and to 7.8 Tcf in 2020. Gas industry sources are reporting up to 3 Bcf/day of new gas supply is expected to begin production in the next few years.

FGT is continually taking steps to assure FGT Shippers will have attractive supply options. An example is the announced plan for an interconnect with Destin Pipeline. This interconnect will have a capacity of 500 BBtu/day and is planned to be in-service this summer. Destin Pipeline will provide FGT Shippers access to the vast new deepwater gas supplies being developed in the Gulf of Mexico.

OPEN SEASON - EXPANSION PROJECT

FGT is currently conducting an open season to solicit requests for incremental firm transportation service beginning in 2000 - 2001. As part of the open season, FGT also solicited offers from existing shippers to permanently release firm capacity that would reduce the need for construction of incremental facilities. FGT is currently analyzing the requests and meeting with the parties who requested new capacity, or offered permanent releases of existing capacity, to determine if an expansion of pipeline capacity is needed for the 2000 - 2001 timeframe. Based on the responses received in the open season, FGT believes the earliest potential need for any expansion facilities would be the fall of 2000. If

an expansion project is required, it may also be possible to accommodate a phased-in expansion beginning in the year 2000. At this time FGT anticipates submitting an expansion project filing to the Federal Energy Regulatory Commission by year end 1998.

CONCLUDING REMARKS

FGT is well positioned for cost effective pipeline expansions in the future. Over 800 miles of 30 and 36-inch pipe were installed as part of FGT's Phase III Expansion which went into service March 1, 1995. Consequently, FGT now has significant mainline expansion capability by adding compression facilities at existing compressor station sites.

FGT's expansion strategy is to construct smaller expansions, which closely match market demand, and to work closely with existing customers to facilitate capacity release transactions.

The location of FGT's pipeline system affords it the maximum opportunity to connect new reserves discovered anywhere in the Gulf Coast and Gulf Offshore areas to meet the future gas requirements of the State of Florida on a timely and reliable basis.

Please call me at 713-853-3162 if you have any questions or desire additional information.

R. E. Hayes

R E. Hayes

Analysis of Suitability of 15% Reserve Margin Criterion for Peninsular Florida

FRCC Resource Working Group (RWG)

May 20, 1998

Background

- In 1997, the FRCC was asked by the FPSC Staff to conduct a Loss-of-Load-Probability (LOLP) study of peninsular Florida in order to better assess the projected reliability of electric service within the peninsula.
- The result of this LOLP analysis was that the projected LOLP for the peninsula did not exceed the 0.1 day/year LOLP criterion for the peninsula for the 1997 - 2006 time frame.
- In 1998, the FRCC was charged with developing a methodology and procedures for assessing resource adequacy.
- In Florida, the dual reliability criteria of reserve margin and LOLP are most commonly used. Since the LOLP criterion was evaluated in 1997, the RWG analyzed the suitability of the current 15% reserve margin criterion. The results of that analysis are presented in this report.

Methodology

- The FRCC's 1998 EIA-411* was the starting point for the RWG's analysis. The Plan presented the following projections of Summer & Winter reserve margins (%) for the peninsula:

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Summer	20	20	18	16	20	21	21	20	19	19
Winter	18	17	15	18	19	19	19	17	17	15

- These reserve margin values utilize projections of 5 components:
  - forecasted loads at peak hours
  - availability of utility's own generation at peak hours
  - availability of firm imports at peak hours
  - availability of firm QF's at peak hours
  - availability of load management at peak hours
- The reserve margin projections essentially assume that each of these 5 components are accurate (i.e., are forecasted with 100% accuracy). The RWG's approach was to look back at the last 5 years (1993-1997) of actual data and see how well projections for these 5 years matched up with actuals.

(* The EIA-411 is prepared ahead of the Load and Resource Plan and as such there may be minor variations between the two reports)

Methodology (Continued)

- The concept is to adjust the 5 components in the FRCC's 1998 reserve margin projection according to the historical accuracy of the utilities' projections for the last 5 years. A simple numerical average of actuals vs. projections was utilized for most components. (For example, if the load forecast projections have averaged being 5% low versus actuals, then the load forecast values in the reserve margin projections would be increased by a factor of 1.05).
- Once all adjustments are made, the projected reserve margins are changed to reflect the historical accuracy of the utilities' projections.
- The suitability of the initial reserve margin projections is then judged by the following guidelines:
    a) If the revised reserve margins are ≥ 0, then the initial reserve margins are suitable for maintaining electric reliability .
    b) If the revised reserve margins are < 0, then the initial reserve margins are unsuitable for maintaining electric reliability.

Summer # 1: with no certainty factors

1998 Load & Resource Plan

FRCC Region

Summary of Capacity, Demand and Reserve Margin

At time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Year	Installed Generation (MW)	Installed Generation Certainty Factor	Net Firm Imports (MW)	Net Firm Imports Certainty Factor	Firm QF (MW)	Firm QF Certainty Factor	Total Available Capacity (MW)	Peak Load Forecast (MW)	Peak Load Certainty Factor	Load Management (MW)	Load Management Certainty Factor	Firm Peak Load (MW)	Original Reserve Margin %	Reserve Margin After Certainty Factor(s) %	Needed Res. Margin Component Caused by Certainty Factor(s) %
1998	35598	1.000	1789	1.000	2226	1.000	39613	35633	1.000	2759	1.000	32874	20	20	0
1999	36127	1.000	1875	1.000	2226	1.000	40228	36628	1.000	2990	1.000	33638	20	20	0
2000	36570	1.000	1802	1.000	2226	1.000	40598	37410	1.000	3105	1.000	34305	18	18	0
2001	36806	1.000	1741	1.000	2226	1.000	40773	38220	1.000	3199	1.000	35021	16	16	0
2002	38795	1.000	1704	1.000	2117	1.000	42616	38644	1.000	3225	1.000	35419	20	20	0
2003	39819	1.000	1623	1.000	2117	1.000	43559	39395	1.000	3283	1.000	36112	21	21	0
2004	40889	1.000	1633	1.000	2117	1.000	44639	40227	1.000	3321	1.000	36906	21	21	0
2005	41814	1.000	1644	1.000	2007	1.000	45465	41112	1.000	3344	1.000	37768	20	20	0
2006	42331	1.000	1630	1.000	2074	1.000	46035	41998	1.000	3369	1.000	38629	19	19	0
2007	43399	1.000	1605	1.000	2074	1.000	47078	42885	1.000	3398	1.000	39487	19	19	0

Historical Accuracy of Projections for 5 Components

Reserve Margin Component	Approx. Magnitude of Value (MW)	How Evaluated	Needed Adjustment Factor
1) Load Forecast of peaks	40,000	• Using 1993 - 1997 actual peaks, forecasts for each of those years from: 2 years prior 3 years prior 4 years prior 5 years prior 6 years prior 7 years prior 8 years prior • Forecasts from earlier than 1988 were not used since forecasting methodologies have changed since 1988.	Summer / Winter 1.007 / 0.976 1.020 / 0.971 1.026 / 0.967 1.026 / 0.960 1.023 / 0.976 1.036 / 1.021 1.042 / 1.036 (Simple numerical averaging was used.)

Historical Accuracy of Projections for 5 Components (Continued)

Reserve Margin Component	Approx. Magnitude of Value (MW)	How Evaluated	Needed Adjustment Factor	
			Summer	Winter
2) Utility Generation available at peaks	40,000	Comparison of actuals for 1993-1997 versus expected values at the beginning of each year.	0.933 (Simple numerical averaging was used.)	0.924
3) Net Firm Imports at peaks.	1,600	• Comparison of actuals for 1993 -1997 versus expected values at the beginning of each year.	0.993 (Simple numerical averaging was used.)	1.001
4) Firm QF's at peaks.	2,200	• Comparison of actuals for 1993-1997 versus expected values at the beginning of each year.	0.903 (Simple numerical averaging was used.)	0.943

Historical Accuracy of Projections for 5 Components (Continued)

Reserve Margin Component	Approx. Magnitude of Value (MW)	How Evaluated	Needed Adjustment Factor	
			Summer	Winter
5) Load management	4,000	•Projected "certainty factors" for load management MW supplied by each utility.	0.945 (approx.) (MW - weighted average of utilities' projected certainty.)	0.947

Summer # 6: w/generation at peak,import, QF's, load forecast & load management certainty factors

1998 Load & Resource Plan
FRCC Region
Summary of Capacity, Demand and Reserve Margin
At time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Year	Installed Generation (MW)	Installed Generation Certainty Factor	Net Firm Imports (MW)	Net Firm Imports Certainty Factor	Firm QF (MW)	Firm QF Certainty Factor	Total Available Capacity (MW)	Peak Load Forecast (MW)	Peak Load Certainty Factor	Load Management (MW)	Load Management Certainty Factor	Firm Peak Load (MW)	Original Reserve Margin %	Reserve Margin After Certainty Factor %	Needed Res. Margin Component Caused by Certainty Factor(s)
1998	35598	0.933	1789	0.993	2226	0.903	36982	35633	1.000	2759	0.945	33026	20	12	---
1999	36127	0.933	1875	0.993	2226	0.903	37561	36628	1.007	2990	0.947	34047	20	10	9
2000	36570	0.933	1802	0.993	2226	0.903	37902	37410	1.020	3105	0.946	35222	18	8	11
2001	36806	0.933	1741	0.993	2226	0.903	38061	38220	1.026	3199	0.946	36186	16	5	11
2002	38795	0.933	1704	0.993	2117	0.903	39781	38844	1.026	3225	0.945	36810	20	8	12
2003	39819	0.933	1623	0.993	2117	0.903	40655	39395	1.023	3283	0.944	37215	21	9	11
2004	40889	0.933	1633	0.993	2117	0.903	41663	40227	1.036	3321	0.944	38535	21	8	13
2005	41814	0.933	1644	0.993	2007	0.903	42437	41112	1.042	3344	0.943	39698	20	7	13
2006	42331	0.933	1630	0.993	2074	0.903	42966	41998	1.042	3369	0.943	40600	19	6	13
2007	43399	0.933	1605	0.993	2074	0.903	43937	42885	1.042	3398	0.942	41499	19	6	13

Winter # 6: w/generation at peak, load forecast,import, QF's certainty factors & load management certainty factors

1998 Load & Resource Plan

FRCC Region

Summary of Capacity, Demand and Reserve Margin

At time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Year	Installed Generation (MW)	Installed Generation Certainty Factor	Net Firm Imports (MW)	Net Firm Imports Certainty Factor	Firm QF (MW)	Firm QF Certainty Factor	Total Available Capacity (MW)	Peak Load Forecast (MW)	Peak Load Certainty Factor	Load Management (MW)	Load Management Certainty Factor	Firm Peak Load (MW)	Original Reserve Margin %	Reserve Margin After Certainty Factor %	Needed Res. Margin Component Caused by Certainty Factor(s)
1998/99	38022	0.924	1889	1.001	2270	0.943	39159	39449	1.000	3778	0.949	35863	18	9	---
1999/00	38444	0.924	1868	1.001	2270	0.943	39528	40383	0.976	3945	0.949	35673	17	11	6
2000/01	38948	0.924	1666	1.001	2270	0.943	39791	41395	0.971	4073	0.949	36335	15	10	5
2001/02	40883	0.924	1680	1.001	2261	0.943	41585	42219	0.967	4148	0.948	36905	18	13	5
2002/03	42225	0.924	1612	1.001	2261	0.943	42756	42998	0.960	4227	0.948	37282	19	15	4
2003/04	43318	0.924	1623	1.001	2261	0.943	43777	43925	0.976	4302	0.947	38798	19	13	6
2004/05	44350	0.924	1633	1.001	2251	0.943	44731	44895	1.021	4330	0.947	41734	19	7	12
2005/06	45128	0.924	1555	1.001	2118	0.943	45246	45896	1.036	4360	0.946	43443	17	4	13
2006/07	46208	0.924	1555	1.001	2118	0.943	46244	46879	1.036	4387	0.945	44438	17	4	13
2007/08	46324	0.924	1555	1.001	2118	0.943	46351	47902	1.036	4410	0.945	45479	15	2	13

Results of Base Case Analysis

- The most important components were, as expected, availability of the utility's generation at peak and load forecast accuracy.

- After adjusting the original Summer & Winter reserve margin projections for the certainty factors, the resulting reserve margins (Col. 15) were well above zero.

- This is an indication that the original reserve margins are suitable for maintaining electric reliability for the peninsula.

- In fact, the analysis suggests (Col. 16) that electric reliability could be maintained with 13% reserve margins for both Summer & Winter. However, the RWG recommends that the current 15% reserve margin criterion be maintained.

Results of Sensitivity Analyses

- The Base Case analysis used a simple numerical averaging approach in order to account for projections that may err on either side of the projected value.

- Sensitivity cases were analyzed using:
  a) the worst year's actual vs. projected utilities' generation;
  b) the worst year's actual vs. projected loads; and,
  c) a) and b) combined.

- The resulting values for "needed"* reserve margins in the sensitivity cases were as follows:

	Summer	Winter
a) worst installed generation year	16%	20%
b) worst load forecast year	15%	21%
c) a) and b)	17 - 18%	27%

* **Note:** the probability of these worst case scenarios is not accounted for.

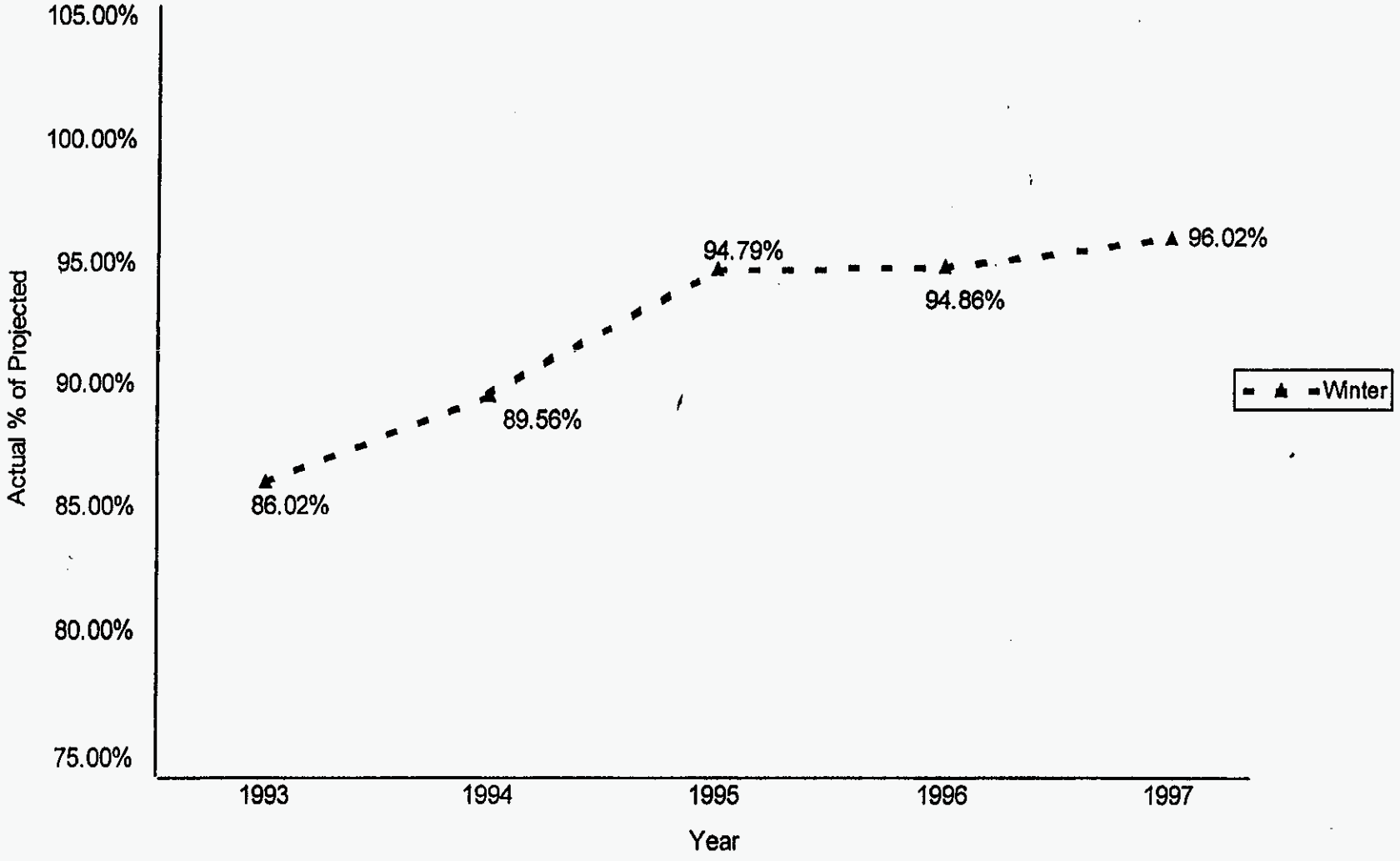
Mitigating Factors for Sensitivity Cases

- The sensitivities point to a required summer reserve margin of 15% - 16%. The recommendation of 15% satisfies this need.

- The winter sensitivity's reserve margin requirement of 20% - 21% needs to be considered in the context of the following mitigating (and unaccounted for in the base case) factors:
- consistently improving unit availabilities over the past 10 yrs.*
  - increased cold weather MW value of DSM.
  - increased cold weather unit capacity.

*1988 EAF: 80.1%
1997 EAF: 89%
Source: NERC GADS

Installed Generation
Penninsular Florida



Mitigating Factors for Sensitivity Winter Case

The list below gives the approximate capacity value, in terms of winter reserve margin credit.

Mitigating factor	Winter Reserve margin credit
Improved unit availability	4%
Increased cold weather MW value of DSM	1%
Increased cold weather unit capacity	1%
	6%

Conclusion: When accounting for the mitigating factors the extreme winter required reserves are in the order of 14% - 15%.

Summary

- From a Base Case analysis perspective, the FRCC's 1998 projection of both Summer and Winter reserve margins appears more than suitable to maintain electric reliability for the peninsula during peak periods.

- From a Sensitivity Case analysis perspective, the FRCC's 1998 reserve margin projections appear suitable for Summer, but not for Winter. However, after accounting for the effect of mitigating factors the Winter sensitivity reserves are also suitable. The probability of the sensitivity cases occurring, the projected duration of outages under the sensitivity cases, nor the costs of building to address the sensitivity cases have been incorporated into the analyses.

- The RWG recommends that the 15% reserve margin criterion be retained for reliability analyses of peninsular Florida.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 5
COMPANY/
WITNESS: FPL
DATE: 12-2-98

5.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Petition of ARK Energy, Inc. and CSW Development-I, Inc. for Determination of Need for Electric Power Plant to be Located in Okeechobee County, Florida	DOCKET NO. 920761-EQ Filed: July 27, 1992

PETITION FOR DETERMINATION OF NEED

ARK Energy, Inc. ("ARK") and CSW Development-I, Inc. ("CSWD), hereinafter referred to as ARK/CSW, hereby petition for an affirmative determination of need for approximately 866 MW of natural gas-fired combined cycle capacity, to be located in Okeechobee County, Florida, and associated facilities to be located in Okeechobee County and St. Lucie County, Florida. The proposed capacity is needed by Florida Power & Light Company ("FPL"), and consistent with the needs of peninsular Florida, to provide adequate and reliable electric service to FPL's customers at the most reasonable cost. This petition is made pursuant to the Florida Electrical Power Plant Siting Act (Siting Act, Act), Section 403.501-.518, F.S., Section 403.519, F.S., and Rules 25-22.080 and 25-22.081, F.A.C.

ARK/CSW has elected to seek a determination of need from the Florida Public Service Commission (FPSC) before filing a Power Plant Siting Act application with the Florida Department of Environmental Regulation (DER), as provided for in Rule 25-22.080(1), F.A.C.

This petition is accompanied by two documents which contain the information required by Rule 25-22.081, F.A.C., to support a petition for a determination of need: Exhibit 1, Project

DOCUMENT NUMBER-DATE
A TRUE COPY
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Chief, Bureau of Records
08296 JUL 27 1992
FPSC-RECORDS/REPORTING

Specific Information for Pahokee Power Partners II Project and Exhibit 2, Florida Power and Light Company's Projected Capacity Needs for 1998 and 1999.

The proposed power plant will consist of two "blocks" or units of power generating facilities each consisting of 2 combustion turbine units, 2 heat recovery steam generators and 1 steam turbine generating unit. The first block/unit may be in service by June 1, 1997, but no later than December 1, 1997; the second block/unit may be in service by June 1, 1998, but no later than December 1, 1998. The 400 MW class units are expected to have a net rating of approximately 433 MW each; depending on the final design, the actual net rating of each may be in the range of 395 MW to 437 MW. ARK/CSW may not provide committed capacity in excess of 437 MW for each unit without the consent of FPL. The units will be constructed by CSW Services, Inc., an affiliate of CSW Corporation. The named contracting party will be Pahokee Power Partners II, Limited Partnership (PPP II, Pahokee Power Partners II) which will own the facility as an independent power project. ARK/CSW has proposed that total energy and capacity from the plant be purchased by FPL pursuant to a thirty year contract for which approval has been requested on this date in a separate docket.

PPP II is comprised of CSW Development-I, Inc. and ARK Energy, Inc. as limited partners with 99% ownership and Pahokee Power GP, Inc. as the general partner holding a 1% ownership interest. The business address of Pahokee Power GP, Inc. is:

23293 South Pointe Drive
Laguna Hills, California 92653

The names and addresses of ARK/CSW's representatives to receive communications regarding this docket are:

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Class B Practitioner
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Arnold R. Klann, President
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Florida Power and Light Company (FPL), the utility affected by this petition, is an investor-owned utility generally subject to the Commission's jurisdiction pursuant to Chapter 366, Florida Statutes. FPL serves a total of 3,226,456 customer accounts in thirty-five counties in Florida. FPL's service territory contains approximately 27,650 square miles with a total population of approximately 6,200,000. FPL's business address is:

9250 West Flagler Street
Miami, Florida 33102-9100

In support of this petition ARK/CSW state the following:

1. The proposed Pahokee Power Partners II Project is subject to the provisions of the Florida Electrical Power Plant Siting Act (Siting Act), Section 403.501-.518, F.S. The Commission held in Order No. 22341, Docket No. 890004-EU, that the need for a power plant to be constructed by an unregulated entity, the output of which will be purchased by a regulated utility, will be determined on the basis of the purchasing utility's need for additional generating capacity. Section 403.519, F.S., establishes

five criteria to be examined by the Commission in making a determination of need for a proposed plant: (1) the need for electric system reliability and integrity; (2) the need for adequate electricity at a reasonable cost; (3) whether the proposed plant is the most cost effective alternative available; (4) whether conservation measures taken by or reasonably available to the applicant might mitigate the need for the proposed power plant, and (5) other matters within the Commission's jurisdiction. As applied to the Pahokee Power Partners II Project, each of these criteria is met.

2. In Docket No. 920520-EQ, FPL has assessed the need for additional capacity in 1998 and 1999 for its system based on reliability levels of 0.1 days per year Loss of Load Probability (LOLP) and a 15% reserve margin based on summer peak demand. The Commission has previously found these reliability criteria to be reasonable for planning purposes.

3. FPL's most probable load forecast shows that, after the effects of conservation, load management, and prior committed capacity additions or purchases are accounted for, 400-500 MW of additional resources are needed beginning January 1, 1998 and, 400-500 MW of additional resources are needed beginning January 1, 1999, to meet the expected demand for electricity and maintain these reliability standards.

4. FPL's identification of need for additional generating capacity in 1998 and 1999 is consistent with the need of peninsular Florida for additional generating resources. The

Florida Electrical Power Coordinating Group (FCG) presented the results of a study of peninsular Florida's needs in a February 1992 Florida Generation Expansion Study, which showed that peninsular Florida has a need for approximately 840 MW in 1998 and 630 MW in 1999. FPL's identification of a 400-500 MW need in those years is consistent with the FCG study.

5. FPL's economic analysis, the results of which were relied upon by Cypress Energy Partners, L.P. (CEP) in its need determination docket, Docket 920520-EQ, determined that two 400 MW class pulverized coal units added in 1998 and 1999 resulted in the lowest cost to FPL's customers. However, FPL's lower-gas-price sensitivity analysis showed that combined cycle/IGCC technology is more cost-effective. The FCG study identified combined cycle capacity as the generating option of choice for peninsular Florida. The natural gas fired ARK/CSW PPP II project exactly matches the combined cycle need identified by the FCG in its February 1992 study and the units identified as most cost-effective in FPL's own sensitivity study.

6. The location of the proposed PPP II project in Okeechobee County is favorable from the standpoint of electric system reliability and integrity. Okeechobee County is close to FPL's load center and the plant will not adversely affect the use of FPL's current and planned transmission system. The PPP II project will interconnect with FPL's transmission system by looping FPL's Martin-Poinsett 500 kV transmission line.

7. The projected cost of the energy and capacity to be supplied by PPP II is less than the cost associated with FPL's most economical construction alternatives. The planning study on which PPP II is relying has been presented in Docket No. 920520-EQ as Exhibit 1. This study was performed in 1991 and showed that the FPL construction alternative with the best economics over a thirty year planning horizon, under base assumptions, is a pulverized coal unit. However, comparison of alternative generation expansion plans on the basis of strategic considerations showed that combined cycle/IGCC technology may offer certain strategic advantages. Therefore, FPL has stated that designation of a preferred technology for its construction alternative is not firmly established.

8. In determining its most economic construction alternative, FPL performed a sensitivity analysis in which lower prices for natural gas and oil were assumed; with this assumption, a generation expansion plan that adds combined cycle capacity has the best economics. ARK/CSW's PPP II project is consistent with the results of this sensivity analysis.

9. CEP and FPL reached agreement as to the terms and conditions of a long term power sales agreement and executed a contract on February 27, 1992. ARK/CSW's Contract, for which ARK/CSW has requested approval in a companion docket, is identical in all material terms and conditions to the CEP contract with FPL with the exception of pricing. Both contracts contain a number of provisions designed to monitor and provide incentives for the

timely construction of the proposed plants and the long term operational reliability of the project. These provisions include the following:

- milestone licensing and construction requirements;
- completion security of $24,960,000 to assure capacity delivery no later than December 1, 1997, and 1998;
- independent review of plant design and maintenance plan;
- FPL's approval of maintenance scheduling for the facility;
- termination fee security in the event of the premature shut down of the plant;
- cash reserve fund of $30,000,000 for major maintenance;
- minimum 10% equity investment in the project by Pahokee Power Partners II, Limited Partnership; and
- long term fuel supply contracts mandated for at least 50% of projected fuel requirements.

10. In addition, the contract includes a "pay for performance" structure for capacity payments which encourages ARK/CSW to maintain a high capacity billing factor, with special incentives for on-peak performance. After the first twenty-four months of operation the Pahokee Power Partners II Project units must achieve a Capacity Billing Factor of 93% to be entitled to the full capacity payment level specified in the contract. For

performance between 60% and 93%, ARK/CSW will receive a reduced capacity payment. (The corresponding Capacity Billing Factor requirements for the first twenty four months of operation are 50% and 89%.)

11. The calculation of the Capacity Billing Factor taken into account all non-scheduled maintenance hours, gives credit for capacity that is available but is not fully dispatched by FPL, and gives extra weight to capacity available during on-peak hours. The extra weight given to performance during on-peak hours provides a strong incentive to ARK/CSW to operate when power is most needed.

12. In addition to a base capacity payment rate of $16,666 per MW/month for the first twenty-two years of the contract (declining thereafter to $10,417 per MW/month by the thirtieth contract year), the contract provides for a fixed O&M payment of $3,152 per MW/month in 1991 dollars adjusted annually on the basis of relevant price indices, and a transmission payment based on the total cost of interconnection facilities spread over the life of the contract.

13. The energy payment structure of the contract provides for a fuel payment which is equal to the product of a unit hourly efficiency factor and a unit fuel cost which is $17.71 per MW in 1991 dollars and is indexed to the lesser of the weighted average indices provided in ARK/CSW's fuel contracts, or the weighted average price of coal delivered pursuant to long term contracts at the St. Johns River Power Park. In addition to the fuel payment, a variable O&M cost, of $1.76 per MWH in 1991

dollars, escalated on the basis of relevant price indices, is included in the energy payment. Unlike the CEP Contract, the ARK/CSW Contract does not have a fixed SO_2 allowance of $0.60 per MW.

14. Under the terms of the contract, FPL and ARK/CSW share in any system fuel cost savings obtained by dispatch of the PPP II units above committed capacity levels.

15. The PPP II units will be fully dispatchable by FPL, which will be able to control both the generation from the facility and the facility's power factor. This means FPL will have the same type of control flexibility as FPL has for its own units.

16. Based upon the evidence presented in this docket, there is a reasonable likelihood that ARK/CSW's PPP II project will be constructed and operated on the terms and conditions on which FPL evaluated CEP's project and will, therefore, be capable of meeting the need for additional generating capacity in 1998 and 1999.

17. ARK/CSW accept FPL's representation that the need for additional generating capacity was identified in FPL's planning study process only after fully accounting for the capacity deferral benefits of all Commission-approved conservation measures. FPL's 1991 power supply planning process incorporated the projected effects of FPL's demand side management programs approved by the Commission in October 1991. In addition, the 1991 planning study reflects the expected results of six additional demand side projects, approved by the Commission on an experimental basis.

Therefore, the 1991 planning study is based on an incremental summer peak demand reduction of 1300 MW from 1990-99, for a total summer peak demand reduction of 1900 MW from 1981-1999.

18. In addition to economic considerations, ARK/CSW's Pahokee Power Partners II Project offers other advantages to FPL and its customers:

- Although FPL has not identified a capacity need before 1998, ARK/CSW's PPP II project may be available as early as June 1, 1997, providing some flexibility for meeting unexpected contingencies.

- The phased-component construction of ARK/CSW's combined cycle units will present the best opportunity for maximum flexibility in meeting changes in FPL's load growth.

- The costs of the ARK/CSW purchase are fixed or indexed to generally accepted benchmarks, thereby protecting FPL ratepayers from cost over-runs or unexpected costs.

- At FPL's option, the contract may be extended for an additional ten years beyond the initial term of thirty years.

- The ARK/CSW purchase allows FPL to maintain the option to build new capacity at the Martin site, which is a developed site with accessible fuel transportation and transmission facilities.

Associated Facilities

19. Associated facilities for the ARK/CSW PPP II project include approximately 30 circuit miles (two separate 500 kV transmission lines of approximately 15 miles each) extending north and then east from the project site to the point of interconnection with FPL at the existing Martin-Poinsett 500 kV transmission line. The interconnection will consist of two 500 kV circuits which will loop the Martin-Poinsett transmission line into the ARK/CSW plant.

The Consequences of Delay

20. FPL's 1991 planning study shows a need for additional generating capacity beginning in 1998. Delay in the in-service dates of the ARK/CSW PPP II units would cause FPL's system LOLP to exceed the standard of 0.1 days per year, beginning in 1998.

WHEREFORE, ARK/CSW respectfully request that the Commission make the following findings:

(1) that FPL has a need for 400-500 MW of additional generating resources in 1998 and a need for 400-500 MW of additional generating resources in 1999;

(2) that FPL's need for additional generating resources in 1998 and in 1999 is established after the effects of all cost-effective conservation measures approved by the Commission have been considered;

(3) that the purchase of capacity and energy from ARK/CSW's Pahokee Power Partners II Project in 1998 and 1999, pursuant to the contract proposed between FPL and Pahokee Power Partners II, Limited Partnership is the best and most cost-effective alternative to meet FPL's need for additional generating resources;

(4) that the purchase of capacity and energy by FPL from Pahokee Power Partners II, Limited Partnership, pursuant to the contract for which approval has been requested, is consistent with the needs of peninsular Florida for additional generating resources;

(5) that the purchase of capacity and energy by FPL from Pahokee Power Partners II, Limited Partnership, pursuant to the contract for which approval has been requested, is necessary to maintain the reliability and integrity of FPL's electrical system;

(6) that the purchase of capacity and energy by FPL from Pahokee Power Partner II, Limited Partnership, pursuant to the contract for which approval has been requested, is necessary to maintain an adequate supply of electricity at a reasonable cost;

(7) that, based on the foregoing findings of fact, an affirmative determination of need for 790 MW to 874 MW of capacity

produced by the proposed Pahokee Power Partners II Project should be, and is granted; and

(8) that the Commission take all actions required by the Florida Electrical Power Plant Siting Act, Section 403.501-.518, F.S., Section 403.519, F.S., and Rule 25-22.080, F.A.C., including the schedule, notice, and report requirements of those laws and regulations in connection with this petition for a determination of need.

Respectfully submitted this 27th day of July, 1992.

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Tallahassee, Florida 32302

Attorneys for ARK Energy, Inc. and
CSW Development-I, Inc.

BY: Karen Villacorta

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing was delivered by U.S. Mail or Hand-Delivery (*) to following this 27th day of July, 1992:

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6

EXHIBIT NO. _____

DOCKET NO: 981042-EM

WITNESS:

PARTY:

DESCRIPTION: Documents for Official Recognition - Requested by the Staff of the Florida Public Service Commission.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 6
COMPANY/ WITNESS: Staff
DATE: 12-2-98

PROFFERING PARTY: STAFF

Documents For Official Recognition
Requested by Staff of the Florida Public Service Commission

Docket No. 981042-EM

Florida Supreme Court Decisions

Nassau Power Corporation v. Beard, 601 So.2d 1175 (Fla. 1992)

Nassau Power Corporation v. Deason, 641 So.2d 396 (Fla. 1994)

Florida Statutes and Rules

Section 186.801, Florida Statutes. Ten-Year Site Plans.

Section 361.01-.18, Florida Statutes. Public Utilities: Special Powers.

Section 366.01-.85, Florida Statutes. Public Utilities.

Section 403.501-519, Florida Statutes. Electrical Power Plant Siting.

Rule 25-17.001-.091, Florida Administrative Code.

Rule 25-22.070-.073, Florida Administrative Code. Ten-Year Site Plans.

Rule 25-22.080-.91, Florida Administrative Code. Permitting Procedures.

Federal Statutes

Public Utility Regulatory Policy Act of 1978.

Energy Policy Act of 1992.

Federal Energy Regulatory Commission Orders

Federal Energy Regulatory Commission Order No. 888.

Federal Energy Regulatory Commission Order No. 888-A.

Federal Energy Regulatory Commission Order No. 889.

Federal Energy Regulatory Commission Order No. 889-A.

Florida Public Service Commission Orders

Order No. 11611, issued February 14, 1983, Docket No. 820460-EU (Florida Crushed Stone).

Order No. 20930, issued March 23, 1989, Order No. 22335, issued December 22, 1989, Docket No. 880309-EU (Seminole Electric Coop., TECO Power Services, TECO).

PAA Order No. 21633, issued July 31, 1989, Order No. 21780, issued August 23,1989, Docket No. 881420-EQ (Florida Power Corporation/CFR Biogen).

Order No. 20671, issued January 30, 1989, Order No. 21491, issued June 30, 1989, Docket No. 881472-EQ (AES Cedar Bay, Inc. and Seminole Kraft Corp.).

Order No. 22341, issued December 26, 1989, Docket No. 890004-EU (Annual Planning Hearing).

Order No. 23079, issued June 15, 1990, Docket No. 890973-EI (FP&L - Lauderdale Repowering).

Order No. 23080, issued June 15, 1990, Docket No. 890974-EI (FP&L - Martin).

PAA Order No. 23963, issued January 7, 1991, Order No. 24821, issued July 16, 1991, Docket No. 900454-EQ (Lee County).

Order No. 24268, issued March 21, 1991, Docket No. 900709-EQ (FP&L/Indiantown).

Order No. 24986, issued August 28, 1991, Docket No. 910382-EM (OUC, FMPA, KUA - Stanton 2).

Order No. 25805, issued February 25, 1992, Docket No. 910759-EI (FPC - Polk).

Order No. 25808, issued February 25, 1992, Docket No.910816-EQ (Nassau Power Corp.).

Order No. PSC-92-0002-FOF-EI, issued March 2, 1992, Docket No. 910883-EI (TECO - Polk).

Order No. PSC-92-1355-FOF-EQ, issued November 23, 1992, Docket No. 920520-EQ (FP&L/Cypress Energy Partners).

Order No. PSC-92-1210-FOF-EQ, issued October 26, 1992, Docket Nos. 920769-EQ, 920761-EQ, 920762-EQ, and 920783-EQ (Nassau Power, Ark Energy, and CSW Development-I).

Order No. PSC-93-1715-FOF-EQ, issued November 30, 1993, Docket No. 930196-EQ (Metropolitan Dade County).

Order No. PSC-94-0761-FOF-EC, issued June 21, 1994, Docket No. 931212-EC (Seminole Electric Coop. - Hardee 3).

Order No. PSC-97-0659-FOF-EM, issued June 9, 1997, Docket No. 961512-EM (Tallahasssee - Purdom 8).

Order No. PSC-97-1456-FOF-EI, issued November 18, 1997, Docket No. 971059-EI (FPC - Tiger Bay).

Order No. PSC-98-1301-FOF-EM, issued October 7, 1998, Docket No. 980802-EM (KUA, FMPA - Cane Island 3).

Publications

1998 Regional Load & Resource Plan, Florida Reliability Coordinating Council, July 1998.

PARTICIPATION AGREEMENT

Dated: February 17, 1998

by and between

Utilities Commission, City of New Smyrna Beach, Florida

and

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 7
COMPANY/ WITNESS: Vaden
DATE: 12-2-98

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EXHIBITS

Exhibit A Description of the Site
Exhibit B Tax Agreement

PARTICIPATION AGREEMENT

This Participation Agreement ("Agreement"), dated as of February 17, 1998, is by and between the Utilities Commission, City of New Smyrna Beach, Florida, a commission ("UCNSB") of the City of New Smyrna Beach, Florida (the "City"), and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P., a limited partnership organized and existing under the laws of the State of Florida ("Duke") (collectively, the "Parties").

WHEREAS, Duke and its affiliates are in the business of developing, owning and operating electric generation facilities throughout the United States;

WHEREAS, in order to meet the power requirements of UCNSB's existing and future customers in a manner that is in the best interest of such customers, and pursuant to a Letter of Intent dated May 21, 1997 (the "LOI") between UCNSB and PanEnergy Power Services, Inc. (now known as Duke Energy Power Services, LLC and an affiliate of Duke), such parties have conducted due diligence investigations regarding the feasibility and economic viability of developing an electric generation facility in New Smyrna Beach, Florida and have reached a definitive agreement for the Parties to proceed with the development of a combined-cycle electric generation facility with a capacity of approximately 240 megawatts or more (the "Facility"); and

WHEREAS, the Facility is to be located on a site presently owned by UCNSB of approximately 20 acres located northwest of the intersection of Interstate I-95 and State Road 44 in Volusia County, Florida and more particularly described on Exhibit A hereto (the "Site"), which Site is adjacent to UCNSB's 115 KV substation (the "Smyrna Substation");

NOW, THEREFORE, in consideration of the mutual agreements contained herein, UCNSB and Duke hereby agree as follows:

1.0 ENTITLEMENT

1.1 General

Duke shall provide to UCNSB an entitlement to 20 megawatts ("MW") of electric capacity (the "Entitlement") from the Facility measured at the ring bus of the Smyrna Substation. The Entitlement shall begin on the commercial operation date ("COD") of the Facility (which is expected to be about 33 months after the date hereof) and continue for the technical and economic life of the Facility (which technical and economic life shall be deemed to be the period during which the Facility, as it is initially constructed prior to the COD, is technically capable (excluding customary outages and force majeure outages) of producing electric energy at a cost that results in a reasonable profit and cash flow to the owner of the Facility when such energy is sold). The Entitlement shall be provided in consideration for UCNSB's contributions to Duke of the Site and certain infrastructure requirements as described in Section 2.0 and UCNSB's other

obligations under this Agreement. There shall be no other charge for the Entitlement.

1.2 Availability

The Entitlement shall be made available to UCNSB for all hours during which the Facility is available. If the Facility is unavailable because of either a scheduled or unscheduled outage, Duke shall have no responsibility to provide for replacement capacity to UCNSB. If the Facility is derated, UCNSB's Entitlement shall be derated proportionately.

1.3 Associated Energy

Beginning at the COD, Duke shall make available to UCNSB, at the ring bus of the Smyrna Substation, 20 megawatt hours ("MWH") of electric energy per hour associated with the Entitlement ("Associated Energy") and UCNSB shall be obligated to take or pay for 18 MWH/hour of Associated Energy for all hours in which the Facility is available. Such amount shall be prorated in conjunction with any derating of the Facility pursuant to Section 1.2. If the Facility is unavailable because of either a scheduled or unscheduled outage, Duke shall have no responsibility to provide for replacement energy. Associated Energy shall be priced at $18.50 per MWH beginning on the COD. On each of the first nine anniversaries of the COD, the Associated Energy price shall be adjusted by multiplying the then existing price by a fraction, the numerator of which is the average of the Weekly Indexes (On-Peak) for the Price of Spot Electricity for the Florida/Georgia Border market as quoted in Power Markets Week published by The McGraw-Hill Companies for the 52 weeks immediately preceding such anniversary, and the denominator of which is the average of such Weekly Indexes for the 52 weeks immediately preceding the COD (in the case of the first anniversary) or the preceding anniversary (in the case of each subsequent anniversary) (or, if such Weekly Index ceases to be quoted, then the Parties shall agree on the publicly quoted index that is the most comparable to such Weekly Index as a substitute therefor); provided, however, that in no event shall the resulting price be greater or less than $18.50 per MWH increased or decreased, respectively, by 3.5% per year (compounded) for each year after the COD (on a cumulative basis). From and after the tenth anniversary of the COD, the Associated Energy price shall be equal to the fair market value of similar quantities of firm wholesale electric energy (including capacity and transmission) delivered by an unrelated third party to another unrelated third party (without any other contractual relationships) at the Smyrna Substation; provided that UCNSB shall be entitled to an annual credit of $1,000,000, one-twelfth of which shall be applied against each month's charges for Associated Energy (which credit shall not reduce any month's charges below zero and shall not be carried forward to future months), to reflect that the new pricing would not be on the same basis as the favorable pricing to UCNSB during the first ten years after the COD. Invoices for Associated Energy provided during a

month shall be delivered by Duke to UCNSB within 10 days after the end of such month and shall be due within 15 days after such delivery.

1.4 Replacement Capacity and Energy

If the Facility is available, but Duke chooses not to dispatch the Facility or the Facility commitments are below the minimum capacity of the Facility as established by Duke, then Duke shall arrange for replacement capacity and energy to be delivered to UCNSB at the ring bus of the Smyrna Substation. There shall be no charge for replacement capacity. Replacement energy shall be priced at the same price as Associated Energy from the Facility as provided in Section 1.3.

1.5 Provision For Modification of Tax Agreement

If at any time during the life of the Facility (which phrase life of the Facility, as used hereinafter, shall include the period of time from the date hereof through the decommissioning and dismantling of the Facility) the Tax Agreement defined in Section 5.2 is modified, is not renewed, or is otherwise affected such that the Facility or Duke incurs City Taxes (as defined in Section 5.2) in excess of $500,000 with respect to the Site and the Facility (and, if applicable, the Additional Capacity as defined in Section 6.1) during any 12 month period beginning on the COD or any anniversary of the COD, Duke shall deliver to UCNSB an invoice or invoices for the amount of such excess and UCNSB shall pay to Duke the amount of such excess within 15 days after delivery of each such invoice.

1.6 Load Following Services

(a) Duke shall furnish load following services to UCNSB that will allow UCNSB to schedule 20 MW for any hour, but take an amount of Associated Energy during the hour which is between 18 and 20 MWH (the "Load Following Services"). Duke shall not be obligated under this Agreement to provide to UCNSB any other ancillary services.

(b) The capacity portion of the Load Following Services will be furnished as part of the 20 MW Entitlement. The energy associated with Load Following Services will be priced pursuant to Section 1.3.

(c) Duke will provide the Load Following Services to UCNSB if the Facility is available. If the Facility is not available, Duke will have no responsibility to provide the Load Following Services. If Duke chooses not to dispatch the Facility or the Facility commitments are below the minimum capacity of the Facility as established by Duke, and if Duke does not arrange for the load following services from a third party, then UCNSB may arrange for the Load Following Services to be provided by another supplier under FERC Order 888 and Duke shall reimburse UCNSB within 15

days of being invoiced by UCNSB for the actual cost of such services minus the energy cost as provided in Section 1.3.

2.0 FACILITY, SITE AND INFRASTRUCTURE

2.1 Facility

Duke shall, at its cost, design, engineer, procure equipment for, construct, finance, own, operate, and market all capacity, energy and ancillary services provided from the Facility.

2.2 Site

UCNSB shall transfer good and marketable title to the Site (free and clear of all liens and encumbrances other than those set forth on Exhibit A hereto) to Duke prior to April 1, 1998. Prior to the commencement of construction of the Facility, Duke shall obtain a Phase I Site Assessment of the Site (to determine real or potential environmental liabilities) performed pursuant to ASTM E 1527-93 guidelines and deliver to UCNSB a copy of the results of such assessment. UCNSB shall indemnify and hold harmless Duke, its affiliates, and Duke's and its affiliates' respective directors, employees and representatives, from and against any and all claims, liabilities, losses and expenses (including costs of suit and attorneys' fees) attributable to the ownership or operation of the Site prior to such transfer or attributable to the condition of the Site at the time of such transfer, regardless of whether same are identified in such assessment. Subject to the foregoing, UCNSB shall not be responsible for, and Duke shall be responsible for, any costs of decommissioning and dismantling of the Facility at the end of its useful life. If, at any time prior to completion of the detailed engineering for the Facility, Duke reasonably determines (based on engineering and technical factors) that the Site is not adequate for the Facility and its related facilities, UCNSB will acquire, at UCNSB's cost and in a timely manner in order for Duke to meet its project schedule for the Facility, and transfer to Duke additional property contiguous with the Site on the same terms as the Site (as described in this Section).

2.3 Make-up Water

UCNSB will, at its cost, complete construction of a wastewater treatment facility (which will include a storage reservoir of at least 2 million gallons for the reuse water) and complete the drilling and equipping of water wells which, together with the reuse water from the water treatment facility, will be capable of supplying all water required by the Facility for the life of the Facility. Such water treatment facility and water wells will be located on land adjacent to the Site and will, contingent on UCNSB's receipt of necessary permits, be completed prior to the commencement of start-up testing of the Facility. From such water treatment facility and water wells, UCNSB will deliver to Duke at the power plant block on the Site all water required by the Facility for the life of the Facility. All of such water shall

be of a quality that meets the technical specifications, prior to demineralization, of the Facility. All of such water will be delivered through a minimum of a 12-inch main with a flow rate of at least 1500 gallons per minute. UCNSB shall charge Duke for all of such water at the lowest rate applicable to major users of reuse water in the area in which reuse water service is provided by UCNSB or by any successor provider (regardless of whether such reuse water is treated at such water treatment facility). Without limiting the foregoing, (a) rate increases will occur only to the extent necessary to meet operation and maintenance cost increases (cost base) associated with the processing of the reuse water, (b) since the Facility will be adjacent to the water treatment facility, capital costs and operation and maintenance costs associated with the transmission of the reuse water will not be included in any rate increases, and (c) Duke shall have the right, through appropriate proceedings, to contest any rate increases. If at any time such water from such water treatment facility and water wells is not sufficient (in terms of quantity or quality) to meet the requirements of the Facility, UCNSB shall deliver to Duke sufficient quantities of potable water as backup water at a price equal to the actual operating costs of pumping such potable water to the Facility (excluding any distribution system costs) and otherwise on the same terms as such water from such water treatment facility and water wells.

2.4 Smyrna Substation

UCNSB shall, at its cost, complete engineering and construction of a modification to the Smyrna Substation's ring bus, associated breakers, relays, instrumentation, etc., to accommodate a position in the ring bus for the Facility prior to the commencement of start-up testing of the Facility. UCNSB shall, at its cost, maintain the Smyrna Substation (including such modification) and provide Duke with access to the Florida Power Corp. and Florida Power & Light Co. transmission grids and with access to use the Smyrna Substation, in each case in a manner that will permit proper operation of the Facility for the life of the Facility.

2.5 Gas Delivery System

Duke shall, at its cost, cause natural gas pipeline service to be made available to the Site prior to the commencement of start-up testing of the Facility and shall also be responsible for any additional gas processing facilities that may be required downstream of the pipeline delivery meter and upstream of the Facility's combustion equipment.

3.0 PERMITS AND APPROVALS

3.1 General

Each Party shall use reasonable efforts to obtain all permits and approvals required to perform its obligations under this Agreement and shall assist the other Party in obtaining its permits and approvals.

3.2 Cost Sharing

Duke and UCNSB will share equally in the first $200,000 of costs approved by Duke (which approval shall not be unreasonably withheld but must be obtained prior to incurring the costs) relating to obtaining and maintaining governmental permits and approvals for the Facility, including charges by Duke's affiliates but excluding Duke, Duke Energy Power Services, LLC and UCNSB staff expenses and excluding the fees and expenses of UCNSB's counsel. Any permitting costs so approved by Duke that are in excess of $200,000 will be the sole responsibility of Duke.

3.3 Sale of Power

The obligation of Duke to provide the Entitlement to UCNSB and to sell Associated Energy to UCNSB, and the obligation of UCNSB to purchase Associated Energy with the Entitlement from Duke, are subject to the receipt of the approval from the Federal Energy Regulatory Commission for the sale of power in a form acceptable to each of the Parties affected thereby in its sole discretion. Recognizing that Duke intends to qualify as an "exempt wholesale generator" under the Public Utility Holding Company Act of 1935, as amended, UCNSB agrees to resell, and not to use for any end use, all of the electric energy provided to it by Duke pursuant to this Agreement.

3.4 Facility and Gas Delivery System

The obligations of Duke under Sections 2.1 and 2.5, including the obligation to construct the Facility and provide for natural gas deliveries to the Facility, are subject to (a) the receipt of all applicable governmental permits and approvals in a form acceptable to each of the Parties affected thereby in its sole discretion, (b) Duke obtaining a reasonably satisfactory agreement for the looping and extension of the existing natural gas pipeline lateral (i.e., the Sanford Lateral) running closest to the Site, (c) Duke obtaining, on or before March 7, 1998, the approval of the Policy Committee of Duke Energy Corporation to proceed with the transactions contemplated in this Agreement, and (d) no circumstance or event existing or having occurred that has had or could reasonably be expected to have a material adverse effect on the feasibility, prospects or business of the Facility. Duke shall give written notice to UCNSB if Duke determines not to complete the Facility as a result of any of the foregoing, in which event neither Party shall have any further obligations under this Agreement;

provided, however, that (i) each Party shall continue to be liable for any breaches hereof occurring prior to such notice, (ii) if at such time the Site has been conveyed to Duke, Duke shall reconvey to UCNSB all of Duke's right, title and interest to the Site, (iii) if such determination is made solely on the basis of the matters described in clause (d) of the immediately preceding sentence, then Duke shall also pay to UCNSB $200,000, and (iv) if within 6 months thereafter UCNSB notifies Duke that UCNSB intends to complete the Facility with another party and requests Duke to transfer any governmental permits and approvals for the Facility and any applications therefor, and if such request is approved by Duke (which approval shall not be unreasonably withheld), Duke will, to the extent legally permissible, transfer to UCNSB any governmental permits and approvals that Duke has received in connection with the Facility and any applications for governmental permits or approvals in connection with the Facility that have not yet been obtained, in each case excluding any confidential or proprietary information of Duke.

4.0 OPERATION AND MAINTENANCE

4.1 General

Duke or its designee (which may, at Duke's option, be or include UCNSB) will be responsible for the Facility's operation and maintenance activities.

4.2 Local Preference for Staffing

Subject to qualifying standards and to the extent commercially reasonable, Duke or its designee will give hiring preference to current UCNSB employees for staff positions at the Facility and will recruit for additional staffing needs from the New Smyrna Beach and Volusia County areas.

5.0 TAXES

5.1 General

Duke will be responsible for the payment of all taxes associated with the sale of capacity or energy from the Facility; provided that UCNSB shall pay (or reimburse Duke on a grossed-up basis for) all taxes (including, without limitation, gross receipts and similar taxes, but excluding (except in connection with a gross-up) federal and state income taxes) associated with the Entitlement or Associated Energy. Except as provided in the preceding sentence or Sections 1.5 or 5.2, Duke will also be responsible for all other federal, state, and local taxes that may be levied as a result of the construction, ownership, or operation of the Facility.

5.2 Special Tax Agreement

Pursuant to the Tax Agreement dated February 17, 1998 by and between the City of New Smyrna Beach, Florida (the "City") and UCNSB (the "Tax Agreement"), the City has agreed to accept an annual payment of $500,000 in lieu of any taxes, fees, user fees, license fees, assessments,

special assessments, or any other charges of any type or nature whatsoever, that the City (or any other special taxing district or instrumentality created by or on behalf of the City) is or may hereafter be in a position to levy, assess, charge, or otherwise impose, either directly or indirectly ("City Taxes", which term includes the payments under the Tax Agreement), regarding sales from, or ownership, construction, operation, decommissioning or dismantlement of, the Facility or the Site. A copy of the Tax Agreement is attached hereto as Exhibit B.

6.0 ADDITIONAL DEVELOPMENT RIGHTS

6.1 General

At any time and from time to time during the life of the Facility, UCNSB shall provide to Duke or its designee, in connection with the development of any additional power generating capacity above 240 MW at or near the Site (which may occur at the same time as the development of the Facility or at one or more subsequent times, and which may be part of the Facility or may be one or more additional facilities), the exclusive right to use the Smyrna Substation (and in such regard, at Duke's request, UCNSB shall provide to Duke, at UCNSB's cost to the extent applicable to the first 260 MW of additional power generating capacity and at Duke's cost to the extent in excess thereof, an additional position on the ring bus at the Smyrna Substation for such additional capacity) and then-currently available land, electric transmission, water treatment and delivery facilities, and other infrastructure at no additional cost. UCNSB shall not provide any such rights to any other parties during the life of the Facility. If, utilizing such rights, Duke develops any such additional power generating capacity above 240 MW that is not merely a modification of the Facility ("Additional Capacity"), then, effective as of the commencement of commercial operations of any Additional Capacity:

(a) Duke shall provide to UCNSB an entitlement to an additional 10 MW of capacity from the Additional Capacity on substantially the same terms as the Entitlement, including a take or pay obligation for 90% of the electric energy from such additional entitlement; provided, however, that (i) if the capacity of such Additional Capacity is less than 240 MW, such additional entitlement shall be adjusted to a number of MW equal to the product (rounded up to the nearest whole MW) of 10 MW multiplied by a fraction, the numerator of which is the capacity of such Additional Capacity and the denominator of which is 240 MW, and (ii) if either the Facility or the Additional Capacity is derated, UCNSB's aggregate entitlement from such two sources shall be derated by multiplying the sum of the entitlements from such two sources by a fraction, the numerator of which is the aggregate availability of such two sources at the time and the

denominator of which is the aggregate capacity of such two sources;

(b) the reference to $500,000 in Section 1.5 shall be revised to be a dollar amount equal to the sum of (i) $500,000 plus (ii) the product of $250,000 multiplied by a fraction, the numerator of which is the capacity of such Additional Capacity and the denominator of which is 240 MW; provided, however, that with respect to any 12 month period beginning on the tenth or any subsequent anniversary of the COD, UCNSB shall not be obligated under Section 1.5 to pay Duke for any ad valorem taxes assessed on the Additional Capacity in excess of the amount described in clause (ii) of this Section 6.1(b), it being understood that, for purposes of allocating ad valorem taxes for this provision between the initial 240 MW of the Facility and the Additional Capacity, the Site and all real and personal property used or useful in connection with such initial 240 MW of the Facility shall be allocated to such 240 MW of the Facility and not to the Additional Capacity (for example, assuming the Additional Capacity is 240 MW, (A) if ad valorem taxes allocable to the Additional Capacity are $250,000 and all other City Taxes allocable to the Additional Capacity are $300,000, UCNSB shall pay to Duke $300,000 with respect to City Taxes allocable to the Additional Capacity, and (B) if ad valorem taxes allocable to the Additional Capacity are $300,000 and all other City Taxes allocable to the Additional Capacity are $250,000, UCNSB shall pay to Duke $250,000 with respect to City Taxes allocable to the Additional Capacity); and

(c) UCNSB shall deliver to Duke all of the water required for such Additional Capacity on the same terms as the water described in Section 2.3 for the Facility, it being agreed that UCNSB shall incorporate into its 5 year capital improvements plan beginning in fiscal year 1998 the capital expenditures required to be in a position to deliver such water for the Additional Capacity.

7.0 REPRESENTATIONS AND WARRANTIES

7.1 Representations and Warranties of Duke

Duke hereby represents and warrants to UCNSB that:

(a) Duke is a duly organized, validly existing Florida limited partnership and is in good standing under the laws of the State of Florida. It has all requisite partnership power and authority to enter into and to perform its obligations under this Agreement.

(b) Its execution, delivery, and performance of this Agreement have been duly authorized, and do not and will not (i) violate any law,

rule, regulation, order, or decree applicable to it, (ii) violate its organizational documents, or (iii) contravene or constitute a default or breach under any instrument, indenture, agreement, or other obligation to which it is a party or by which it is bound.

(c) This Agreement is a legal and binding obligation of Duke, enforceable against Duke in accordance with its terms, except to the extent enforceability is modified by bankruptcy, reorganization and other similar laws affecting the rights of creditors generally and by general principles of equity.

(d) There is no litigation or administrative proceeding (excluding permit applications and similar matters) pending or, to the best of its knowledge, threatened involving Duke that, if adversely determined, could have a material adverse effect on the financial condition, prospects, or business of the Facility or Duke's ability to perform its obligations under this Agreement.

7.2 Representations and Warranties of UCNSB

UCNSB hereby represents and warrants to Duke that:

(a) UCNSB is a duly organized, validly existing commission of the City and pursuant to Section 214 of Chapter 15 of the City's Charter UCNSB has been delegated the authority to manage, operate and control the City's utilities. Pursuant to the authority delegated to UCNSB by the City, UCNSB has all requisite power and authority to enter into and to perform its obligations under this Agreement.

(b) UCNSB's execution, delivery, and performance of this Agreement have been duly authorized, and do not and will not (i) violate any law, rule, regulation, order, or decree applicable to it or the City, (ii) violate its organizational documents, or (iii) contravene or constitute a default or breach under any instrument, indenture, agreement, or other obligation to which it is a party or by which it is bound.

(c) This Agreement is a legal and binding obligation of UCNSB, enforceable against UCNSB in accordance with its terms, except to the extent enforceability is modified by bankruptcy, reorganization and other similar laws affecting the rights of creditors generally and by general principles of equity.

(d) There is no litigation or administrative proceeding (excluding permit applications and similar matters) pending or, to the best of its knowledge, threatened involving UCNSB that, if adversely determined, could have a material adverse effect on the financial

condition, prospects, or business of the Facility or UCNSB's ability to perform its obligations under this Agreement.

8.0 MISCELLANEOUS

8.1 Notices

All notices, requests or consents provided for or permitted to be given under this Agreement shall be in writing, shall be delivered to the recipient in person, by courier or mail, or by facsimile, telex or similar transmission, and shall be effective (a) upon receipt, if sent by personal delivery, mail or courier, or (b) upon the sender's receipt of electronic confirmation of transmission, if sent by facsimile, telex or similar transmissions during regular business hours on a business day (or, if not sent during regular business hours on a business day, on the next succeeding business day). All notices, requests and consents to be sent to a Party shall be sent to the following addresses or such other address as a Party may specify for its address by notice to the other Party:

If to UCNSB:

Utilities Commission, City of
New Smyrna Beach, Florida
Post Office Box 100
200 Canal Street
New Smyrna Beach, Florida 32170
Telephone: 904-427-7100
Facsimile: 904-423-7175
Attention: Director of Utilities

If to Duke:

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.
400 South Tryon Street
Suite 1800
Charlotte, N.C. 28285
Telephone: 704-382-5963
Facsimile: 704-382-1452
Attention: Mr. David Hauser

8.2 Exclusivity

From the date hereof until the COD, each Party shall use reasonable efforts to promote the business of the Facility and shall not solicit or engage in negotiations or discussions with any other party relating to the Facility or any other similar project within the area in which electric service is provided by UCNSB or any successor provider, if such

negotiations or discussions could reasonably be expected to have a material adverse effect on the business or prospects of the Facility.

8.3 Disclosure of Information

The Parties acknowledge that UCNSB is a publicly owned and operated utility and that UCNSB, its commissioners, employees and agents are subject to the provisions and requirements of Chapters 119 and 286, Florida Statutes, regarding the handling of public records and open meetings. Subject to such requirements, each Party shall maintain in confidence all information received from the other Party or its affiliates relating to the Facility; provided, however, that such Party may disclose such information (a) to its affiliates and its affiliates' respective directors, employees, and representatives (it being understood that they shall be informed by such Party of the confidential nature of such information and that such Party shall cause them to treat such information confidentially), (b) with the approval of Duke if such disclosure is reasonably necessary to develop, construct, finance or promote the business of the Facility, (c) if required to do so by applicable laws, rules, regulations, or orders (including any applicable securities exchange rules), (d) if such information was or becomes generally available to such Party on a non-confidential basis, provided that the source of such information was not known by such Party to be bound by a confidentiality obligation, or (e) if such information is generally available to the public.

8.4 Assignment

No assignment of any of the rights or obligations under this Agreement shall be made by either Party other than to an affiliate of such Party unless (a) it can be demonstrated to the reasonable satisfaction of the non-transferring Party that the financial creditworthiness of the transferee party is at least equal to or better than that of the transferring Party and (b) the non-transferring Party has consented in writing prior thereto, which consent shall not be unreasonably withheld; provided that it is understood that no assignment shall relieve the transferring Party of its obligations hereunder unless the non-transferring Party has consented in writing prior thereto, which consent shall be in such non-transferring Party's sole discretion. For purposes of this Agreement, an "affiliate" of a party shall be any other party controlling, controlled by, or under common control with such party. Without limiting the foregoing, if either Party transfers all or substantially all of its assets to another party, such Party shall cause such transferee party to assume all of such Party's obligations under this Agreement.

8.5 Binding Effect; No Third Party Beneficiaries

This Agreement shall be binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns. Except to the extent Section 2.2 (relating to rights of certain parties to be indemnified) provides otherwise, this Agreement is solely for the benefit of the Parties and their respective successors and permitted assigns, and this Agreement shall not otherwise be deemed to confer upon or give to any other party any rights, claims or remedies.

8.6 Expenses

Except as otherwise provided herein, each Party agrees to bear any costs incurred by it in connection with this Agreement and the development of the Facility.

8.7 Indemnification

Each Party shall indemnify and hold harmless the other Party from and against all claims, liabilities, losses, and expenses (including costs of suit and attorneys' fees) that it may incur on account of any breach by the indemnifying Party of any of its representations, warranties or obligations under this Agreement.

8.8 Further Assurances

Each Party agrees to negotiate in good faith and to execute and deliver as soon as practicable after the date hereof a power purchase agreement more fully reflecting the matters described in Section 1.0 hereof. Each Party also agrees to execute such other documents and take such further actions as may be necessary or desirable to effectuate the provisions of this Agreement.

8.9 Compliance with Laws

Each Party shall comply with all laws, rules and regulations applicable to it, the Facility, or the infrastructure described in Section 2.0.

8.10 GOVERNING LAW

THIS AGREEMENT IS GOVERNED BY AND SHALL BE CONSTRUED IN ACCORDANCE WITH THE LAW OF THE STATE OF FLORIDA, EXCLUDING ANY CONFLICT-OF-LAWS RULE OR PRINCIPLE THAT MIGHT REFER THE GOVERNANCE OR THE CONSTRUCTION OF THIS AGREEMENT TO THE LAW OF ANOTHER JURISDICTION.

8.11 Dispute Resolution

In the event of any dispute between the Parties, the Parties shall first attempt to settle such dispute amicably if possible and, failing that, such dispute shall be submitted to the services of a professional mediation service (the cost of which shall be borne equally by the Parties) which shall attempt to mediate the dispute. If the Parties cannot agree upon a mediation service or if the dispute has not been resolved within 60 days after either Party requested mediation services, each Party shall be free to pursue any other means of resolution available to such Party.

8.12 Consequential Damages

Notwithstanding anything to the contrary contained herein, except for actual damages, neither Party shall be liable or have any responsibility to the other Party for any indirect, special, consequential, punitive or other delay-related or performance-related damages including, without limitation, lost earnings, production or profits. Such limitation on liability shall apply with respect to any claim or action, whether it is based in whole or in part on contract, negligence, strict liability, tort, statutory or any other theory of liability. The Parties specifically acknowledge that the benefits each Party contemplates deriving from the provisions of this Agreement reflect such allocation of risk and limitation on liability.

8.13 Remedies

Notwithstanding anything to the contrary contained herein, if UCNSB fails to pay any amounts aggregating over $50,000 for more than 30 days after the due dates therefor, Duke shall have the right to cease providing energy to UCNSB until such failure is cured and, if such failure continues for more than 90 days after the due dates therefor, Duke shall have the right to terminate (upon notice to UCNSB) the Entitlement and all of Duke's obligations under Section 1.0. Subject to Section 8.12, the rights and remedies provided by this Agreement are cumulative and are in addition to any other rights and remedies a Party may have by law, statute or otherwise.

8.14 Waivers

Any waiver, express or implied, by a Party of any right under this Agreement shall be effective only if it is set forth in a written document executed by such Party and shall not constitute or be deemed to be a waiver of any other right, whether of a similar or dissimilar nature.

8.15 Severability

If any provision of this Agreement or the application thereof to any Party or circumstance shall be held invalid or unenforceable to any extent, the remainder of this Agreement and the application of such provision to the other Party or circumstances shall not be affected thereby and shall be enforced to the greatest extent permitted by law. In such event, the Parties agree that the provisions of this Agreement shall be modified and

reformed so as to effect the original intent of the Parties as closely as possible with respect to any such provision held invalid or unenforceable.

8.16 No Partnership

Nothing in this Agreement shall be construed (a) to create or constitute a partnership, agency or similar relationship, (b) to create any joint and several liability on the part of either of the Parties, or (c) to cause the Parties not to be separate legal entities.

8.17 Entire Agreement; Amendment

This Agreement and the Tax Agreement constitute the entire agreement among the Parties and their respective affiliates relating to the Facility and supersede all prior written or oral agreements among any such parties with respect to such matter (including, without limitation, the LOI). This Agreement may be amended or modified only by a written document executed by each of the Parties.

8.18 Headings; References

The headings of the Sections of this Agreement are included for convenience of reference only and shall not be used in construing or limiting the language of any particular Section. All references to a Party shall be deemed to include its successors and permitted assigns. Unless otherwise expressly provided, all references to "Sections" are to the Sections of this Agreement and all references to "Exhibits" are to the Exhibits attached hereto, each of which is made a part hereof for all purposes.

8.19 Counterparts

This Agreement may be executed in any number of counterparts with the same effect as if each Party had signed the same document. All counterparts shall be construed together and constitute the same instrument.

8.20 Limited Recourse Against UCNSB

The obligations of UCNSB under this Agreement shall not constitute general obligations of UCNSB or the City as "bonds" within the meaning of the Constitution of Florida, but shall be payable solely from, and shall be secured equally and ratably by a first lien on and pledge of, the Net Revenues from UCNSB's System on a parity with UCNSB's Series 1992 Certificates, Series 1993 Certificates, Series 1996 Certificates, and any Additional Parity Obligations without any preference, priority or distinction of any such certificate or obligation over any other thereof (with capitalized terms used in this Section but not otherwise defined in this Agreement having the meanings given to them in Resolution No. 28-78, adopted by UCNSB on June 30, 1978). UCNSB hereby grants to Duke such a first lien on and security interest in, and so pledges to Duke, such Net Revenues to secure the payment and performance of UCNSB's

obligations under this Agreement. UCNSB agrees to comply with all of its obligations set forth in such Resolution No. 28-78 as if such obligations were set forth herein.

IN WITNESS WHEREOF, each of the undersigned Parties has executed and delivered this Agreement as of the date first set forth above.

Attest: Ellen Simmons

UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH, FLORIDA

By: Ronald Vaden
Name: Ronald L. Vaden
Title: Utilities Director

Approved as to form and correctness:

Counsel to UCNSB: Hal Spence
Hal Spence, Esquire

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

By: Duke Energy Power Services
Mulberry GP, Inc.,
its general partner

By: James M. Donnell
Name: James M. Donnell
Title: Senior Vice President

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EXHIBIT A

Description of the Site

The Site shall be the West 1320 feet of the North 660 feet of the NE 1/4 of Section 21, Township 17 South, Range 33 East, containing 20 acres more or less, but excluding the land covered by the Smyrna Substation.

EXHIBIT B

TAX AGREEMENT

This Tax Agreement (this "Agreement"), dated as of February 17, 1998, is by and between the Utilities Commission, City of New Smyrna Beach, Florida (the "Commission") and the City of New Smyrna Beach, Florida (the "City").

WHEREAS, the Commission, pursuant to Section 214 of the City's Charter, has been charged with the responsibility to manage, operate and control all of the City's utilities and, pursuant to Section 217 of the City's Charter, is authorized to furnish the electricity and power, among other utilities, to private individuals and corporations and in furtherance of said power, the Commission has the right to acquire, construct, maintain, extend, improve and develop electric production and distribution systems and to contract with public bodies, and private corporations, partnerships and individuals for such purposes; and

WHEREAS, the Commission has negotiated and expects to enter into a Participation Agreement (the "Participation Agreement") with Duke Energy New Smyrna Beach Power Company, a Delaware limited partnership ("Duke Energy LP", which term shall include its successors and assigns) for the purpose of developing a combined-cycle electric generating facility on an approximately 20 acre tract of land in Volusia County, Florida (the "Site") with a capacity of approximately 240 megawatts ("MW") or more and including its gas delivery and related infrastructure and any modifications to such facility or infrastructure (collectively, the "Facility"); and

WHEREAS, in consideration for the undertakings as set forth in the Participation Agreement, the Commission will be entitled to 20 MW of electric capacity from the Facility (the "Entitlement") and 20 MW hours of electric energy per hour associated with the Entitlement; and

WHEREAS, entering into the Participation Agreement and this Agreement will serve a public purpose of providing the Commission with an economical and long-term source of electric energy for the benefit of customers of the Commission and residents of the City; and

WHEREAS, as a condition of entering into the Participation Agreement, Duke Energy LP has requested that the Commission and the City enter into this Agreement to set forth the understanding of the parties hereto and Duke Energy LP related to the taxation and the exaction of any fees, charges or assessments by the City (or any other special taxing district or instrumentality created by or on behalf of the City) upon the Site, the improvements to be constructed which comprise the Facility and the electricity to be generated and sold by the owners of the Facility; and

NOW, THEREFORE, in consideration of the mutual agreements contained herein, the parties hereto agree as follows:

1. As provided in the Participation Agreement, Duke Energy LP, or its successors or assigns, has agreed to pay to the City $500,000 payable in twelve equal monthly installments on the first day of each month commencing on the first day of the month following the commercial operation date ("COD") of the Facility and continuing until notice from Duke Energy LP that the Facility is no longer expected to be used for commercial operations. Such amount shall represent the total amount due to the City (or any other special taxing district or instrumentality created by or on behalf of the City) with respect to the Site, the Facility, the construction, ownership, operation, decommissioning and dismantlement of the Facility and the electricity generated, transmitted or sold therefrom. In consideration of such $500,000 per year payments to the City by Duke Energy LP, the City covenants (i) to favorably consider any application to abate (or for exemption from) ad valorem property taxes, as provided by law, (ii) not to levy or impose a franchise fee applicable to the Facility or the electricity generated, transmitted or sold therefrom, (iii) to waive any payments to the city's general fund required pursuant to Section 218 of the City Charter, and (iv) not to directly or indirectly levy, assess, charge or impose (and to cause all other municipal entities not to directly or indirectly levy, assess, charge or impose) any taxes, fees, user fees, license fees, assessments, special assessments, or any other charges of any type or nature whatsoever that the City (or any other special taxing district or instrumentality created by or on behalf of the City) is or may hereafter be in a position to levy, assess, charge, or otherwise impose, either directly or indirectly, regarding the Site, the Facility, the construction, ownership, operation, decommissioning and dismantlement of the Facility, or the electricity generated, transmitted or sold therefrom.

2. In the event Duke Energy LP, or its successors or assigns, constructs additional power generating capacity above 240 MW at or near the Site utilizing the Commission's available facilities and infrastructure at no additional cost to Duke Energy LP (which additional power generating capacity is not merely a modification of the Facility) (the "Additional Capacity"), the amount due the City from Duke Energy LP shall be increased to an annual amount equal to the sum of (a) $500,000 plus (b) the product of $250,000 multiplied by a fraction, the numerator of which is the capacity of such Additional Capacity and the denominator of which is 240 MW, as provided in the Participation Agreement.

3. This Agreement does not relate to, and Duke Energy LP is responsible for, the payment of any and all taxes to be levied or fees, charges or assessment that may now or hereafter be imposed on Duke Energy LP or the Facility by any state or federal governmental unit or agency (other than the City or any other special taxing district or instrumentality created by or on behalf of the City).

4. The provisions of this Agreement relating to exemption from ad valorem tax shall terminate on the date which is 10 years from the COD if and to the extent required by Section 196.1995(6), Florida Statutes, unless renewed based on terms and provisions mutually agreed upon by the parties hereto.

5. This Agreement shall inure to the benefit of and shall be binding upon the City, the Commission, and their respective successors and assigns, and shall be governed by and construed

in accordance with the laws of the State of Florida. Duke Energy LP shall be a third party beneficiary of this Agreement.

6. In the event any provision of this Agreement shall be held invalid or unenforceable by any court of competent jurisdiction, the remainder of this Agreement shall not be affected thereby if such remainder would then continue to conform to the requirements of applicable law.

7. This Agreement represents the entire agreement between the parties. This Agreement may be supplemented, modified or amended only with the prior written consent of Duke Energy LP.

8. This Agreement may be simultaneously executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

IN WITNESS WHEREOF, the City has caused this Agreement to be executed by its Mayor and the seal of the City to be hereto affixed and attested by its City Clerk and the Utilities Commission, City of New Smyrna Beach, Florida has duly caused this Agreement to be executed by its Chairman and the seal of the Commission to be hereto affixed and attested by its Secretary Treasurer, all as of the date first above written.

(SEAL)

UTILITIES COMMISSION,
CITY OF NEW SMYRNA, FLORIDA

By: _____
Chairman

ATTEST:

_____
Secretary-Treasurer

CITY OF NEW SMYRNA BEACH, FLORIDA

(SEAL)

By: _____
Mayor

ATTEST:

_____
City Clerk

F:\BB0429\DUKE\SMYRNA\AGMT05.DOC

AMENDMENT NUMBER ONE
TO PARTICIPATION AGREEMENT
BY AND BETWEEN
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH, FLORIDA
AND
DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

This Amendment Number One to the Participation Agreement By and Between Utilities Commission, City of New Smyrna Beach, Florida and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. ("Amendment") is made and entered into March 11, 1998, by and between Utilities Commission, City of New Smyrna Beach, Florida ("UCNSB") and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. ("Duke"), collectively, the "Parties".

RECITALS

WHEREAS, UCNSB and Duke are Parties to the Participation Agreement to proceed with the development of a combined-cycle electric generation facility with a capacity of approximately 240 megawatts or more (the "Facility"), dated Feb. 17, 1998, ("Agreement").

WHEREAS, UCNSB and Duke desire to revise the Agreement;

NOW, THEREFORE, in consideration of the foregoing and of the mutual covenants contained herein, the Parties do hereby agree to amend the Agreement as follows:

1. Insert in Section 2.2, Site:

   "and shall transfer back to UCNSB good and marketable title to the Site"

2. Delete in Section 3.4, Facility and Gas Delivery System:

   "Policy Committee" and replace with:

   "Board of Directors of Duke Energy Power Services, LLC, a subsidiary"

3. Add in Section 3.4, Facility and Gas Delivery System:

   "(d) Duke obtaining, within 60 days after all necessary permits are obtained, approval for funding for construction of the project by the Duke Energy Corporation Board of Directors"

   and update subsequent (d) to (e); and add "or (e)" to item (iii).

4. Add to Exhibit B, Tax Agreement, Paragraph 3:

   "Ltd., L.L.P."

   and replace "Delaware" with "Florida".

This Amendment Number One shall be come effective on March 11, 1998.

IN WITNESS WHEREOF, the Parties hereto have caused this Amendment Number One to the Agreement to be executed by their duly authorized officers as of the day and year first above stated.

ATTEST:

By: _____

UTILITIES COMMISSION,
CITY OF NEW SMYRNA BEACH, FLORIDA

By: _____
Name: Ronald Vaden
Title: Utilities Director

Approved as to form and correctness:

Counsel to UCNSB: _____

DUKE ENERGY NEW SMYRNA BEACH
POWER COMPANY LTD., L.L.P.

By: Duke Energy Power Services
Mulberry GP, Inc.
its general partner

ATTEST:

By: _____

By: _____
Name: James M. Donnell
Title: Senior Vice President

2.2 Site

UCNSB shall transfer good and marketable title to the Site (free and clear of all liens and encumbrances other than those set forth on Exhibit A hereto) to Duke prior to April 1, 1998. Prior to the commencement of construction of the Facility, Duke shall obtain a Phase I Site Assessment of the Site (to determine real or potential environmental liabilities) performed pursuant to ASTM E 1527-93 guidelines and deliver to UCNSB a copy of the results of such assessment. UCNSB shall indemnify and hold harmless Duke, its affiliates, and Duke's and its affiliates' respective directors, employees and representatives, from and against any and all claims, liabilities, losses and expenses (including costs of suit and attorneys' fees) attributable to the ownership or operation of the Site prior to such transfer or attributable to the condition of the Site at the time of such transfer, regardless of whether same are identified in such assessment. Subject to the foregoing, UCNSB shall not be responsible for, and Duke shall be responsible for, any costs of decommissioning and dismantling of the Facility and shall transfer back to UCNSB good and marketable title to the Site at the end of its useful life. If, at any time prior to completion of the detailed engineering for the Facility, Duke reasonably determines (based on engineering and technical factors) that the Site is not adequate for the Facility and its related facilities, UCNSB will acquire, at UCNSB's cost and in a timely manner in order for Duke to meet its project schedule for the Facility, and transfer to Duke additional property contiguous with the Site on the same terms as the Site (as described in this Section).

3.4 Facility and Gas Delivery System

The obligations of Duke under Sections 2.1 and 2.5, including the obligation to construct the Facility and provide for natural gas deliveries to the Facility, are subject to (a) the receipt of all applicable governmental permits and approvals in a form acceptable to each of the Parties affected thereby in its sole discretion, (b) Duke obtaining a reasonably satisfactory agreement for the looping and extension of the existing natural gas pipeline lateral (i.e., the Sanford Lateral) running closest to the Site, (c) Duke obtaining, on or before March 7, 1998, the approval of the Board of Directors of Duke Energy Power Services, LLC, a subsidiary of Duke Energy Corporation, to proceed with the transactions contemplated in this Agreement, (d) Duke obtaining, within 60 days after all necessary permits are obtained, approval for funding for construction of the project by the Duke Energy Corporation Board of Directors, and (e) no circumstance or event existing or having occurred that has had or could reasonably be expected to have a material adverse effect on the feasibility, prospects or business of the Facility. Duke shall give written notice to UCNSB if Duke determines not to complete the Facility as a result of any of the foregoing, in which event neither Party shall have any further obligations under this Agreement; provided, however, that (i) each Party shall continue to be liable for any breaches hereof occurring prior to such notice, (ii) if at such time the Site has been conveyed to Duke, Duke shall reconvey to UCNSB all of Duke's right, title and interest to the Site, (iii) if such determination is made solely on the basis of the matters described in clause (d) or (e) of the immediately preceding sentence, then Duke shall also pay to UCNSB $200,000, and (iv) if within 6 months thereafter UCNSB notifies Duke that UCNSB intends to complete the Facility with another party and requests Duke to transfer any governmental permits and approvals for the Facility and any applications therefor, and if such request is approved by Duke (which approval shall not be unreasonably withheld), Duke will, to the extent legally permissible, transfer to UCNSB any governmental permits and approvals that Duke has received in connection with the Facility and any applications for governmental permits or approvals in connection with the Facility that have not yet been obtained, in each case excluding any confidential or proprietary information of Duke.

Utilities Commission, City of New Smyrna Beach
Historical and Projected Customers, 1992-2008

Historical Customers						
	1992	**1993**	**1994**	**1995**	**1996**	**1997**
Residential Customers (Average/Month)	16,914	17,213	17,496	17,734	17,856	17,995
General Service Customers (Average/Month)	1,689	1,705	1,691	1,702	1,715	1,728

Projected Customers						
	1998	**1999**	**2000**	**2001**	**2002**	**2003**
Residential Customers (Average/Month)	18,143	18,289	18,436	18,584	18,733	18,883
General Service Customers (Average/Month)	1,769	1,800	1,831	1,863	1,898	1,934

Projected Customers						
	2004	**2005**	**2006**	**2007**	**2008**	
Residential Customers (Average/Month)	19,035	19,187	19,341	19,496	19,653	
General Service Customers (Average/Month)	1,967	2,001	2,035	2,069	2,105	

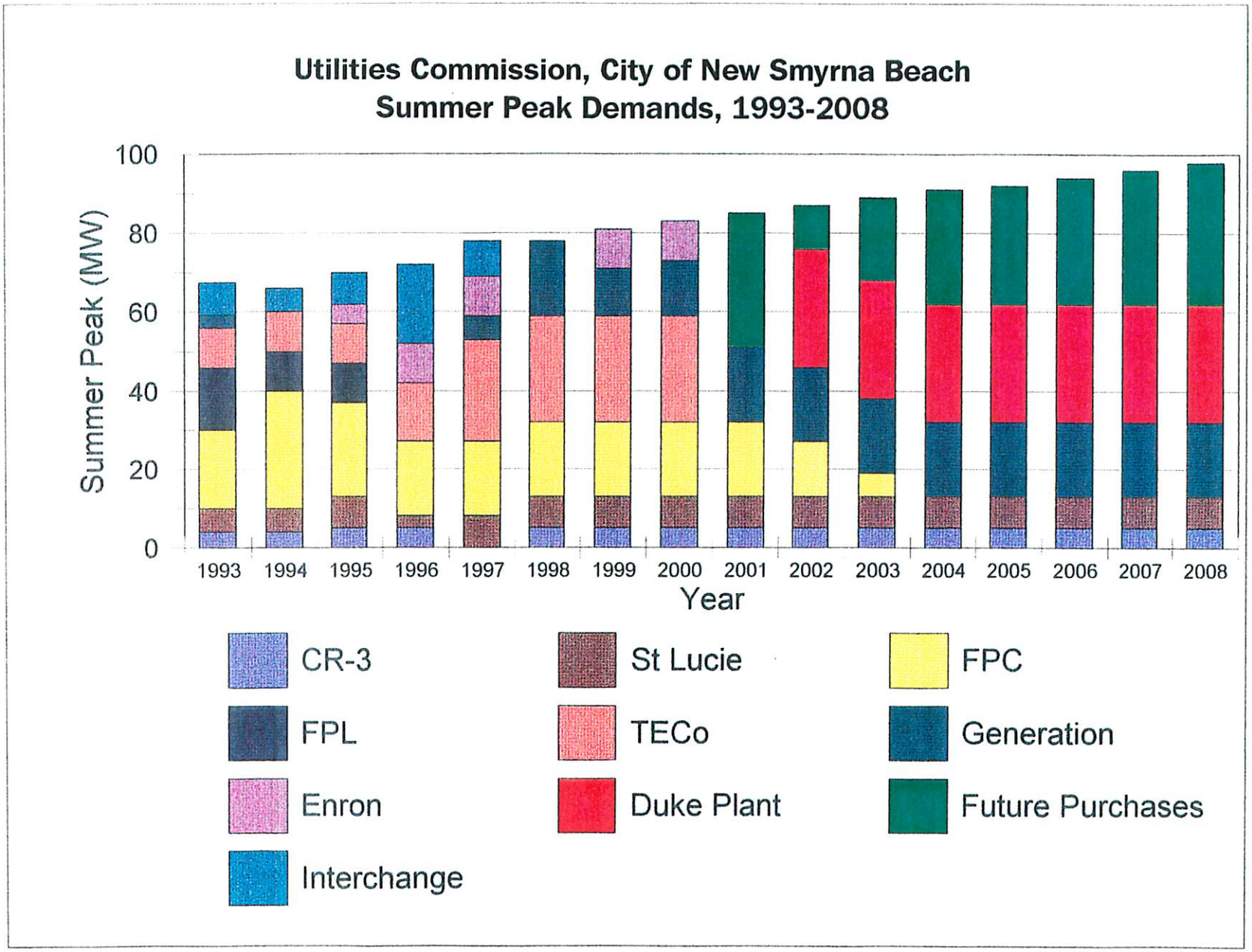
Utilities Commission, City of New Smyrna Beach
Historical and Projected Peak Demands,
1993-2008 (MW)

Peak Demand (MW)

	1993	1994	1995	1996	1997	1998	1999	2000
Summer	68	66	70	72	78	78	81	83
Winter	72	70	88	89	83	68	91	94

	2001	2002	2003	2004	2005	2006	2007	2008
Summer	85	87	89	91	92	94	96	98
Winter	96	98	100	102	104	106	108	110

FPSC Docket No. 981042-EI
UCNSB/Duke New Smyrna
Witness: Vaden
Exhibit _____ (RLV-3)
Page 1 of 3


Utilities Commission, City of New Smyrna Beach
Summer Peak Demands, 1993-2008
Summer Peak (MW)
100
80
60
40
20
0
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
CR-3
St Lucie
FPC
FPL
TECo
Generation
Enron
Duke Plant
Future Purchases
Interchange

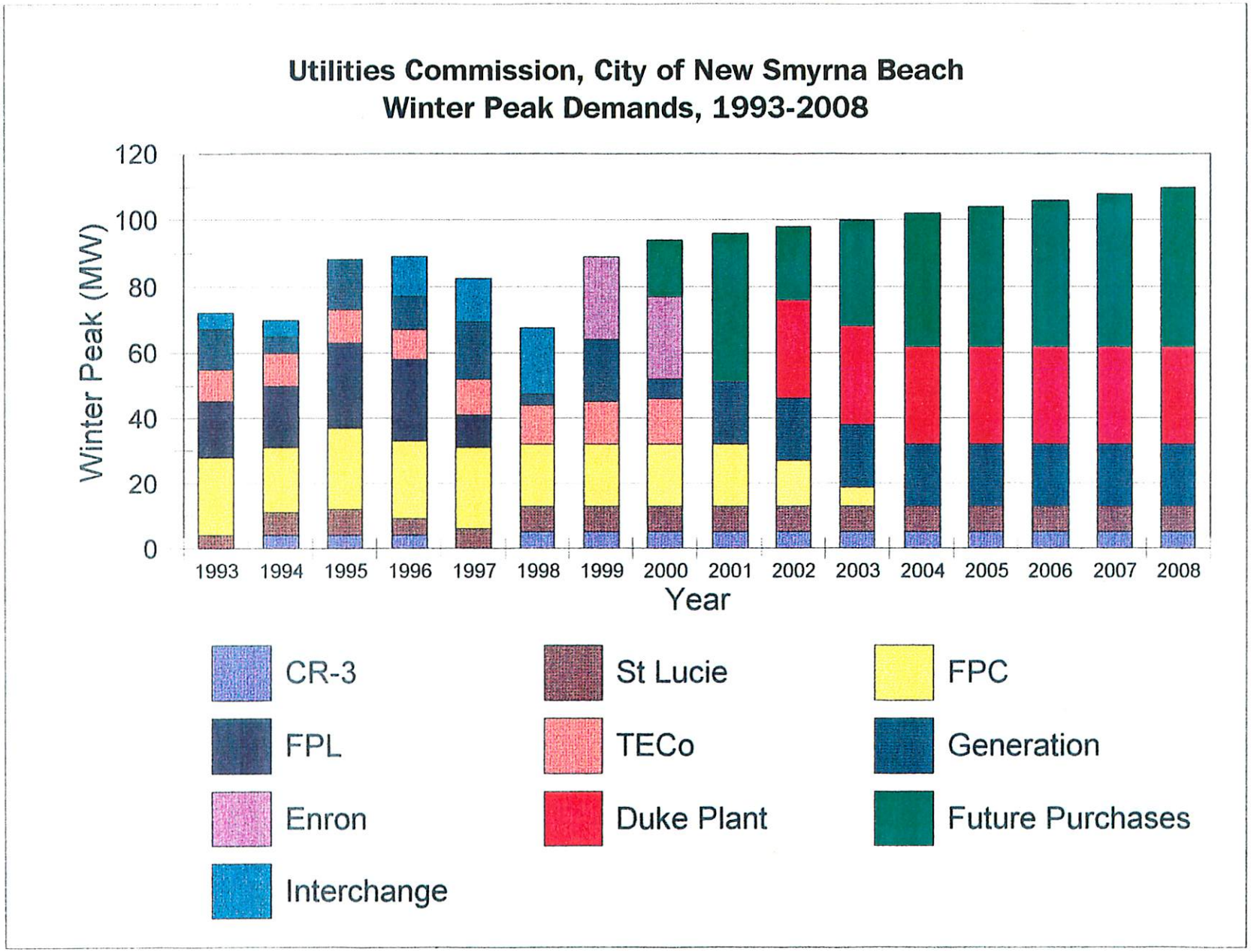


Exhibit _____ (RLV-3)
Page 3 of 3

Utilities Commission, City of New Smyrna Beach
Historical and Projected Energy Requirements, 1992-2008

Historical Energy Requirements (MWH)						
	1992	1993	1994	1995	1996	1997
Energy Requirements	287,167	292,485	301,883	318,962	331,285	325,229

Projected Energy Requirements (MWH)						
	1998	1999	2000	2001	2002	2003
Energy Requirements	334,109	344,450	349,513	354,421	359,686	364,168

Projected Energy Requirements (MWH)						
	2004	2005	2006	2007	2008	
Energy Requirements	369,380	374,666	380,028	385,467	390,984	

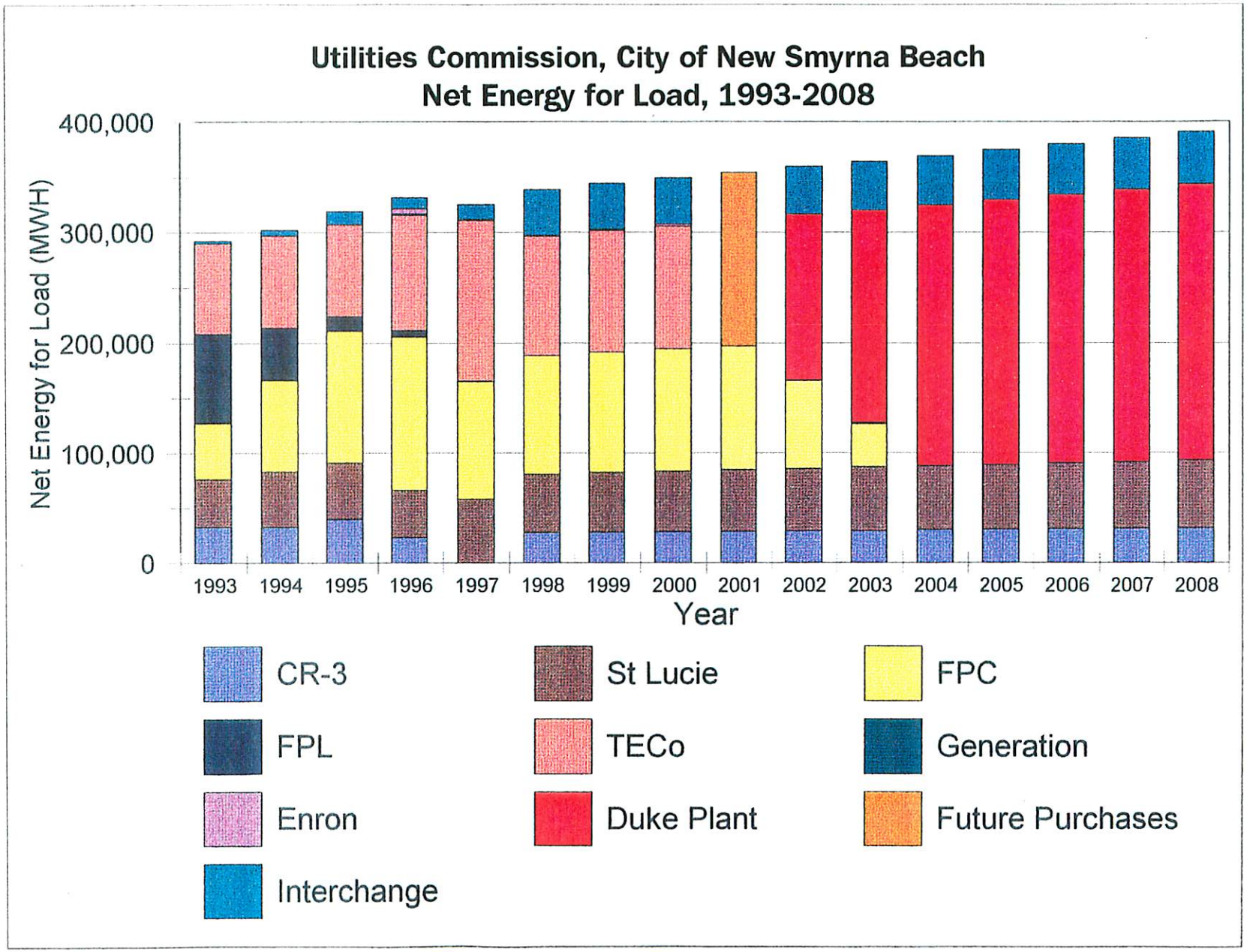


Exhibit _____ (RLV-4)
Page 2 of 2

Utilities Commission, City of New Smyrna Beach
Power Supply Resources

Resource Name	Peak Capacity (MW)	Expiration Date
St. Lucie/FMPA	7.1	N/A
Crystal River 3	5.4	N/A
Florida Power Corp. PR	24.0	Phased to 0 MW as of October 1, 2004
Florida Power Corp. Stratified Peaking	6.0	February 29, 2000
Enron Short Term	25.0	March 31, 2000
Tampa Electric Co. Schedule 'D'	13.0	February 29, 2000
Tampa Electric Co. Summer Service	5.0	September 30, 1999
Tampa Electric Co. Supplemental	10.0	September 30, 1999
Local Generation	18.8	N/A

UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH
FISCAL YEAR 2000 BUDGET WITHOUT NEW SMYRNA BEACH POWER PROJECT

Month	Year	NEL MWH	Peak MW	Load Factor	Res Margin	LOLP days/yr	LOLP hrs/yr
Total	2000	349513	87	45.74	10.70	0	0

Resource Name	NEL MWH	Start-up Cost $	Energy Cost $	Energy $/MWH	Res. C.F.%	Fixed Cost $	Total Cost $	Total Cost $/MWH
CR-3	35623	0	187021	5.25	99.98	68400	255421	7.17
Clinch-Pk	2270	0	149729	65.96	4.31	0	149729	65.96
Dual Fuel	406	0	26780	65.96	0.36	0	26780	65.96
Enron Res	0	0	0	0.00	0.00	0	0	0.00
EnronST	3601	0	126035	35.00	7.08	242000	368035	102.20
FPC PR	86607	0	1987504	22.95	58.00	2204352	4191856	48.40
FPC Peak	6587	0	382046	58.00	12.50	267264	649310	98.57
PR Base	17568	0	403266	22.95	100.00	256320	659586	37.54
PR Res.	0	0	0	0.00	0.00	0	0	0.00
Reg-Res-Bk	0	0	0	0.00	0.00	263552	263552	0.00
St. Lucie	57438	0	709359	12.35	99.98	0	709359	12.35
TECo S	7096	0	159486	22.48	99.99	0	159486	22.48
TECo S2	4086	0	91835	22.48	57.58	0	91835	22.48
TECo10a	14192	0	390262	27.50	99.99	0	390262	27.50
TECo10b	4210	0	115770	27.50	29.66	0	115770	27.50
TECoBase	109829	0	1926978	17.55	96.72	854510	2781488	25.33
Uns Energy	0	0	0	0.00	0.00	0	0	0.00
TOTALS	349513	0	6656071	19.04		4156398	10812469	30.94

UCNSB/Duke New Smyrna
Witness: Vaden
Exhibit ____ (RLV-6)
Page 1 of 3

UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH
FISCAL YEAR 2000 BUDGET WITH NEW SMYRNA BEACH POWER PROJECT

Month	Year	NEL MWH	Peak MWs	Load Factor	Res Margin	LOLP days/yr	LOLP hrs/yr
Total	2000	349513	87	45.74	17.12	0	0

Resource Name	NEL MWH	Start-up Cost $	Energy Cost $	Energy $/MWH	Res. C.F.%	Fixed Cost $	Total Cost $	Total Cost $/MWH
Base30	218612	0	4044322	18.50	82.96	0	4044322	18.50
CR-3	35623	0	187021	5.25	99.98	68400	255421	7.17
Clinch-Pk	56	0	3694	65.96	0.11	0	3694	65.96
Dual Fuel	0	0	0	0.00	0.00	0	0	0.00
Peaking	37784	0	1511360	40.00	12.78	1212000	2723360	72.08
St. Lucie	57438	0	709359	12.35	99.98	0	709359	12.35
Uns Energy	0	0	0	0.00	0.00	0	0	0.00
TOTALS	349513	0	6455756	18.47		1280400	7736156	22.13

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK, WITHOUT NEW SMYRNA BEACH POWER PROJECT

Year	INSTALLE CAPACITY (MW)	NET CONTRAC FIRM INTERCHG (MW)	PROJECTE FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABL CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1998	35485	1412	2220	39117	35633	3484	9.78	2776	32857	6260	19.05
1999	36112	1702	2220	40034	36628	3406	9.30	3011	33617	6417	19.09
2000	36356	1852	2220	40428	37410	3018	8.07	3130	34280	6148	17.93
2001	36866	1766	2295	40927	38220	2707	7.08	3227	34993	5934	16.96
2002	38406	1704	2286	42396	38844	3552	9.14	3256	35588	6808	19.13
2003	39430	1623	2286	43339	39395	3944	10.01	3317	36078	7261	20.13
2004	40500	1633	2286	44419	40227	4192	10.42	3356	36871	7548	20.47
2005	41325	1644	2276	45245	41112	4133	10.05	3379	37733	7512	19.91
2006	42042	1630	2143	45815	41998	3817	9.09	3405	38593	7222	18.71
2007	43096	1755	2143	46994	42885	4109	9.58	3434	39451	7543	19.12

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK, WITH NEW SMYRNA BEACH POWER PROJECT 476 MW IN 2002

Year	INSTALLE CAPACITY (MW)	NET CONTRAC FIRM INTERCHG (MW)	PROJECTE FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABL CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1998	35485	1412	2220	39117	35633	3484	9.78	2776	32857	6260	19.05
1999	36112	1702	2220	40034	36628	3406	9.30	3011	33617	6417	19.09
2000	36356	1852	2220	40428	37410	3018	8.07	3130	34280	6148	17.93
2001	36866	1766	2295	40927	38220	2707	7.08	3227	34993	5934	16.96
2002	38882	1704	2286	42872	38844	4028	10.37	3256	35588	7284	20.47
2003	39906	1623	2286	43815	39395	4420	11.22	3317	36078	7737	21.45
2004	40976	1633	2286	44895	40227	4668	11.60	3356	36871	8024	21.76
2005	41801	1644	2276	45721	41112	4609	11.21	3379	37733	7988	21.17
2006	42518	1630	2143	46291	41998	4293	10.22	3405	38593	7698	19.95
2007	43572	1755	2143	47470	42885	4585	10.69	3434	39451	8019	20.33

*476 MW ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002

SOURCES: Florida Reliability Coordinating Council,
1998 Load & Resource Plan, Peninsular Florida,
July 1, 1998; Duke Energy Power Services, L.L.C.

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Vaden
Exhibit ____ (RLV-7)
Page 1 of 2

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK, WITHOUT NEW SMYRNA BEACH POWER PROJECT

Year	INSTALLE CAPACITY (MW)	NET CONTRAC FIRM INTERCHG (MW)	PROJECTE FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABL CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1998/99	38037	1939	2240	42216	39450	2766	7.01	3784	35666	6550	18.36
1999/00	38402	1916	2240	42558	40388	2170	5.37	3955	36433	6125	16.81
2000/01	38809	1691	2240	42740	41395	1345	3.25	4078	37317	5423	14.53
2001/02	40638	1705	2315	44658	42219	2439	5.78	4153	38066	6592	17.32
2002/03	41980	1612	2306	45898	42998	2900	6.74	4232	38766	7132	18.40
2003/04	43073	1623	2306	47002	43925	3077	7.01	4307	39618	7384	18.64
2004/05	44105	1633	2296	48034	44895	3139	6.99	4335	40560	7474	18.43
2005/06	44883	1555	2163	48601	45896	2705	5.89	4365	41531	7070	17.02
2006/07	45916	1630	2163	49709	46879	2830	6.04	4392	42487	7222	17.00
2007/08	46076	1555	2163	49794	47902	1692	3.95	4415	43487	6307	14.50

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK, WITH NEW SMYRNA BEACH POWER PROJECT 548 MW IN 2001/02

Year	INSTALLE CAPACITY (MW)	NET CONTRAC FIRM INTERCHG (MW)	PROJECTE FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABL CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1998/99	38037	1939	2240	42216	39450	2766	7.01	3784	35666	6550	18.36
1999/00	38402	1916	2240	42558	40388	2170	5.37	3955	36433	6125	16.81
2000/01	38809	1691	2240	42740	41395	1345	3.25	4078	37317	5423	14.53
2001/02	41186	1705	2315	45206	42219	2987	7.08	4153	38066	7140	18.76
2002/03	42528	1612	2306	46446	42998	3448	8.02	4232	38766	7680	19.81
2003/04	43621	1623	2306	47550	43925	3625	8.25	4307	39618	7932	20.02
2004/05	44653	1633	2296	48582	44895	3687	8.21	4335	40560	8022	19.78
2005/06	45431	1555	2163	49149	45896	3253	7.09	4365	41531	7618	18.34
2006/07	46464	1630	2163	50257	46879	3378	7.21	4392	42487	7770	18.29
2007/08	46624	1555	2163	50342	47902	2440	5.09	4415	43487	6855	15.76

*548 MW ADDED TO TOTAL AVAILABLE CAPACITY COLUMN STARTING IN 2001/02

SOURCES: Florida Reliability Coordinating Council,
1998 Load & Resource Plan, Peninsular Florida,
July 1, 1998; Duke Energy Power Services, L.L.C.

COMPARISON OF PENINSULAR FLORIDA
PLANNED AND PROPOSED GENERATING UNITS

UTILITY/UNIT	IN-SERVICE YEAR	CAPACITY SUMMER	CAPACITY WINTER	FUELS PRIMARY	FUELS ALTERNATE	HEAT RATE (Btu/kWH)(HHV)	EQUIVALENT AVAILABILITY FACTOR %	TOTAL INSTALLED COST ($/KW)	DIRECT CONSTRUCTION COST ($/KW)
DUKE/NSBPP*	2001	476	548	GAS	NONE	6832	96	N/A	311
FPL/FT.MYERS	2002	837	1062	GAS	NONE	6815	96	593	495
FPL/SANFORD	2003	914	1076	GAS	NONE	6777	96	612	494
FPL/MARTIN 5	2006	419	448	GAS	NO. 2	6081	96	647	492
FPL/MARTIN 6	2007	419	448	GAS	NO. 2	6081	96	599	444
FPC/HINES 1**	1998	470	505	GAS	NO. 2	6962	91	600 *	NOT REPORTED
FPC/HINES 2	2004	470	505	GAS	NO. 2	6962	91	NOT REPORTED	NOT REPORTED
FPC/HINES 3	2006	470	505	GAS	NO. 2	6962	91	NOT REPORTED	NOT REPORTED
SEC/HARDEE 3	2002	451	527	GAS	NO. 2	7430	88	723	519
FMPA-KUA CANE ISLAND 3	2001	246	272	GAS	NO. 2	6815	92	449	319
LKLAND McINTOSH 5	1999	245	264	GAS	NO. 2	9486	86	216	NOT REPORTED

*DUKE/NSBPP DATA IS BASED ON INFORMATION FROM NEED DETERMINATION FILING

**FPC HINES 1 DATA BASED ON PROJECTED CAPITAL INVESTMENT OF $300,000,000 / NOMINAL CAPACITY 500 MW AS SHOWN IN 1996 TYSP

OTHER UTILITY UNIT DATA TAKEN FROM: 1998 TEN YEAR SITE PLANS, SCHEDULE 9

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Vaden
Exhibit _____ (RLV-8)

8

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Ft. Myers Expansion & Repowering

(2) **Capacity**

a. Summer	837	MW Incremental (1400 MW Total After Expansion)
b. Winter	1,062	MW Incremental (1625 MW Total After Expansion)

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	1998
b. Commercial In-service date:	2002

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	None

(6) **Air Pollution and Control Strategy:** LNB (Low Nox Burners)

(7) **Cooling Method:** OTS (Once Through - Saline)

(8) **Total Site Area:** 466 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performnace Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	96%	(First Year)
Average Net Operating Heat Rate (ANHOR):	6,815	Btu/kWh

(13) **Projected Unit Financial Data, *, ****

Book Life (Years):	30	years
Total Installed Cost (In-Service Year $/kW):	593	
Direct Construction Cost ($/kW):	495	
AFUDC Amount ($/kW):	58	
Escalation ($/kW):	40	
Fixed O&M ($/kW-Yr.):	17	(1997$)
Variable O&M ($/MWH):	***	
K Factor:	1.648	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 8
COMPANY/ WITNESS: FPL
DATE: 12-2-98

* $/kW values are based on incremental capacity values only.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing stean capacity at the site.
*** Variable O&M is included as part of the Fixed O&M

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sanford Expansion & Repowering

(2) **Capacity**

a. Summer	914	MW Incremental (1457 MW Total After Expansion)
b. Winter	1,076	MW Incremental (1625 MW Total After Expansion)

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2000
b. Commercial In-service date:	2004

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	None

(6) **Air Pollution and Control Strategy:** LNB (Low Nox Burners)

(7) **Cooling Method:** CP (Cooling Pond)

(8) **Total Site Area:** 1,889 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performnace Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	96%	(First Year)
Average Net Operating Heat Rate (ANHOR):	6,777	Btu/kWh

(13) **Projected Unit Financial Data *, ****

Book Life (Years):	30	years
Total Installed Cost (In-Service Year $/kW):	612	
Direct Construction Cost ($/kW):	494	
AFUDC Amount ($/kW):	60	
Escalation ($/kW):	59	
Fixed O&M ($/kW -Yr.):	15	(1997$)
Variable O&M ($/MWH):	***	
K Factor:	1.648	

* $/kW values are based on incremental capacity values only.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing stean capacity at the site.
*** Variable O&M is included as part of the Fixed O&M

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Martin 5

(2) **Capacity**

a. Summer	419	MW
b. Winter	448	MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2002
b. Commercial In-service date:	2006

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	Distillate

(6) **Air Pollution and Control Strategy:** LNB (Low Nox Burners)

(7) **Cooling Method:** CP (Cooling Pond)

(8) **Total Site Area:** 11,179 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performnace Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	96%	(First Year)
Average Net Operating Heat Rate (ANHOR):	6,081	Btu/kWh

(13) **Projected Unit Financial Data**

Book Life (Years):	30	years
Total Installed Cost (In-Service Year $/kW):	647	
Direct Construction Cost ($/kW):	492	
AFUDC Amount ($/kW):	60	
Escalation ($/kW):	94	
Fixed O&M ($/kW -Yr.):	11	(1997$)
Variable O&M ($/MWH):	0.38	(1997$)
K Factor:	1.647	

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Martin 6

(2) **Capacity**

a. Summer	419	MW
b. Winter	448	MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2003
b. Commercial In-service date:	2007

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	Distillate

(6) **Air Pollution and Control Strategy:** LNB (Low Nox Burners)

(7) **Cooling Method:** CP (Cooling Pond)

(8) **Total Site Area:** 11,179 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performnace Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	96%	(First Year)
Average Net Operating Heat Rate (ANHOR):	6,081	Btu/kWh

(13) **Projected Unit Financial Data**

Book Life (Years):	30	years
Total Installed Cost (In-Service Year $/kW):	599	
Direct Construction Cost ($/kW):	444	
AFUDC Amount ($/kW):	57	
Escalation ($/kW):	98	
Fixed O&M ($/kW -Yr.):	11	(1997$)
Variable O&M ($/MWH):	0.38	(1997$)
K Factor:	1.647	

EXHIBIT NO. 9

DOCKET NO: 981042-EM

WITNESS: Ronald L. Vaden

PARTY: The Utilities Commission, City of New Smyrna Beach, Florida

DESCRIPTION: Transcript of the Deposition of Ronald L. Vaden, Taken at the Instance of the Staff of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 9
COMPANY/ WITNESS: Staff
DATE: 10-2-98

PROFFERING PARTY: STAFF

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	DOCKET NO. 981042-EM

DEPOSITION OF:	RONALD L. VADEN
TAKEN AT THE INSTANCE OF:	FPSC Staff
DATE:	Wednesday, November 18, 1998
TIME:	Commenced at 9:00 a.m. Concluded at 12:30 p.m.
PLACE:	FPSC 2540 Shumard Oak Boulevard Room 362 Tallahassee, Florida
REPORTED BY:	NANCY S. METZKE, RPR, CCR

BUREAU OF REPORTING

RECEIVED 11-19-98

C & N REPORTERS
REGISTERED PROFESSIONAL REPORTERS
POST OFFICE BOX 3093
TALLAHASSEE, FLORIDA 32315-3093
(850)697-8314 / FAX (850)697-8715

APPEARANCES:

LESLIE J. PAUGH, ESQUIRE, FPSC, 2540 Shumard Oak Boulevard, Suite 370, Tallahassee, Florida 32399-0850.

CHARLES A. GUYTON, ESQUIRE, FP&L, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301.

ROBERT SCHEFFEL WRIGHT, ESQUIRE, Duke New Smyrna, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302.

WILLIAM H. HOLLIMON, ESQUIRE, TECO, Ausley & McMullen, 227 South Calhoun Street, Tallahassee, Florida 32301

ALSO PRESENT:

JIM BREMAN, FPSC Staff.

MARK FUTRELL, FPSC Staff.

EVA SAMAAN, FPSC Staff.

TARIK NORIEGA, FPSC Staff.

PETE LESTER FPSC Staff.

PAUL STALLCUP, FPSC Staff

* * * *

STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

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RONALD L. VADEN

Examination by Ms. Paugh 6

INDEX OF EXHIBITS

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#1	(Late-filed) Benchmark rate	16

Whereupon,

RONALD L. VADEN

was called as a witness by the FPSC Staff and, after being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. PAUGH:

Q Good morning, Mr. Vaden, my name is Leslie Paugh and I'm the -- one of two staff counsel for the Public Service Commission in this docket, Number 981042. I'm going to ask you a series of questions, some of which will require yes or no answers, and I would request that you answer yes or no; and then if your answer needs explanation, please do so.

If you do not understand a question at any time, please just stop me and we'll either read it back or I'll repeat it or rephrase it, but rather than have you be confused, we'll just take the time to get it right, okay?

A Yes.

Q Do you have any questions?

A No.

Q Okay. Please state your name for the record.

A Ronald Vaden.

Q And by whom are you employed, Mr. Vaden?

A The Utilities Commission, City of New Smyrna

Beach, Florida.

Q How long have you been employed by the Utilities Commission?

A Approximately 12 years.

Q All right. Please describe your duties with the Utilities Commission.

A The Utilities Commission has a five-member board that I report to. They set policy. I carry out the policy. Basically responsible for the day-to-day operation, long-term planning and et cetera for electric, water, reuse and Internet service utilities.

Q That's a broad list of duties, sir.

A Yes, it is.

Q I wouldn't begin to know where to begin with the Internet service part, that's for sure.

A That's the easy one.

Q Naturally. All right. Have you filed direct testimony in this docket?

A Yes, I have.

Q Can you please summarize that testimony for us?

A That's a broad question. The testimony basically describes the relationship for the project between Duke Energy and the Utilities Commission New Smyrna Beach and how it affects the Utilities Commission of the City of New Smyrna Beach.

Q That is a summary. Thank you, sir.

Do you have any additions or corrections to your testimony?

A No, I do not.

Q Okay. Thank you.

I'm going to ask you first a series of questions regarding the most cost effective alternative standard for need determinations. The attempt will be to discern some of the financial assumptions underlying the project. If at any time I ask a question that relates to confidential information, please let me know immediately. It is not my intent to have that divulged at this deposition.

Mr. Vaden, do you know what is the cost of capital factored in the calculation of most cost effectiveness of this project?

A Cost of capital, I think we need to probably elaborate on the question. Cost of capital as related to New Smyrna Beach's portion of the plant? I think you need to elaborate more on the question.

Q What is the return on investment that makes the project financially viable?

A The Utilities Commission.

MR. WRIGHT: Object to the form. Viable to whom, please?

MS. PAUGH: Viable to New Smyrna Beach.

THE WITNESS: We do not use a rate of return.
BY MS. PAUGH (Continuing):
Q What is the return on investment that makes the project viable to Duke, do you know?
A No, I do not.
MR. WRIGHT: Leslie, just to try to be helpful, you want to ask him what discount rate they use.
MS. PAUGH: We'll get there. Thank you.
MR. WRIGHT: Okay.
BY MS. PAUGH (Continuing):
Q All right. Mr. Vaden, I'm handing you a document that is titled "Florida Power and Light Company's First Set of Interrogatories to Duke Energy, New Smyrna Beach Power Company, Ltd. L.L.P.. This is discovery requested by Florida Power and Light in this docket. Are you familiar with this discovery?
A Yes, I am.
Q Please turn to Interrogatory Number 12. You'll note that this is the, just the interrogatory request, not the responses. Can you please explain and quantify the sources of internal funds Duke Energy New Smyrna Beach Power Company, Ltd. expects to finance this project?
A Again, I guess this is vague. This asks for funds -- to clarify, this asks for funds that Duke is going to expend not to New Smyrna Beach?

Q Do you not know the answer to the question?
A If the question is asked for Duke.
Q It does.
A I do not. I do not know the answer to that.
Q Okay. Thank you.
Do you have a copy of the exhibits to the petition with you, Mr. Vaden?
A Yes, I do.
Q Please turn to Page 4 of the exhibit to the joint petition.
(WITNESS COMPLIED)
A Okay.
Q Please read into the record the last paragraph, the last sentence -- the last sentence of the last paragraph, starting "This project" or "The project."
A "The project will be constructed and bought in commercial service solely with internal Duke New Smyrna Funds."
Q Thank you, sir.
Is the cost of equity higher than the cost of debt for the project?
MR. WRIGHT: Object to the form, vague.
Q As it relates to Duke New Smyrna funds, is the cost of equity higher than the cost of debt?
MS. PAUGH: Does that satisfy your objection?

MR. WRIGHT: Yes.

THE WITNESS: And I still have no knowledge of Duke's financing of the project and their cost of monies, equities or returns.

MS. PAUGH: Would you please read back my last question?

(WHEREUPON, THE COURT REPORTER REREAD THE QUESTION)

MS. PAUGH: Thank you.

BY MS. PAUGH (Continuing):

Q Do you know, Mr. Vaden, if the cost of equity for New Smyrna is higher than the cost of debt?

A I'm not sure what you mean by "equity." We have approximately 6% interest rate on any monies that we borrow.

MS. PAUGH: All right. Let's go off the record for a moment.

(DISCUSSION OFF THE RECORD)

BY MS. PAUGH (Continuing):

Q Mr. Vaden, I'm handing you a document titled "Duke Energy New Smyrna Beach Power Company, Ltd. L.L.P., Response to Staff's First Set of Interrogatories, Numbers 1 through 11." Could you please verify that?

A Yes.

Q Are you familiar with this document?

A I've browsed through it. I've not read it in its entirety. As I understand, this is Duke Energy, not New Smyrna Beach's first set. This is interrogatories to Duke, not to the Utilities Commission, which this is.

Q Okay. Thank you.

I will ask you to take a look Page 10 of the document. Please tell me if you have made any of the responses as indicated on the document to this Interrogatory 9b.

A Yes, I'm familiar with the discount rate in b.

Q Okay. Thank you, sir.

Staff has supplied you with a packet of copies, one of those pages should be this same page. Would you please verify that? I'm going to ask you a series of questions on this page.

A I don't believe I have that page.

Q All right. Thank you, Mr. Vaden.

Do you see a reference on this Page 10 of the interrogatory response to NARG? I believe you'll find it in the last paragraph.

A Yes.

Q What is NARG?

A I do not know.

Q Who would know?

A I guess, again, this is Duke Energy's response,

not New Smyrna Beach's responses.

Q Okay.

MR. GUYTON: Go off the record for a minute.

MS. PAUGH: Sure.

(DISCUSSION OFF THE RECORD)

BY MS. PAUGH (Continuing):

Q Mr. Vaden, do you know how the present worth discount rate -- Let me start over.

How was the present worth discount rate determined for purposes of evaluating the New Smyrna Beach project?

A Yeah, we used --

MR. WRIGHT: Object to the form, vague. By whom, please.

MS. PAUGH: By the Utilities Commission, City of New Smyrna. You'll get me trained.

MR. WRIGHT: I just don't want his answer to be ambiguous as between Duke New Smyrna and the Utilities Commission.

MS. PAUGH: That's absolutely fair.

THE WITNESS: And that's why I'm trying, to keep those two distinct too. The Utilities Commission used a 6% present value to determine the net present value savings to the Utilities Commission.

Q Thank you, sir.

Was the present worth discount rate calculated assuming a 10% real return on equity and a 5% real interest on debt by the Utilities Commission?

A No, it was not.

Q How was it calculated?

A As indicated on Page 66 of the exhibits for the joint petition of need, it was calculated using the 6% net present value method.

Q Okay. Thank you, sir.

Mr. Vaden, if you know, how did the Utilities Commission use the present worth discount rate?

A Well, again, the Utilities Commission took the annual savings from the project from the year 2002 to the year 2021 and used the present -- net present value method of 6%, which is the Utilities Commission's cost of money for bond issues, and arrived a cumulative net present value in savings. I guess maybe where the confusion is, is we don't have a rate of return; we are nonprofit. So we don't assess projects with a rate of return.

Q Okay. Thank you, sir.

All right. We are still referring to the response to Interrogatory 9b. It appears you did not file this response, so you may not know the answer to the question. If that's so, that's fine. Please read into the record the second to last sentence of the last paragraph.

MR. WRIGHT: I'm just going to object to the extent that there might be some attempt to characterize that as Mr. Vaden's testimony.

MS. PAUGH: We are not attempting to characterize it as Mr. Vaden's testimony.

MR. WRIGHT: Okay.

THE WITNESS: The present worth discount rate was calculated by assuming a 10% real return on equity and a 5% real investment on debt.

BY MS. PAUGH (Continuing):

Q Would you please read the next sentence?

A "We furthermore assumed that financing was 60% equity and that the income tax rate is 40%."

Q Do you know, Mr. Vaden, if this is the capital structure reflective cf Duke New Smyrna's project?

A No, I do not. I have no knowledge.

Q Thank you. That is a fair answer.

All right. On Page 11, which also should have been handed to you, you will find the response to Interrogatory 9c. Are you familiar with this response or any portion thereof?

A I need to -- The first sentence I am.

Q Thank you, sir.

Would you please read the first sentence into the record?

A "The Utilities Commission, City of New Smyrna Beach uses a discount rate of 6% for calculating the present value of savings from the project."

Q Thank you.

Which benchmark rate is comparable to the discount rate of 6%?

MR. WRIGHT: Objection, vague. Can you explain what you mean by benchmark rate, please?

MS. PAUGH: We'll have to go off the record.

(DISCUSSION OFF THE RECORD)

BY MS. PAUGH (Continuing):

Q Mr. Vaden, by benchmark I mean some sort of rate that's in a published document that we can compare your 6% to for reasonableness. Do you know of any such published rate?

A There are published indicators. I do not know the name of it. The Utilities Commission periodically checks those rates, and when this testimony was filed 6% was New Smyrna Beach's cost of money, if we had went out on a 30-year bond issue; but the name of the indicator I do not have with me.

Q Would it be possible for you to supply us with a late-filed exhibit with that information? It could be titled benchmark rate.

A Yes, I'd be happy to.

Q That will be Late-filed Exhibit 1.

Do you know what the current benchmark rate is?

A Not to the exact number. It's somewhere between five and a half and 6% currently. As I stated, when this document was put together it was at 6%.

Q Okay. Thank you.

Limiting your answer to the financial and economic assumptions you applied, why is the Duke New Smyrna project with respect to the Utilities Commission considered to be the most cost effective alternative?

A We looked at all of the other resources that New Smyrna Beach currently has, and looked at the marketplace to try to determine if we could get any resources less expensive than we currently have. We feel that any replacement that we have would be more expensive than we currently have, and we used those numbers to evaluate the offer from Duke.

Q What replacements did you look at, Mr. Vaden?

A Okay, we used our current power supply contacts, which I'll just quickly go through.

Q What document are you referring to?

A They are on, in the -- it's RLV-6, Page 1, 2, and 3 of the exhibits for the joint petition application.

Q Is that the exhibit to the application?

A I'm sorry.

Q Or is that to your testimony?
A It's in my testimony. It's in both.
Q Just being clear.
A Okay. I stand corrected; it's RLV-6 of my direct testimony.
Q And in the joint petition, what page is it?
A Page 64 of the exhibits of the joint petition.
Q Thank you, sir.
A Page 64, 65 and 66.
Q All right. The table to which Mr. Vaden is referring is Table 12, "Utilities Commission, City of New Smyrna Beach, Fiscal Year 2000 Budget Without New Smyrna Beach Power Project." If you can please explain to me where the replacements are in this exhibit just so I understand how to read it.
A This table, Table 12, Page 64, was benchmarked. If New Smyrna Beach did not enter into an agreement with Duke Power, this is the least-cost alternative of continuing existing contracts if we were able to continue to meet New Smyrna Beach's needs.
Q Yes, sir.
A And we used this as our benchmarking. If you would like me to read the resources, it's the CR-3.
Q I'd like you to summarize the resources, please.
A Okay. The first one is CR-3, Crystal River 3,

which New Smyrna Beach has an ownership of approximately five megawatts. Clinch Street and dual fuel are the next two items, or New Smyrna Beach's peaking unit, which is approximately 18 megawatts. The Enron Reserves and Enron ST is a total of 25 megawatts. They have varying levels for different months of the year. The next four total up to 30 megawatts which is Florida Power Corporation's purchases. This is broken down into four categories depending upon how we dispatch it. The next item is the St. Lucie, which New Smyrna Beach has approximately seven megawatts of, and the next, one, two, three, four -- or five is Tampa Electric Company resources that we purchase. And that is the best-case resources that we would be able to secure if we were not going into the project, but it would be highly unlikely that we would be able to receive these favorable contracts that we have.

Q Okay. Mr. Vaden, if we can expand upon your answer regarding this list of alternatives and your choice of the Duke New Smyrna project, I wonder if you can explain for us how, what your economic assumptions were in choosing the Duke New Smyrna project over these other alternatives?

A Yes. This table, 12, Page 64, has the resources I outlined on the left-hand column. It has the energy cost and the fixed cost and so forth associated with the project. This represents a simulated dispatch of every

hour in the year for the year 2000. The total cost of the -- each of the resources, the next to the last column, and the total on the next to the last column, what you see is 10 million 812 thousand dollars. So if New Smyrna Beach were able to secure these contracts in the year 2000 which, as I state, we don't think we would be able to do that, that would be the total cost of our power supply projected into that year. So again, that's 10.8 million dollars.

Q Is that an annual cost?

A That's an annual cost.

Q And how does that compare with the cost under the Duke?

A Okay, now the next page, Table 13 on Page 65, starting again -- I'll explain it the same as the table before -- the first column, the Base30 represents the 30 megawatts that New Smyrna Beach would take from Duke; and as you see across the fourth column, it's represented $18.50 energy cost.

Q Yes, sir.

A And as you go across two columns further, the fixed costs, you see a zero fixed cost. So the 18.50 represents a full cost on a per unit basis.

The CR-3, back to the left hand column again, is a purchase that we -- or really a ownership that we keep. The Clinch Street and diesel units, we will keep those

units for extreme peaking; and the peaking is megawatts that we have yet to purchase. We will be negotiating for peaking resources to cover our load. And the St. Lucie is the ownership we have. Under that scenario, the next to the last column, the bottom number is 7.73 million. So it indicates that we would have a savings in the year 2000, a minimum savings of a difference between 10.8 million and 7.7 million for the total project.

Q Mr. Vaden, have you used a cost escalation or inflation factor in making these analyses?

A Okay, you may have to rephrase the question. The analysis that we went through was for one model year.

Q Okay. So you would not have used escalation factors?

A Not in this one-year analysis.

Q Would you have used it anywhere?

A In a -- We performed a 10-year analysis and, yes, we did.

Q All right. Can you please tell me where that information may be located?

A Yes. The summary for it is shown on Page 66.

Q For the record, he is referring to Page 66 of the exhibits to the joint petition entitled "Table 14, Utilities Commission, City of New Smyrna Beach purchase Power Demand and Energy Savings From the New Smyrna Beach

Power Project."

Go ahead, sir.

A Okay, now your question was, as I understand it, did we escalate the prices in the future years?

Q Yes, sir.

A Okay, that's in the, located in the, I think the second set of interrogatories from FPL, and it shows that we -- the fuel prices that we used for the future years. It wasn't just a flat escalation rate. It's fuel prices that we projected.

Q How was that escalation derived? Is that a fair question?

A I believe that we've looked at the Florida Power Corp numbers. We used an increase based on increases that we had had in the past. A lot of the resources, as an example in our peakers in St. Lucie and CR-3, we put no escalation factors on them.

Q How is that reasonable? Can you please explain that for me?

A It's on the very conservative side. When we looked at a scenario to enter into the contract with Duke, we wanted to put the most conservative numbers we could together to represent a savings. Those numbers that we put together is extremely conservative.

Q Okay.

MS. PAUGH: We'll go off the record for a moment.

(DISCUSSION OFF THE RECORD)

BY MS. PAUGH (Continuing):

Q All right. Mr. Vaden, my next series of questions will delve into the validity of the UCNSB forecasting assumptions relating to the 30-megawatt of need for the City, and I'm going to ask you first to please refer to your load forecast methodology on Page 13 of your direct testimony. Please read into the record Lines 16 through 22.

A "The Utilities Commission, New Smyrna Beach load forecast is developed by the Utilities Commission, New Smyrna Beach staff based on regression analysis of historical loads, energy use, customer growth and future economic considerations. System energy requirements are forecast using separate regression analysis for four customer classes: residential, general service non-demand, general service demand, and street lights. For the residential class, expected sales are estimated using a regression model based on historical sales data."

Q Thank you, sir.

Would you characterize this testimony as utilizing a multiple variable or multi-variant analysis to develop the load forecast?

A We use the -- I guess multiple variable would be time, and net energy sales are time and number of customers for each of the classes.

Q Let's refer to the testimony again. You say you're using separate regression analyses for the four customer classes.

A Right.

Q And you referred to energy use and customer growth in your testimony; is that correct?

A That's correct.

Q Were these items, such as the energy use, customer growth, and future economic considerations variables that you used in your analysis?

A Yes, they were.

Q Thank you, sir.

Please refer now to a document I am handing you entitled "Duke Energy, New Smyrna Beach Power Company Limited, L.L.P.'s Response to Staff's First Request for Production of Documents, Number 1 through 23." Please review that document and tell me if you're familiar with it.

A As I understand it, this is the response from Duke Energy, not New Smyrna Beach; and, no, I'm not familiar with it.

Q Okay.

MR. WRIGHT: You can ask him to look at a specific document in there, if you like.

Q Mr. Vaden, I would like you to take a look at Page 19 of the document we just described. I have another copy if you would like to take a look at that, Scheff.

MR. WRIGHT: Leslie, may I look at the whole document?

MS. PAUGH: Certainly, and we are getting you another copy from my file. Gentlemen, here's the copy from my file.

BY MS. PAUGH (Continuing):

Q Okay. Thank you. May I have this back? I'm going to ask you some questions regarding Page 19 of this document, which we'll put in the center so we can all refer to if we need to.

Referring to Page 19 of this discovery response, can you please describe what the UCNSB equation represents?

A This equation starting with the A equals Y minus BX. A is the future sales. You plug the variables described X and Y into formula B and do it for the plugging in historical data, and then A would represent the sales and future data as described on Page 13 of my direct testimony.

So if you plugged in the variables for the X and the Y as described, which would be basically the sales and

the year associated with it, into the model, then you would get the future projected sales out, which would be sales equals A plus BM. It's a simple regression analysis program.

Q What are the variables reflected on this Discovery Response Number 17, please?

A The variables would be the years -- the year and the sales.

Q Mr. Vaden, it appears to me, and correct me if I'm wrong, that your testimony refers to multiple variables. In other words, it's a multi-variant analysis, and the discovery response is uni-variant. Can you please reconcile that?

A Yes, I have the confusion. This model as described in the text on Page 13, this model is run to determine first off sales. So I would project out, using this model, my megawatt hours, project the sales for each year. That's one case.

The second case, I would turn around and do the same thing by plugging in customers instead of sales, so then I project my customers out. So I have a projection of my megawatt hours out. I have a projection of my customers out, and then as described in the text on, I believe top of Page 14, I would divide my customers by my sales and see if I come out with a use per customer that is a reasonable

basis. So it's not a multiple variable formula; it's just used by multiple situations.

Q Okay. Thank you, sir.

The analysis you've just described, do you have that documented any place in your testimony or discovery to which you've responded to your knowledge?

A It's only described in text on page 13 and 14. It is not described in formula form except what you've just shown me, and to my knowledge it's not in any of my testimony. It's just described in text.

Q It would be very helpful to staff if they could take a look at these multi-variant analyses.

A It's not -- Well, I don't think it's multi -- I think that's where our confusion is. It's not multiple variable.

Q Is it multiple uni-variant; is that what you're saying?

A This formula is used one time for sales, and then it's used one time for customer base. As it's stated here it's not done for general service demand, customers, or NEL, all the different classes; and then the customers are put together and they are divided into each other to see if we come up with a reasonable answer. If we come up, as an example, we feel that a customer should be using 12 hundred kilowatt hours a month and it comes out, it's three

thousand kilowatt hours a month, we've got a hole somewhere.

Q Mr. Vaden, would you agree that this analysis you've just described is essentially a trend analysis?

A It's a pure linear regression analysis, and I think it could be classified as a trend. Yes, I would feel comfortable with that. The only difference in this formula between the sales projections and the customer projections is in one case Y would be sales and one case Y would be customers, and besides that it is identical.

Q We understand now. Thank you, sir.

A I was confused.

Q Did UCNSB measure the impact of weather for its load forecast analysis?

A We do not use weather as a direct analytical analysis. We use sales and years, but what we do do, if we have a year that we know that weather has greatly changed the formula, then we may or may not go back and adjust that year; but as we use it directly, no.

Q Why not?

A We have been using this model since 1987. We have been getting excellent responses to it. Our forecast and actual, each year we go back and check, and it does have a very good job, so we continue to use it.

Q Thank you, sir.

We're continuing to refer to the response to production of documents, Number 17. Sorry, I thought it might have been an interrogatory. Did UCNSB use the impact of weather when generating its load forecast model for this response to Number 17?

A I would say no, but this is not my response. Again, this is Duke's response. I'm comfortable with this, yes.

Q Okay. Thank you.

We're still referring to the Production of Documents Number 17. What number of consecutive years of historical data did you use with reference to the independent variables?

A I believe it's seven years.

Q Why did you use seven years?

A Right now I couldn't tell you. We have been using seven years for a long time; and we, again, feel that the results that we have been achieving from our model as going back and bouncing it against the actual at the end of the year is very close to the seven-year model since we've worked effectively. And that decision was made several years, and I haven't revisited it.

Q And why not?

A I don't know.

Q Just a joke, sir.

A That's on my things to-do list.

Q Does the seven-year time frame of historical data tend to reduce the effects of abnormalities?

A Yes, the longer the model -- the greater number of years, I would think so, yes.

Q Do you recall how the seven-year assumption was initially developed?

A No, I do not.

Q Do you know why a seven-year period is significant in order to correct the data referenced in your discovery response?

A No, I do not.

Q Please turn now to Page 10 of your direct testimony. Please read the answer on Lines 13 through 15 into the record, sir.

A "Since 1992, energy requirements for Utilities Commission, New Smyrna Beach has grown at an average rate of 2.6%. Net energy for load for the last full fiscal year 1997 was 325,229 megawatt hours."

Q Thank you.

I now need to refer you to the same production of documents response you're holding, Number 16 -- I'm sorry, Number 21, I apologize, and that is on Page 24.

(WITNESS REVIEWED DOCUMENT)

Q Are you familiar with this response?

A No, I'm not. This is Duke Energy's responses, not New Smyrna Beach's responses.

Q Are you familiar with the document that is behind Response to Production of Documents Number 21? It would be Page 25 if it were numbered, but it's not. It is a chart or a schedule labeled "Forecast Net Energy for Load and Load Factor."

A Yes, I am.

Q Excellent. Thank you.

All right. My next series of questions deals with the percentages of net energy for load. Your testimony indicated an average rate of 2.6; is that not correct?

A It was 2.6 over a period of time, since 1992.

Q 1992 through 1997; is that correct?

A Yes, that's correct.

Q Thank you, sir.

Now what we would like you to do is take a moment and calculate that same percentage for the years 1998 through, say, 2005. My staff indicates that can be fairly easily accomplished.

A I believe you have calculated them on the left-hand side.

Q We have, sir, but we need you to run the calculation because it's your testimony and not ours. If

you'd like, we will go off the record for a few minutes.

A I concur with the numbers that you have.

Q Okay. Great. Thank you. That was fast.

Please describe for me the forecasted average annual growth rate for years 1999 through 2005. What percentage did you come up when you calculated?

MR. WRIGHT: Do you need the calculator back, Mr. Vaden?

THE WITNESS: No.

A It indicates after 1999 the growth rate levels off at around 1.4 to 1.5% in the model.

Q Thank you, sir.

Why are the percentages so much lower for this period we've selected? And we can take it out longer if you like, but I thought this would be faster. Why are the values lower than the value reflected in your testimony?

A These values were plugged into the regression analysis model that we had discussed a few moments ago, and this is the numbers that come out. It should be noted, in the summations, the X squares and Y squares and so forth in the regression analysis, the numbers, like for instance in 1994 the 5.66%, that's why these numbers are squared and pulled back toward the middle so it takes out the effects of large growth years in the model. But this is the -- unless we busted a number, and I don't think we have, this

is the growth rates that we show which look level.

Q But do you have any idea why there is such a difference?

A No, not sitting right here right now. This is what I understand to come out of the model.

Q Yeah, we are not questioning what the amounts are. What we would like to know is why there's a difference for 2.6 down to 1.5 for the out years, and I believe your testimony is that you don't know?

A I cannot answer that right now.

Q Is it fair to characterize this analysis as projecting a lower growth rate in the out years of '99 through 2005 than you have historically as reflected in your testimony from '92 to '97?

A That is correct.

Q Okay. Thank you, sir.

I refer you now to the same production of documents to which we've been referring, Production of Documents Response Number 18 on Page 21. If you'd like to take a moment to refresh your memory on this, I believe there is a UCNSB section. All right, and if you'll refer to the page following that, you'll see a schedule entitled "Utilities Commission, City of New Smyrna Beach, Florida, Numbers Customers (ELEC)."

A Yes.

Q Are you familiar with the schedule?

A Yes, I am.

Q Thank you, sir.

Referring to this schedule, can you please describe what each column is referring to? You'll see there are heading, such as RE1P. Please tell me what these mean.

A The first column, fiscal year by month. Second column, residential single phase. Next column is residential three phase. Next column general service single phase, general service three phase, general service demand; and that is all number of customers and the -- by month, and then in the next column kilowatts, which represent the kilowatts from the general service demand.

Q And reading on across the schedule, starting here is that the same?

A It's the same thing, just different number of years. This page represents fiscal year '91, 2, 3 and 4.

Q Okay. Thank you, sir.

Now referring to the staff question in the production of documents, if you'll take a look at that, where there is a list of items on page 21.

A Right.

Q Does this list correspond with what you have just described as the schedule reflecting? We don't know if

they are the same thing.

A The residential, rural and residential, for example, service territory population, we don't have population figures, so we probably did not. It wasn't given to you. We are based on customers not population. We have no population data. Numbers per household we, do not have that data. Gigawatt hours would have been furnished. It would have been furnished in a different place, but I do not see it here unless it's further into this. We utilize customers per class, and that's what we have furnished, customers per class of service, and then the gigawatt hours associated with that. So following the question, there is one, two, three, four, five -- 10 pages forward, which is labeled 18, "Forecast Sales." That would be the megawatt hours -- I think this is in kilowatt hours actually -- that's associated with the customers on the first sheet. So, yes, that information is there.

Q All right. Let's go back a moment. Which information is it your testimony that you did not provide?

A Okay we did not provide service territory population. We do not have that number, or members per household, we do not have that number. The gigawatt hours are supplied in the tables ten pages forward as I indicated. The average number of customers are indicated on the preceding pages, and the consumption per customer

could be calculated from those two numbers. I don't think we could calculate it. We do have it. Average number of customers, consumption per customers, it's located on the bottom of the one I'm referring to as ten pages forward, at label 18, "Forecast," at the bottom of the page.

Q Okay. Thank you, sir.

Okay. Mr. Vaden, what we're going to do now is try to discern which items from the list of staff's request for production of documents fits on to which columns in your schedule, if you could help us out with that.

A Yes. Referring to page 21 and the page following that, which it does not have a page number, "Service Territory Population" we do not use. "Members per household" we do not use. Okay, the average number of customers is presented on these pages by month and by customer class.

MS. PAUGH: Just a moment. Let's go off the record.

(DISCUSSION OFF THE RECORD)

Q Go ahead, Mr. Vaden.

A Okay, the Question 19 -- 18, I'm sorry, on Page 21 which asks the questions about the population, number of households, gigawatt hours, average number of customers, kilowatt hours, consumption per customer is represented on the following 11 pages. The Utilities Commission does not

keep population or members per household data. We have no way to obtain that. We do, however, obtain the -- instead of average number of customers, we have customer by class, and then the gigawatt hours used for those classes we obtain; and then from that it's been derived the average kilowatt hours for each class of those customers.

I'd like to describe the class of the customers. As you know, New Smyrna Beach is 80% roughly of residential customers, a retirement community, so that's the bulk of New Smyrna Beach. That is the column 1 which is RE single phase, so we classify that as just a typical residential customer in New Smyrna Beach.

Now the next column is RE-3 phase. That is a three-phase residential customer, and to classify that, is someone might have an extremely large home that a single phase service would not handle, we'd put a three-phase service in. And as you can see at 1991 it's 144, and in 1994 it's 164. So it's just a very unique class of customers, but we break those out in our models.

The next one, general service single phase, which is a -- again, this refers to just a single phase service run to a business. New Smyrna Beach has a lot of small shops, souvenir shops is a good example of a single phase general service customer; so that's a customer class that's inherent to New Smyrna Beach which we keep statistics on.

The next one is a general service three phase, which I would classify as a 7-11 store, convenience store, something like that. New Smyrna Beach has several of those in its service area, and the last one is general service demand. Now this is what is kind of hard to go back and identify your commercial industrial. Now a general service demand customer for New Smyrna Beach would be a Publix grocery store, a K-Mart, a Walmart, the hospital. A Utilities Commission wastewater treatment plant, for example, would be a general service demand, but it's a customer class that we can identify and go out and physically count the numbers, and so this is the best way we find to model our own system.

Now from that on the -- I keep referring to the 10th page forward. The kilowatt hours for each of those classes are shown, and then at the bottom -- well, we put the -- I'm sorry, we put the kilowatt hours for all the general service -- general service demand, non-demand is all in one class; it's not itemized out. And then at the bottom of the page we put the average number of customers, which I think was asked for; and then the bottom two lines is the average consumption per customer, which I believe we were asked for, consumption per customer.

Q Okay. Mr. Vaden, referring back to staff's discovery request, can you please tell me where the items

railroads and railways, street and highway lights, other sales to public authorities, and total sales to ultimate customers fits into the model -- and schedules, I should say, that you've just been describing, if at all?

A Yes, the railroad and railways, what is -- could you elaborate on that question, just what that is?

MS. PAUGH: We'll go off the record.

(DISCUSSION OFF THE RECORD)

THE WITNESS: The railroad and railway, New Smyrna Beach has no classes. We have no amount of electricity that is purchased by a railroad that we would specify out separately.

Q That's fine.

A The street and highway lighting is indicated by the street lighting on the -- in kilowatt hours in the pages, the one I keep referring to, ten ahead. The street lighting by accounts is also shown in Pages 1 of 8 under actual electric sales which is the third page, beginning on the third page following Page 2.

MR. WRIGHT: Just so we are clear, Mr. Vaden, would you tell the staff what the abbreviation for street lighting is as used in those tables?

A SL.

Q SL?

A SL.

Q Thank you.

A That would cover, street and highway lighting would both be covered in that. I need to elaborate. It's street lighting, highway lighting, if a customer requests an individual security light at their home, it would be included in the street light category.

Q Okay. Thank you.

A The other sales to public authorities, I'm not sure what you mean by that, but we don't have any sales to public authorities. We -- as an example, the City of New Smyrna Beach is a customer of ours in several of their locations, but they are integrated into the general service demand or general service non-demand rates, wherever they may fall.

Q Okay. Thank you.

A Total sale to ultimate customer is, again, the page I'm referring to, ten forward, under the column labeled "Grand Totals."

Q Okay. Thank you, sir.

I believe you have in your prior testimony given us your definitions of residential single phase, residential three phase. That was large residential; is that correct?

A That's correct.

Q General service single phase was what you

described as a small shop, like a souvenir shop; is that correct?

A Correct. That's correct.

Q I did not catch the general service three phase definition.

A A general service three phase, if we have a commercial customer that has a kw of less than 50 kw per month, but they have a three-phase service, they are a general service three-phase customer, and an example of that would be a convenience store, 7-11 store, so on.

Q Okay. And general service demand was?

A That's our largest customers, which we don't have many. The Utilities Commission themselves is part of those customers. A wastewater treatment plant would be one of those customers. Our water plant would be one of those customers. The hospital of New Smyrna Beach would be a customer, Publix, WalMarts. I could probably name 50 of the 94 sitting right here.

Q I bet you could, Mr. Vaden. That's fine though. Thank you.

And the general service non-demand, how do you characterize that category?

A The general service non-demand would be the combination of general service single phase and general service three-phase, a combination of those two.

Q General service single phase?

A Yeah, your question was how do I classify general service non-demand?

Q Yes, sir.

A That would be the two columns, general service single phase and general service three phase; they are just broken into two categories, whether a single-phase service or a three-phase service.

Q Thank you, sir. I have no further questions along this line of questioning.

MR. WRIGHT: Could we go off the record for just a minute?

MS. PAUGH: Certainly.

(DISCUSSION OFF THE RECORD)

BY MS. PAUGH (Continuing):

Q Mr. Vaden, just for clarification, would you please describe for us how much of your general service demand would be classified as commercial and how much of that category would be classified as industrial?

A Okay, as I understand, my definition of an industrial customer would be someone that is a manufacturing process, as an example, that manufactures materials, factories and so forth. We have one small manufacturing facility in New Smyrna Beach which is a plastics company which has come into the business since any

of these documents were put together. It's a very small 500 kw customer. Besides that, we really have no industrial customers in the New Smyrna Beach except the Utilities Commission itself, as I stated, the wastewater treatment plant, and the water treatment and so forth. So the rest of them would be classified as commercial. We try to classify the small commercial and large commercial and then the Publix or the convenience stores.

Q Do you recall how much of your customer base is residential?

A I would have to calculate it out. It's in the testimony. I think it's in excess of --

Q If you would like to refer to Page 9 of your testimony, Lines 15 through 17.

A 90% is residential customers.

Q Okay. Thank you, sir.

MS. PAUGH: All right. We'll take a short break at this point.

(BRIEF RECESS)

BY MS. PAUGH (Continuing):

Q Okay. Mr. Vaden, my next series of questions is relative to fuel prices and estimating fuel prices and that sort of thing. You are being handed a document, but first I'd like you to verify, this is from my file, "Duke Energy New Smyrna Beach Power Company, Ltd.'s Response to Staff's

First Request for Production of Documents, Numbers 1 through 23." Is this document familiar to you?

A No, this is Duke Energy's, request for Duke Energy, not New Smyrna Beach; so I would have to look at the specific documents.

Q All right. Let me turn you to Page 4 of this document which is the Response to Production of Documents Number 3. Is this response familiar to you?

A Yes, it is.

Q Excellent. It is on these pages that I have a series of questions, and the document you have been handed is a photocopy of it. Would you verify that it is the same document? We have copied them just for convenience.

A Yes, it is.

Q Okay. Mr. Vaden, are you the appropriate witness at hearing of which to inquire regarding this production of documents response? And by "this" I mean the Response to Production of Documents Number 3 from staff.

A Yes, I am.

Q Okay. Thank you.

Is this response a composite copy of preexisting documents, or was it drafted specifically for the production of documents request?

A I believe, but not absolutely positive, but I believe it was drafted for the response to the documents.

Q Thank you, sir.

A I'm not absolutely sure on that.

Q Mr. Vaden, I'm going to request that we verify whether this was a preexisting document or drafted specifically for the response. That can be done in a one-page late-filed deposition answer relative to that, if it's acceptable to counsel.

A I might expand on this to clarify.

Q Okay.

A We had -- in the discovery for New Smyrna Beach Document 5 was a summary sheet for all of the documents here. And when I say was it produced for this, we probably went back and took out of the computer these printouts to get the backup documents to documents already been supplied. The numbers weren't derived, but the document may have been produced.

Q When you say Document 5, to what are you referring, sir?

A This is the Utilities Commission, City of New Smyrna Beach First Request for Production, Document 1 through 13.

MR. WRIGHT: Just to be clear, it's the response to FPL's First Request for Production.

MS. PAUGH: Okay. Thank you.

THE WITNESS: So when you asked if it was

derived, the numbers weren't derived for the response, but they were probably printed out for the response. This piece of paper didn't exist. It was on a spread sheet. We printed it out and sent it to you.

Q Okay. That answers our question. Do you know when this document was created?

A It has a date on the bottom of it. No, I don't. The document is not dated.

Q All right. I believe it's your testimony that this document, which is the response to staff's production of documents, was generated from spread sheets on a computer; is that correct?

A That's correct.

Q Why were those spread sheets originally generated on a computer?

A All of this, backup documents for RLV-6 of my direct testimony, all these discussions -- the sheets that you gave me, the sheets that I refer to, the Document 5 is a backup documentation that leads to these numbers on RLV-6.

Q Does RLV -- did RLV-6 pre date as a document your testimony, or was it generated as part of your testimony?

A It predated the testimony. This is an analysis we used to enter into the contracts with Duke.

Q Thank you, sir.

Referring back to the Response to Production of Documents Number 3 of which you've been handed a copy, does it list fuel types such as coal, oil and natural gas?

A No, it does not unless you are specific with the resource.

Q In the textual answer which is on Page 4, you see in the first sentence the phrase "Fuel Rates," do you not?

A Yes, I do.

Q What does "fuel rates" mean to you?

MR. WRIGHT: In the context of this answer?

MS. PAUGH: In the context of this answer.

THE WITNESS: Fuel rates as it applies to these documents are the fuel costs that New Smyrna Beach would receive from each of its resources, and just as an example, TECO summer has associated costs of $22.48. That's what --

BY MS. PAUGH (Continuing):

Q I'm sorry, if I may interrupt you.

A Sure.

Q To what document are you referring, Mr. Vaden?

A The document you handed me, it's the second page after Page 4.

Q Is that designated as 1 of 3, fuel -- forecast fuel costs 2002 to 2010?

A Yes, that's correct.

Q Okay. Please continue with your answer.

A Okay, if you just look at the first group under 2002, for instance, the first resource, CR-3, and it has a fuel cost of $5.25. That is nuclear resource, obviously. The second one is St. Lucie, 12.35, that's a nuclear. Florida Power Corp PR, partial requirements contract, you can see three different, that's what Florida Power Corp charges us for those resources for the energy portion. The TECO base summer and supplemental are resources that's tied to, I believe, two of Tampa Electric's coal units, and that's the prices associated with those units.

But the contract does specify, I believe, if the coal resource is not available it may come from some other oil resources, but it's dominantly the coal resources, the Big Bend units. The Enron purchase is just an open market purchase. I believe it's tied to Orlando Utilities Commission. I'm not sure what the fuel source is. And then local generation is New Smyrna Beach's peaking resources, which is oil resources.

Q Do the prices that you're referring to include plant generation losses?

A Plant generation losses. This is the -- this is the dollar amount that we are charged from the supplier. So if we purchase this resource from Tampa, that's the price we pay from Tampa, so any losses will be into their calculations.

Q Do you basically equate energy with fuel rates and fuel prices?

A No, we do not, except for the one resource local generation, which is the cost of fuel to New Smyrna Beach for the peaking units which we very seldom run; but the other resources are a negotiated price. As an example -- I guess I need to back up.

Q Please, do, sir, because I'm not clear on your answer yet.

A Okay, the Tampa contracts, which is our biggest supplier, is a negotiated price. They guarantee a price to New Smyrna Beach. That's set and done. It doesn't matter what the fuel cost for those resources are.

The Florida Power Corp PR pricing is based on their monthly system average cost with a true up. So if their fuel cost is a certain thing one month, we are billed based on that fuel cost. If it exceeds -- if it goes up that month, we get a true up the following month, so it's based on their fuel costing. The St. Lucie, CR-3, which is obviously just their refueling cost, which is pretty much a fixed level cost.

Q Okay. Thank you.

Are you purchasing energy or fuel from FPC?

A Energy in all situations of all my resources, I purchase energy except for my local generation.

Q Okay. Thank you, sir.

Does the phrase "fuel rates" appear on the tables included in the Response to Production of Documents 3?

A No, instead of fuel rate, it should have been energy cost and that should have been the dollar per megawatt hour column which I've been describing.

Q Please turn now to the first table of the Response to Production of Documents Number 3. It is designated as Page 1 of 1, and at the top it says "3, dash, base cost." At the bottom it's labeled "Forecasted Fuel and Purchased Power Costs."

What does Base30 stand for?

A This document, so we can keep it all tied together, is the exact document that we had referred to this morning that I described, which is RLV-6, Page 1 of 3 -- Page 2 of 3.

Q Thank you.

A Now would you repeat your question again, please, ma'am?

Q What does the phrase "Base30" stand for? And you will find that phrase or designation, if you will, in the first column under resource name.

A Yeah, that's just a name that we applied to the 30 megawatts that we'll be receiving from Duke Energy under this contract, and -- yeah, that's the answer to that.

Q Is that a natural gas fired option?

A Yes, it is. It is the -- pursuant to the participation agreement with Duke Energy, the 30 megawatts base loaded at an all-in cost of $18.50 per megawatt hour, which is one hundred percent natural gas fired, yes.

Q Is that owned and operated by UCNSB?

A That is -- will be the plant that Duke Energy builds at New Smyrna Beach.

Q Will it be owned and operated by UCNSB?

A Certain portions will be owned by New Smyrna Beach, certain portions by Duke Energy, and the same with operational aspects of it.

Q Which portions? Can you describe those?

A The New Smyrna Beach will own the substation for the facility, the existing New Smyrna substation we referred to. It will be modified to accommodate the Duke plant as we refer to, and New Smyrna Beach will have ownership of those new facilities, and New Smyrna Beach will own any facilities that supplies ground and reuse water to the facilities. The plant itself will be owned by Duke Energy.

Q What does, referring still to this first column, the designation Clinch-Pk mean?

A Right, okay, it may be simpler if I just run down the whole left-hand column.

Q Certainly.

A Base30 is the Duke plant as was described. CR-3 is New Smyrna Beach's ownership in Crystal River-3. Clinch peaking and dual fuels, that is the 18.8, I believe, megawatts of diesel, slow speed diesel that New Smyrna Beach has; it uses for peaking purposes. Clinch Street is six megawatts that can be remotely operated is why it's broken out into a separate item, and the dual fuels cannot be remotely operated, but they have the same fuel cost.

That was the Clinch Street and dual fuels. The next resource is peaking. That's a resource that New Smyrna Beach currently does not have contracts for. When the Duke plant is built and we'll have the 30 megawatts of base, is as the other resources are shown, we will still have to purchase peaking capacity to recover our needs. St. Lucie is roughly seven megawatts, I believe, in participation through FMPA of the St. Lucie nuclear plant.

Q And u-n-s energy.

A That's just unserved energy as if we had not had resources to cover it. Unserved energy which you see is zero, so in other words, it's nothing.

Q Are these items that we've just been defining from the first column competing alternatives for the same load or a portfolio of sources to meet a specific load?

A The resources that we've discussed takes into

consideration the Duke plant with its 30 megawatts and what resources we would use other than the resources of Duke to meet our loads at New Smyrna Beach.

Q Would you describe those as competing alternatives then?

A No, the competing alternatives is shown in Page 1 of 3 in RLV-6 of my direct testimony.

Q Referring to Page 1 of 3 of RLV-6 of your direct testimony, please tell us which of the resources are competing alternatives.

A As we discussed earlier, the page that we are now referencing was a portfolio of existing contracts if we could extend them and was modeled against -- for the competing resources against the Duke project. We don't feel that all these resources are obtainable at these prices, but if they were, this is the competing resources. As you'll notice, there's Tampa Electric, Florida Power Corp, and Enron; and these resources are modeled under the existing contracts that we with those three suppliers.

Q I'm sorry, Mr. Vaden, I'm not understanding. When you say Tampa Electric, for example, do you mean TECO S, TECO S2, all of them, or some of them? Which ones do you refer to?

A All four of them. The TECO -- These resources are broken out, that's the way they're modeled. As an

example, TECO base, as you can see in the capacity factor it's a 96% loaded resource. We just call it base. We break it out. The summer resources, there's an S-1 S-2, have different commitments under the contracts. But to answer your direct question more straightforward, the resources that would be competing against are the one, two, three, four, five TECO resources that we have labeled, and the Florida Power Corp, three resources: Florida Power Corp Peaking, and Florida Power Corp PR, and Florida Power Corp base, and the Enron reserves, and Enron ST. So there's one, two, three, four, five, six, seven -- ten resources, which is three different suppliers.

Q All right. Let's just make sure I'm clear. The competing resources are both of the Enron designations?

A Correct.

Q All right. So that's Enron res, or r-e-s, and Enron ST; is that correct?

A That is correct.

Q All right. And the next competing resources are which?

A The three Florida Power Corp, which is Florida Power Corp -- the next three after Enron: Florida Power Corp PR, Florida Power Corp peaking and Florida Power Corp base.

Q And that's what's designated as PR base, that's

Florida Power Corp?

A Yes.

Q Okay. I think that's what's confusing me.

A It is. It's not a good label. And the next one is the five labeled TECO.

Q Okay. Thank you, sir.

Mr. Vaden, if you would now turn to Page 1 of 3 of the Production of Documents Number 3 to which we have been referring titled "Utilities Commission, City of New Smyrna Beach 3-Fuel Cost, Forecast Fuel Cost, 2002 to 2010."

A Yes.

Q Are the energy sources on this page the same as those listed on the prior page of this document response?

A The prior page of the document response is the year 2000, which we used for a base case to show the cost savings entered into the Duke project. The subsequent documents that you are referring to are the projections using the same resources for the year 2000 through the year 2010.

Q Okay. Thank you, sir.

Still referring to this document, you'll see in the first column the phrase "Local Gen." What does that mean, sir?

A The local generation is the combination of the

Clinch peaking and dual fuels indicated on the prior page. It's those two resources combined together.

Q Is that a natural gas fired option?

A No, that's the 18.8 megawatts of peaking diesel units that New Smyrna Beach has.

Q Peaking diesel; is that correct?

A Yes, ma'am.

Q And this is owned and operated by New Smyrna Beach?

A New Smyrna Beach.

Q And how many megawatts is that?

A Approximately 18.8.

Q Okay. Where is this 18.8 megawatt peaker located with respect to where the Duke plant would be located if it's permitted?

A If it's permitted? When it's permitted.

The diesel units are not located close to the Duke plant, and I mean by close to, I'd say in the neighborhood of four to five miles away. They are actually located in two separate locations, one is downtown New Smyrna Beach.

Q Really?

A About six units housed in a large building. Well, they never run; they sit there. And the other units are located north of downtown approximately two miles on

the side of the intercoastal water way, and all the units are low speed diesels. They fit in -- they have a four kb transformer step up, and they are sitting there for peaking purposes. Severe winter peak is what they are used for.

Q Referring, again, to the first column of this document, production of documents response Page 1 of 3, please tell us what the designation "reg-res-bk" means?

A I believe -- Yes. Currently, Florida Power Corporation -- Currently New Smyrna Beach passes its ACE on a real-time basis to Florida Power Corporation.

Q Passes its what?

A Its ACE, its load control. Its ACE, commonly called. They integrate it within their system, and they control our ACE, and they charge us for that service. So it's a -- Load-following service may be a different term that you use.

Q A load what service?

A Load-following service.

Q Following?

A Following, yes. I need to expand on that answer.

Q Please do.

A Okay, Reg, regulation. Res, reserves, and Bk, backup.

Q What does the regulation stand for? What kind of regulation?

A Okay, regulation is what I just described where Florida Power Corporation is controlling our ACE. They are following our load, and they charge us for that service. It is not under the -- it's included in our Florida Power Corp PR contract.

The reserves is a second contract that we have with Florida Power Corp, and we have less than one megawatt requirement of spinning and non-spinning reserves. We purchase the spinning and non-spinning reserves from Florida Power Corporation.

The backup, we pay a backup charge for anything that's delivered to New Smyrna Beach on the Florida Power Corp line to Florida Power and Light. It's a transmission backup charge.

Q Okay.

A Those three are included in that 263 thousand dollars per year.

Q Under what circumstances would you use this backup? Is that a fair question?

A It's never been used. If the Florida -- if we had a resource that was being delivered on the Florida Power Corp transmission line that was under a firm transmission agreement with Florida Power Corporation and that line opened up and we instantaneously bought other lights line and didn't find a replacement, we would pay

Florida Power and Light a backup transmission charge during that time.

Q Mr. Vaden, I'll direct you now please to the exhibits attached to your petition. Do you have a copy of that with you?

A Yes, I do.

Q Please turn to Page 67. This document is titled "Table 15, New Smyrna Beach Power Project Generating Alternatives Evaluated." Are you familiar with this document?

A Yes, I am.

Q Did UCNSB participate in the evaluations referenced on this page?

A No.

Q What roles did UCNSB perform in the evaluation process, if any?

A May I clarify something?

Q Please do.

A Okay. As I understand what this document is, it's the alternatives that Duke Energy looked at, what type plant they would build at New Smyrna Beach.

Q Okay.

A And if that is what this document is, New Smyrna Beach did not participate.

Q All right. That's a fair answer.

Does UCNSB prepare fuel price forecasts on an annual basis?

A We do not do fuel forecasts at all. We, as we discussed before, we look at energy pricing of our contracts. We have no need to do fuel pricing except for our diesel peaking units, which is such a small piece of the pie.

Q That is all the questions I have on fuel, sir.

(BRIEF RECESS)

BY MS. PAUGH (Continuing):

Q Mr. Vaden, are you familiar with the Florida Public Service Commission's regulatory framework concerning electric generation?

A Yes.

Q Would you please describe your understanding of that framework?

A I believe that the Florida Public Service Commission has the general jurisdiction over the electric utilities in the State of Florida and has the role to be sure that generation expansion is economical for the ratepayers, uses the environmental resources of the state in the proper manner and keep from duplication of services in that area.

Q That's a good summary, sir. I'm going to ask you a couple of specific questions now.

Are you familiar with the Power Plant Siting Act?

A I have read it, yes.

Q Yes, and I'm not asking for a legal analysis.

A Right. Okay, good.

Q Are you generally familiar with the Public Service Commission need determination statutes and criteria?

A Yes, I am.

Q Are you familiar with the bidding rule, which is Rule 25-22.082.

A I have read through it some time ago. I couldn't quote it now, but, yes, in general.

Q Neither can I, so you're not alone.

Are you familiar with the ten-year site plan process?

A Yes, I am.

Q And are you familiar with FEECA, the Florida Energy Efficiency and Conservation Act?

A Yes.

Q Okay. Thank you.

I'd like to discuss for a few moments the need determination criteria. Are you familiar with the criteria for need determination proceedings?

A Yes.

Q Can you describe those for me?

A The need determination, again, I think as I described a moment ago, the need determination, the utility that is going to build generation applies to the Public Service Commission. They see if -- they determine whether the plant has a need in the state under the criteria of the statutes.

Q Are you familiar with the criteria in Florida Statutes 403.519 for need determinations for a plant to be the most cost effective alternative?

A Yes, I am.

Q The statutory quote is, quote, the most cost effective alternative available, just for your reference.

A Yes.

Q Please turn to page 16 of your direct testimony. If you would, sir, please summarize the question and answer beginning on Line 20 and continuing through to Page 17, Line 18. Please take a moment to review that and refresh your memory.

A Yes. The question asked for New Smyrna Beach's cost effective evaluation as related to this project. The answer described the evaluation of the project. Basically it states that New Smyrna Beach looked at options and modeled it, the different options and found that the Duke project would have in the first year approximately three million dollars worth of savings to the ratepayers -- that

was actually escalating over the first ten years -- and two million per year thereafter savings by building the plant with Duke Energy.

Q Did you evaluate the opportunity under the participation agreement against any other alternatives?

A The other alternatives that we evaluated against was what we had been discussing earlier, which is RLV-6, I believe, which, again, are the Florida Power Corp and Tampa and Enron purchases which, again, those resources were the best case of any resources that we could actually hope to enter into contracts with in the state.

Q Okay. Thank you.

Is UCNSB currently meeting a portion of its requirements through purchases from TECO and Power Corp?

A The majority, yes.

Q Could you please describe those arrangements? And I'm not asking you to divulge any confidential information.

A The arrangements are probably in some other document in front of me. Let me get the exact megawatts.

Q When you find the document, if you could let us know, I'd appreciate it.

A Do you need exact numbers, or do you need within a couple of megawatts? As an example, I know that Florida Power Corp is 30 megawatts.

Q Just general, sir.

A Okay, the Tampa Electric -- I mean, I'm sorry, the Florida Power Corp all purchases is 30 megawatts currently. It is loaded on a base and intermediate, 24, megawatts is base, intermediate level. Six megawatts is peaking. The Tampa Electric company, we have a 12-month contract of approximately 13 to 14 megawatts. We have a three-month contract of 10 megawatts and a second three-month contract, I think, of 10 megawatts; and all those resources are loaded between 60 and 100% load factors. So, obviously, that's where the biggest bulk of energy is coming from. And then the two nuclear units which, obviously, is base loaded. It totals to about 12 megawatts.

Q Now did you evaluate your opportunities under the participation agreement against purchasing from Power Corp?

A Power Corp -- a combination of Power Corp and Tampa.

Q When you made that evaluation, did you assume that the rates and terms of the current contracts would continue in effect?

A The rates and terms of the current contract and the fuel escalation -- energy escalation; I keep using the term incorrectly -- which is depicted on Document 5 of the Florida Power and Light's request of New Smyrna Beach First

Request for Production of Documents.

Q What is the title of that document, please, if it has one?

A "Forecast Fuel Pricing." I can read the escalation.

Q Mr. Vaden, perhaps I'm not understanding you. My question was whether you assumed that the current contracts would continue in effect when you evaluated that against your opportunity under the participation agreement.

A Yes, I took the assumption, which is an assumption that's going to be hard to achieve, that the current contracts would be extended with the terms and conditions with no escalation transmission cost, no escalation capacity cost.

Q Okay. How long did you assume that each of these contracts would continue in effect?

A For the life of the evaluation, which I believe is through the year 2011.

Q Please turn now to Exhibit RLV-6, Page 1 of 3 of your direct testimony. We have previously discussed this exhibit, but I have what I hope are a little bit different questions this time. Please describe again what this exhibit depicts.

A This exhibit is a base case to be able to analyze the savings between New Smyrna Beach extending its current

contracts with Enron, Corp and Tampa, base case which is evaluated against Page 2 of the same document, which is the -- includes the Duke plant and excludes the Enron, Corp and TECO.

Q When does UCNSB's fiscal year begin and end, sir?

A October 1st, September the 31st.

Q What is the in-service date of the proposed project?

A November 2001.

Q Referring to the second column on the document RLV-6, you'll see the year 2000 designated.

A Right.

Q Is that a year 2000 beginning October 1st, 2000?

A Yes, it would be October 1999. It would be our fiscal year 2000.

Q So this would end September 31st of the year 2000?

A Year 2000, that's correct.

Q Okay. Thank you.

Please tell us what assumptions you made to calculate the energy cost for this Exhibit RLV-6.

A The assumptions are, again, shown on Document 5.

Q Right. Okay. Thank you, sir. We have trod that trail.

Please turn now to Page 2 of 3 of RLV-6. You'll

see in the last column under total cost the figure 18.50; is that correct?

A That's correct.

Q What is the source of the 18.50 per megawatt hour energy cost?

A This column running from left to right, Base30, all the way across to the 18.50 is the Duke plant 30 megawatt entitlement to New Smyrna Beach at with -- of with -- it's been a long now; this afternoon is going to be rough -- and the 18.50 is the total cost under the participation agreement that New Smyrna Beach will pay Duke Energy for taking that resource, or every megawatt it takes, for every hour it will pay Duke 18.50; and that is the total end cost.

Q Total end cost?

A Total 100% cost of that resource.

Q Thank you, sir.

Please turn now to -- I'm sorry. I got ahead of myself. I'd like to refer you to the line item "peaking."

A Yes.

Q What sources did UCNSB assume for the peaking resource?

A Okay, the peaking resource, when the Duke plant comes on line, this is a resource that we have not entered into agreements, we have to negotiate for; and this peaking

resource we used a total cost, as you see, of $72 per megawatt hour which we feel is a good reasonable or even high peaking number for that resource. And based on, we just -- this is actually based on New Smyrna Beach's diesel units or in the neighborhood of $60. Florida Power Corporation's peaking six megawatts we have is in the neighborhood of $60, so we just took that and just added a small escalator on it.

Q From what source will the megawatt hours come from from the Duke plant -- I'm sorry, from the peaking?

A And again, that is contracts we have yet to enter into, but normally what we do on a situation like that is we would purchase peaking capacity at a low cost from another utility and then just buy the energy on the market as available. And if the energy was not available, then we would rely on that resource just as we use Florida Power Corp peaking contract currently.

Q Okay. Thank you, sir.

Please turn now to Page 3 of 3 of Exhibit RLV-6. This document is entitled "Utilities Commission, City of New Smyrna Beach Purchase Power Demand and Energy Savings From the New Smyrna Beach Power Project." Is this document reflecting a fiscal year or a calendar year?

A Fiscal year.

Q Why is fiscal years 2000 and 2001 -- I shouldn't

say why -- are fiscal years 2000 and 2001 not on the exhibit?

A The plant will be on line November 2001, so it would just be two months of that first fiscal year, and we did not include it.

MR. WRIGHT: Can I just ask a clarifying question?

MS. PAUGH: Certainly.

MR. WRIGHT: Is November 2001 in the Utilities Commission's 2002 fiscal year?

THE WITNESS: I'm not trying to formulate that in my mind right now.

A Okay, fis. year 2000, yes. What's not included is November and December of fiscal year 2001 that the plant has been on line, so this represents the 20 years excluding the two months, so we just did not run a separate model for those two months.

Q What is not included is November and December of 2001; is that your testimony?

A That's correct.

Q Does this exhibit assume that UCNSB will continue to purchase the Base30 from the Duke New Smyrna project?

A Yes. The $18.50 per hour, 30 megawatts is included in this, yes.

Do you want me to explain exactly how this is

derived?

Q Please do.

A The two prior documents here are the year 2000, which the year 2000 is not included. These documents exist for all the ten years out. The difference between these two is this first column of numbers.

Q Do the calculations on this exhibit, and that is Page 3 of 3 of RLV-6, assume an escalation of the $18.50 per megawatt hour energy cost for the Duke New Smyrna purchase?

A No, it stays flat at 18.50.

Q Okay.

MS. PAUGH: We'll go off the record for a moment.

(DISCUSSION OFF THE RECORD)

BY MS. PAUGH (Continuing):

Q Mr. Vaden, we've just had an off-the-record discussion. Would you please state for the record a summary of what we've just discussed?

A Okay, RLV-6, Page 3 of 3 shows the anticipated savings of the project from the year 2002 to 2021. The first 10 years of the project, 2002 through 2011, the estimated annual savings are derived from a comparison of Page 2, RLV-6 and -- I need to know the name of this document -- and Number 3 of staff's --

Q It's a response to staff Production of Documents

Number 3.

A Number 3. So the difference between those documents and Page 2 of 3 of RLV-6 is the estimated annual savings shown in the second column of Page 3 of RLV-3 and after -- this is analyzed through 2011 because the participation agreement between New Smyrna Beach and Duke calls for the 18.50 fuel for the first ten years; and after that, the next ten years, the contract calls for a guaranteed savings of two million dollars at wherever the market based rates are at that time.

Q Mr. Vaden, did you perform a cost effectiveness evaluation on any other supply-side alternatives?

A We did cursory reviews by looking at the marketplace and the other utilities. We looked for, at documents -- at costing from FMPA different sources in the state and quickly determined that there was no way in the world that we were going to get a price all-in cost of a resource less than $18.50 per megawatt hour, so we didn't burn any more energies in that direction.

Q Okay. I'm handing you a document. At the top it's titled "UCNSB's Response to FPL's Second Set of Interrogatories" dated November 3, 1998, Page 2, and it goes through -- it's just Page 2. The remainder of the document is Attachment B. Do you have a copy of the full document response to FPL's second set of interrogatories?

A Yes, I do.

Q Does the document I have handed you appear to be a true and correct copy of the full document?

A Yes, it is.

Q Okay. Thank you, sir.

MR. GUYTON: Leslie, are we going to mark this or just ask questions from it?

MS. PAUGH: Just ask questions.

MR. GUYTON: That's fine, I just wanted to make sure.

MS. PAUGH: Unless I need to mark it.

BY MS. PAUGH (Continuing):

Q What did this interrogatory ask of the UCNSB?

A This was number --

Q I'm sorry, Interrogatory Number 18, what did it ask of UCNSB?

A Clarify the previous question you asked me, and what we have been looking at was other purchase power options at New Smyrna Beach. I looked at this option, specifically looked at other generation alternatives that New Smyrna Beach had looked at. The only other generation option in any detail we had looked at would be a self-built for New Smyrna Beach without a partnership. If New Smyrna Beach had built a unit, it would be in the neighborhood, if I remember correctly, of 40 to 50 megawatts. General

Electric in 1993 conducted a study for New Smyrna and did a comparison of building a self-built gas fired single cycle and combined cycle at New Smyrna Beach to meet its needs and compared the results of that self-built option against the three options of New Smyrna Beach. Option 1 was utilizing some TECO and FP&L purchases from FP&L at 35.1 megawatt unit, the second, 41.1 megawatt unit. The evaluation showed that an LM6000 was the best option for New Smyrna Beach instead of continuing its contracts with Florida Power Corp and TECO, except, I think, partial purchases from TECO. We concluded this investigation which did not include building a gas line at New Smyrna Beach, and when we investigated the gas line at New Smyrna Beach which is in, I think, my direct testimony, the price of gas line for this unit made the project uneconomical.

Q Okay. Thank you, sir. That was a very complete answer.

What was the size of the LM6000?

A Not complete enough you'd ask me again. As I previously stated, the unit was looked at at two different sizes, a 35.1 megawatt and a 41.1 megawatt. The same size unit one included a chiller -- the same size unit except the 41.1 included a chiller.

Q Why did General Electric recommend a unit that did not entirely meet the forecasted needs of UCNSB, if you

know?

A It would be in a situation exactly like the Duke plant and the RLV-6, Page 2 of 3 where we have additional peaking resources that New Smyrna Beach will contract for. It will be uneconomic for New Smyrna Beach to buy peaking resources out of a plant that is high efficient and should be loaded at a higher load factor.

Q Okay. Please turn now to Page 15 of your direct testimony. If you'll take a look at the testimony beginning on Line 8, perhaps refresh your memory. Does this testimony that you UCNSB -- does this testimony indicate that UCNSB evaluated self-build options?

A Yes, the self-build option just described by General Electric.

Q Right. Did you evaluate any self-build options apart from the General Electric study that we've just been discussing?

A No.

Q Did the UCNSB evaluate joint ownership of a generating unit or units?

A Yes, we did, and that would be the Duke plant that we are going to build.

Q Did you evaluate any other joint ownership arrangements?

A We have -- maybe be specified as joint

ownership. We did look at the FMPA all requirements.

Q Please turn to Page 9 of your direct testimony. All right. I apologize, we are still on Page 15 of your direct testimony. If you'll take a look at Line 9 of that testimony, you state that UCNSB evaluated other purchase options, do you not?

A Yes, I did.

Q Please explain what those other purchase options were.

A The purchase options, again, back to RLV-6, the Corp, Tampa and Enron purchases.

Q Okay.

A Which we feel was, by far, the least alternatives that would be available, if available.

Q Okay. Did you issue a request for proposals to solicit supply-side alternatives to the participation agreement?

A No, we did not. And may I elaborate on that one?

Q Please do.

A Okay. Again, when we got to the price of 18.50, it was a no-brainer. You know, you don't -- you know, we didn't want to go out and spend a hundred thousand dollars for power supplies, but it was just a no-brainer at that point.

Q Okay. Thank you, Mr. Vaden.

MS. PAUGH: All right. Let's go off the record for a minute.

(DISCUSSION OFF THE RECORD)

BY MS. PAUGH (Continuing):

Q Mr. Vaden, I'm now going to ask you a series of questions regarding UCNSB's need for power. Would you please turn to Page 13 of your direct testimony?

A Yes.

Q Please review the question and answer beginning on Line 1.

A Yes.

Q Does this question and answer show the projected demand and energy requirements of UCNSB?

A Yes, it does.

Q What is UCNSB's projected demand for 2001?

A 93 -- 95 megawatts.

Q Is 2001 the in-service date for Duke New Smyrna project?

A November of 2001.

Q Right. How much additional capacity will have to be provided in addition to the entitlement to meet UCNSB's needs in 2001?

A Approximately 40 megawatts. If you want an exact number, I'll have to -- This is over and above the, be

sure I'm right, the nuclear units, the peaking units that we have, and the 40 megawatt purchase, this is additional, which is the peaking.

Q Okay. Thank you, sir.

Could all of UCNSB's capacity requirements be satisfied by the Duke New Smyrna project?

A That's not a yes-or-no answer, and the reason: It, obviously, possibly could be, but it would not be cost effective because the 40 additional megawatts is a peaking resource and it would be uneconomical to buy a peaking resource out of a high efficient plant that should be base loading.

Q Thank you.

Could the reliability of UCNSB's system be maintained by continuing to purchase from TECO and FPC or other power suppliers?

A I don't think that could be answered. If those contracts were renewed, the answer would be yes. If they were not renewed, the answer would be no; and we have not been able to renew those contracts at this point.

Q Have you tried?

A We are currently negotiating with Tampa for the two-year gap, but we have not looked at contracts past 2002 with other suppliers for the simple reason we can't; no one is going to sell it to us less than $18.50, back to the

no-brainer.

Q Okay. Thank you.

In your opinion, is the capacity to be provided pursuant to the participation agreement needed in order to maintain system reliability of UCNSB?

A Absolutely.

Q Please turn now to exhibit RLV-1 attached to your direct testimony. All right. If you'll get into the body of the exhibit, if you'll turn to Page 6.

A Okay.

Q Please describe this exhibit.

A The exhibit itself is the participation agreement between the Utilities Commission, City of New Smyrna Beach and Duke Energy New Smyrna Beach Power Company, Page 6, Section 3.0 specifically is permitting and approvals.

Q Thank you, sir.

Section 3.4 of the exhibit, if you would refer to that. Would you please read the first two and a half lines of Subsection d. into the record. It's within the paragraph.

A Paragraph 3.3?

Q 3.4, sir.

A Okay. "No circumstances are, again, existing or having occurred that has had or could reasonably be expected to have a material adverse effect on the

feasibility prospects or business of the facility."

Q Thank you.

What is your understanding of this provision?

A This provision needs to be taken into conjunction with the Amendment Number 1 to the contract, which is still included within this; and it has, if I can just shore it up and read into it. The amendment adds to the Section 3.4 in Item d., "Duke obtaining within 60 days after all necessary permits are obtained, approval for funding for construction of the project by Duke Energy Corporation Board of Directors."

Now my understanding of the two together, once the approval process through the Public Service Commission and all the permitting agencies have issued the permits to build, in other words, Duke has got all the authority that it has to build the projects, it has 60 days in which to start construction of the plant, to make the decision.

Q Does this provision also allow Duke Energy New Smyrna Beach to end its obligations to UCNSB if it's not profitable?

A Yes.

Q If so -- or since that is so, would the 30-megawatt entitlement be terminated?

A Yes, it would.

Q How secure is the 30-megawatt entitlement?

A Outside the scope of --

Q No within the scope of this provision.

A I think you stated it very clearly. At the point that New Smyrna Beach has obtained all the permits, ready to build the plant, if it's not economical to build the plant, Duke has by the Amendment One 60 days to declare to New Smyrna Beach that they are not going to be able to permit the plant; and if they're not, they hand over all working permits that's been acquired for the plant to New Smyrna Beach at that time.

Q In your opinion, under these provisions, can Duke Energy New Smyrna Beach unilaterally terminate the participation agreement?

A Duke could unilaterally terminate the participation agreement if the plant at that point is not economical.

Q Thank you, sir.

Is the capacity to be provided pursuant to the participation agreement needed because it is expected to be more economic source of power than purchasing from another power supplier?

A That is the Number 1 reason.

Q I'm going to ask you a few questions about your back-up fuel supply, sir. What will the primary fuel of the proposed power plant be?

A Natural gas.

Q Are you familiar with the plans for transporting natural gas to the site?

A Not fully.

Q Do you know what entities will be involved with the transportation of natural gas to the site?

A Yes, I do.

Q And who would those entities be?

A Enron, Florida Gas Transmission, and -- I would have to look the other entity up. Cypress, I believe. Do I need to look that up? Is that close enough?

Q That's close enough, sir. I believe it's correct.

Are you familiar with FGT's pipeline network in the State of Florida?

A Somewhat, not real familiar. I couldn't tell you where the major trunk lines and so forth are.

Q Do you know if there was an explosion at FGT's pumping station near Perry, Florida earlier this year?

A What I read in news releases.

Q Based on what you read in the news releases, what is your understanding of the circumstances of that event?

A I'm not sure what caused it, but it was an explosion as I understood. They got a transfer or pumping station which jeopardized a large gas flow into the state.

Q Do you have any knowledge of the impact that the explosion had on power producers in the State of Florida?

A No, not specifically. Again, I just read a few articles.

Q Do you have any general knowledge of the impact it had?

A General knowledge. I know it was a large impact, but it was not large enough to cause blackouts or brownouts or anything of that nature.

Q Do you know if it caused interruptions in service?

A Electric service? I don't believe it caused any interruption of electric service.

Q Do you know if that event -- and by that I mean the explosion at FGT's pumping station -- caused any power plants to use backup fuel?

A As I understand, it did.

Q Will the proposed power plant that's the subject of this docket have a backup fuel supply?

A No.

Q Your testimony is that you don't have backup fuel supply; is that correct?

A To my knowledge, no.

Q Okay. Did UCNSB analyze the reliability of the proposed plant prior to executing the participation

agreement with Duke New Smyrna?

A I'm not sure what you mean by analyzing reliability.

Q With respect to fuel supplies and backup fuels. I apologize, that's the overall performance in availability of the plant.

A Yes, Duke represented the availability factor of the unit to New Smyrna Beach of when the plant would be available, their projections. We looked at those, and so the answer would be, yes.

Q And what are those availabilities?

A I'm not sure what document it's in. It's in -- Availability factor of 96%. It's Page 9 of the needs application.

Q Did UCNSB analyze the risk of an interruption to natural gas to the site in its analysis of the reliability of the proposed plant?

A The contract, participation agreement, has certain provisions if it's available. Plant is not available for New Smyrna is one thing that should be addressed. The second, after the explosion that you referred to, we did sit down with Duke Energy which in turn had sat down with their suppliers. I did not ask who their suppliers was, but obviously FGT I think and Cypress (phonetics) -- whatever the name of the company -- and so

forth. They came back and they assured me that situations like this would be looked into, that the gas suppliers was looking into situations throughout the state that similar things could happen where they have these explosions and they were going to look into different ways to make it more secure.

Q Do you have any idea what those analyses will entail?

A It's totally outside of my expertise, and I feel comfortable with what we did in that area.

Q I understand.

In terms of number of days, what would you consider to be a prudent backup supply of fuel for a natural gas fired plant of the nature that we're discussing in this docket?

MR. WRIGHT: Object to the form. You can answer it.

THE WITNESS: I wouldn't. If I was building the plant, New Smyrna Beach was putting money into this plant, I myself would not put a backup fuel source for the natural gas unit.

BY MS. PAUGH (Continuing):

Q If there is a fuel supply interruption to the proposed plant, will Duke New Smyrna be responsible for providing UCNSB's 30-megawatt entitlement?

A As I understand it, if the plant is up and able to run, that they would still be obligated to supply us the 30 megawatts; and if the fuel source is not available to the plant, they would still be responsible for supplying us the 30 megawatts.

Q They would?

A Yes.

Q Okay. Thank you, sir.

A And it's my understanding, I'll add that.

Q That's what we're here for, is your understanding.

Mr. Vaden, I'm now going to ask you some bonus questions. Mr. Vaden, I have just handed you a document entitled "Constellation Announces Peak Power Project in Florida for Immediate Release." This document appears to be a press release. The document is dated on the fax stamp, November 17th, 1998, as well as in the body of the document.

A Question?

Q Have you taken a moment to familiarize yourself with this document?

MS. PAUGH: Do you have an objection?

MR. WRIGHT: No, I was under the impression that you were waiting for him to answer a question that I had not heard be posed.

MS. PAUGH: No, that's because it hadn't been?
BY MS. PAUGH (Continuing):
Q Okay. Were you aware of this proposed project prior to reading this press release?
A No, I was not.
Q Based on your reading of this press release today, does Constellation Power appear to claim that it will not have to go through the power plant siting process? I would refer you to the last full paragraph on the first page.
A It looks like what Wolfinger says.
Q Yes, sir.
Do you know if under the Power Plant Siting Act if a plant without a steam cycle can be permitted without going through the Power Plant Siting Act?
MR. GUYTON: I'll object if it calls for a legal opinion.
MS. PAUGH: I'm not. I'm asking for his understanding of the Power Plant Siting Act, which he previously testified briefly to.
THE WITNESS: I would have to go back and read it again, but as I understand it, a certain size plant that didn't have a steam cycle may be able to be permitted, but I'd have to review myself.
BY MS. PAUGH (Continuing):

Q Are you familiar with the term "merchant plant"?

A Yes, I am.

Q How would you define the term "merchant plant"?

A A merchant is a plant that is built by an entity which total cost of that plant is borne by the company building the plant, and any of the monies to build the plant is not rolled through the rate base of the territory or service -- territory, I guess, the state that it's being built in. So i.e., if New Smyrna Beach builds a plant at New Smyrna Beach and its considered a merchant plant, the megawatt -- the cost of that plant would not be included in the rate base of any ratepayer in the State of Florida, and it's solely for the purpose of the wholesale market.

Q Thank you, sir.

Based on your reading just now of this press release, do you believe that this proposed plant of Constellation could be considered a merchant plant as you have defined that term?

A I don't think there is enough information here to make that call. Anyone that is going to build an 850-megawatt plant just for using it out four months out of the year has got a problem to start with, so I wouldn't put a lot of credibility in what we're looking at.

Q Thank you.

MS. PAUGH: All right. Thank you, we have no

further questions.

(WHEREUPON, THE DEPOSITION WAS CONCLUDED)

* * * *

ERRATA SHEET

DOCKET NUMBER 981042-EM
RONALD L. VADEN
NOVEMBER 18, 1998

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that RONALD L. VADEN personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 18th day of November, 1998.

Nancy S. Metzke

NANCY S. METZKE
Notary Public - State of Florida

Nancy S. Metzke
MY COMMISSION # CC677518 EXPIRES
September 13, 2001
BONDED THRU TROY FAIN INSURANCE, INC.

CERTIFICATE OF DEPONENT

This is to certify that I, RONALD L. VADEN, have read the foregoing transcription of my testimony, Page 1 through 88, given on November 18, 1998 in Docket Number 981042-EM, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the errata sheet attached hereto.

_____

RONALD L. VADEN

Sworn to and subscribed before me this
_____ day of _____, 19_____

_____
NOTARY PUBLIC
State of _____
My Commission Expires:

REPORTER'S DEPOSITION CERTIFICATE

STATE OF FLORIDA)
COUNTY OF LEON)

I, NANCY S. METZKE, Certified Shorthand Reporter and Registered Professional Reporter, certify that I was authorized to and did stenographically report the deposition of RONALD L. VADEN; that a review of the transcript was requested; and that the transcript is a true and complete record of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 18th day of November, 1998.

Nancy S. Metzke

NANCY S. METZKE, RPR, CCR

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EXHIBIT NO. 10

DOCKET NO: 981042-EM

WITNESS: Ronald Vaden

PARTY: Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

DESCRIPTION:

1. Late Filed Deposition Exhibit of Ronald Vaden, titled "Benchmark Rates"

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 10
COMPANY/ WITNESS: Staff
DATE: 12-2-98

PROFFERING PARTY: STAFF

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	)	DOCKET NO. 981042-EM FILED: NOVEMBER 30, 1998

NOTICE OF FILING
LATE FILED DEPOSITION EXHIBIT NO. 1
OF RONALD L. VADEN

The Utilities Commission, City of New Smyrna Beach, Florida ("UCNSB") and Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P. ("Duke New Smyrna") hereby gives notice of filing late filed deposition Exhibit No. 1, of Ronald L. Vaden.

Respectfully submitted this 30th day of November, 1998.

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Duke Energy New Smyrna Beach Power
Company Ltd., L.L.P.

CERTIFICATE OF SERVICE
DOCKET NO. 981042-EM

I HEREBY CERTIFY that a true and correct copy of the foregoing has been served by hand delivery (*) or by United States Mail, postage prepaid, on the following individuals this 30th day of November, 1998:

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RONALD L. VADEN
LATE FILED DEPOSITION
EXHIBIT NO. 1

"BENCHMARK RATES"

FEDERAL RESERVE statistical release

These data are released each Monday. The availability of the release is announced on (202) 452-3206.

H.15 (519)

SELECTED INTEREST RATES

Yields in percent per annum

For immediate release
November 16, 1998

Instruments	1998 Nov 9	1998 Nov 10	1998 Nov 11	1998 Nov 12	1998 Nov 13	Week Ending Nov 13	Week Ending Nov 6	1998 Oct
Federal funds (effective) [1 2 3]	4.95	4.84	4.84	5.13	4.98	5.20	5.22	5.07
Commercial paper [3 4 5 6]								
Nonfinancial								
1-month	5.10	5.10		5.10	5.13	5.11	5.11	5.14
2-month	5.23	5.25		5.30	5.27	5.28	5.09	5.08
3-month	5.15	5.13		5.13	5.12	5.13	5.08	5.04
Financial								
1-month	5.14	5.17		5.17	5.15	5.16	5.16	5.18
2-month	5.27	5.32		5.32	5.35	5.32	5.17	5.12
3-month	5.25	5.24		5.24	5.21	5.24	5.13	5.09
Bankers acceptances (top rated) [3 4 7]								
3-month	5.18	5.18		5.18	5.25	5.20	5.13	5.12
6-month	4.95	4.95		4.95	4.99	4.98	4.85	4.88
CDs (secondary market) [3 8]								
1-month	5.21	5.19		5.18	5.19	5.19	5.22	5.24
3-month	5.32	5.30		5.30	5.31	5.31	5.27	5.21
6-month	5.15	5.10		5.10	5.10	5.11	5.08	4.99
Eurodollar deposits (London) [3 9]								
1-month	5.19	5.19		5.19	5.13	5.17	5.16	5.21
3-month	5.31	5.31		5.31	5.25	5.30	5.21	5.17
6-month	5.13	5.13		5.06	5.06	5.09	5.01	4.94
Bank prime loan [2 3 10]	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.12
Discount window borrowing [2 11]	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.86
U.S. government securities								
Treasury bills								
Auction high [3 4 12]								
3-month	4.47					4.47	4.43	4.08
6-month	4.50					4.50	4.38	4.16
1-year	4.40					4.40		4.06
Secondary market [3 4]								
3-month	4.62	4.43		4.37	4.42	4.44	4.43	3.96
6-month	4.50	4.44		4.40	4.43	4.44	4.43	4.05
1-year	4.43	4.32		4.29	4.34	4.35	4.27	3.95
Treasury constant maturities [13]								
3-month	4.68	4.54		4.48	4.47	4.52	4.56	4.07
6-month	4.66	4.61		4.56	4.54	4.59	4.59	4.20
1-year	4.54	4.53		4.50	4.52	4.52	4.46	4.12
2-year	4.57	4.50		4.47	4.54	4.52	4.40	4.09
3-year	4.63	4.57		4.52	4.58	4.57	4.50	4.18
5-year	4.55	4.50		4.47	4.53	4.51	4.45	4.18
7-year	4.84	4.78		4.74	4.78	4.79	4.75	4.46
10-year	4.88	4.81		4.77	4.82	4.82	4.83	4.53
20-year	5.51	5.48		5.46	5.46	5.48	5.54	5.30
30-year	5.28	5.27		5.25	5.26	5.27	5.29	5.01
Composite								
Over 10 years (long-term) [14]	5.46	5.43		5.41	5.41	5.43	5.38	5.24
Corporate bonds								
Moody's seasoned								
Aaa	6.47	6.44		6.41	6.42	6.44	6.56	6.37
Baa	7.34	7.35		7.33	7.34	7.34	7.42	7.18
A-utility [15]					7.00	7.00	7.12	6.96
State & local bonds [16]				5.04		5.04	5.04	4.93
Conventional mortgages [17]					6.93	6.93	6.89	6.71

See overleaf for footnotes

FOOTNOTES

1. The daily effective federal funds rate is a weighted average of rates on trades through N.Y. brokers.
2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.
3. Annualized using a 360-day year or bank interest.
4. On a discount basis.
5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). See Board's Commercial Paper Web pages (http://www.federalreserve.gov/releases/cp) for more information.
6. The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page.
7. Representative closing yields for acceptances of the highest rated money center banks.
8. An average of dealer offering rates on nationally traded certificates of deposit.
9. Bid rates for Eurodollar deposits collected around 9:30 a.m. Eastern time.
10. One of several base rates used by banks to price short-term business loans.
11. Rate for the Federal Reserve Bank of New York.
12. Auction date for daily data; weekly and monthly averages computed on an issue-date basis. On and after October 28, 1998, data are stop yields from uniform-price auctions. Before that date, they are weighted average yields from multiple-price auctions.
13. Yields on actively traded issues adjusted to constant maturities. Source: U.S. Treasury.
14. Unweighted average of rates on all outstanding bonds neither due nor callable in less than 10 years.
15. Estimate of the yield on a recently offered, A-rated utility bond with a maturity of 30 years and call protection of 5 years; Friday quotations.
16. Bond Buyer Index, general obligation, 20 years to maturity, mixed quality; Thursday quotations.
17. Contract interest rates on commitments for fixed-rate first mortgages. Source: FHLMC.

Note: Weekly and monthly figures are averages of business days unless otherwise noted.

Current and historical H.15 data are available on the Federal Reserve Board's web site (http://www.federalreserve.gov/). For information about individual copies or subscriptions, contact Publications Services at the Federal Reserve Board (phone 202-452-3244, fax 202-728-5886). For paid electronic access to current and historical data, call STAT-USA at 1-800-728-6372 or 202-482-1986.

DESCRIPTION OF THE TREASURY CONSTANT MATURITY SERIES

Yields on Treasury securities at "constant maturity" are interpolated by the U.S. Treasury from the daily yield curve. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 3 and 6 months and 1, 2, 3, 5, 7, 10, 20, and 30 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. In estimating the 20-year constant maturity, the Treasury incorporates the prevailing market yield on an outstanding Treasury bond with approximately 20 years remaining to maturity.

EXHIBIT NO. 11

DOCKET NO: 981042-EM

WITNESS: Ronald Vaden

PARTY: Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

DESCRIPTION:

1. Response to Staff's 1st Set of Interrogatories, Item 9-pages 10-11

2. Attachment to Item 9-Forecast Fuel Pricing Chart 2002-2011

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 11
COMPANY/ WITNESS: Staff
DATE: 10-3-98

PROFFERING PARTY: STAFF

9. Please provide the economic and financial assumptions underlying this project:

a. escalation or inflation rate(s),

b. present worth discount rate(s),

c. discount rates used to calculate savings.

Please include an explanation and basis upon which these rates were derived.

Response to Interrogatory 9:

9. a. The Utilities Commission, City of New Smyrna Beach used escalation rates as shown in the attached table titled Forecast Fuel Pricing 2002-2011. (Vaden)

Duke New Smyrna relies on the analyses performed by Dr. Dale Nesbitt of Altos Management Partners. (Butler)

All the calculations and results within NARG, for purposes of the New Smyrna Beach evaluation, are performed in perpetual constant dollars and all results are reported in perpetual constant dollars. The escalation and inflation rates were set equal to zero in the model. (The model would allow alternative assumptions, but we chose to use zero escalation and zero inflation and to insert all interest and discount rates in constant dollars.) (Nesbitt)

b. The Utilities Commission, City of New Smyrna Beach uses a discount rate of 6.0 percent for calculating present worth values. (Vaden)

Duke New Smyrna considers this information to be confidential, proprietary, competitively sensitive business information and questions its relevance to the evaluation of the New Smyrna Beach Power Project, for which Duke New Smyrna is taking all business and operating risk. (Butler)

All the calculations and results within NARG, for purposes of the New Smyrna Beach evaluation, are performed in perpetual constant dollars and all results are reported in perpetual constant dollars. The present worth discount rate was calculated by assuming a 10% real return on equity and a 5% real interest on debt. We futhermore assumed that financing is 60% equity and the income tax rate is 40%. These economic

and financial assumptions imply an overall real discount rate of 6.5% after tax. The model operates with an effective discount rate at this level, but it creates interest and principal repayment schedules on debt and discounts those rates at the assumed return on equity. (Nesbitt)

These returns were used for modeling purposes only and are not necessarily indicative of Duke New Smyrna's expectations as to the returns from the Project. (Butler)

c. The Utilities Commission, City of New Smyrna Beach uses a discount rate of 6.0 percent for calculating the present value of savings from the Project. (Vaden)

Duke New Smyrna considers this information to be confidential, proprietary, competitively sensitive business information and questions its relevance to the evaluation of the New Smyrna Beach Power Project, for which Duke New Smyrna is taking all business and operating risk. (Butler)

All the calculations and results within NARG, for purposes of the New Smyrna Beach evaluation, are performed in perpetual constant dollars and all results are reported in perpetual constant dollars. The discount rate used to calculate present worth was identical when calculating savings, 6.5%. (Nesbitt)

These returns were used for modeling purposes only and are not necessarily indicative of Duke New Smyrna's expectations as to the returns from the Project. (Butler)

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FACSIMILE COVER SHEET

NUMBER OF PAGES (INCLUDING COVER SHEET): 2

DATE: 10/21/98

TO: Leslie Paugh

FAX NO: 413-6184

FROM: **Schef Wright,** Landers & Parsons

Telephone: (850) 681-0311 **FAX:** (850) 224-5595

MESSAGE:

Attmt to Response to Interrog #9

Please call me if you can't read. Vickie

IF ANY PROBLEMS, PLEASE CALL VICKIE AT: (850) 681-0311

CONFIDENTIALITY NOTE

THE INFORMATION CONTAINED IN THIS FACSIMILE MESSAGE IS LEGALLY PRIVILEGED AND CONFIDENTIAL INFORMATION INTENDED ONLY FOR THE USE OF THE INDIVIDUAL OR ENTITY NAMED ABOVE. IF THE READER OF THIS MESSAGE IS NOT THE INTENDED RECIPIENT, YOU ARE HEREBY NOTIFIED THAT ANY DISSEMINATION, DISTRIBUTION OR COPY OF THIS TELECOPY IS STRICTLY PROHIBITED. IF YOU HAVE RECEIVED THIS TELECOPY IN ERROR, PLEASE IMMEDIATELY NOTIFY US BY TELEPHONE AND RETURN THE ORIGINAL MESSAGE TO US AT THE ADDRESS ABOVE VIA THE UNITED STATES POSTAL SERVICE. THANK YOU.

Utilities Commission, City of New Smyrna Beach, Florida

Forecast Fuel Pricing 2002-2011

	CR-3	St. Lucie	FPC PR	% Increase	FPC Peaking	TECo Base	% Increase	TECo Summer	TECo Supp.	Enron	Local
2002	5.25	12.35	23.09		58.00	17.54		22.48	27.50	35.00	65.96
2003	5.25	12.35	23.78	3.0%	58.00	17.79	1.4%	22.48	27.50	35.00	65.96
2004	5.25	12.35	24.49	3.0%	58.00	17.93	0.8%	22.48	27.50	35.00	65.96
2005	5.25	12.35	25.22	3.0%	58.00	18.13	1.1%	22.48	27.50	35.00	65.96
2006	5.25	12.35	25.98	3.0%	58.00	18.37	1.3%	22.48	27.50	35.00	65.96
2007	5.25	12.35	26.76	3.0%	58.00	18.67	1.6%	22.48	27.50	35.00	65.96
2008	5.25	12.35	27.74	3.7%	58.00	18.83	0.9%	22.48	27.50	35.00	65.96
2009	5.25	12.35	28.85	4.0%	58.00	18.94	0.6%	22.48	27.50	35.00	65.96
2010	5.25	12.35	30.00	4.0%	58.00	19.09	0.8%	22.48	27.50	35.00	65.96
2011	5.25	12.35	31.20	4.0%	58.00	19.26	0.9%	22.48	27.50	35.00	65.96
Average				3.4%			1.0%				

FPC PR increases based on historical increases in energy pricing for the 1988-1998 period of approximately 3.4%

TECo Base increased a relatively small amount based on the consistent and minimal increases over the life of the current Schedule D contract.

EXHIBIT NO. 12

DOCKET NO: 981042-EM

WITNESS: Ronald L. Vaden

PARTY: Utilities Commission, City of New Smyrna Beach, Florida and Duke Energy New Smyrna Beach Power Company Ltd., LLP

DESCRIPTION: UCNSB History and Forecast of Net Energy for Load and Load Factor

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 12
COMPANY/ WITNESS: Staff
DATE: 12-2-98

PROFFERING PARTY: STAFF

Forecast Net Energy for Load and Load Factor

	Total Energy NEL (GWh)	Residential Conservation	Retail Energy For Load	Peak Demand (MW)	Load Factor
1992	287.2	N/A	287.2	70.6	0.46
1993	292.5	N/A	292.5	72.1	0.46
1994	301.9	N/A	301.9	69.9	0.49
1995	319.0	N/A	319.0	88.3	0.41
1996	331.3	N/A	331.3	89.2	0.42
1997	325.2	N/A	325.2	82.5	0.45
1998	334.1	N/A	334.1	80.2	0.48
1999	344.5	N/A	344.5	91.0	0.43
2000	349.5	N/A	349.5	94.0	0.42
2001	354.4	N/A	354.4	96.0	0.42
2002	359.7	N/A	359.7	98.0	0.42
2003	364.2	N/A	364.2	100.0	0.42
2004	369.4	N/A	369.4	102.0	0.41
2005	374.7	N/A	374.7	104.0	0.41
2006	380.0	N/A	380.0	106.0	0.41
2007	385.5	N/A	385.5	108.0	0.41
2008	391.0	N/A	391.0	110.0	0.41
2009	396.6	N/A	396.6	112.0	0.40
2010	402.3	N/A	402.3	114.0	0.40
2011	408.0	N/A	408.0	116.0	0.40
2012	413.9	N/A	413.9	118.0	0.40
2013	419.8	N/A	419.8	120.0	0.40
2014	425.8	N/A	425.8	122.0	0.40
2015	431.9	N/A	431.9	124.0	0.40
2016	438.1	N/A	438.1	126.0	0.40
2017	444.3	N/A	444.3	128.0	0.40

EXHIBIT NO. 13

DOCKET NO: 981042-EM

WITNESS: Ronald L. Vaden

PARTY: Utilities Commission, City of New Smyrna Beach, Florida and Duke Energy New Smyrna Beach Power Company Ltd., LLP

DESCRIPTION: UCNSB Summer Peak Demand: History and Forecast

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 13
COMPANY/ WITNESS: Staff
DATE: 12-2-98

PROFFERING PARTY: STAFF

Summer Peak Demand

	Total Demand	Wholesale Demand	Retail Demand	Interruptible Demand	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Conservation	Other Demand Reductions	Summer Net Demand
1991	62.9	0.0	62.9	0.0	0.0	N/A	0.0	N/A	0.0	62.9
1992	70.3	0.0	70.3	0.0	3.0	N/A	0.0	N/A	0.0	67.3
1993	67.5	0.0	67.5	0.0	0.0	N/A	0.0	N/A	0.0	67.5
1994	69.8	0.0	69.8	0.0	3.8	N/A	0.0	N/A	0.0	66.0
1995	75.0	0.0	75.0	0.0	5.0	N/A	0.0	N/A	0.0	70.0
1996	78.0	0.0	78.0	0.0	6.0	N/A	0.0	N/A	0.0	72.0
1997	84.1	0.0	84.1	0.0	6.0	N/A	0.0	N/A	0.0	78.1
1998	86.2	0.0	86.2	0.0	6.0	N/A	0.0	N/A	0.0	80.2
1999	87.0	0.0	87.0	0.0	6.0	N/A	0.0	N/A	0.0	81.0
2000	89.0	0.0	89.0	0.0	6.0	N/A	0.0	N/A	0.0	83.0
2001	91.0	0.0	91.0	0.0	6.0	N/A	0.0	N/A	0.0	85.0
2002	94.0	0.0	94.0	0.0	7.0	N/A	0.0	N/A	0.0	87.0
2003	96.0	0.0	96.0	0.0	7.0	N/A	0.0	N/A	0.0	89.0
2004	98.0	0.0	98.0	0.0	7.0	N/A	0.0	N/A	0.0	91.0
2005	99.0	0.0	99.0	0.0	7.0	N/A	0.0	N/A	0.0	92.0
2006	101.0	0.0	101.0	0.0	7.0	N/A	0.0	N/A	0.0	94.0
2007	103.0	0.0	103.0	0.0	7.0	N/A	0.0	N/A	0.0	96.0
2008	105.0	0.0	105.0	0.0	7.0	N/A	0.0	N/A	0.0	98.0
2009	107.0	0.0	107.0	0.0	7.0	N/A	0.0	N/A	0.0	100.0
2010	109.0	0.0	109.0	0.0	7.0	N/A	0.0	N/A	0.0	102.0
2011	111.0	0.0	111.0	0.0	7.0	N/A	0.0	N/A	0.0	104.0
2012	114.0	0.0	114.0	0.0	8.0	N/A	0.0	N/A	0.0	106.0
2013	117.0	0.0	117.0	0.0	8.0	N/A	0.0	N/A	0.0	109.0
2014	119.0	0.0	119.0	0.0	8.0	N/A	0.0	N/A	0.0	111.0
2015	121.0	0.0	121.0	0.0	8.0	N/A	0.0	N/A	0.0	113.0
2016	123.0	0.0	123.0	0.0	8.0	N/A	0.0	N/A	0.0	115.0
2017	125.0	0.0	125.0	0.0	8.0	N/A	0.0	N/A	0.0	117.0

EXHIBIT NO. 14

DOCKET NO: 981042-EM

WITNESS: Ronald L. Vaden

PARTY: Utilities Commission, City of New Smyrna Beach, Florida and Duke Energy New Smyrna Beach Power Company Ltd., LLP

DESCRIPTION: UCNSB Winter Peak Demand: History and Forecast

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 14
COMPANY/ WITNESS: Staff
DATE: 12-2-98

PROFFERING PARTY: STAFF

Winter Peak Demand

	Total Demand	Wholesale Demand	Retail Demand	Interruptible Demand	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Conservation	Other Demand Reductions	Winter Net Demand
1991	75.3	0.0	75.3	0.0	0.0	N/A	0.0	N/A	0.0	75.3
1992	70.6	0.0	70.6	0.0	0.0	N/A	0.0	N/A	0.0	70.6
1993	76.7	0.0	76.7	0.0	4.6	N/A	0.0	N/A	0.0	72.1
1994	74.0	0.0	74.0	0.0	4.1	N/A	0.0	N/A	0.0	69.9
1995	97.7	0.0	97.7	0.0	9.4	N/A	0.0	N/A	0.0	88.3
1996	96.7	0.0	96.7	0.0	7.5	N/A	0.0	N/A	0.0	89.2
1997	90.5	0.0	90.5	0.0	8.0	N/A	0.0	N/A	0.0	82.5
1998	75.6	0.0	75.6	0.0	8.0	N/A	0.0	N/A	0.0	67.6
1999	99.0	0.0	99.0	0.0	8.0	N/A	0.0	N/A	0.0	91.0
2000	102.0	0.0	102.0	0.0	8.0	N/A	0.0	N/A	0.0	94.0
2001	104.0	0.0	104.0	0.0	8.0	N/A	0.0	N/A	0.0	96.0
2002	106.0	0.0	106.0	0.0	8.0	N/A	0.0	N/A	0.0	98.0
2003	108.0	0.0	108.0	0.0	8.0	N/A	0.0	N/A	0.0	100.0
2004	110.0	0.0	110.0	0.0	8.0	N/A	0.0	N/A	0.0	102.0
2005	113.0	0.0	113.0	0.0	9.0	N/A	0.0	N/A	0.0	104.0
2006	115.0	0.0	115.0	0.0	9.0	N/A	0.0	N/A	0.0	106.0
2007	117.0	0.0	117.0	0.0	9.0	N/A	0.0	N/A	0.0	108.0
2008	119.0	0.0	119.0	0.0	9.0	N/A	0.0	N/A	0.0	110.0
2009	121.0	0.0	121.0	0.0	9.0	N/A	0.0	N/A	0.0	112.0
2010	123.0	0.0	123.0	0.0	9.0	N/A	0.0	N/A	0.0	114.0
2011	125.0	0.0	125.0	0.0	9.0	N/A	0.0	N/A	0.0	116.0
2012	128.0	0.0	128.0	0.0	10.0	N/A	0.0	N/A	0.0	118.0
2013	130.0	0.0	130.0	0.0	10.0	N/A	0.0	N/A	0.0	120.0
2014	132.0	0.0	132.0	0.0	10.0	N/A	0.0	N/A	0.0	122.0
2015	134.0	0.0	134.0	0.0	10.0	N/A	0.0	N/A	0.0	124.0
2016	136.0	0.0	136.0	0.0	10.0	N/A	0.0	N/A	0.0	126.0
2017	138.0	0.0	138.0	0.0	10.0	N/A	0.0	N/A	0.0	128.0

EXHIBIT NO. 15

DOCKET NO: 981042-EM

WITNESS: Ronald L. Vaden

PARTY: The Utilities Commission, City of New Smyrna Beach, Florida

DESCRIPTION: Duke Energy New Smyrna Beach Power Company, LTD., L.L.P.'s Response to Staff's Request for Production of Documents No. 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 15
COMPANY/ WITNESS: Staff
DATE: 12-3-98

PROFFERING PARTY: STAFF

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	)	DOCKET NO. 981042-EM FILED: OCTOBER 16, 1998

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY, LTD., L.L.P.'S RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1 - 23)

Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P. ("Duke New Smyrna"), pursuant to Uniform Rule 28-106.206, Florida Administrative Code, hereby responds to Staff's First Request for Production of Documents (Nos. 1-23).

Respectfully submitted,

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Attorneys for the Utilities Commission, City of New Smyrna Beach, Florida,

and

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

3. Please provide complete copies of each fuel price forecast used in developing the estimated savings listed on Table 14, page 66 of the Exhibits attached to the Joint Petition for Determination of Need.

See attached documents and diskette (hereinafter the "UCNSB Diskette").

The attached schedule indicates forecasted fuel rates and MWh requirements for the first ten years of Table 14. These costs are evaluated against the fuel and purchased power cost analysis for the base year, 2000, to determine the savings. The second ten year span (2012-2021) has no agreed upon fuel pricing between Duke Energy and the Utilities Commission. The Participation Agreement does guarantee a minimum savings to be realized by the Commission of $2,000,000.00 annually.

Month	Year	NEL MWH	Peak MWs	Load Factor	Res Margin	LOLP d/yr	LOLP hr/yr
Total	2000	349513	87	45.74	17.12	0	0

Resource Name	NEL MWH	Start-up Cost $	Energy Cost $	Energy $/MWH	Res. C.F.%	Fixed Cost $	Total Cost $	Total Cost $/MWH
Base30	218612	0	4044322	18.50	82.96	0	4044322	18.50
CR-3	35623	0	187021	5.25	99.98	68400	255421	7.17
Clinch-Pk	56	0	3694	65.96	0.11	0	3694	65.96
DualFuel	0	0	0	0.00	0.00	0	0	0.00
Peaking	37784	0	1511360	40.00	12.78	1212000	2723360	72.08
St Lucie	57438	0	709359	12.35	99.98	0	709359	12.35
Uns Energy	0	0	0	0.00	0.00	0	0	0.00
TOTALS	349513	0	6455756	18.47		1280400	7736156	22.13

Forecast Fuel Costs 2002-2010

2002

	MWH	Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	109,153	2,460,672	23.09	4,981,014.77
FPC Peaking	8,196	267,264	58.00	742,632.00
TECo Base	110,432	854,510	17.54	2,791,487.28
TECo Summer	11,448	0	22.48	257,351.04
TECo Supp	19,105	0	27.50	525,387.50
Enron	4,412	242,000	35.00	396,420.00
Local Gen.	4,134	0	65.96	272,678.64
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	359,686			11,192,825

2003

	MWH	Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	110,986	2,460,672	23.78	5,099,919.08
FPC Peaking	8,334	267,264	58.00	750,636.00
TECo Base	112,287	854,510	17.79	2,852,095.73
TECo Summer	11,640	0	22.48	261,667.20
TECo Supp	19,426	0	27.50	534,215.00
Enron	4,486	242,000	35.00	399,010.00
Local Gen.	4,203	0	65.96	277,229.88
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	364,168			11,400,626

2004

	MWH	Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	113,118	2,460,672	24.49	5,230,931.82
FPC Peaking	8,494	267,264	58.00	759,916.00
TECo Base	114,443	854,510	17.93	2,906,472.99
TECo Summer	11,864	0	22.48	266,702.72
TECo Supp	19,799	0	27.50	544,472.50
Enron	4,572	242,000	35.00	402,020.00
Local Gen.	4,284	0	65.96	282,572.64
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	369,380			11,618,942

2005

	MWH	Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	115,280	2,460,672	25.22	5,368,033.60
FPC Peaking	8,656	267,264	58.00	769,312.00
TECo Base	116,631	854,510	18.13	2,969,030.03
TECo Summer	12,091	0	22.48	271,805.68
TECo Supp	20,177	0	27.50	554,867.50
Enron	4,660	242,000	35.00	405,100.00
Local Gen.	4,368	0	65.96	287,981.36
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	374,667			11,851,984

Forecast Fuel Costs 2002-2010

	2008			
	MWH	Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	117,474	2,460,672	25.98	5,512,646.52
FPC Peaking	8,821	267,264	58.00	778,882.00
TECo Base	118,850	854,510	18.37	3,037,784.50
TECo Summer	12,321	0	22.48	276,976.08
TECo Supp	20,561	0	27.50	565,427.50
Enron	4,748	242,000	35.00	408,180.00
Local Gen.	4,449	0	65.96	293,456.04
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	380,030			12,099,206

	2007			
	MWH	Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	119,698	2,460,672	26.76	5,663,790.48
FPC Peaking	8,988	267,264	58.00	788,568.00
TECo Base	121,101	854,510	18.67	3,115,465.67
TECo Summer	12,554	0	22.48	282,213.92
TECo Supp	20,951	0	27.50	576,152.50
Enron	4,838	242,000	35.00	411,330.00
Local Gen.	4,533	0	65.96	298,996.68
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	385,469			12,362,371

	2008			
	MWH	Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	121,955	2,460,672	27.74	5,843,703.70
FPC Peaking	9,157	267,264	58.00	798,370.00
TECo Base	123,384	854,510	18.83	3,177,830.72
TECo Summer	12,791	0	22.48	287,541.68
TECo Supp	21,346	0	27.50	587,015.00
Enron	4,929	242,000	35.00	414,515.00
Local Gen.	4,619	0	65.96	304,669.24
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	390,988			12,639,499

	2009			
	MWH	Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	124,244	2,460,672	28.85	6,045,111.40
FPC Peaking	9,329	267,264	58.00	808,346.00
TECo Base	125,700	854,510	18.94	3,235,268.00
TECo Summer	13,031	0	22.48	292,936.88
TECo Supp	21,746	0	27.50	598,015.00
Enron	5,022	242,000	35.00	417,770.00
Local Gen.	4,706	0	65.96	310,407.76
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	396,583			12,933,709

Forecast Fuel Costs 2002-2010

	MWH	2010 Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	126,565	2,460,672	30.00	6,257,622.00
FPC Peaking	9,503	267,264	58.00	818,438.00
TECo Base	128,048	854,510	19.09	3,298,946.32
TECo Summer	13,274	0	22.48	298,399.52
TECo Supp	22,153	0	27.50	609,207.50
Enron	5,116	242,000	35.00	421,060.00
Local Gen.	4,793	0	65.96	316,146.28
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	402,259			13,245,673

	MWH	2010 Fixed Cost	$/MWH	Total
CR-3	35,525	68,400	5.25	254,906.25
St. Lucie	57,281	0	12.35	707,420.35
FPC PR	128,920	2,460,672	31.20	6,482,976.00
FPC Peaking	9,680	267,264	58.00	828,704.00
TECo Base	130,430	854,510	19.26	3,366,591.80
TECo Summer	13,521	0	22.48	303,952.08
TECo Supp	22,565	0	27.50	620,537.50
Enron	5,211	242,000	35.00	424,385.00
Local Gen.	4,883	0	65.96	322,082.68
Reg-Res-Bk	0	263,527	0.00	263,527.00
NEL	408,016			13,575,083

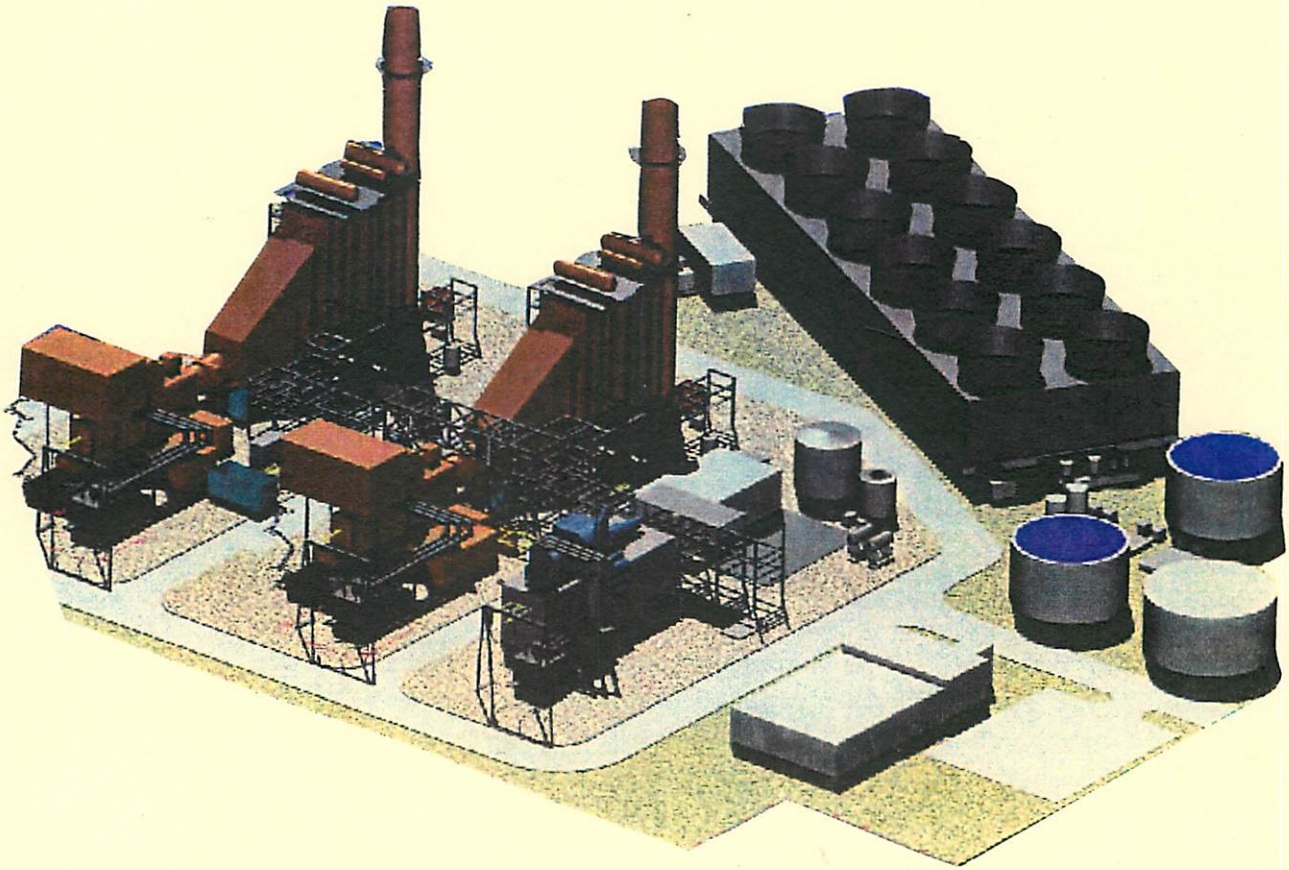
EX16 - VADEN'S PORTION

981042-EU

UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

JOINT PETITION FOR DETERMINATION OF NEED FOR THE NEW SMYRNA BEACH POWER PROJECT



EXHIBITS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EU EXHIBIT NO. 16
COMPANY/ WITNESS: Duke Energy
DATE: 12-2-98

AUGUST 19, 1998

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FPSC-RECORDS/REPORTING

JOINT PETITION FOR DETERMINATION OF NEED FOR THE NEW SMYRNA BEACH POWER PROJECT

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JOINT PETITION FOR DETERMINATION OF NEED FOR THE NEW SMYRNA BEACH POWER PROJECT

EXECUTIVE SUMMARY

General Description of the New Smyrna Beach Power Project

The Utilities Commission, City of New Smyrna Beach, Florida ("UCNSB" or "Utilities Commission"), a municipal utility authorized under Chapters 67-1754 and 85-503, Laws of Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P., a public utility subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act, apply for the Commission's determination of need for the New Smyrna Beach Power Project, a 514 MW natural gas fired combined cycle generating unit that will be located in New Smyrna Beach in Volusia County, Florida. Expected to achieve commercial in-service status in November 2001, the Project will supply 30 MW of capacity and associated energy to the Utilities Commission of the City of New Smyrna Beach ("UCNSB") for resale to its customers, with the balance of the Project's capacity and energy being made available for sale, at wholesale, to other utilities. Virtually all of these wholesale sales are expected to be made to other Peninsular Florida utilities.

The Project will include two advanced technology combustion turbines, two heat recovery steam generators, and one steam turbine generator. The Project will have a heat rate of approximately 6,832 Btu per kWh (based on the Higher Heating Value of natural gas) and will satisfy all applicable environmental requirements.

Most of the Project's process and make-up water will be supplied by an advanced wastewater treatment plant currently being constructed by the UCNSB adjacent to the Project site.

Duke New Smyrna's current projections indicate that the Project will operate between 7,000 and 8,500 hours per year, with projected generation between 3,700,000 and 4,200,000 MWH per year.

The Project will be interconnected to the Peninsular Florida transmission grid at the Smyrna Substation of the UCNSB. A firm delivered supply of natural gas will be provided to the Project pursuant to a long-term contract with Citrus Trading Corp., an affiliate of Florida Gas Transmission Company. Gas will be supplied via a 42-mile, 16-inch lateral pipeline that will be connected to the FGT main line near Mt. Plymouth in Lake County.

Ownership and Management

The New Smyrna Beach Power Project will be developed by Duke Energy Power Services, L.L.C. ("DEPS") and owned by Duke Energy New Smyrna Beach Power Project Ltd., L.L.P., an affiliate of DEPS. Duke Energy Power Services is the power plant development affiliate of Duke Energy Corporation. Engineering and construction of the Project will be performed by Duke/Fluor Daniel, a partnership of Duke Project Services, Inc. and FD Illinois, Inc. The Project will be managed, operated, and maintained by the operations and maintenance group of Duke/Fluor Daniel.

Power produced by the New Smyrna Beach Power Project will be sold at wholesale to other utilities for resale to their customers. As outlined in the Participation Agreement bewtween Duke New Smyrna

and the UCNSB, the UCNSB will receive 30 MW of the Project's capacity and associated energy for resale to its retail electric customers (or to other wholesale customers, if the UCNSB chooses to make such sales).

Site Description and Location

The Project will be located in the northwest quadrant of the intersection of Interstate Highway 95 and Florida State Road 44, within the city limits of New Smyrna Beach in west central Volusia County. The site consists of approximately 30.5 acres immediately adjacent to the Smyrna Substation of the UCNSB and also adjacent to an advanced wastewater treatment plant currently being constructed by the UCNSB.

Description of the Power Plant and Related Facilities

The power plant will consist of two advanced technology combustion turbine generators ("CTGs") (GE Frame 7FA or equivalent) with two matched heat recovery steam generators ("HRSGs"). Steam from both HRSGs will feed into one steam turbine generator ("STG"). The total electrical output of the plant will be 514 MW at ISO temperature and humidity conditions.

Water supply for the Project will be provided by reuse water from the UCNSB's adjacent wastewater treatment plant and from on-site or off-site wells. Most of the Project's process and make-up water is expected to be reuse water from the wastewater treatment plant; supplemental water is expected to be provided from wells providing raw water that will be treated on the Project site.

The Project will be electrically interconnected to the Peninsular Florida transmission grid at the Smyrna Substation, a 115 kV substation owned by the UCNSB. To facilitate and support power deliveries from the Project to other Peninsular Florida utilities located south of the Project, a second circuit is planned to be added to the 18-mile 115 kV Smyrna-Cassadaga transmission line, and a new 7.5-mile 115 kV circuit is planned to connect the Cassadaga substation to the Lake Helen substation.

Fuel Supply

The Project will be fueled by natural gas. Gas for the Project will be delivered to the Project by a 42-mile, 16-inch lateral pipeline that will originate at Florida Gas Transmission Company's ("FGT") main pipeline near Mt. Plymouth, Florida. The gas will be supplied by Citrus Trading Corp., an affiliate of FGT and Enron Corp., pursuant to a long-term contract for delivered firm gas supply.

Project Costs and Financing

The Project's direct construction cost, including all engineering, procurement, and construction functions, is expected to be approximately $160 million, reflecting a cost of approximately $311 per kW of installed capacity. The Project will be constructed and brought into commercial service solely with internal Duke New Smyrna funds.

I. INTRODUCTION

The purpose of the Joint Petition for Determination of Need submitted by the Utilities Commission of New Smyrna Beach and Duke New Smyrna is to obtain the Florida Public Service Commission's affirmative determination of need for the New Smyrna Beach Power Project, a 514 MW (at ISO temperature and humidity conditions) natural gas fired combined cycle generating unit that will be located in New Smyrna Beach in Volusia County, Florida.

The Commission's determination of need pursuant to Section 403.519, Florida Statutes, is part of the comprehensive permitting process for the Project under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, Florida Statutes ("the Siting Act"). Under Section 403.519, the Commission is to consider the following factors when making its decision whether to grant a determination of need for a power plant subject to the Siting Act:

1. The need for electric system reliability and integrity;
2. The need for adequate electricity at a reasonable cost;
3. Whether the proposed plant is the most cost-effective alternative available for serving an identified need for power;
4. Conservation measures taken by, or reasonably available to, the affected utility or utilities which might mitigate the need for the proposed plant; and
5. Other matters within the Commission's jurisdiction which the Commission deems relevant to its determination.

In these Exhibits, the UCNSB and Duke New Smyrna demonstrate that the New Smyrna Beach Power Project satisfies all relevant criteria under Section 403.519. The Project will provide a power

supply resource with proven, reliable, highly efficient, highly available, and environmentally benign technology. Pursuant to the Participation Agreement between the UCNSB and Duke New Smyrna, the Project will provide 30 MW of capacity and associated energy to the UCNSB at very cost-effective wholesale rates. As a wholesale power plant offering capacity and energy to other utilities in Peninsular Florida at negotiated, market-based prices, the output of which no utility (other than the UCNSB) is obligated to buy, the Project also provides a cost-effective power supply alternative for meeting the needs of other utilities in Peninsular Florida.

The Project will contribute significantly to the reliability of the power supply system in Peninsular Florida, to lower cost generation, to enhanced efficiency in electricity generation in Peninsular Florida, and to improvements in the environmental profile of power generation in Florida.

Section II of these Exhibits provides a description of the joint applicants, the Utilities Commission of the City of New Smyrna Beach, Florida and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. Section III describes the Project, including the site, generating technology, operational reliability and related information, major systems, associated facilities, fuel supply, and the schedules for permitting and constructing the Project. Section IV describes the consistency of the Project with the power supply needs of the UCNSB and with the power supply needs of Peninsular Florida. Section V describes the cost-effectiveness of the Project, and Section VI addresses the adverse consequences

on power supply reliability, power supply cost, and Florida's environment of delaying the construction and operation of the New Smyrna Beach Power Project.

II. THE APPLICANTS

The joint applicants for the Commission's determination of need are the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. This section of the Exhibits describes the organization and ownership structure of the Project and of both applicants, including Duke New Smyrna's affiliates that are also involved in the energy industry.

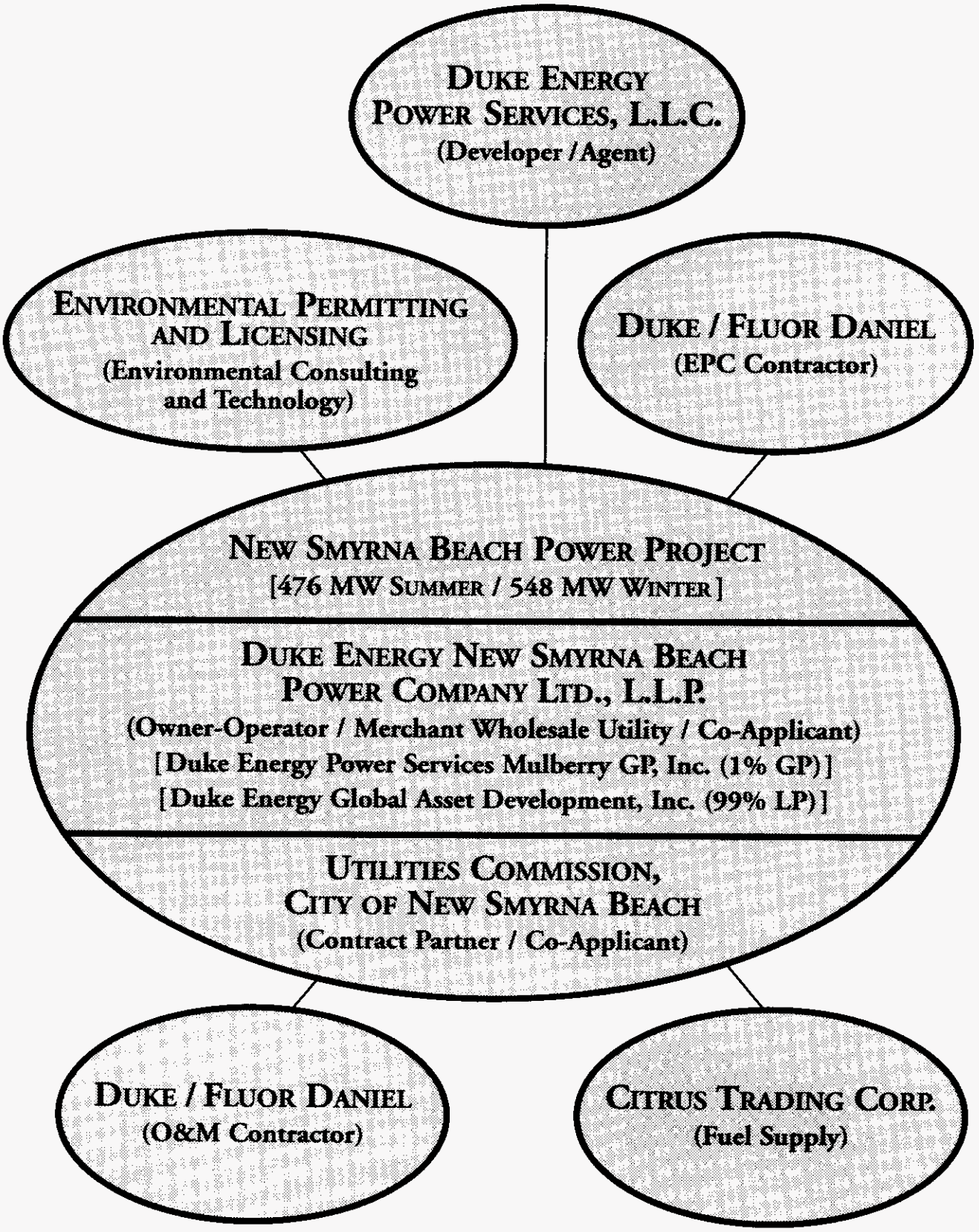
A. Overview and Project Structure

Figure 1 depicts the overall structure of the New Smyrna Beach Power Project. Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. is the owner of, and has operational responsibility for, the New Smyrna Beach Power Project. Duke New Smyrna is a FERC-jurisdictional, FERC-regulated wholesale public utility that will sell the Project's merchant capacity and energy at wholesale directly to other utilities. The Utilities Commission of New Smyrna Beach is Duke New Smyrna's contract partner and co-applicant for the Commission's determination of need for the Project. Duke Energy Power Services, L.L.C. ("DEPS") is the developer of the Project, and in that role functions as Duke New Smyrna's agent for arranging the various contracts that will support the Project's development, construction, and operation. Financing will be provided by Duke New Smyrna. As the engineering, procurement, and construction ("EPC") contractor for the Project, Duke/Fluor Daniel will design, engineer, and construct the Project. The contractor for environmental licensing and permitting activities is

Figure 1

New Smyrna Beach Power Project

Project Structure



Environmental Consulting and Technology, Inc. Natural gas will be supplied by Citrus Trading Corp., an affiliate of Enron Corp. and Florida Gas Transmission Company, pursuant to a long-term contract with DEPS. Duke/Fluor Daniel's operations and maintenance group will be the actual operator of the Project.

B. The Utilities Commission, City of New Smyrna Beach, Florida

The Utilities Commission of New Smyrna Beach is a legislatively created unit of the City of New Smyrna Beach. The UCNSB was created by Chapters 67-1754 and 85-503, Laws of Florida. The UCNSB provides electric, water, wastewater, reuse water, and internet access services to the citizens of the City of New Smyrna Beach and surrounding areas of Volusia County. With respect to the jurisdiction of the Commission, the UCNSB is an electric utility, specifically a municipal electric utility, under Section 366.06(2), Florida Statutes. The UCNSB is governed by a board of five commissioners who are appointed by the City Commission for three-year terms. Pursuant to its authorizing legislation, the UCNSB has broad authority to provide various utility services.

The UCNSB serves approximately 19,900 electric customers within its 72-square-mile service area, which consists of the City of New Smyrna Beach and surrounding unincorporated areas, mainly to the south and west of the City. The UCNSB's customer base is largely residential; residential customers comprise approximately 90 percent (by number) of the UCNSB's total customers, and residential use accounts for approximately 65 percent of total system electric consumption.

The UCNSB is a winter peaking electric system. Its historic peak demand of 89 MW was experienced in the winter of 1996. The UCNSB's historic summer peak was 80.2 MW, registered in June 1998. Since 1992, the UCNSB's net energy for load ("NEL") has grown at an annual average rate of 2.6 percent, from 287,167 MWH in 1992 to 325,229 MWH in 1997. The UCNSB's peak demands and NEL are projected to grow steadily over the next ten years, due largely to steady growth in the system's residential customer base.

The UCNSB presently owns and operates two power plants with total generating capacity of 18.8 MW. The UCNSB has an entitlement to a portion of the capacity of the St. Lucie No. 2 nuclear unit through the Florida Municipal Power Agency and partial ownership in the Crystal River No. 3 nuclear unit. The UCNSB also has power purchase contracts with Tampa Electric Company, Florida Power Corporation, and Enron Power Marketing, Inc.

The UCNSB offers a load management program and energy audits on request. The UCNSB's load management program enables the UCNSB to reduce its summer and winter peak demands by approximately 10 percent, or by 8 to 9 MW. In emergency conditions, the UCNSB can achieve reductions between 12 and 13 MW by implementing full, unlimited exercise of the load management program.

C. Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

Duke New Smyrna is a Florida limited liability partnership created in 1997. The general partner is Duke Energy Power Services Mulberry GP, Inc., which has a 1 percent ownership interest, and the sole limited partner is Duke Energy Global Asset Development,

Inc., which has a 99 percent ownership interest in Duke New Smyrna The ownership structure of Duke New Smyrna is shown in Figure 2.

Duke New Smyrna is a public utility under Section 201 of the Federal Power Act. By its order issued on June 25, 1998, the Federal Energy Regulatory Commission ("FERC") approved Duke New Smyrna's Rate Schedule No. 1, which permits Duke New Smyrna to enter into negotiated wholesale power sales agreements with willing purchasers. Duke Energy New Smyrna Beach Power Company Ltd., L.L.P., 83 FERC §61,316. Pursuant to a FERC order issued on June 9, 1998, Duke New Smyrna is also an Exempt Wholesale Generator ("EWG"). Duke Energy New Smyrna Beach Power Company Ltd., L.L.P., 83 FERC §62,220. Copies of these orders are included in the Appendix to these Exhibits.

D. Duke Energy Power Services, L.L.C.

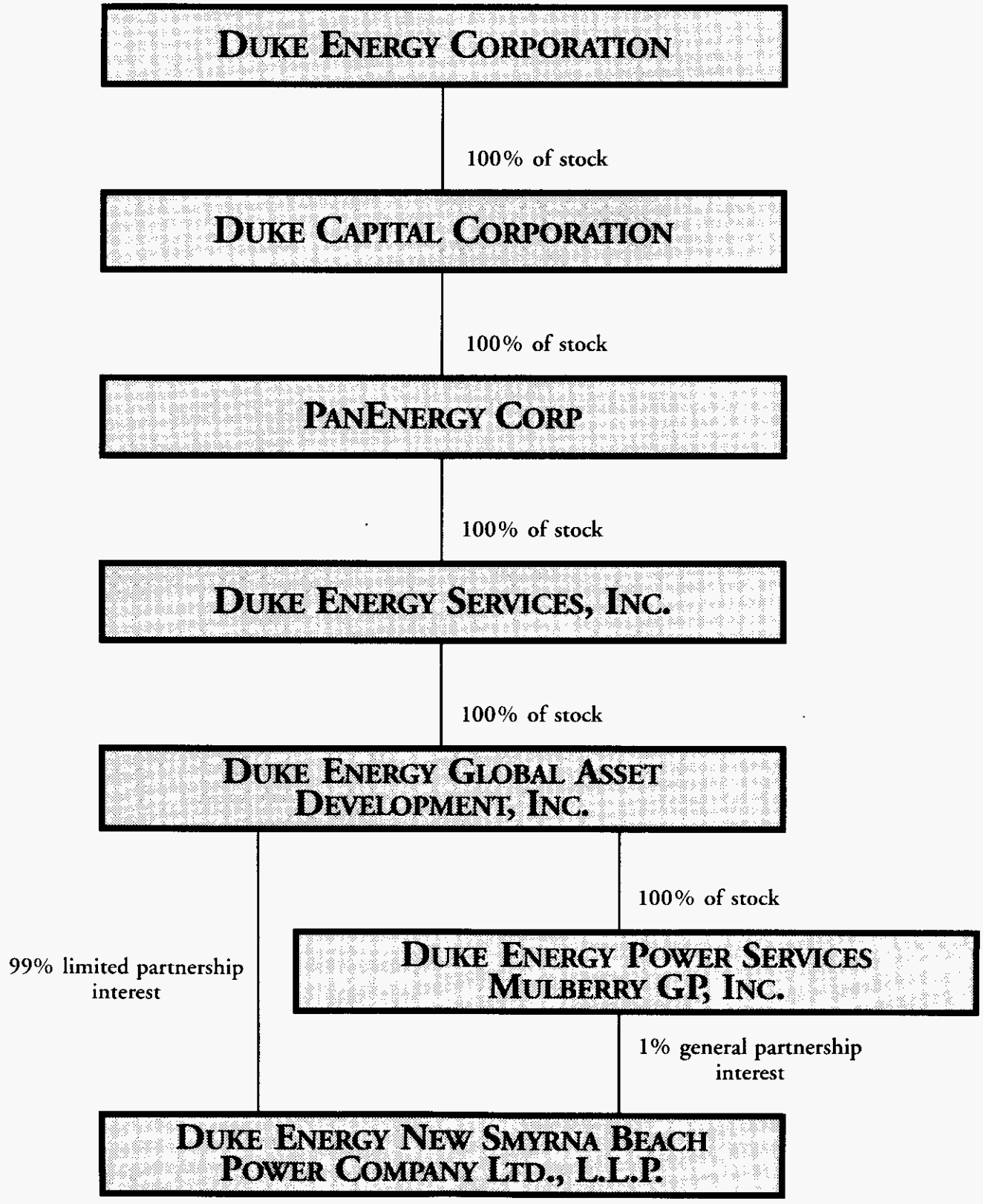
Duke Energy Power Services, L.L.C. ("DEPS") is a Delaware limited liability corporation created in 1997. DEPS is a subsidiary of Duke Energy Corporation engaged in the business of developing and acquiring power plants to be operated as wholesale "merchant" power plants selling power to wholesale customers for resale.

DEPS is the developer of the New Smyrna Beach Power Project. Pursuant to agreements with several experienced contractors, DEPS is arranging for the permitting of the Project, for the engineering, procurement, and construction of the Project, for the Project's fuel supply, and for other services necessary to bring the Project to commercial operation. The engineering, procurement,

Figure 2

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

OWNERSHIP STRUCTURE



and construction for the Project will be performed by Duke/Fluor Daniel, a joint venture of Duke Project Services, Inc. and FD Illinois, Inc.

Duke Energy Power Services has closed on the acquisition of three power plants in California, with total generating capacity of 2,645 MW. These power plants are now owned by three affiliated entities of DEPS. Duke Energy Morro Bay, L.L.C. owns and operates the Morro Bay Generating Station, a 1,002 gas-fired unit. Duke Energy Moss Landing, L.L.C. owns and operates the Moss Landing Generating Station, a 1,478 MW gas-fired unit. Duke Energy Oakland, L.L.C. owns and operates the Oakland Generating Station, a 165 MW diesel-fueled unit. These plants are operated as merchant plants, selling power predominantly into the California wholesale market.

DEPS is presently developing the Bridgeport Energy Project, a 520 MW (nominal) natural gas fired combined cycle power plant that will, as an EWG and FERC-regulated public utility, provide wholesale power to the United Illuminating Company, based in New Haven, Connecticut, and to other wholesale customers in New England. The Bridgeport Project is presently under construction: Phase I of the Project, 350 MW of combustion turbine capacity, is currently producing test power and is scheduled to achieve commercial operation in the fall of 1998. The complete combined cycle plant, including 170 MW of steam turbine generation, is expected to achieve commercial operation status in July 1999. Like the New Smyrna Beach Power Project, the Bridgeport Power Project

will be operated by a Duke subsidiary, Duke Bridgeport Energy, L.L.C., which is also the majority (95.9 percent) owner of the Bridgeport Project.

In conjunction with Associated Electric Cooperative, Inc. ("AECI"), Duke is developing a 250 MW gas-fired combined cycle power plant in Southeast Missouri. This power plant is expected to achieve commercial operation in mid-1999. DEPS is pursuing additional development opportunities in the United States.

E. Duke Energy Corporation

Duke Energy Corporation ("Duke Energy") was formed in 1997 by the merger of Duke Power Company and PanEnergy Corp. With more than 20,000 MW of power generation in operation and moving approximately 12 percent of all natural gas in interstate commerce in the United States, Duke Energy is the seventh largest energy company in the world. Other Duke Energy activities and operations include power generation development and operation, power plant engineering services, pipeline operations, and energy marketing.

Through Duke Power Company and Nantahala Power & Light Company, Duke Energy provides retail electric service to approximately two million customers in North Carolina and South Carolina.

F. The Participation Agreement Between the UCNSB and Duke New Smyrna

The Utilities Commission of New Smyrna Beach and Duke New Smyrna entered into a negotiated Participation Agreement earlier this year. The Agreement has been approved by Duke New Smyrna, by

the Utilities Commission of the City of New Smyrna Beach, and by the New Smyrna Beach City Commission.

The key features of the Participation Agreement are as follows.

1. The UCNSB will furnish the site for the New Smyrna Beach Project to Duke New Smyrna.

2. The UCNSB will also furnish an interconnection point for the New Smyrna Beach Project to the 115 kV bus at the UCNSB's Smyrna Substation.

3. The UCNSB will provide reuse water from its adjacent wastewater treatment plant (currently under construction) and will provide other water supply sufficient for the process and make-up water requirements of the Project. More than 50 percent of the water required for the Project will be supplied by reuse water from the adjacent UCNSB wastewater treatment plant which is currently under construction.

4. The UCNSB will design, engineer, and construct modifications of the UCNSB Smyrna Substation to accommodate the proposed plant.

5. Duke New Smyrna has granted to the UCNSB an "entitlement" to 30 MW of the Project's capacity and associated energy for the technical and economic life of the Project. Duke New Smyrna will provide the energy associated with the entitlement capacity at agreed-upon pricing. When the final power purchase agreement is negotiated and executed, Duke New Smyrna will, consistent with FERC regulations, file that agreement with the FERC.

6. Duke New Smyrna will design, engineer, construct, finance, own, and operate the Project, and will market all capacity, energy, and, subject to future FERC approval, ancillary services provided from the Project. Duke New Smyrna is also responsible for the provision of natural gas fuel to the Project.

III. DESCRIPTION OF THE NEW SMYRNA BEACH POWER PROJECT

This section of the Exhibits describes the New Smyrna Beach Power Project, including the Project's location, site arrangement, major systems and facilities, associated facilities, capital costs and financing, fuel supply, operational reliability, construction and permitting schedules, and operation and maintenance plan.

A. Site Location

The Project will be located in the northwest quadrant of the intersection of Interstate Highway 95 and Florida State Road 44, within the city limits of New Smyrna Beach in west central Volusia County. The site consists of approximately 30.4 acres immediately adjacent to the Smyrna Substation of the UCNSB and also adjacent to an advanced wastewater treatment plant currently being constructed by the UCNSB. A 115 kV transmission line owned and operated by Florida Power & Light Company runs through the site approximately parallel to I-95. Another 115 kV transmission line owned by Florida Power Corporation originates at the Smyrna Substation and runs northward from the substation in the same corridor as the FPL line before turning west to FPC's Cassadaga substation. A map of the site location is included here as Figure 3.

B. Site Arrangement

The general arrangement of the power plant and substation on the Project site is shown in Figure 4. A detailed drawing of the layout of the actual generators, cooling towers, water processing and storage facilities, substation facilities, and stormwater

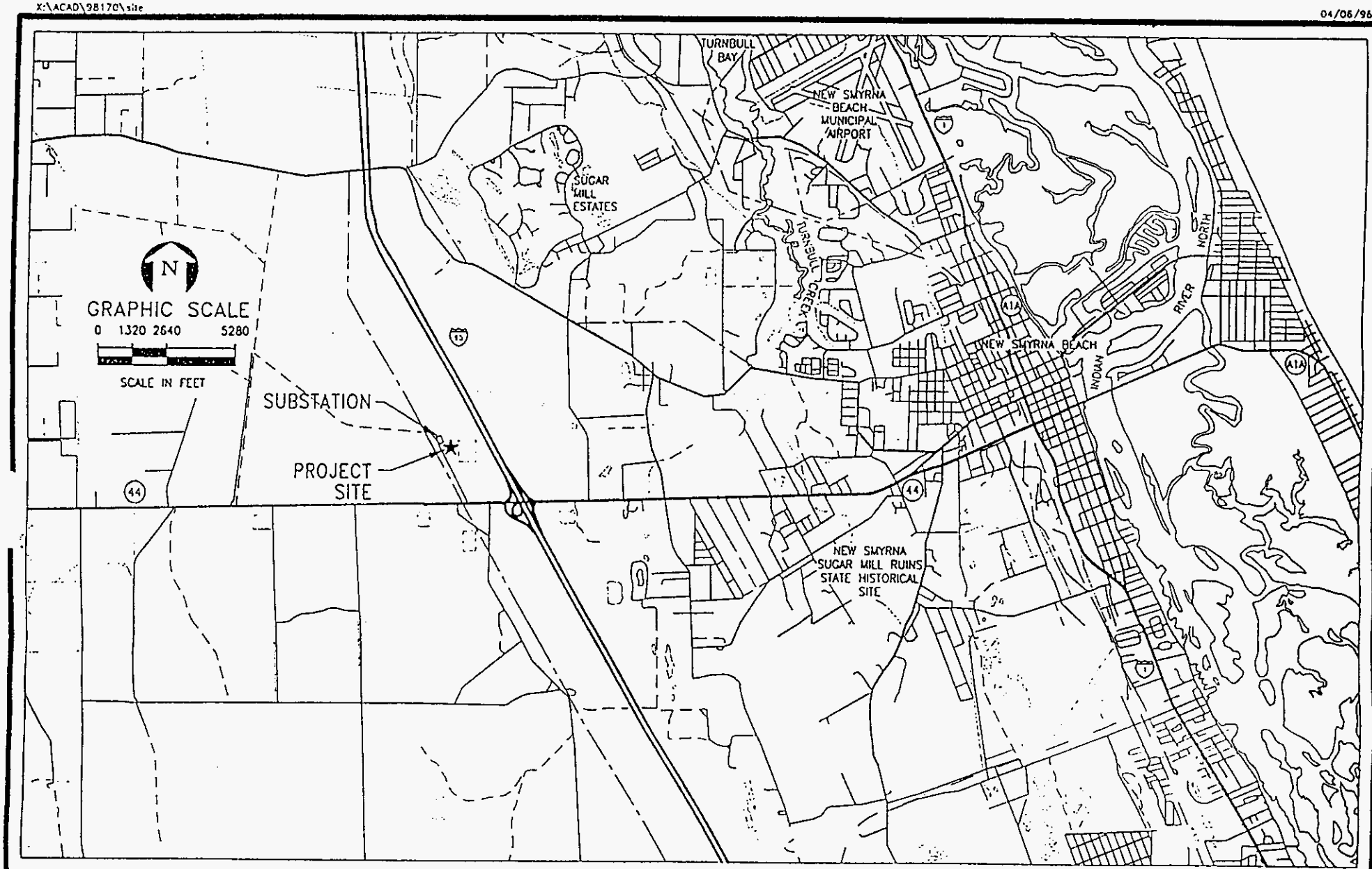
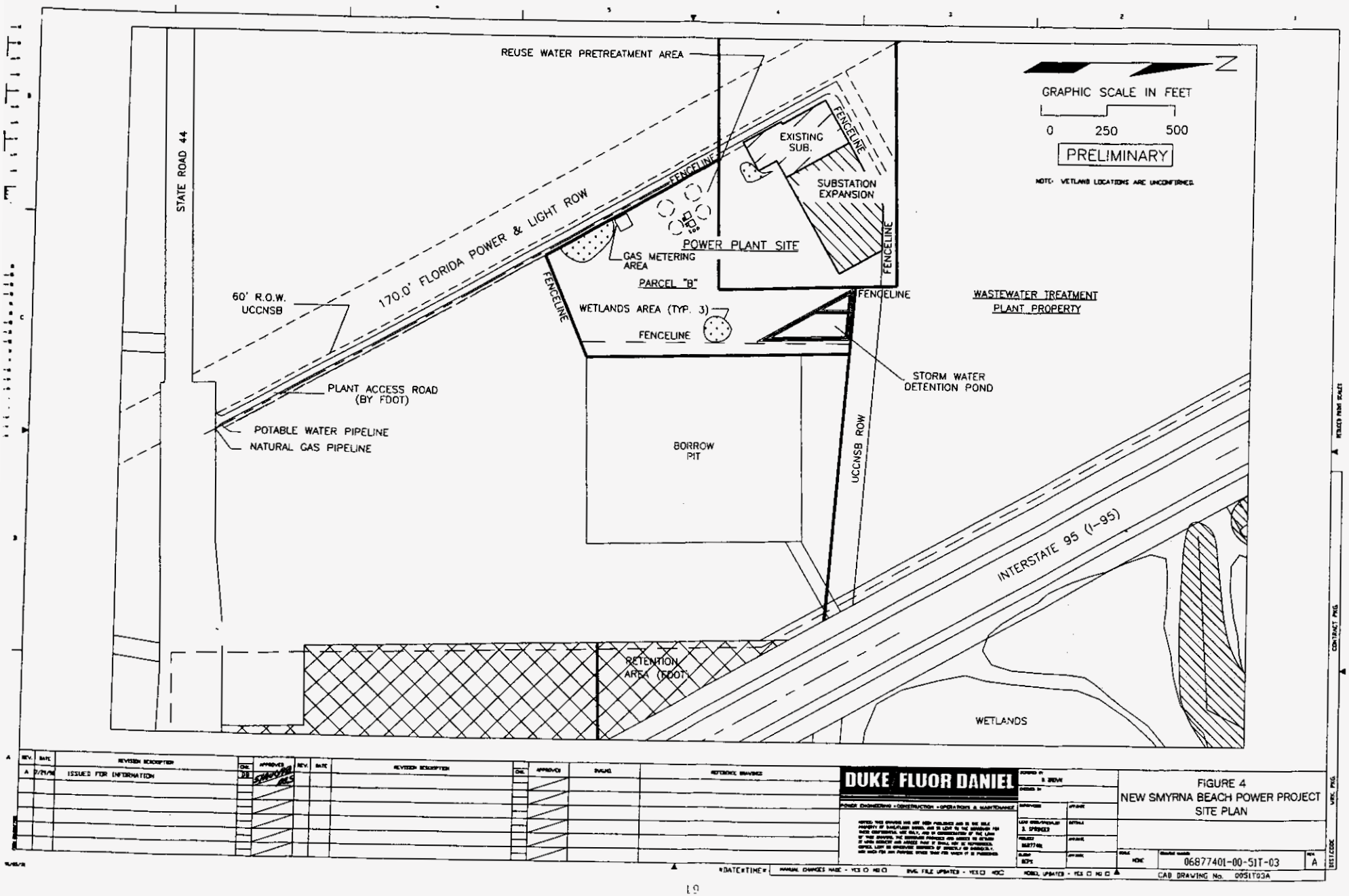


FIGURE 3
NEW SMYRNA BEACH POWER PROJECT
SITE LOCATION RELATIVE TO LOCAL LANDMARKS

Source: USGS Quads: New Smyrna Beach, FL, 1993; Edgewater, FL, 1970; Samsula, FL, 1993; Lake Ashby, FL, 1988.

ECT
Environmental Consulting & Technology, Inc.



REV.	DATE	REVISION DESCRIPTION	CHK	APPROVED
A	7/21/98	ISSUED FOR INFORMATION	DB	SMYRNA

DUKE FLUOR DANIEL

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FIGURE 4
NEW SMYRNA BEACH POWER PROJECT
SITE PLAN

SCALE: NONE | 06877401-00-51T-03 | REV. A

CAD DRAWING No. 005IT03A

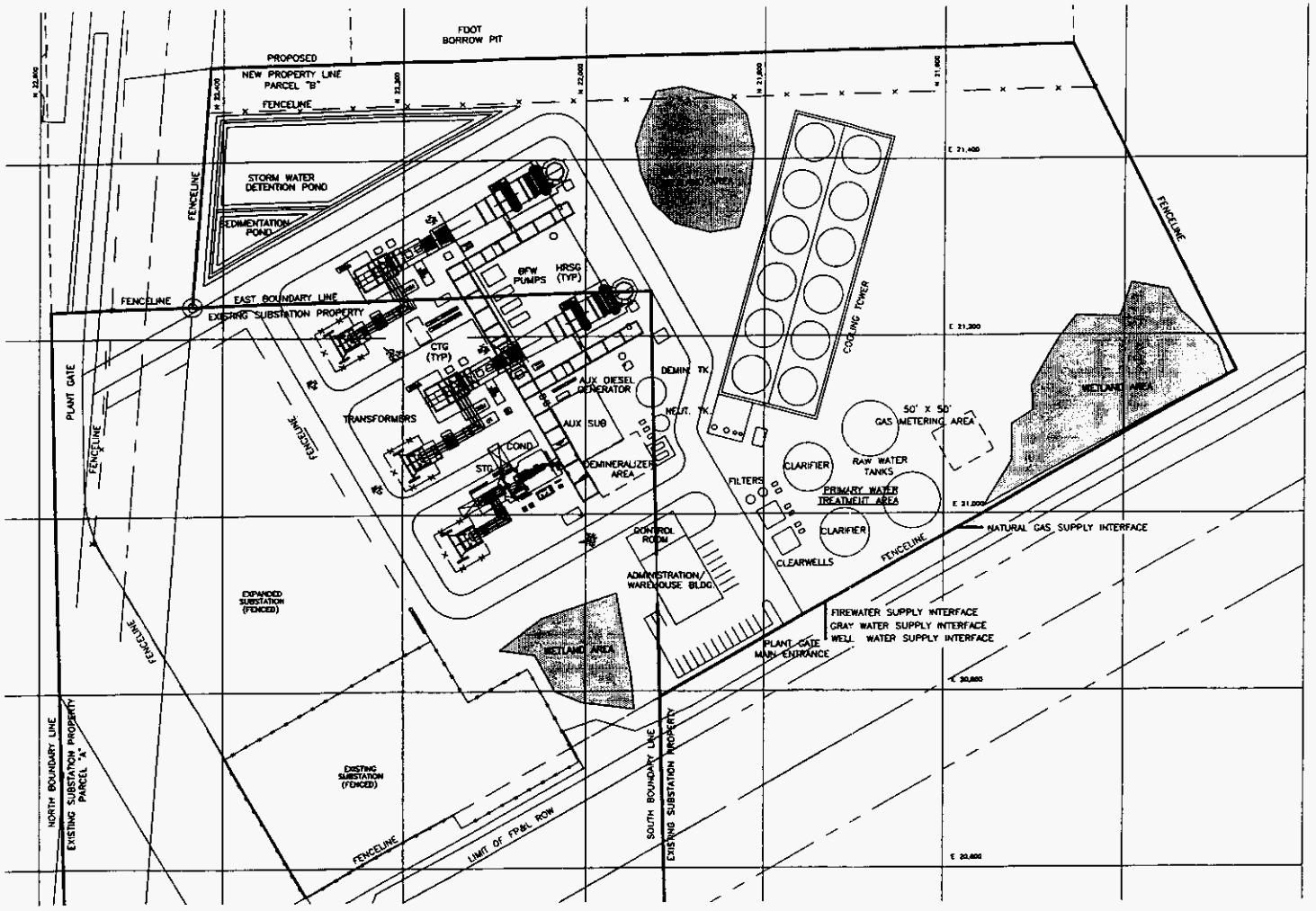
retention ponds, is shown in Figure 5, the plot plan for the Project. Graphic renditions of the power plant and major structures are depicted in Figures 6 and 7.

C. Description of Major Systems and Facilities

The Project will have 514 MW of capacity at ISO temperature and humidity conditions; the Project is rated at 476 MW for summer operation and 548 MW for winter operation. The power block will consist of two advanced technology combustion turbines (General Electric Frame 7FA or equivalent), two matched heat recovery steam generators, and one steam turbine generator. Process and makeup water will be supplied by reuse water from the adjacent UCNSB wastewater treatment plant (initially approximately 2.0 million gallons per day) and from on-site or off-site wells (initially at an annual average rate of approximately 1.8 million gallons per day). Wastewater will be returned to the UCNSB's wastewater treatment plant for treatment and reuse. Preliminary water balances are shown in Figures 9 and 10.

The Project is expected to have an equivalent availability factor of 96 percent, and a capacity factor ranging from approximately 83 percent in 2002 to 94 percent or more by 2012. The Project's direct construction cost is projected to be approximately $160 million, or approximately $311 per kW of nominal capacity. The Project will utilize low-NOx combustors and will have very low gaseous emissions and no heavy metals emissions.

These and additional data are presented in Table 1, Project Profile. More detailed plant performance and emissions data are



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B	2/98	ADDED GATE, PIPING INTERFACES	DB	
C	2/98	ISSUED FOR INFORMATION ONLY	DB	
D	2/98	ISSUED FOR SITE BORING & RESIST. TESTS	DB	
E	4/98	ISSUED FOR NEW ORIENTATION AND SUBSTATION	DB	
F	4/98	INDICATED SOIL BORINGS LOCATIONS FOR TANKS	DB	
G	5/98	ISSUED FOR GEOTECH INVESTIGATION	DB	DS
H	6/98	REV. BORING "7", ROADS, PARKING, POND	DB	DS
J	6/98	ADDED AUX. DIESEL GENERATOR	DB	DS
K	7/98	ADDED PARCEL B & GEN. REVISION	DB	DS
L	8/98	ADDED WETLANDS & REV. METERING AREA	DB	DS
M	9/17/98	REV. WETLANDS, EQUIP. LOCATIONS	DB	DS

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DRAWN BY: C. BROWN
DESIGNED BY: DCS 1/6/98
LEAD DISCIPLINE: GEPS
SCALE: 1" = 80'
DRAWING No.: 06877401-00-51T-01
REV.: M
CAD DRAWING No.: 0051T01m.DWG

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FIGURE 5
NEW SMYRNA BEACH POWER PROJECT
PROPOSED PLOT PLAN

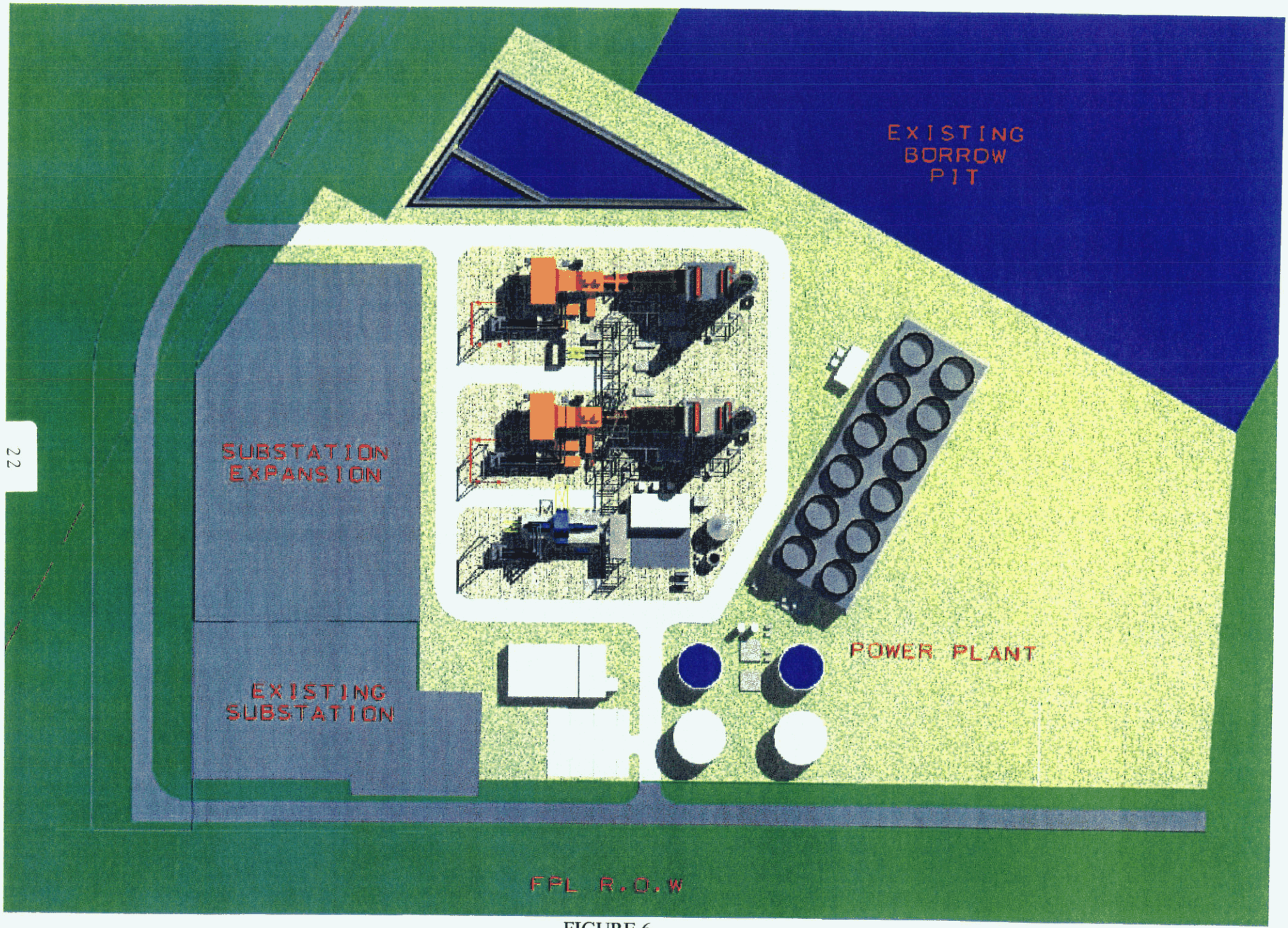


FIGURE 6
NEW SMYRNA BEACH POWER PROJECT
OVERHEAD RENDITION

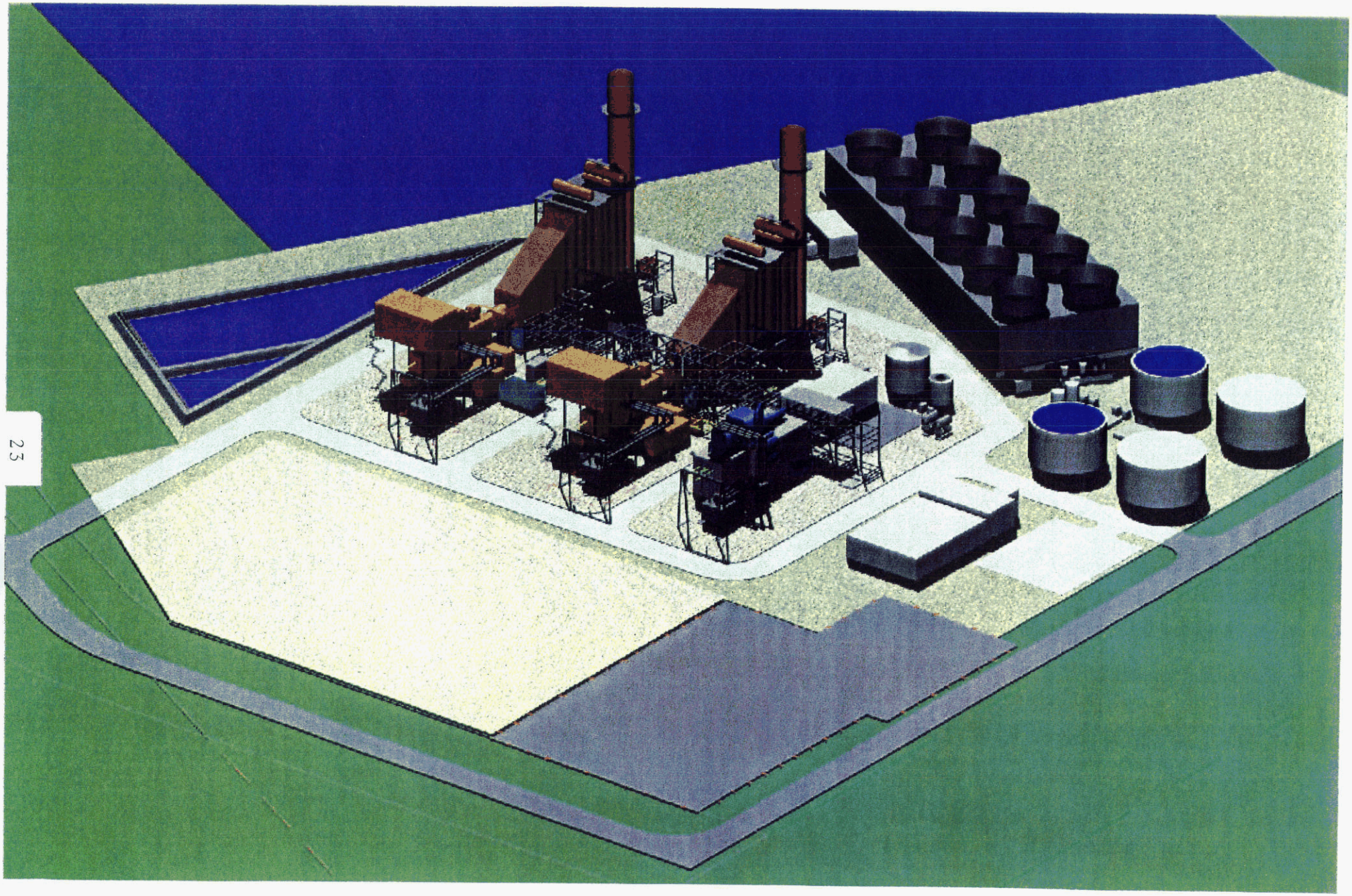
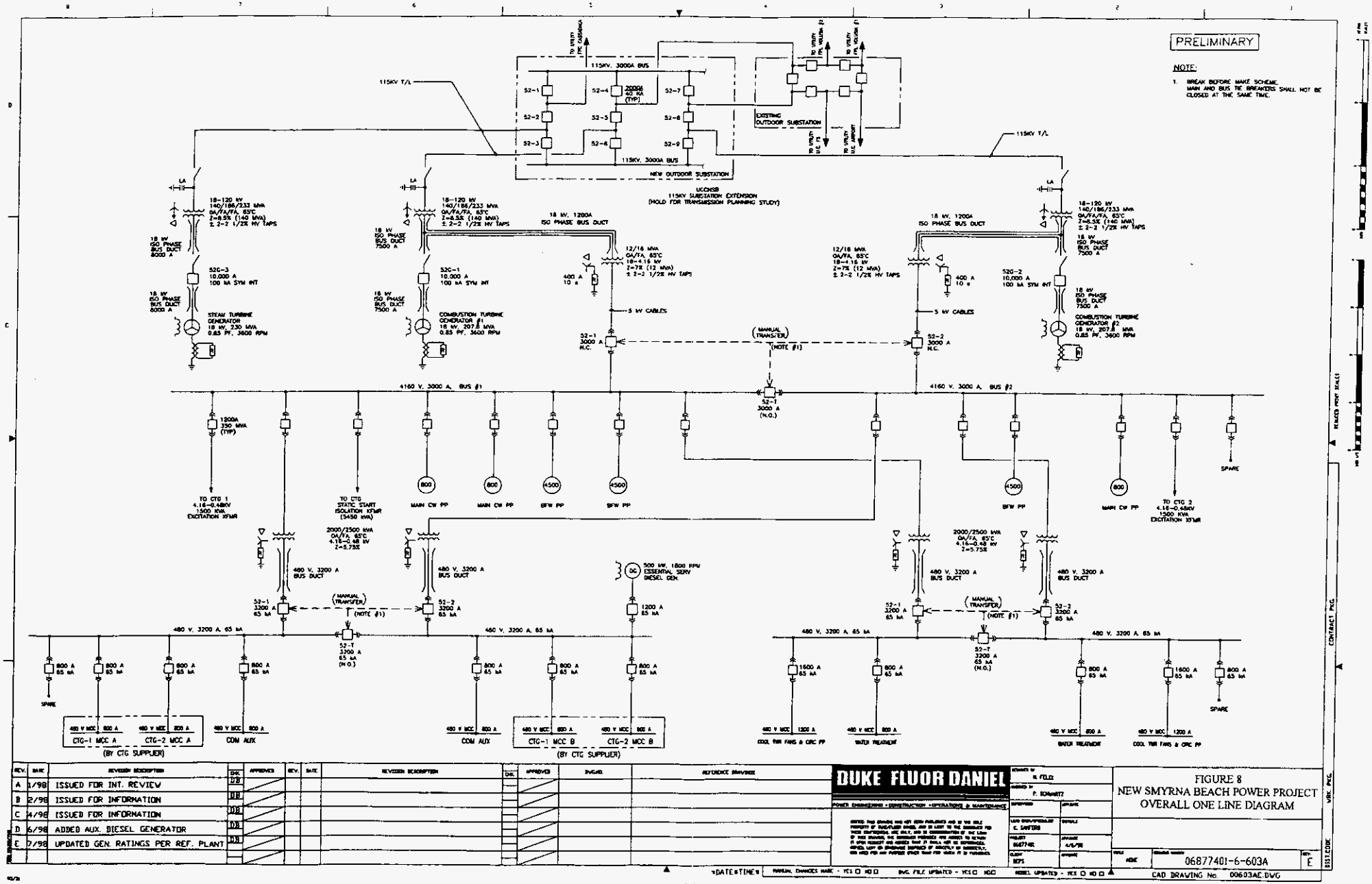


FIGURE 7
NEW SMYRNA BEACH POWER PROJECT
PERSPECTIVE RENDITION



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B	2/98	ISSUED FOR INFORMATION	DB	
C	4/98	ISSUED FOR INFORMATION	DB	
D	6/98	ADDED AUX. DIESEL GENERATOR	DB	
E	7/98	UPDATED GEN. RATINGS PER REF. PLANT	DB	

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FIGURE 8
NEW SMYRNA BEACH POWER PROJECT
OVERALL ONE LINE DIAGRAM

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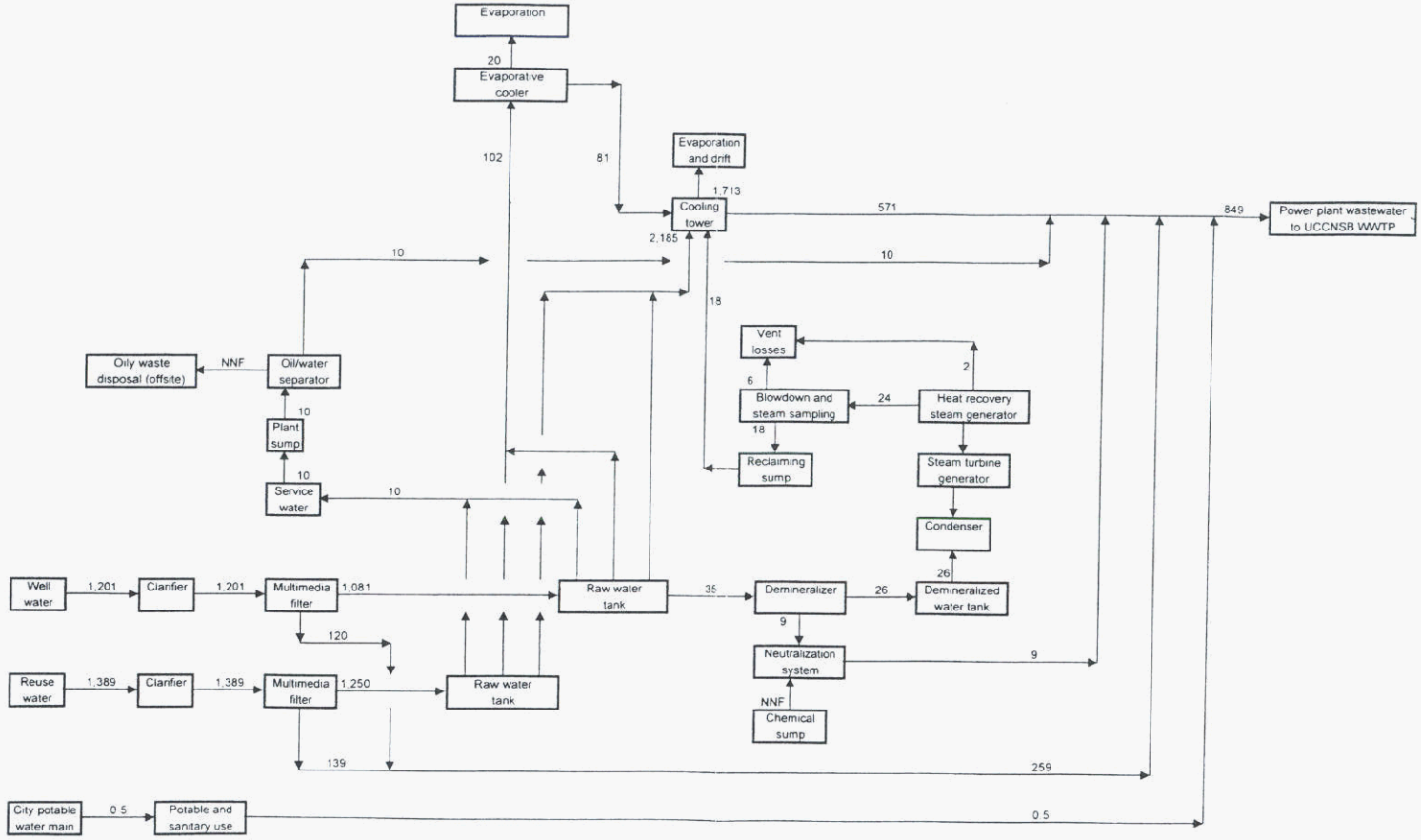
CAD DRAWING No. 00603AE.DWG

FIGURE 9

Duke Energy Power Services
New Smyrna Beach Power Project
New Smyrna Beach, Florida

Preliminary Water Balance
ISO Temperature & Relative Humidity
100% CTG Load, 59°F, 60% Relative Humidity
Reuse Water Flow = 2.0 MGD

Duke/Fluor Daniel
Contract 06-605102
August 5, 1998



NOTES:
1) Flows are in gpm.
2) Cooling tower blowdown is based on four cycles of concentration.
3) NNF - normally no flow.

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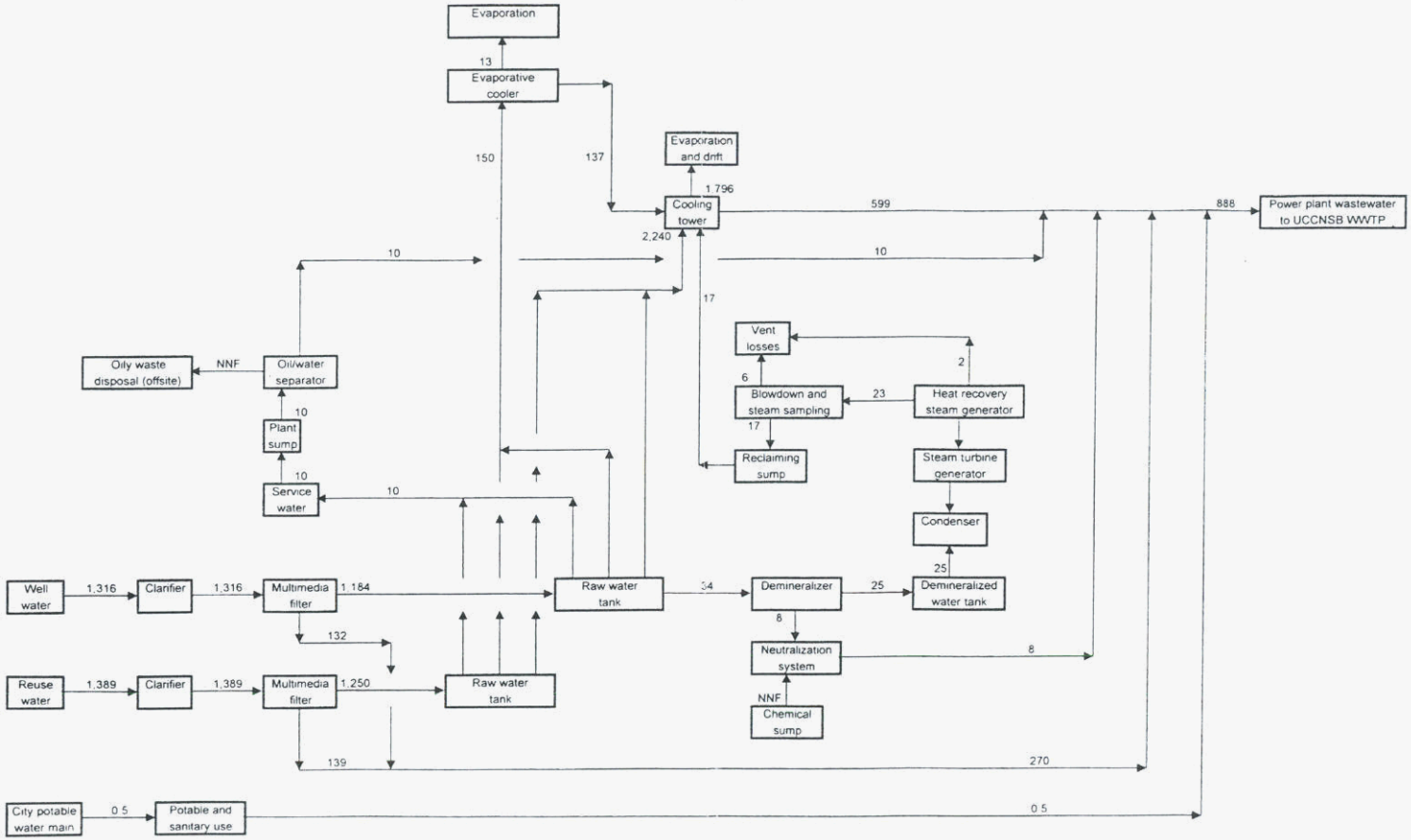
FIGURE 10

Duke Energy Power Services
New Smyrna Beach Power Project
New Smyrna Beach, Florida

Preliminary Water Balance
Max Annual 24 Hour
100% CTG Load, 73°F, 78% Relative Humidity
Reuse Water Flow = 2.0 MGD

Duke/Fluor Daniel
Contract 06-605102
August 6, 1998



NOTES
1) Flows are in gpm
2) Cooling tower blowdown is based on four cycles of concentration
3) NNF - normally no flow

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TABLE 1

NEW SMYRNA BEACH POWER PROJECT
PROJECT PROFILE

Expected Plant Capacity:

a.	Nominal rating:	500 MW
b.	Annual average (71F°, 78%RH):	496 MW
c.	Summer (84F°, 80%RH):	476 MW
d.	Winter (15F°, 78%RH):	548 MW
e.	ISO Temperature and Humidity (59F°, 60%RH):	514 MW

Project Energy Production: Approximately 4,000,000 MWH/year

Technology Type: Two Advanced Firing Temperature Technology Combustion Turbines, Two Heat Recovery Steam Generators, and One Steam Turbine Generator in Combined Cycle Configuration

Anticipated Construction Schedule:

a.	Project release date:	December 1999
b.	Construction mobilization date:	May 2000
c.	Commercial in-service date	October 2001

Fuel Type

a.	Primary Fuel	Natural Gas
b.	Alternate Fuel	None

Fuel Use: Approximately 85 Million Standard Cubic Feet of Natural Gas/day, annual average (71F, 78%RH), full load

Air Pollution Control Strategy: Low NOx Burners

Cooling Method: Cooling Tower

Total Site Area: 30.5 acres (approximate)

Construction Status: Planned

Certification Status: Need Determination application filed, anticipate filing Site Certification application Fall 1998

Status with Federal Agencies: EWG Status certified by FERC; market-based rates approved by FERC; federal environmental permit applications under preparation

TABLE 1

NEW SMYRNA BEACH POWER PROJECT
PROJECT PROFILE
(CONTINUED)

Projected Unit Performance Data:	
Planned Outage Factor (POF):	3 %
Forced Outage Factor (FOF):	1 %
Equivalent Availability Factor (EAF):	96 %
Resulting Capacity Factor(%):	75-92 % (first 10 years)
Average Net Operating Heat Rate (ANHOR):	6,832 Btu/kWh (HHV) (59F°, 60%RH)expected
Projected Unit Financial Data (per Duke Energy):	
Book Life (years):	30 years
Direct Construction Cost (Actual):	$160 Million
AFUDC Amount:	Not applicable
Escalation ($/kW):	Not applicable
Fixed O&M ($/kW per year):	Proprietary
Variable O&M ($/MWH):	Proprietary
K-Factor:	Not applicable
Project Life:	30 years
Expected Plant Air Emissions:	NOx: 12 ppmvd @15% O_2 CO: 9 ppmvd PM: 18 lbs./hour SO_2: 20 lbs./hour Uncombusted Hydrocarbons: 7 ppmvw
Transmission Lines Required:	Approx. 150 feet of 115 kV conductor from step-up transformer to bus at Smyrna Substation
Gas Pipeline Required: (per Duke Energy)	Approx. 42 miles of 16-inch (tentative size) lateral pipeline
Water Requirements:	Approx. 3.9 MGD, annual average (71F°, 78%RH), at full load
Wastewater Discharge:	Zero offsite discharge: wastewater returned to UCNSB treatment plant for reuse

shown in Table 2 of the Exhibits. An overall process flow diagram is presented in Figure 11.

D. Transmission Facilities

The Project will be electrically interconnected to the Peninsular Florida transmission system at the Smyrna Substation, providing connections to both FPL's and FPC's transmission systems. The direct interconnection will be accomplished by 18 kV-to-115 kV step-up transformers (one for each generation source), short lengths (approximately 150 feet) of appropriately sized 115 kV conductor, and appropriate switchgear. These facilities are illustrated, schematically, on the electrical one line diagram included here as Figure 8.

To facilitate and support power deliveries from the Project to other Peninsular Florida utilities located south of the Project, a second circuit is planned to be added to the 18-mile 115 kV Smyrna-Cassadaga transmission line, and a new 7.5-mile 115 kV circuit is planned to connect the Cassadaga substation to the Lake Helen substation. These transmission circuits are depicted in the transmission system map in Figure 12.

E. Associated Facilities

Natural gas will be provided to the Project via a 42-mile long, 16-inch lateral pipeline that will originate at FGT's main pipeline near Mt. Plymouth, in Lake County, Florida, and run through Lake, Seminole, and Volusia Counties to the Project. The permits for the lateral gas pipeline will be obtained by FGT. The

TABLE 2

Estimated Plant Performance and Emissions Data
2 x 1 Combined Cycle Plant
Two General Electric Model PG7241(FA) Combustion Turbine Generators
Two Unfired Heat Recovery Steam Generators
One Reheat Condensing Steam Turbine Generator

Combustion turbine load	100%	100%	100%	100%	75%	75%	75%	75%	50%	50%	50%	50%
Ambient temperature (°F)	84	71	59	15	84	71	59	15	84	71	59	15
Relative humidity	80%	78%	60%	78%	80%	78%	60%	78%	80%	78%	60%	78%
Net plant power output (kW)	476,273	496,303	514,328	548,041	384,705	400,592	415,310	438,015	283,468	295,527	309,021	324,276
Net CTG power output (kW)	303,827	318,037	333,072	364,908	229,772	240,897	252,040	273,783	153,365	160,680	167,862	182,095
Net STG power output (kW)	172,446	178,266	181,256	183,133	154,933	159,695	163,270	164,232	130,103	134,847	141,159	142,181
Net plant heat rate, LHV basis (btu/kWh)	6,265	6,217	6,211	6,263	6,532	6,446	6,439	6,417	7,017	6,896	6,907	6,852
Net plant heat rate, HHV basis (btu/kWh)	6,892	6,839	6,832	6,889	7,185	7,091	7,083	7,059	7,719	7,586	7,598	7,537
Net CTG heat rate, LHV basis (btu/kWh)	9,820	9,701	9,591	9,406	10,937	10,719	10,610	10,266	12,970	12,684	12,715	12,203
Net CTG heat rate, HHV basis (btu/kWh)	10,802	10,671	10,550	10,347	12,031	11,791	11,671	11,293	14,267	13,952	13,987	13,423
CTG fuel flow rate (lb/h) - total for two CTGs	138,662	143,389	148,458	159,514	116,789	120,007	124,272	130,627	92,442	94,717	99,192	103,266
CTG heat input, LHV basis (mmbtu/h) - total for two CTGs	2,984	3,085	3,194	3,432	2,513	2,582	2,674	2,811	1,989	2,038	2,134	2,222
CTG exhaust gas flow (lb/h) - total for two CTGs	6,690,340	6,916,800	7,139,660	7,622,280	5,654,260	5,758,760	5,948,460	6,051,540	4,761,600	4,819,320	5,023,200	5,043,300
CTG exhaust gas composition (by volume)												
- Nitrogen + argon	73.64%	74.50%	75.17%	75.93%	73.65%	74.49%	75.16%	75.83%	73.80%	74.65%	75.31%	75.99%
- Oxygen	12.25%	12.45%	12.58%	12.70%	12.27%	12.40%	12.54%	12.45%	12.75%	12.86%	12.98%	12.88%
- Carbon dioxide	3.66%	3.68%	3.70%	3.74%	3.65%	3.70%	3.72%	3.86%	3.44%	3.49%	3.52%	3.66%
- Water	10.45%	9.37%	8.55%	7.63%	10.43%	9.41%	8.58%	7.86%	10.01%	9.00%	8.19%	7.47%
NOx as NO2 (lb/h) - 12 ppmvd @15% O2 - total for two stacks	144	149	154	166	121	125	129	135	95.8	98.2	103	107
CO (lb/h) - 9 ppmvd - total for two stacks	53.6	55.9	58.0	62.3	45.3	46.5	48.3	49.4	38.3	39.1	41.0	41.3
UHC as CH4 (lb/h) - 7 ppmvd - total for two stacks	26.6	27.4	28.2	30.0	22.5	22.8	23.5	23.8	18.9	19.1	19.8	19.8
VOC as CH4 (lb/h) - 1.4 ppmvd - total for two stacks	5.32	5.48	5.64	6.00	4.50	4.56	4.70	4.76	3.78	3.82	3.96	3.97
SOx as SO2 (lb/h) - total for two stacks	18.8	19.4	20.1	21.6	15.8	16.3	16.8	17.7	12.5	12.8	13.4	14.0
Particulates (lb/h) - total for two stacks	18	18	18	18	18	18	18	18	18	18	18	18
Stack velocity (ft/s) - based on a 19 ft. diameter stack	55.5	56.9	58.2	61.8	46.0	46.3	47.5	47.8	38.1	38.1	39.3	39.1
Stack temperature (°F)	193	190	187	185	181	176	173	168	171	166	161	157

NOTES:
1) SOx emissions are based on firing pipeline quality natural gas with a maximum sulfur content of 2 grains/100 scf.

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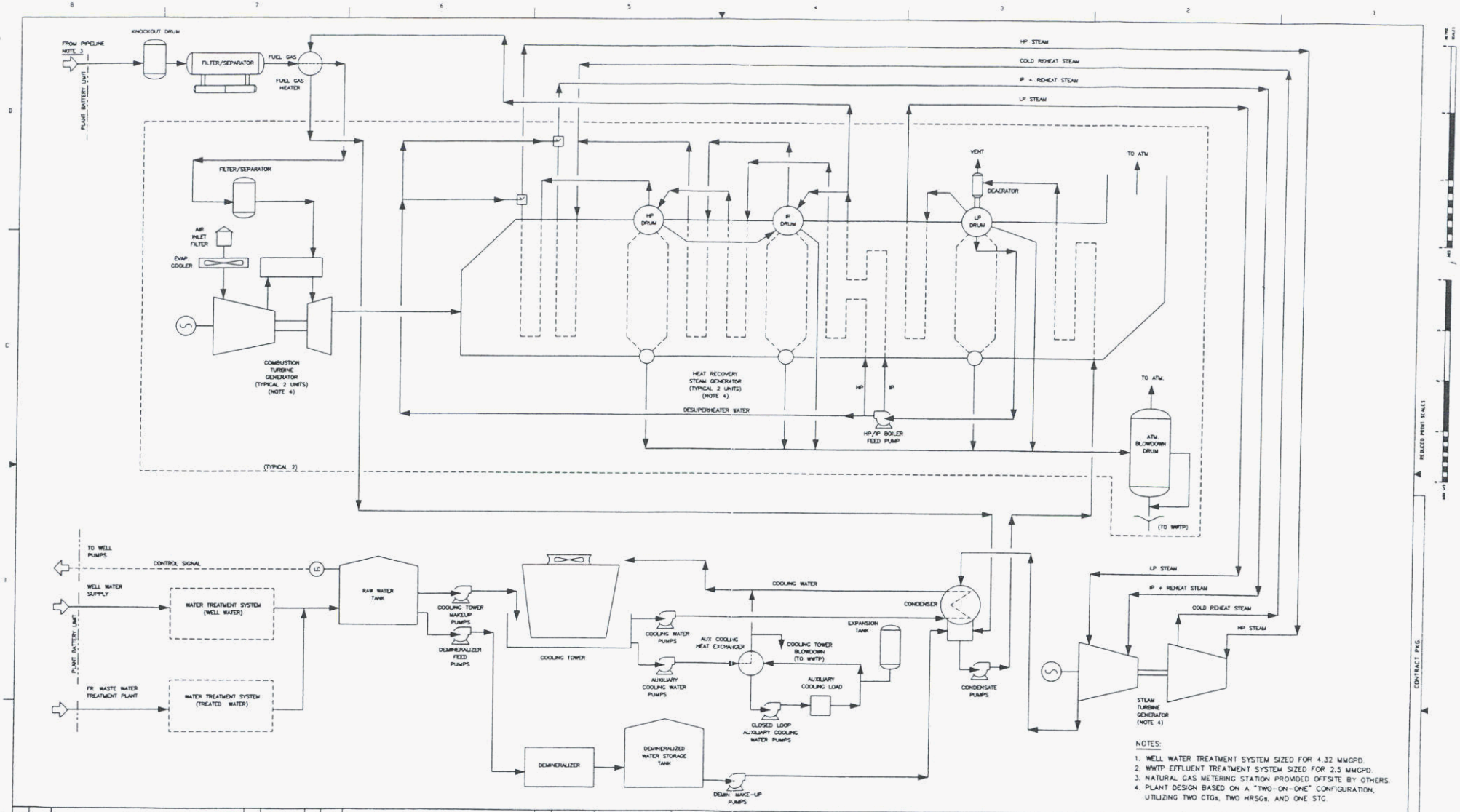

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D	2/98	ISSUED FOR INFORMATION ONLY	DB	
E	2/98	ISSUED FOR INFORMATION ONLY	DB	
F	4/98	REVISED WATER TREATMENT, NOTE 4	DB	

DUKE/FLUOR DANIEL

POWER ENGINEERING + CONSTRUCTION + OPERATIONS @ MAINTENANCE

DESIGNED BY: I. BROWN
CHECKED BY:
SUPERVISOR: BCS — APP. DATE: 04/06/98
LEAD DISC./SPECIALIST: — DETAILS:
PROJECT: 06877401 — APP. DATE:
GROUP: BDPS — APP. DATE:

FIGURE 11
NEW SMYRNA BEACH POWER PROJECT
PROCESS FLOW DIAGRAM

SCALE: NONE
DRAWING NUMBER: 06877401-PFD-001
REV: F
CAD DRAWING No. PFD-001F

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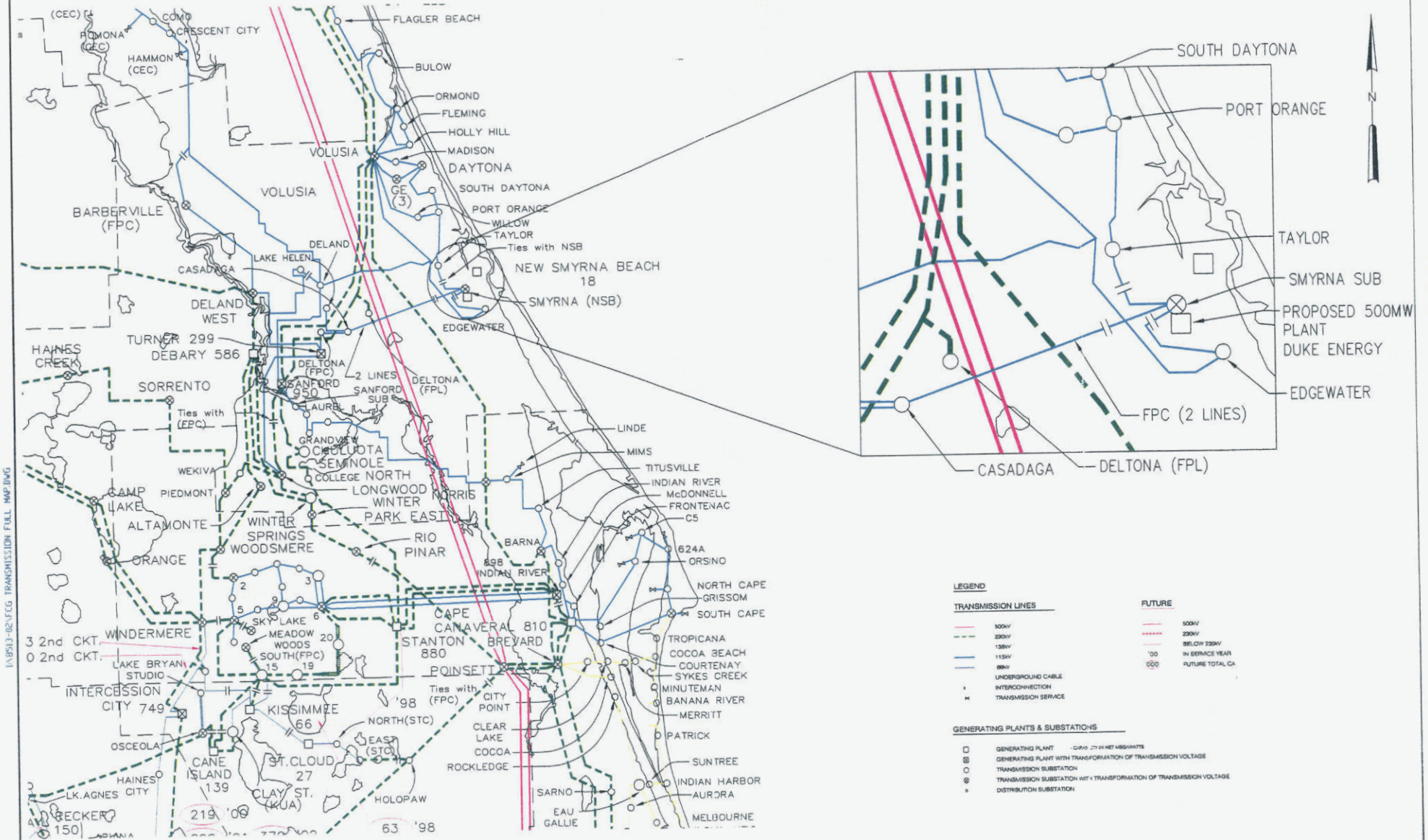


DESIGNED LARRY JAMES
DRAWN —
CHECKED —
PROJ. ENGR. —

FRANK ALONSO P.E. 38091
DATE

RMI
RESOURCE MANAGEMENT INTERNATIONAL, INC.

SCALE NONE
CAD REF. FCG TRANSMISSION FULL MAP
PROJ. NO. 8513.02

DUKE ENERGY POWER SERVICES

FIGURE 12
NEW SMYRNA BEACH POWER PROJECT
TRANSMISSION INTERCONNECTION

DATE: AUGUST 1998
SHEET: — OF —
DRAWING: F-1

route of the planned lateral pipeline is shown on Figure 13.

F. Capital Cost of the New Smyrna Beach Power Project

The projected direct construction cost of the New Smyrna Beach Power Project is $160 million, including the direct transmission interconnection facilities (step-up transformer, switchgear, and conductor to the bus at the Smyrna Substation), but not including the cost of the lateral gas pipeline. (The pipeline will be installed by FGT at its expense.)

G. Financing of the Project

At this time, Duke New Smyrna anticipates that the Project will be constructed and brought into commercial service with internal funds. While Duke New Smyrna may ultimately refinance part of its investment in the Project with debt instruments, there are no plans to do so at this time.

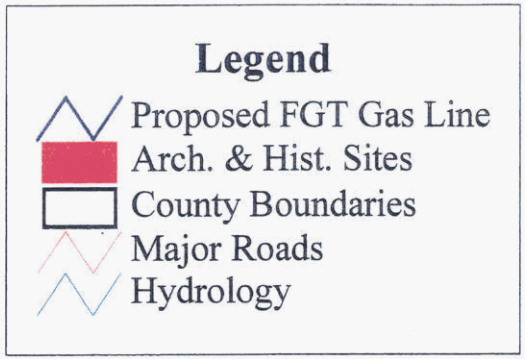
H. Fuel Supply

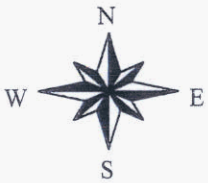
The Project will be fueled by natural gas. Gas will be delivered to the Project by a 42-mile, 16-inch lateral pipeline that will originate at FGT's main pipeline near Mt. Plymouth, Florida. The gas will be supplied by Citrus Trading Corp., an affiliate of FGT and Enron Corp., pursuant to a long-term contract for delivered firm gas supply.

The initial term of the DEPS-Citrus firm gas supply contract is 20 years. After the initial 20-year term, the gas supply contract is renewable from year to year. If the contract is terminated, Duke Energy Power Services, Duke New Smyrna's agent for

Figure 13

Proposed Route Map for 16-Inch
New Smyrna Beach Lateral Gas Pipeline
Florida Gas Transmission Company





Data Source: Bureau of Archaeological Research
Projection: Albers, NAD 1927, FL East, meters
July 23, 1998

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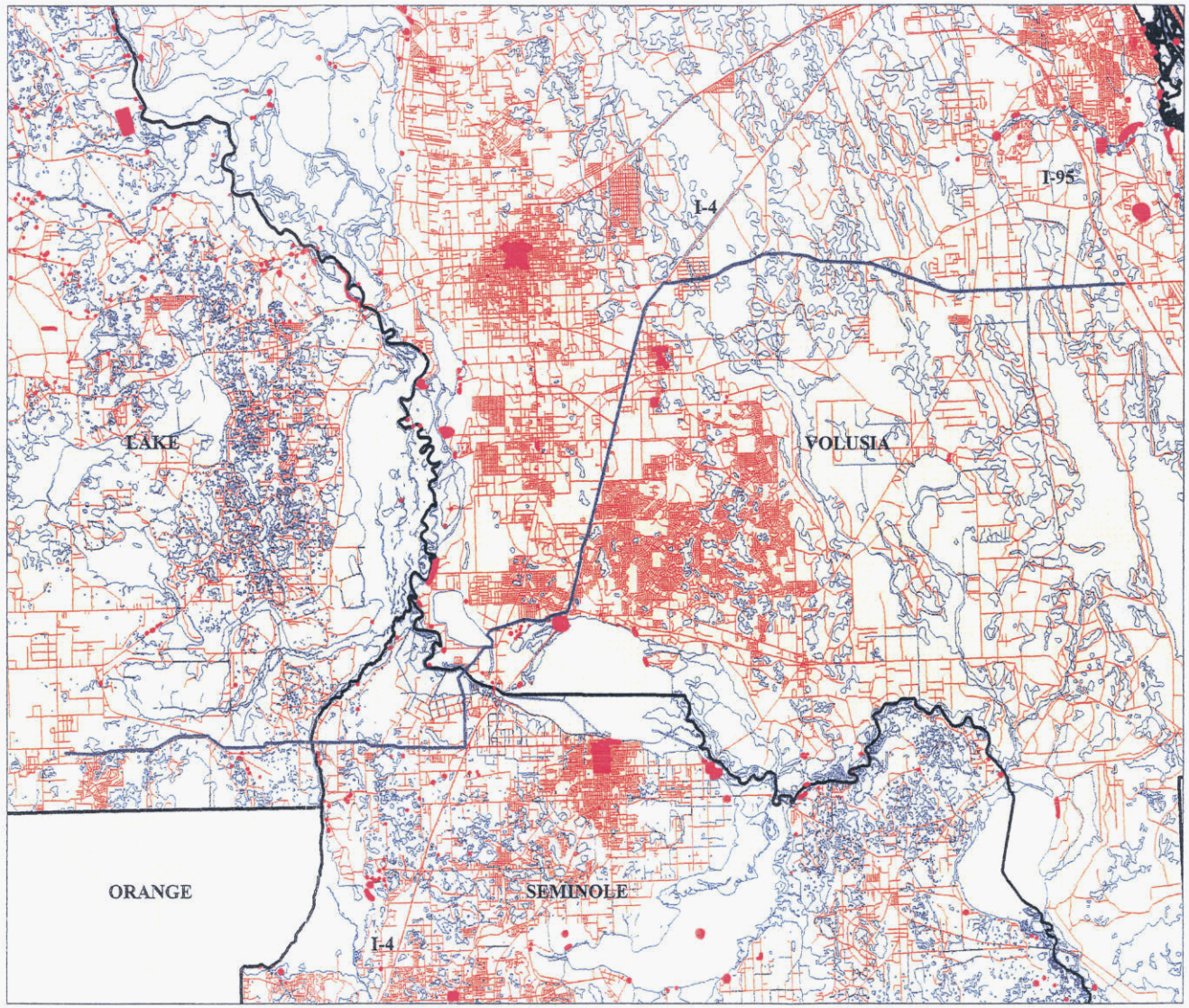


NATURAL SYSTEMS ANALYSIS, INC.
Mapping
Geographic Information Systems
Environmental Consulting

purposes of the gas contract, has the right to acquire Citrus's gas transportation capacity on FGT's system.

I. Projected Operational Reliability

The combined cycle generating unit is projected to have high efficiency and availability. With a heat rate of 6,832 Btu per kWh (based on the Higher Heating Value of natural gas), the net thermal efficiency is expected to be approximately 50 percent. Based on its heat rate of 6,211 Btu/kWh with the Lower Heating Value of natural gas, the Project's efficiency is 55 percent. The Project is expected to have an Equivalent Availability Factor of 96 percent, a Forced Outage Rate of 1 percent and a Planned Outage Rate of 3 percent. The Project is expected to operate at Capacity Factors ranging from approximately 83 percent in 2002, its first full year of operation, to approximately 94 percent in 2012. Basic operational reliability information for the Project is shown on the Project Profile included here as Table 1. Projected operation levels are shown on Table 10.

J. Project Schedule

The preliminary site evaluation is complete, and detailed site analyses -- geotechnical and hydrogeological evaluations -- are in progress. Preliminary engineering is scheduled to begin in April 1999, and detailed design and engineering are scheduled to begin in October 1999. Full release of the long-lead-time components -- the combustion turbines, heat recovery steam generators, and steam turbine generator -- is projected to be issued, and construction is

expected to begin, immediately following issuance of the site certification in late 1999. The Project is scheduled to achieve commercial in-service status in the fall of 2001. The Project engineering and construction schedule is depicted in Figure 14.

K. Regulatory and Permitting Schedules

This need determination application was filed on August 19, 1998, and the need determination hearing is expected to be held in November 1998. The Commission's order is expected by the end of January 1999. The Site Certification Application for the Project will be filed in late September or early October 1998. The land use hearing is expected to be held by May 1999, and the site certification hearing is expected to be held by July 1999. Final certification by the Siting Board is expected by December 1999. Detail of the permitting schedule is shown in Figure 15, and a detailed listing of all federal, state, regional, and local permitting requirements is shown in Table 3.

L. Operations and Maintenance

The New Smyrna Beach Power Project will be operated by Duke/Fluor Daniel's operations and maintenance group.

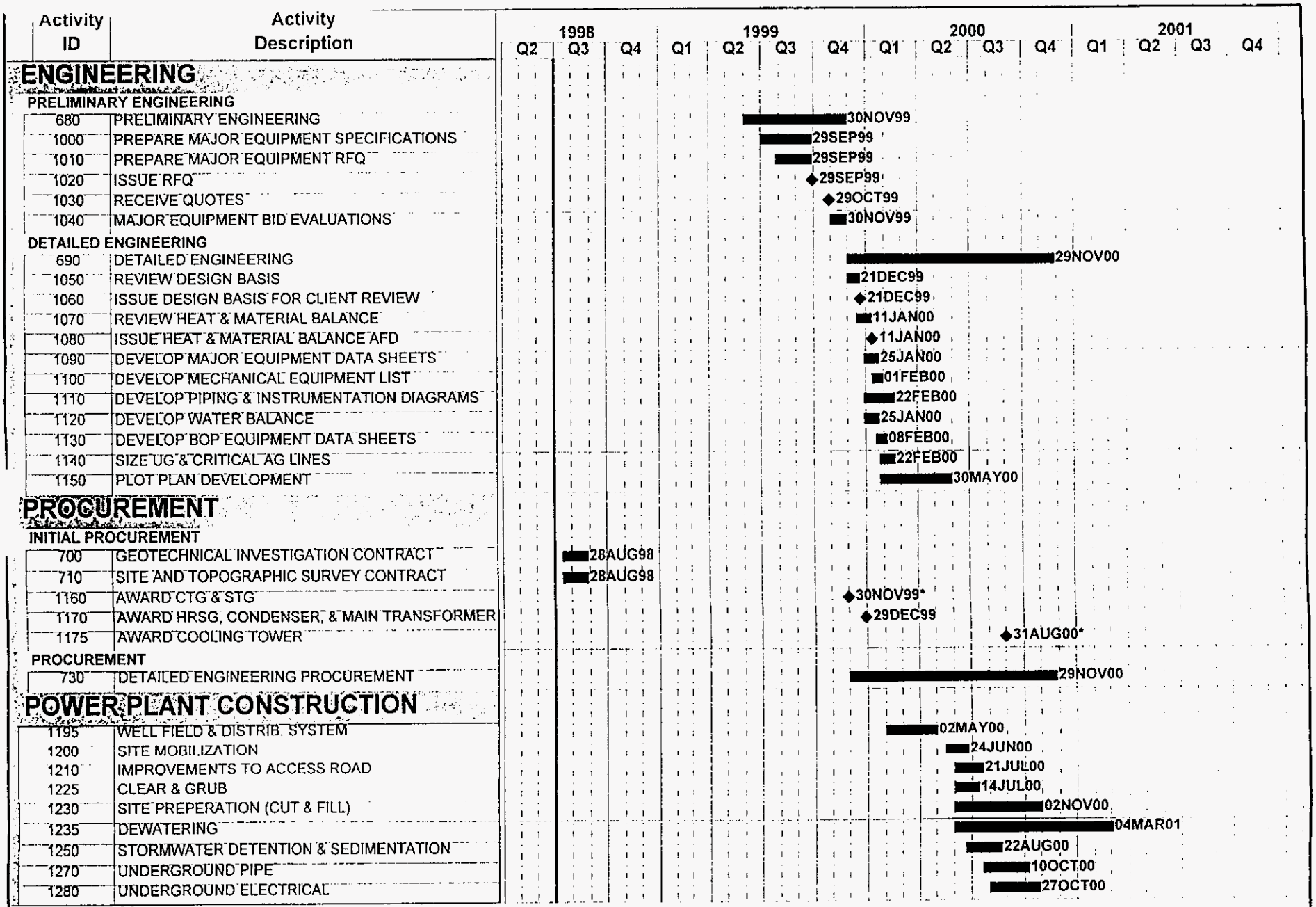
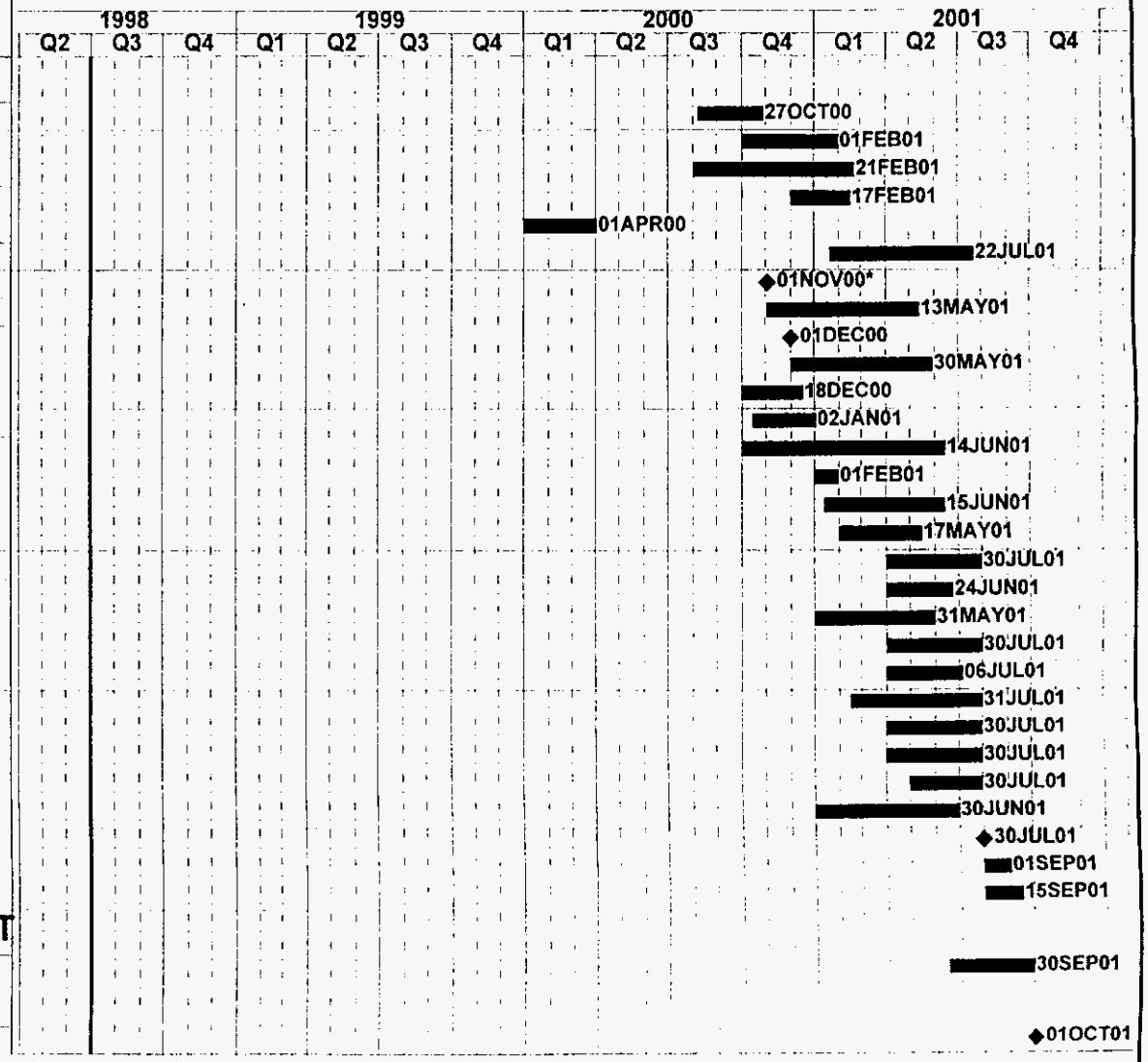


FIGURE 14
NEW SMYRNA BEACH POWER PROJECT
PROJECT SCHEDULE

Activity ID	Activity Description
POWER PLANT CONSTRUCTION	
1300	PILING
1310	ADMIN/WAREHOUSE & CONTROL ROOM
1320	CONCRETE
1330	PIPERACK ERECTION
1335	REUSE WATER SYSTEM TO PLANT
1340	BOP MECHNICAL
1370	CTG 1 DELIVERY
1380	CTG 1 INSTALLATION
1400	CTG 2 DELIVERY
1410	CTG 2 INSTALLATION
1420	HRSG 1 DELIVERY
1430	HRSG 2 DELIVERY
1440	HRSG INSTALLATION (1 & 2)
1442	STG DELIVERY
1444	STG INSTALLATION
1450	COOLING TOWER BASIN
1460	COOLING TOWER ERECTION
1480	ERECT TANKS & CLARIFIERS
1482	SUBSTATION
1484	115 KV XMISSION LN. DBL. CIRCUITING
1486	TRANSFORMER INSTALLATION
1488	BOP ELECTRICAL
1490	CEMS
1492	DCS
1494	PAINTING & INSULATION
1496	GAS SUPPLY PIPELINE & METERING STATION
1500	MECHANICAL COMPLETION
1505	IN-PLANT ROADS
1510	PAVING PLANT ACCESS ROAD FROM SR 44
COMMISSIONING, STARTUP, & PERF. T	
770	COMMISSIONING, STARTUP, PERFORMANCE
COMMERCIAL OPERATION	
780	COMMERCIAL OPERATION



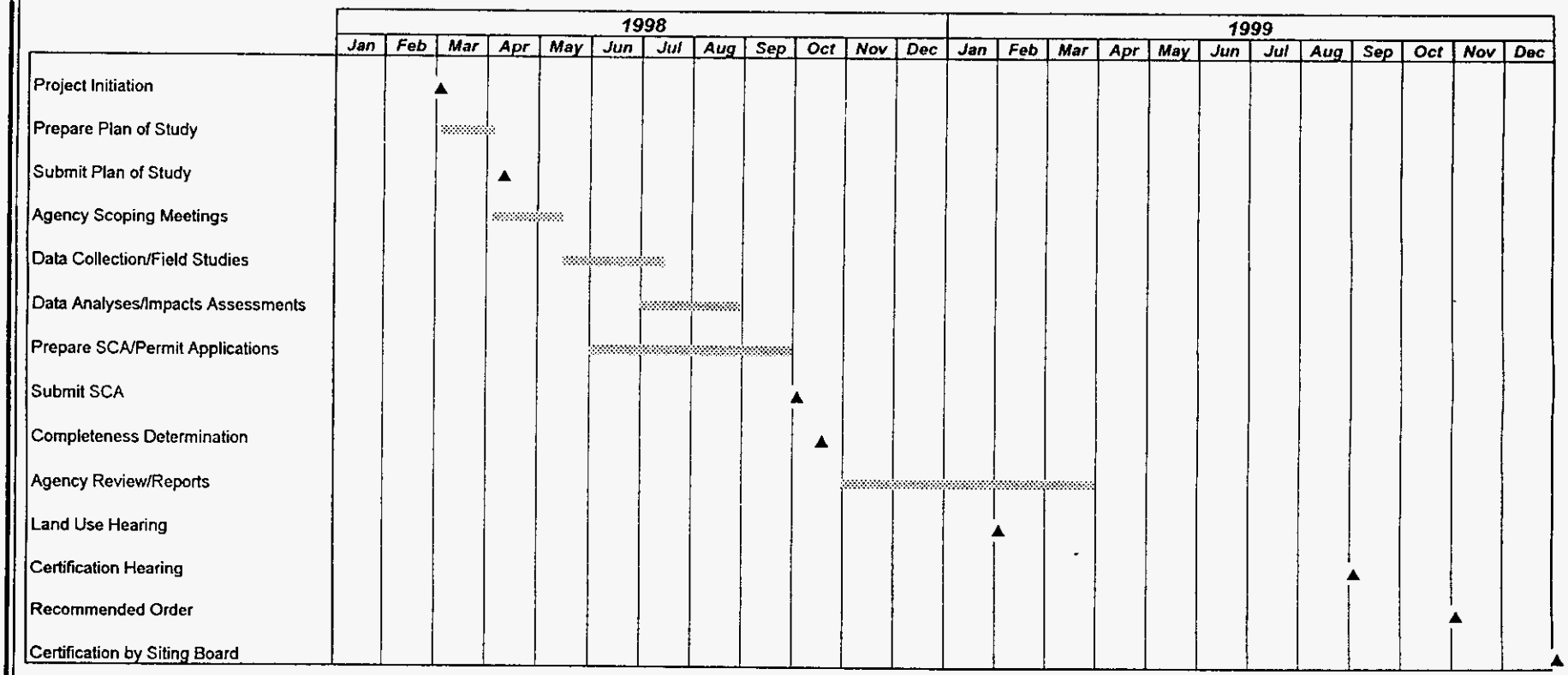


FIGURE 15
NEW SMYRNA BEACH POWER PROJECT
ENVIRONMENTAL LICENSING SCHEDULE

Source: ECT, 1998.

ECT
Environmental Consulting & Technology, Inc.

TABLE 3
NEW SMYRNA BEACH POWER PROJECT
Major Potentially Applicable Environmental Regulations and Licensing Considerations*

Federal

1. Air: NAAQS (EPA 40 CFR 50)
2. Air: PSD (EPA 40 CFR 52.21)
3. Air: NSPS (EPA 40 CFR 60, Subpart GG)
4. Wastewater, including Storm Water: NPDES (EPA 40 CFR 423, 122)
5. Dredge and Fill (USACE Section 404 (33 U.S.C. §1344; 33 CFR 320-330)
6. Stack Height (FAA 14 CFR 77; EPA 40 CFR 51)
7. Endangered Species (USFWS 50 CFR 17)
8. Fuel Use Act (DOE 42 U.S.C. §8311; 10 CFR 501)
9. NEPA (42 U.S.C. §§4321-4370; CEQ 40 CFR 1500-1517)

State

1. Power Plant Siting Act (FDEP 403.501-403.518, F.S.; Ch. 62-17, F.A.C.)
2. Transmission Line Siting Act (FDEP 403.52-403.539, F.S.; Ch. 62-17, F.A.C.)
3. Permits (FDEP Ch. 373 and 403, F.S.; Ch. 62-4, F.A.C.)
4. Storm Water Discharge (FDEP Ch. 403, F.S.; Ch. 62-25, F.A.C.)
5. Water Policy (FDEP Ch. 373 and 403, F.S.; Ch. 62-40, F.A.C.)
6. Sampling and Analysis: Quality Assurance (FDEP Ch. 373, 376, and 403, F.S.; Ch. 62-160, F.A.C.)
7. Air: AAQS (FDEP Ch. 403, F.S.; Ch. 62-204.240, F.A.C.)
8. Air: PSD (FDEP Ch. 403, F.S.; Ch. 62-212.400, F.A.C.)
9. Air: NSPS (FDEP Ch. 403, F.S.; Ch. 62-296, F.A.C.)
10. Surface Water Discharge: Surface Water Quality Standards (FDEP Ch. 403, F.S.; Ch. 62-302, F.A.C.)
11. Dredge and Fill: Wetlands (FDEP Ch. 373 and 403, F.S.; Ch. 62-312, F.A.C.)
12. Environmental Resource Permitting (FDEP Ch. 120, 373, and 403, F.S.; Ch. 62-330, -341, -343, F.A.C.)
13. Ground Water Standards (FDEP Ch. 403, F.S.; Ch. 62-520, F.A.C.)
14. Wellhead Protection (FDEP Ch. 403, F.S.; Ch. 62-521, F.A.C.)
15. Water Well Permitting and Construction (FDEP Ch. 373, F.S.; Ch. 62-532, F.A.C.)
16. Reuse of Reclaimed Water (FDEP Ch. 403, F.S.; Ch. 62-610, F.A.C.)
17. Wastewater Discharge: Wastewater Facility Permitting (FDEP Ch. 403, F.S.; Ch. 62-620, F.A.C.)
18. Wastewater Discharge: Pretreatment Requirements (FDEP Ch. 403, F.S.; Ch. 62-625, -650, -660, F.A.C.)
19. Solid Waste (FDEP Ch. 403, F.S.; Ch. 62-701, F.A.C.)
20. Oil/Water Separator: Used Oil Management (FDEP Ch. 403, F.S.; Ch. 62-710, F.A.C.)
21. Hazardous Waste (FDEP Ch. 403, F.S.; Ch. 62-730, F.A.C.)
22. Underground Storage Tank Systems (FDEP Ch.. 376, F.S.; Ch. 62-761, F.A.C.)
23. Aboveground Storage Tank Systems (FDEP Ch. 376, F.S.; Ch. 62-761, F.A.C.)
24. Natural Gas Transmission Pipeline Siting (FDEP Ch. 403; F.S.; Ch. 62-807, F.A.C.)
25. Electric and Magnetic Fields (FDEP Ch. 403, F.S.; Ch. 62-814, F.A.C.)
26. Endangered/Threatened Wildlife Species (FGFWFC Ch. 372, F.S.; Ch. 39-27, F.A.C.)

Major Potentially Applicable Environmental Regulations and Licensing Considerations*
(Continued, Page 2 of 3)

27. Preservation of Native Flora of Florida (FDOA, Ch. 581, F.S.)
28. Archaeology/Historical (FDOS Ch. 267, F.S.; Ch. 1A, F.A.C.)
29. Access Road/Highway/Railroad (FDOT Ch. 14, F.A.C.)
30. Stack Height (FDOT Ch. 330, 333, and 334, F.S.; Ch. 14-60.009, F.A.C.)
31. Land Use: FDCA Coastal Zone Areas (Ch. 380, Part II, Ch. 380.23, F.S.); Environmentally Endangered Land (Ch. 259, F.S.); Areas of Critical Concern (Ch. 380, F.S.); Aquatic Preserves (Ch. 258, Part II, F.S.); Outstanding Florida Waters (FDEP Ch. 403, F.S.; Ch. 62-302.700, F.A.C.); State Parks, Recreation Areas, and Wilderness Areas (Ch. 375, F.S., Ch. 258, F.S.); National Forests, National Wildlife Refuges, and State Wildlife Management Areas (Ch. 372, F.S.); Indian Reservations (Ch. 285, F.S.)

Regional

1. Permits Required: Organization and Procedure (SJRWMD Ch. 40C-1, F.A.C.)
2. Consumptive Water Use, Well Construction: (SJRWMD Ch. 40C-2,-3, F.A.C.)
3. Environmental Resource Permits: Surface Water Management Systems (SJRWMD Ch. 40C-4, -40, -42, -400, F.A.C.)
4. Works of District (SJRWMD Ch. 40C-6, F.A.C.)
5. Ground Water Withdrawal: Minimum Levels (SJRWMD Ch. 40C-8, F.A.C.)
6. Construction Dewatering: Noticed General Permit (SJRWMD Ch. 40C-22, F.A.C.)
7. Water Resource Caution Area (SJRWMD Ch. 40C-23, F.A.C.)
8. Land Use: Regional Comprehensive Policy Plan (ECFRPC, Ch. 29F-19, F.A.C.)

Local

1. Land Use: Local Government Comprehensive Planning Act of 1975 with Amendments (Ch. 163, F.S.); City of New Smyrna Beach and Volusia County
2. Noise: City of New Smyrna Beach Ordinance No. 16-95
3. Noise: Volusia County Ordinance No. 83-22
4. Well Construction: Volusia County Code, § 74-39
5. Environmental Protection: Volusia County Code, § 50-105 *et seq.*
6. Wetlands: Volusia County Code, § 50-209
7. Well-Field Protection: Volusia County Code, § 50-281
8. Storage of Hazardous Substances: Volusia County Code, § 50-284
9. Tree Removal: Volusia County Code, § 50-167
10. Construction Permits, including Setbacks and Height Restrictions

Note: AAQS = ambient air quality standards.
CEQ = Council on Environmental Quality.
CFR = Code of Federal Regulations.
DOE = Department of Energy.
ECFRPC = East Central Florida Regional Planning Council.
EPA = U.S. Environmental Protection Agency.
FAA = Federal Aviation Administration.

Major Potentially Applicable Environmental Regulations and Licensing Considerations*
(Continued, Page 3 of 3)

F.A.C. = Florida Administrative Code.
FDCA = Florida Department of Community Affairs.
FDEP = Florida Department of Environmental Protection.
FDOA = Florida Department of Agriculture and Consumer Services
FDOS = Florida Department of State.
FDOT = Florida Department of Transportation.
FGFWFC = Florida Game and Fresh Water Fish Commission.
F.S. = Florida Statutes.
NEPA = National Environmental Policy Act.
NAAQS = national ambient air quality standards.
NPDES = National Pollutant Discharge Elimination System.
NSPS = new source performance standards.
PSD = Prevention of Significant Deterioration.
SJRWMD = St. Johns River Water Management District.
USACE = U.S. Army Corps of Engineers.
U.S.C. = United States Code.
USFWS = U.S. Fish and Wildlife Service.

*Not all of the listed regulations will apply to the project.

Source: ECT, 1998.

IV. CONSISTENCY OF THE NEW SMYRNA BEACH POWER PROJECT WITH THE POWER SUPPLY NEEDS OF THE UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH AND OF PENINSULAR FLORIDA

The New Smyrna Beach Power Project will provide total net generation capability of 476 MW in the summer and 548 MW in the winter. This additional capacity is consistent with the power supply needs of the UCNSB and will significantly increase the reliability of power supply in Peninsular Florida.

A. Power Supply Needs of the Utilities Commission, City of New Smyrna Beach

The UCNSB serves approximately 19,900 electric customers within a service area of 72 square miles. The service area consists of the City of New Smyrna Beach and the surrounding unincorporated areas mainly to the south and west of the City. The customer base for UCNSB is largely (90%) residential and energy sales to the residential customers account for 65% of all energy sales. Table 4 presents historic and projected numbers of customers for the UCNSB electric system.

The UCNSB electric system is a winter peaking system. The UCNSB's historical maximum peak demand of 89 MW was experienced in the winter of 1996. The UCNSB's all-time summer peak demand was 80.2 MW in June of this year. Peak demand levels have grown linearly over the past several years and are expected to grow steadily for the foreseeable future due to consistent customer growth, largely in the residential customer class. Table 5 and Figures 16 and 17 present the UCNSB's historical and projected summer and winter peak demands, including the amount of each peak

TABLE 4

Utilities Commission, City of New Smyrna Beach
Historical and Projected Customers, 1992-2008

Historical Customers						
	1992	1993	1994	1995	1996	1997
Residential Customers (Average/Month)	16,914	17,213	17,496	17,734	17,856	17,995
General Service Customers (Average/Month)	1,689	1,705	1,691	1,702	1,715	1,728

Projected Customers						
	1998	1999	2000	2001	2002	2003
Residential Customers (Average/Month)	18,143	18,289	18,436	18,584	18,733	18,883
General Service Customers (Average/Month)	1,769	1,800	1,831	1,863	1,898	1,934

Projected Customers						
	2004	2005	2006	2007	2008	
Residential Customers (Average/Month)	19,035	19,187	19,341	19,496	19,653	
General Service Customers (Average/Month)	1,967	2,001	2,035	2,069	2,105	

TABLE 5

Utilities Commission, City of New Smyrna Beach
Historical and Projected Peak Demands,
1993-2008 (MW)

Peak Demand (MW)

	1993	1994	1995	1996	1997	1998	1999	2000
Summer	68	66	70	72	78	78	81	83
Winter	72	70	88	89	83	68	91	94

	2001	2002	2003	2004	2005	2006	2007	2008
Summer	85	87	89	91	92	94	96	98
Winter	96	98	100	102	104	106	108	110

FIGURE 16

Utilities Commission, City of New Smyrna Beach
Summer Peak Demands, 1993-2008

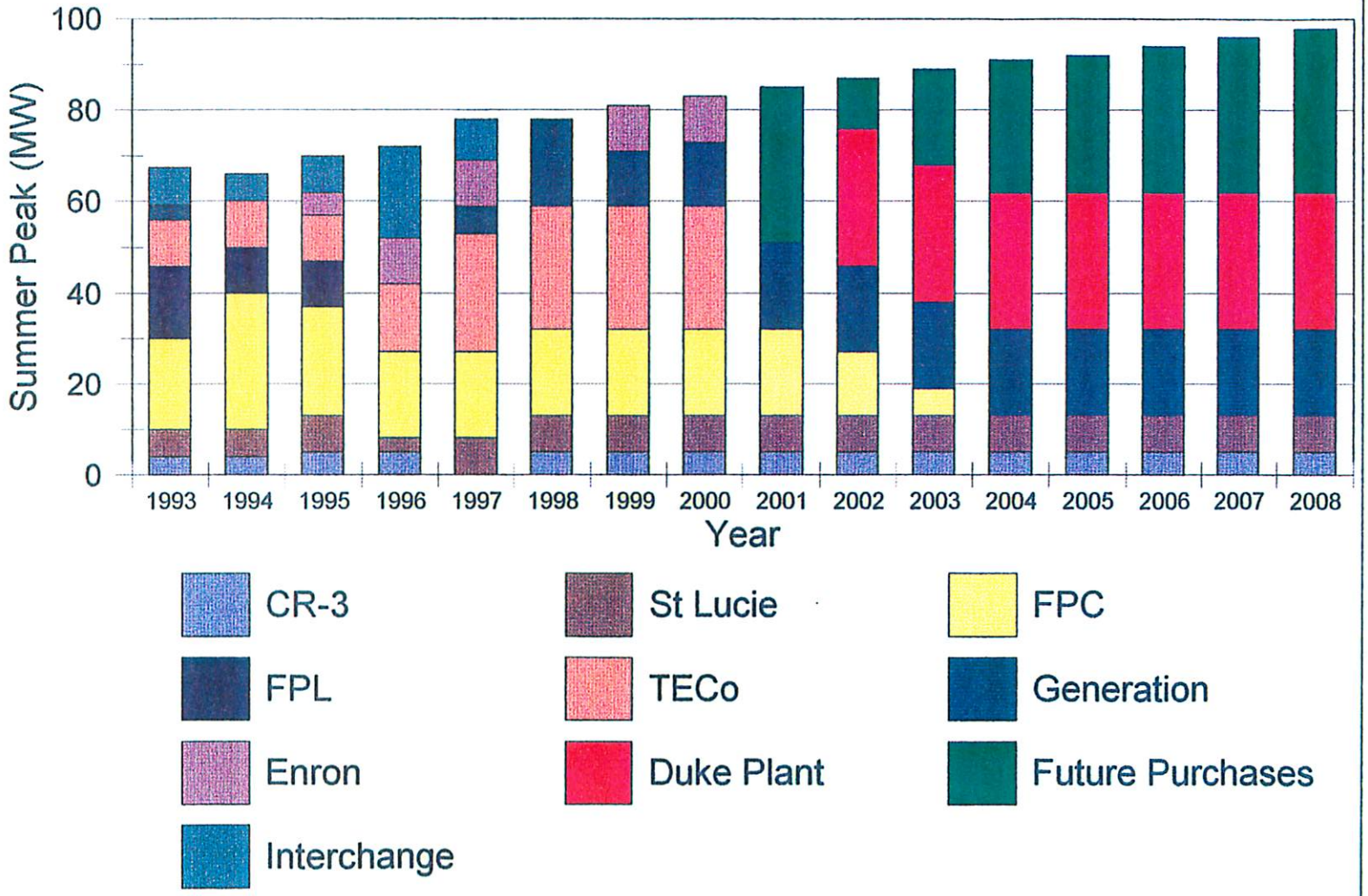
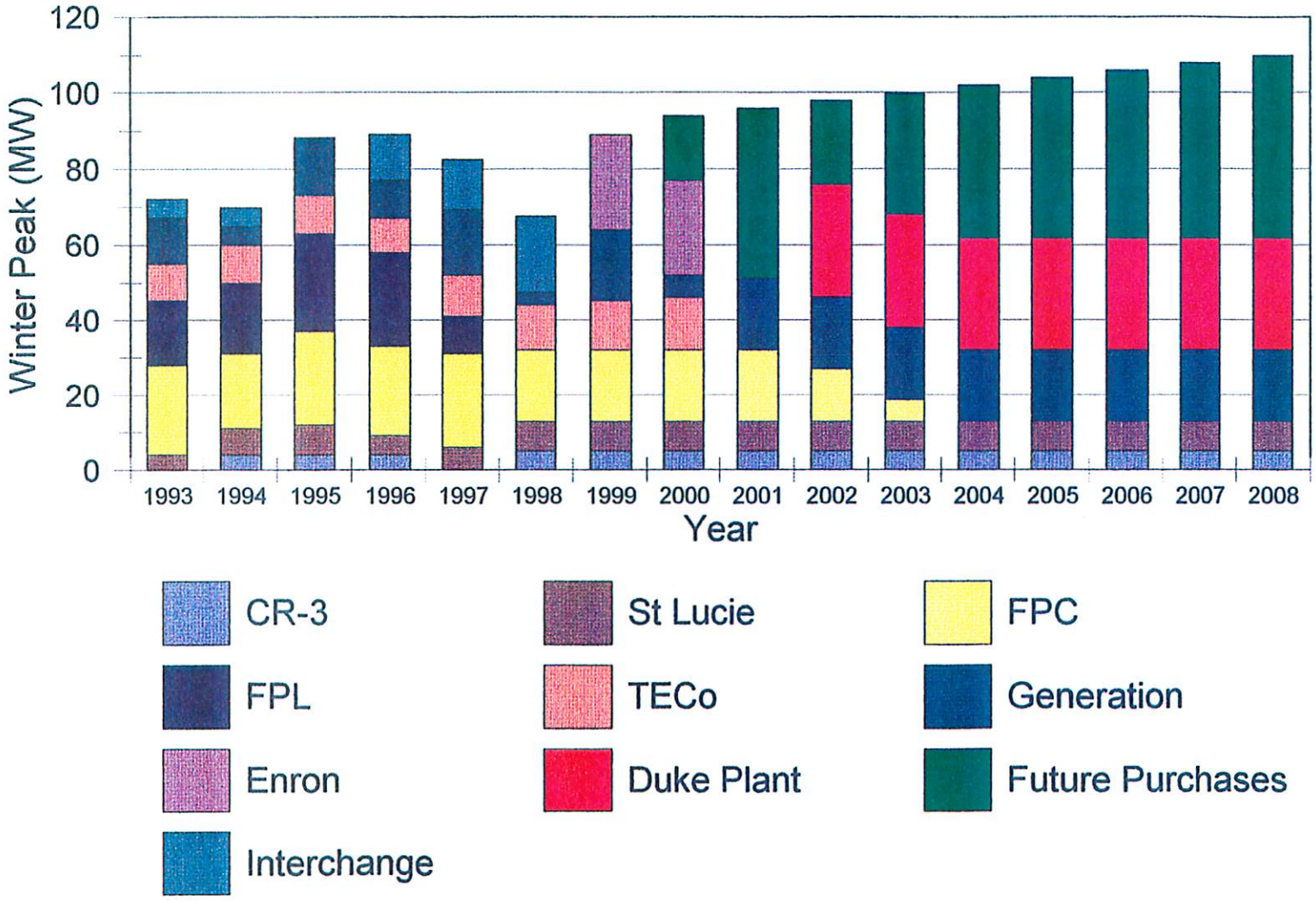


FIGURE 17

Utilities Commission, City of New Smyrna Beach
Winter Peak Demands, 1993-2008



that was served by the UCNSB's various power supply resources. The UCNSB's summer peak demand is projected to grow to 98 MW by 2008, and the system's winter peak demand is projected to increase to 110 MW by 2008.

Since 1992, energy requirements for the UCNSB system have grown at an average rate of 2.6 percent per year. Net Energy for Load (NEL) for the last full fiscal year (1997) was 325,229 MWH. Table 6 presents the historical and projected energy requirements for the UCNSB electric system. Figure 18 presents historical and projected NEL data, including the amount of each year's NEL that was provided by the UCNSB's various power supply resources. The UCNSB's Net Energy for Load is projected to grow to approximately 390,000 MWH per year in 2008.

The UCNSB's load forecast is developed by the UCNSB staff, based on regression analyses of historical loads, energy use, customer growth, and future economic considerations. System energy requirements are forecast using separate regression analyses for four customer classes: residential, general service non-demand, general service demand, and streetlighting. For the residential class, expected sales are estimated using a regression model based on historical sales data. Verification of the results is based on a comparison with the forecasted average use per customer. The number of residential customers is forecast using historical data and projected growth in known (permitted or well into the planning stages) Planned Unit Developments. Project sales of the general service non-demand, general service demand, and streetlighting

TABLE 6

Utilities Commission, City of New Smyrna Beach
Historical and Projected Energy Requirements, 1992-2008

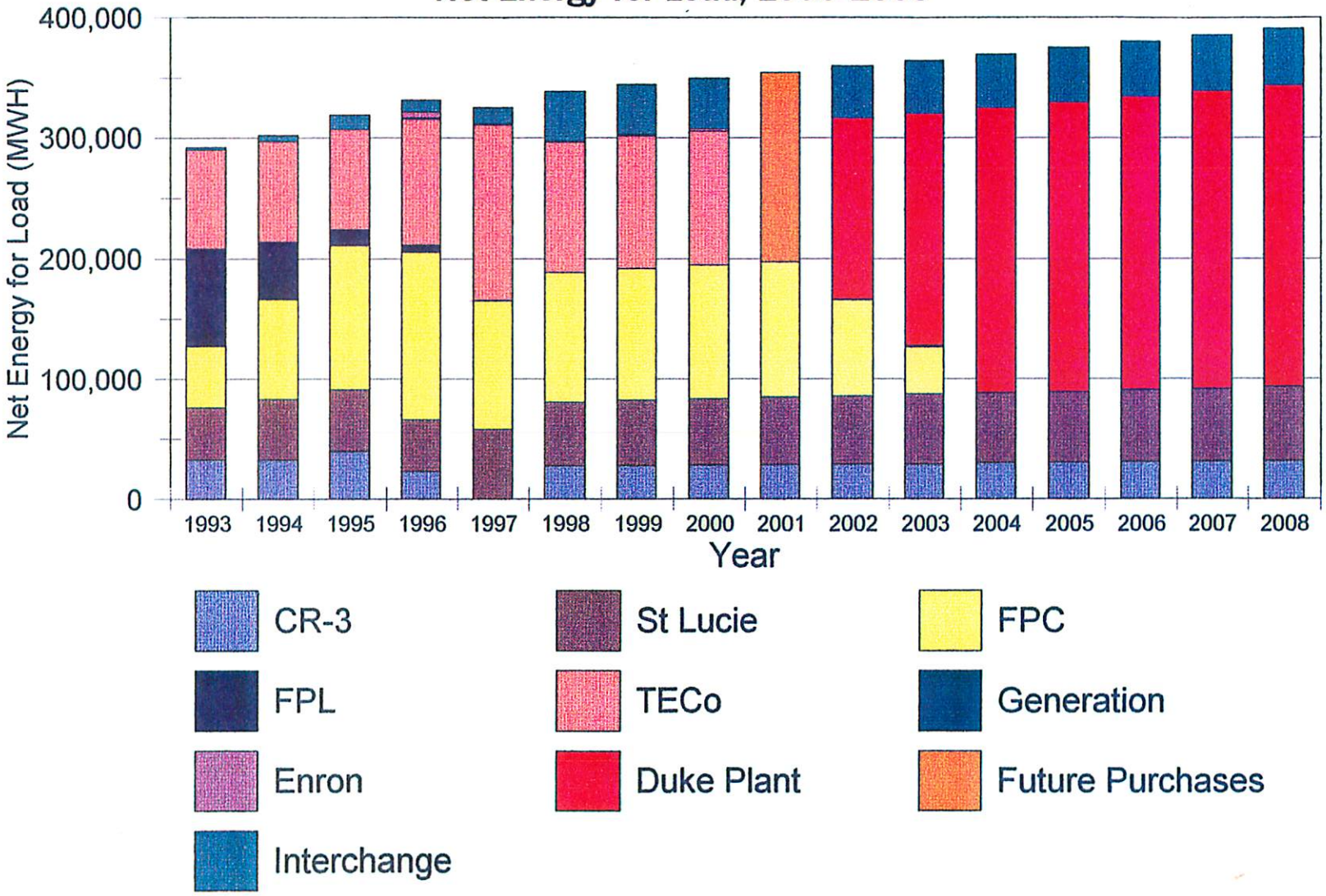
Historical Energy Requirements (MWH)						
	1992	**1993**	**1994**	**1995**	**1996**	**1997**
Energy Requirements	287,167	292,485	301,883	318,962	331,285	325,229

Projected Energy Requirements (MWH)						
	1998	**1999**	**2000**	**2001**	**2002**	**2003**
Energy Requirements	334,109	344,450	349,513	354,421	359,686	364,168

Projected Energy Requirements (MWH)						
	2004	**2005**	**2006**	**2007**	**2008**	
Energy Requirements	369,380	374,666	380,028	385,467	390,984	

FIGURE 18

Utilities Commission, City of New Smyrna Beach
Net Energy for Load, 1993-2008



classes are based on time series regression analyses. After the regression analyses are complete, the final load forecasts are refined based on projected weather conditions (e.g., an El Nino year), future economic considerations, and a review of recent projections against actual results.

The UCNSB currently owns and operates two power plants fired by No. 2 fuel oil with total capacity of 18.8 MW. The UCNSB also has entitlement to a portion of the St. Lucie #2 Nuclear Power Plant through the Florida Municipal Power Agency (FMPA) and partial ownership of Florida Power Corporation's Crystal River 3 Nuclear Power Plant. The UCNSB has power purchase contracts with Florida Power Corporation (FPC), Tampa Electric Company (TECO), and Enron Power Marketing (EPM). Most of these contracts expire between September 1999 and March 2000; the Partial Requirements service that the UCNSB purchases from FPC is scheduled to ramp down from 24 MW in 2000 to 10 MW in 2002, and to phase out entirely as of October 1, 2004. Table 7 lists the UCNSB's current power supply resources.

The UCNSB needs the New Smyrna Beach Power Project to provide reliable and cost-effective power to its electric customers. The Project's reliable generating technology, as well as its location at the UCNSB's substation, will significantly enhance the reliability of the UCNSB's service to its customers. The cost-effectiveness of the power to be supplied to the UCNSB pursuant to the Participation Agreement is discussed below.

TABLE 7

Utilities Commission, City of New Smyrna Beach
Power Supply Resources

Resource Name	Peak Capacity (MW)	Expiration Date
St. Lucie/FMPA	7.1	N/A
Crystal River 3	5.4	N/A
Florida Power Corp. PR	24.0	Phased to 0 MW as of October 1, 2004
Florida Power Corp. Stratified Peaking	6.0	February 29, 2000
Enron Short Term	25.0	March 31, 2000
Tampa Electric Co. Schedule 'D'	13.0	February 29, 2000
Tampa Electric Co. Summer Service	5.0	September 30, 1999
Tampa Electric Co. Supplemental	10.0	September 30, 1999
Local Generation	18.8	N/A

B. Power Supply Needs of Peninsular Florida

The New Smyrna Beach Power Project will provide reliable and cost-effective power to the UCNSB and to other utilities that provide retail service in Peninsular Florida. Peninsular Florida needs more than 8,000 MW of new installed capacity in order to maintain reserve margins (with exercise of load management and interruptible resources) above 14.5 percent from the winter of 1998-1999 through the winter of 2007-2008. (See Table 11.) The Project will contribute meaningfully to Peninsular Florida's summer and winter reserve margins and to cost-effective power supply.

According to the 1998 Regional Load & Resource Plan, dated July, 1998, prepared by the Florida Reliability Coordinating Council (the "FRCC 1998 Regional Plan"), without the New Smyrna Beach Power Project, Peninsular Florida's summer reserve margins in 2002 through 2007 will range from 9.1 percent to 10.4 percent, without exercising load management and interruptible capabilities. With the Project, the reserve margins will be improved by approximately 1.1 to 1.25 percent in each year, e.g., from 9.1 percent to 10.4 percent in 2002. The annual summer reserve margins for Peninsular Florida, with and without the Project's capacity, are shown in Table 8.

Similarly, based on data presented in the FRCC 1998 Regional Plan, without the New Smyrna Beach Power Project, Peninsular Florida's winter reserve margins in 2001-2002 through 2007-2008 are projected to be between 4.0 percent and 7.0 percent, without exercising load management and interruptible capabilities. With

TABLE 8

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK, WITHOUT NEW SMYRNA BEACH POWER PROJECT

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABL CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1998	35485	1412	2220	39117	35633	3484	9.78	2776	32857	6260	19.05
1999	36112	1702	2220	40034	36628	3406	9.30	3011	33617	6417	19.09
2000	36356	1852	2220	40428	37410	3018	8.07	3130	34280	6148	17.93
2001	36866	1766	2295	40927	38220	2707	7.08	3227	34993	5934	16.96
2002	38406	1704	2286	42396	38844	3552	9.14	3256	35588	6808	19.13
2003	39430	1623	2286	43339	39395	3944	10.01	3317	36078	7261	20.13
2004	40500	1633	2286	44419	40227	4192	10.42	3356	36871	7548	20.47
2005	41325	1644	2276	45245	41112	4133	10.05	3379	37733	7512	19.91
2006	42042	1630	2143	45815	41998	3817	9.09	3405	38593	7222	18.71
2007	43096	1755	2143	46994	42885	4109	9.58	3434	39451	7543	19.12

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK, WITH NEW SMYRNA BEACH POWER PROJECT 476 MW IN 2002

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABL CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1998	35485	1412	2220	39117	35633	3484	9.78	2776	32857	6260	19.05
1999	36112	1702	2220	40034	36628	3406	9.30	3011	33617	6417	19.09
2000	36356	1852	2220	40428	37410	3018	8.07	3130	34280	6148	17.93
2001	36866	1766	2295	40927	38220	2707	7.08	3227	34993	5934	16.96
2002	38882	1704	2286	42872	38844	4028	10.37	3256	35588	7284	20.47
2003	39906	1623	2286	43815	39395	4420	11.22	3317	36078	7737	21.45
2004	40976	1633	2286	44895	40227	4668	11.60	3356	36871	8024	21.76
2005	41801	1644	2276	45721	41112	4609	11.21	3379	37733	7988	21.17
2006	42518	1630	2143	46291	41998	4293	10.22	3405	38593	7698	19.95
2007	43572	1755	2143	47470	42885	4585	10.69	3434	39451	8019	20.33

*476 MW ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002

SOURCES: Florida Reliability Coordinating Council,
1998 Load & Resource Plan, Peninsular Florida,
July 1, 1998; Duke Energy Power Services, L.L.C.

TABLE 9

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK, WITHOUT NEW SMYRNA BEACH POWER PROJECT

Year	INSTALLE CAPACITY (MW)	NET CONTRAC FIRM INTERCHG (MW)	PROJECTE FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABL CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1998/99	38037	1939	2240	42216	39450	2766	7.01	3784	35666	6550	18.36
1999/00	38402	1916	2240	42558	40388	2170	5.37	3955	36433	6125	16.81
2000/01	38809	1691	2240	42740	41395	1345	3.25	4078	37317	5423	14.53
2001/02	40638	1705	2315	44658	42219	2439	5.78	4153	38066	6592	17.32
2002/03	41980	1612	2306	45898	42998	2900	6.74	4232	38766	7132	18.40
2003/04	43073	1623	2306	47002	43925	3077	7.01	4307	39618	7384	18.64
2004/05	44105	1633	2296	48034	44895	3139	6.99	4335	40560	7474	18.43
2005/06	44883	1555	2163	48601	45896	2705	5.89	4365	41531	7070	17.02
2006/07	45916	1630	2163	49709	46879	2830	6.04	4392	42487	7222	17.00
2007/08	46076	1555	2163	49794	47902	1892	3.95	4415	43487	6307	14.50

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK, WITH NEW SMYRNA BEACH POWER PROJECT 548 MW IN 2001/02

Year	INSTALLE CAPACITY (MW)	NET CONTRAC FIRM INTERCHG (MW)	PROJECTE FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABL CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1998/99	38037	1939	2240	42216	39450	2766	7.01	3784	35666	6550	18.36
1999/00	38402	1916	2240	42558	40388	2170	5.37	3955	36433	6125	16.81
2000/01	38809	1691	2240	42740	41395	1345	3.25	4078	37317	5423	14.53
2001/02	41186	1705	2315	45206	42219	2987	7.08	4153	38066	7140	18.76
2002/03	42528	1612	2306	46446	42998	3448	8.02	4232	38766	7680	19.81
2003/04	43621	1623	2306	47550	43925	3625	8.25	4307	39618	7932	20.02
2004/05	44653	1633	2296	48582	44895	3687	8.21	4335	40560	8022	19.78
2005/06	45431	1555	2163	49149	45896	3253	7.09	4365	41531	7618	18.34
2006/07	46464	1630	2163	50257	46879	3378	7.21	4392	42487	7770	18.29
2007/08	46624	1555	2163	50342	47902	2440	5.09	4415	43487	6855	15.76

*548 MW ADDED TO TOTAL AVAILABLE CAPACITY COLUMN STARTING IN 2001/02

SOURCES: Florida Reliability Coordinating Council,
1998 Load & Resource Plan, Peninsular Florida,
July 1, 1998; Duke Energy Power Services, L.L.C.

the New Smyrna Beach Power Project, the reserve margins will be improved by approximately 1.1 to 1.4 percent in each year, e.g., from 5.8 percent to 7.1 percent in the winter of 2001-2002. Winter reserve margins for Peninsular Florida, with and without the Project's capacity, and with and without exercising load management and interruptible resources, are shown in Table 9.

The Project is expected to operate at capacity factors ranging from approximately 83 percent in 2002 to approximately 94 percent in 2012, reflecting between 7,000 and 8,500 operating hours per year and between 3,700,000 and 4,200,000 MWH per year of net generation. See Table 10.

The primary market for power produced by the New Smyrna Beach Power Project is wholesale sales to other utilities in Peninsular Florida. Duke New Smyrna projects that all, or virtually all -- more than 99 percent -- of all sales from the Project over the 2002-2012 period are expected to be to other utilities in Peninsular Florida (i.e., within the FRCC region), on the basis of the relative economics of the Project and other Peninsular Florida generation facilities.

The advanced technology, natural gas fired combined cycle design of the Project is consistent with the type of capacity being added by many other Peninsular Florida utilities. Table 11, which presents data from utility ten year site plans and other published sources, shows that from 1998 through 2007, other Peninsular Florida utilities are projecting the addition of nearly 5,000 MW of gas-fired combined cycle capacity. Of these units, only FPC's

TABLE 10

NEW SMYRNA BEACH POWER PROJECT
PROJECTED OPERATIONS AND FUEL SAVINGS

YEAR	GENERATION (MWH)	CAPACITY FACTOR %	PRIMARY ENERGY SAVED (MMBtu)	SAVINGS @ 100% NO. 6 OIL DISPLACED (BARRELS)	SAVINGS @ 100% NATURAL GAS DISPLACED (MCF)
2002	3,719,550.72	82.61	13,647,032	5,992,568	13,647,032
2003	3,768,894.72	83.70	13,828,075	6,072,066	13,828,075
2004	3,818,238.72	84.57	14,009,118	6,151,564	14,009,118
2005	3,862,154.88	85.54	14,170,246	6,222,318	14,170,246
2006	3,906,071.04	86.75	14,331,375	6,293,071	14,331,375
2007	3,952,454.40	87.78	14,501,555	6,367,799	14,501,555
2008	3,998,837.76	88.57	14,671,736	6,442,528	14,671,736
2009	4,046,701.44	89.63	14,847,348	6,519,641	14,847,348
2010	4,094,565.12	90.94	15,022,959	6,596,754	15,022,959
2011	4,164,140.16	92.48	15,278,230	6,708,846	15,278,230
2012	4,233,715.20	93.77	15,533,501	6,820,939	15,533,501
TOTALS			159,841,174	70,188,094	159,841,174

NOTES: (1) Primary energy saved estimated as the difference between Btu required to generate MWH in Column (2) in gas/oil steam generators with an average heat rate of 10,501 Btu/kWh and the Btu required to generate the same MWH at the NSB Project's heat rate of 6,832 Btu/kWh.
(2) Oil savings reflects total oil displaced assuming that all of the Project's output displaces oil-fired steam generation.
(3) Gas savings reflects net gas reduction to generate MWH in Column (2).

TABLE 11

COMPARISON OF PENINSULAR FLORIDA
PLANNED AND PROPOSED GENERATING UNITS

UTILITY/UNIT	IN-SERVICE YEAR	CAPACITY SUMMER	CAPACITY WINTER	FUELS PRIMARY	FUELS ALTERNATE	HEAT RATE (Btu/kWH)(HHV)	EQUIVALENT AVAILABILITY FACTOR %	TOTAL INSTALLED COST ($/KW)	DIRECT CONSTRUCTION COST ($/KW)
DUKE/NSBPP*	2001	476	548	GAS	NONE	6832	96	N/A	311
FPL/FT.MYERS	2002	837	1062	GAS	NONE	6815	96	593	495
FPL/SANFORD	2003	914	1076	GAS	NONE	6777	96	612	494
FPL/MARTIN 5	2006	419	448	GAS	NO. 2	6081	96	647	492
FPL/MARTIN 6	2007	419	448	GAS	NO. 2	6081	96	599	444
FPC/HINES 1**	1998	470	505	GAS	NO. 2	6962	91	600 *	NOT REPORTED
FPC/HINES 2	2004	470	505	GAS	NO. 2	6962	91	NOT REPORTED	NOT REPORTED
FPC/HINES 3	2006	470	505	GAS	NO. 2	6962	91	NOT REPORTED	NOT REPORTED
SEC/HARDEE 3	2002	451	527	GAS	NO. 2	7430	88	723	519
FMPA-KUA									
CANE ISLAND 3	2001	246	272	GAS	NO. 2	6815	92	449	319
LKLAND McINTOSH 5	1999	245	264	GAS	NO. 2	9486	86	216	NOT REPORTED

*DUKE/NSBPP DATA IS BASED ON INFORMATION FROM NEED DETERMINATION FILING

**FPC HINES 1 DATA BASED ON PROJECTED CAPITAL INVESTMENT OF $300,000,000 / NOMINAL CAPACITY 500 MW AS SHOWN IN 1996 TYSP

OTHER UTILITY UNIT DATA TAKEN FROM: 1998 TEN YEAR SITE PLANS, SCHEDULE 9

Hines Unit 1 and the Cane Island 3 unit of the Florida Municipal Power Agency and the Kissimmee Utilities Authority are projected to be in-service before the New Smyrna Beach Power Project.

The studies of the Project's operations prepared for Duke New Smyrna were prepared using the Altos North American Regional Electricity Model and the Altos North American Regional Gas Model developed by Altos Management Partners, Inc., an economic and management consulting firm with offices in San Jose, California, and Dallas, Texas. The Altos North American Regional Electricity Model is a 32-region integrated model of the North American electricity system that includes generation, transmission, consumption, fuels, and fuel competition. The model includes all of the generation regions, all of the existing and prospective transmission interconnections, and all of the demand regions of North America. Generally speaking, the model includes all of the reliability coordinating regions in the U.S., Canada, and Mexico, plus numerous sub-regions. For example, the model treats the Southern Electric Reliability Council region ("SERC") as four separate sub-regions: the Southern Company system, TVA, VCR (Virginia and the Carolinas), and Entergy, which was formerly designated as the southeastern component of the Southwestern Power Pool.

The Altos Electricity Model includes transmission system integration and interconnection, consideration of multiple fuels and energy products, existing capacity and its cost structure, future changes in the cost structure of existing plants,

retirements and decommissioning, new generation plant entry, inbound and outbound transmission capabilities, transmission entry, and demands and load shapes that vary over time.

The North American Regional Gas Model (the "NARG Model") includes all gas supply basins, all existing and prospective interconnecting pipelines, and all of the gas demand regions of North American. In the NARG Model, each category of resource in each supply region is characterized by a detailed supply sub-model, each pipeline is characterized by a detailed transportation sub-model, and each demand region is characterized by a detailed demand sub-model. The NARG Model estimates, over time, the set of regional prices that simultaneously clear the markets in every wellhead, wholesale, and other market in North America.

C. Strategic Considerations

The Project is also consistent with strategic factors that may be considered when determining to build a power plant, both from Duke New Smyrna's perspective and from the perspective of the State. The Project will be fueled by domestically produced natural gas rather than by an imported fuel that may be subject to interruption due to political or other events. The Project has a low installed cost and a highly efficient heat rate, assuring its long-term economic viability. As a merchant plant constructed at the expense of Duke New Smyrna, the Project will provide power with no risk to Florida electric customers and will impose no obligation on either Florida utilities or their customers. The Project's gas-fired combined cycle technology is exceptionally clean

environmentally, minimizing potential risks associated with future changes in environmental regulations. The Project's efficient technology and use of clean, natural gas fuel will improve the overall environmental profile of electricity generation in Florida. The Project will also contribute to reducing the consumption of petroleum fuels for electricity generation in Florida.

V. COST-EFFECTIVENESS OF THE NEW SMYRNA BEACH POWER PROJECT

The New Smyrna Beach Power Project is the most cost-effective alternative available to the UCNSB for meeting the needs of its customers and to Duke New Smyrna for meeting its obligations to deliver the entitlement capacity and energy to the UCNSB as well as to satisfy its projected wholesale supply commitments. Moreover, the Project will necessarily be cost-effective to other Peninsular Florida utilities and their ratepayers.

A. Cost-Effectiveness to the Utilities Commission, City of New Smyrna Beach

In its consideration of whether to enter into the Participation Agreement and to obtain the entitlement capacity and energy from the Project, the UCNSB evaluated both self-build generation options and other purchase options. The self-build generation alternatives considered were relatively small gas-fired technologies, with capacities in the range of 20 to 50 MW. These were rejected for two reasons. First, their small size rendered them non-cost-effective because the capital cost necessary to bring natural gas to New Smyrna Beach outweighed the savings that the gas units would have provided. If gas had been available with no additional capital outlays required, however, these small units would have been cost-effective as compared to continued purchases. Second, their higher heat rates rendered them uneconomic, or non-cost-effective, as compared to the Project.

The UCNSB evaluated the power supply opportunity afforded under the Participation Agreement against purchasing capacity and

energy from Tampa Electric Company ("TECO") and Florida Power Corporation ("FPC"). Compared to the TECO-FPC purchase options, the power supply option offered by the New Smyrna Beach Power Project is projected to save the UCNSB approximately $3.1 million per year, for the first ten years of the Participation Agreement, and approximately $2 million per year for the following ten years. The total projected net present value of the savings provided to the UCNSB by the Project is approximately $39 million. The UCNSB's cost-effectiveness evaluations are shown in Tables 12 through 14.

B. Cost-Effectiveness to Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

The Project also represents the most cost-effective alternative available to Duke New Smyrna for meeting its obligations under the Participation Agreement and for meeting its projected wholesale power commitments. Table 15 shows the generating alternatives evaluated by Duke New Smyrna. The economic evaluation considered gas-fired and oil-fired combustion turbines, gas-fired and oil-fired combined cycle units, gas-fueled steam generation units, oil-fueled steam generation units, pulverized coal units, integrated coal gasification combined cycle ("IGCC") units, nuclear units, and waste-to-energy technologies. These evaluations clearly indicate that the economic choice for Duke New Smyrna is gas-fired combined cycle capacity. This is borne out by the fact that other Florida utilities are planning to add similar capacity, and by the fact that this type of unit is the technology of choice for the majority of new power plant capacity planned in

TABLE 12
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH
FISCAL YEAR 2000 BUDGET WITHOUT NEW SMYRNA BEACH POWER PROJECT

Month	Year	NEL MWH	Peak MW	Load Factor	Res Margin	LOLP days/yr	LOLP hrs/yr
Total	2000	349513	87	45.74	10.70	0	0

Resource Name	NEL MWH	Start-up Cost $	Energy Cost $	Energy $/MWH	Res. C.F.%	Fixed Cost $	Total Cost $	Total Cost $/MWH
CR-3	35623	0	187021	5.25	99.98	68400	255421	7.17
Clinch-Pk	2270	0	149729	65.96	4.31	0	149729	65.96
Dual Fuel	406	0	26780	65.96	0.36	0	26780	65.96
Enron Res	0	0	0	0.00	0.00	0	0	0.00
EnronST	3601	0	126035	35.00	7.08	242000	368035	102.20
FPC PR	86607	0	1987504	22.95	58.00	2204352	4191856	48.40
FPC Peak	6587	0	382046	58.00	12.50	267264	649310	98.57
PR Base	17568	0	403266	22.95	100.00	256320	659586	37.54
PR Res.	0	0	0	0.00	0.00	0	0	0.00
Reg-Res-Bk	0	0	0	0.00	0.00	263552	263552	0.00
St. Lucie	57438	0	709359	12.35	99.98	0	709359	12.35
TECo S	7096	0	159486	22.48	99.99	0	159486	22.48
TECo S2	4086	0	91835	22.48	57.58	0	91835	22.48
TECo10a	14192	0	390262	27.50	99.99	0	390262	27.50
TECo10b	4210	0	115770	27.50	29.66	0	115770	27.50
TECoBase	109829	0	1926978	17.55	96.72	854510	2781488	25.33
Uns Energy	0	0	0	0.00	0.00	0	0	0.00
TOTALS	349513	0	6656071	19.04		4156398	10812469	30.94

TABLE 13
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH
FISCAL YEAR 2000 BUDGET WITH NEW SMYRNA BEACH POWER PROJECT

Month	Year	NEL MWH	Peak MWs	Load Factor	Res Margin	LOLP days/yr	LOLP hrs/yr
Total	2000	349513	87	45.74	17.12	0	0

Resource Name	NEL MWH	Start-up Cost $	Energy Cost $	Energy $/MWH	Res. C.F.%	Fixed Cost $	Total Cost $	Total Cost $/MWH
Base30	218612	0	4044322	18.50	82.96	0	4044322	18.50
CR-3	35623	0	187021	5.25	99.98	68400	255421	7.17
Clinch-Pk	56	0	3694	65.96	0.11	0	3694	65.96
Dual Fuel	0	0	0	0.00	0.00	0	0	0.00
Peaking	37784	0	1511360	40.00	12.78	1212000	2723360	72.08
St. Lucie	57438	0	709359	12.35	99.98	0	709359	12.35
Uns Energy	0	0	0	0.00	0.00	0	0	0.00
TOTALS	349513	0	6455756	18.47		1280400	7736156	22.13

TABLE 14

UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH PURCHASE POWER DEMAND AND ENERGY SAVINGS FROM THE NEW SMYRNA BEACH POWER PROJECT

YEAR	EST. ANNUAL SAVINGS FROM NSBPP ($ Million)	NET PRESENT VALUE @ 6% ($ Million)	CUMULATIVE NET PRESENT VALUE @ 6% ($ Million)
2002	3.456	3.076	3.076
2003	3.664	3.076	6.152
2004	3.883	3.076	9.228
2005	4.116	3.076	12.304
2006	4.363	3.076	15.380
2007	4.625	3.076	18.456
2008	4.903	3.076	21.532
2009	5.197	3.076	24.608
2010	5.509	3.076	27.684
2011	5.839	3.076	30.760
2012	2.000	0.994	31.754
2013	2.000	0.938	32.692
2014	2.000	0.885	33.576
2015	2.000	0.835	34.411
2016	2.000	0.787	35.198
2017	2.000	0.743	35.941
2018	2.000	0.701	36.641
2019	2.000	0.661	37.302
2020	2.000	0.624	37.926
2021	2.000	0.588	38.514

base year=2000

TABLE 15

NEW SMYRNA BEACH POWER PROJECT
GENERATING ALTERNATIVES EVALUATED

I. GENERATION TECHNOLOGIES CONSIDERED

Combustion Turbine (Gas/Oil)	Not cost-effective based on Florida market projections
Combined Cycle - Gas	Selected
Combined Cycle - Oil	Not cost-effective against Combined Cycle - Gas
Pulverized Coal	Not cost-effective against Combined Cycle
Coal Gasification Combined Cycle	Not cost-effective against Combined Cycle
Nuclear	Not cost-effective against Combined Cycle
Gas/Oil Steam	Not cost-effective against Combined Cycle
Waste to Energy	Not cost-effective against Combined Cycle

II. COMBINED CYCLE MANUFACTURERS CONSIDERED

General Electric

Westinghouse

Siemens

ASEA Brown Boveri (ABB)

the U.S. For example, a recent compilation of proposed new power plants indicates that of more than 35,000 MW of planned or proposed merchant power plant capacity, approximately 33,000 MW is gas-fired capacity, with much of that combined cycle.

Duke New Smyrna, DEPS, and Duke/Fluor Daniel also evaluated two alternative combined cycle configurations: (1) a 250 MW "one-on-one" configuration with one CTG, one HRSG, and one STG, and (2) the "two-on-one" 500 MW-class configuration selected. The 500 MW-class unit was selected because of the substantial economies of scale achievable from this technology. Duke New Smyrna, DEPS, and Duke/Fluor Daniel also evaluated proposals for the combined cycle components from four different manufacturers, General Electric, Westinghouse, Siemens, and ASEA Brown Boveri ("ABB").

C. Cost-Effectiveness of the New Smyrna Beach Power Project to Peninsular Florida Electric Customers

The Project will be cost-effective to Peninsular Florida in that it will provide a necessarily cost-effective option for retail-serving utilities to obtain needed capacity and energy for resale to their customers, and in that it will help to hold down wholesale power costs.

Assuming rational, cost-minimizing behavior by Florida's retail-serving utilities, it is reasonable to conclude that they will only buy power from the Project when it is cost-effective for them to do so, i.e., when it is less expensive for them to buy power from the Project than to generate it themselves or to buy from another supplier. Reasonably assuming that the cost of power

purchased from the Project is passed directly through to the purchasing utilities' ratepayers, i.e., that it is recovered directly through the utilities' fuel and purchased power cost recovery charges and not subjected to any markup or diverted to other wholesale purchasers for a profit, such purchases will necessarily be cost-effective to those ratepayers. This is because the retail-serving Peninsular Florida utilities are not obligated to buy -- nor subject to being forced to buy -- the Project's output. Similarly, as distinguished from traditional regulatory treatment, Florida electric customers are not vulnerable to being required to pay for either the capital or operating costs of the Project. As distinguished from traditional utility-built generation, Florida customers will only pay for power from the Project that their retail-serving utilities rationally choose to buy and resell to them.

Moreover, because the Project will be constructed entirely with Duke New Smyrna's capital investment and because no utility or retail ratepayers are being asked to commit to purchase the Project's output, no ratepayers will be at risk for the cost of the Project. Because the Project's output will be sold only at wholesale to other utilities, predominantly if not entirely within Florida, such sales will necessarily be at cost-effective rates to the purchasing utilities. (If the rates for purchases from the Project exceed the cost of other power supply alternatives, utilities will simply obtain needed power elsewhere.) Thus, the Project will necessarily provide economic power supply to the

purchasing utilities and their retail ratepayers.

Additionally, the New Smyrna Beach Power Project's costs and efficiency compare favorably to other gas-fired combined cycle generating units planned or proposed by other utilities in Peninsular Florida. Table 11, which presents data from the utilities' ten year site plans and other published sources, shows that of all the gas-fired combined cycle power plants proposed by Peninsular Florida utilities, only the Cane Island 3 unit, a joint project of the Florida Municipal Power Agency and the Kissimmee Utilities Authority, is expected to have a direct construction cost and heat rate comparable to that of the Project. The others reflect direct construction costs, on a dollars-per-kW basis, significantly greater than that of the Project, with generally comparable heat rates.

VI. CONSEQUENCES OF DELAY

Delaying the construction and operation of the New Smyrna Beach Power Project in the amount and time sought will adversely affect the reliability of the Peninsular Florida bulk power supply system, will adversely affect the availability of adequate electricity at a reasonable cost, and will adversely affect the environment of Florida.

A. Reliability Consequences of Delay

The New Smyrna Beach Power Project will be a highly reliable and highly efficient gas-fired combined cycle power plant. It will use proven, state-of-the-art technology. The Project's high reliability -- an equivalent availability factor of 96 percent -- assures its contributions to improving the reserve margins and reliability of the Peninsular Florida power supply system.

Tables 8 and 9 show that the Project will improve Peninsular Florida's summer and winter reserve margins by approximately 1.1 to 1.4 percent beginning with the Project's in-service date in the Fall of 2001 and continuing throughout the period covered in the FRCC 1998 Regional Plan.

The presence of this additional capacity (476 MW summer, 548 MW winter) will improve reliability and reduce Peninsular Florida's exposure to outages due to extreme weather or unanticipated events such as major generation outages. The presence of this capacity will mean that, in an extreme event, approximately 500 MW of load will be served that would not otherwise be. This means that the

Project would enable Florida's retail-serving utilities to maintain service to approximately 80,000 to 100,000 residential customers (at a coincident peak demand of 5 kW to 6 kW per household) during such conditions.

If the Project is not constructed and brought into commercial operation in 2001 as planned and sought, these reliability benefits will be lost, and Florida electric customers will be exposed to a greater probability of service interruption than they would experience if the Project were built as planned and sought by the UCNSB and Duke New Smyrna.

B. Power Supply Cost Consequences of Delay

The New Smyrna Beach Power Project is a proven, highly reliable, and highly efficient gas-fired combined cycle power plant. The Project's high efficiency assures its contributions to reducing wholesale power supply costs in Peninsular Florida.

Delaying the construction and operation of the Project will cost the UCNSB and its retail customers more than $3 million per year, for each year of delay.

The presence of the Project will reduce generation costs and will also suppress wholesale power prices, to at least some degree, in Peninsular Florida. This is the simple economic result of an increase in supply (i.e., an outward shift in the supply curve for bulk power). Even at nominal differences in the wholesale cost of power with and without the Project, the savings can be expected to be substantial. Moreover, the Project will provide real, tangible economic benefits - real reductions in the amount of primary fuels

used to generate the same amounts of electricity - to Florida and society in general by virtue of the Project's more efficient use of fuel.

If the Project is not constructed and brought into commercial operation in 2001 as planned and sought, these economic benefits will be lost, and Florida electric customers will pay more for their power service than if the Project were built.

C. Environmental Consequences of Delay

The New Smyrna Beach Power Project is a high-efficiency, state-of-the-art gas-fired combined cycle electric generating plant. Because of its high efficiency and natural gas fuel, the Project will have a benign environmental profile. The Project will displace production from older, less efficient and generally more pollution-intensive power plants, e.g., less efficient oil-fired steam generating plants, less efficient gas-fired steam generating units, and combustion turbine plants fired by oil or gas. This will result in substantial savings in primary fuel consumption for electricity generation and will also result in reduced environmental emissions from power production in Florida.

The projections prepared for Duke New Smyrna indicate that the Project's generation will generally displace production from older steam generating units fired by heavy fuel oil and natural gas, which generally have heat rates in the range of 10,000 to 10,800 Btu per kWh. Regardless of the primary fuel displaced, the Project's operations will result in significant savings of primary fuels; because of its better heat rate, the Project uses

approximately 30 to 35 percent less primary fuel energy (Btu) than steam generation units to produce the same amount of electricity. See Table 10.

Under reasonable assumptions regarding the marginal fuels displaced by the Project's operations, and reasonably assuming that the displaced oil-fired and gas-fired generation will not be sold outside Florida, the Project's operations are expected to improve the overall environmental profile of electricity generation in Florida. When the Project's output displaces generation using heavy fuel oil, there will be significant reductions in emissions of sulfur dioxide, nitrogen oxides, and particulate matter, and measurable reductions in carbon monoxide emissions. Even when the Project displaces gas-fired steam generation, there will be reductions in emissions due to the Project's significantly more efficient use of natural gas; because of its better heat rate, the Project uses approximately 30 to 35 percent less gas than gas-fired steam generation units to produce the same amount of electricity. If the Project is not constructed and brought into commercial operation in 2001 as planned and sought, these environmental benefits will be lost, and pollution from electric generation in Florida will be significantly greater than it would otherwise be.

APPENDIX

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

697363

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt Hébert, Jr.

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	))	Docket No. ER98-2624-000

ORDER ACCEPTING FOR FILING
PROPOSED TARIFFS FOR MARKET-BASED POWER SALES
AND REASSIGNMENT OF TRANSMISSION CAPACITY

(Issued June 25, 1998)

In this order, we accept for filing, without hearing or suspension, the tariffs filed by Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. (Duke New Smyrna), under which it proposes to sell power at wholesale at market-based rates and to reassign transmission capacity.

Background

On April 21, 1998, Duke New Smyrna, an indirect wholly-owned subsidiary of Duke Energy Corporation (Duke), filed an application requesting Commission authorization to sell electric capacity and energy at market-based rates. The power is to be produced from a generating facility for which construction has not commenced. Duke New Smyrna states that it has an agreement to sell 30 MW of the 500 MW output of the generating facility to the Utilities Commission of the City of New Smyrna Beach, Florida (New Smyrna Beach) and that Duke New Smyrna will file that agreement once it is finalized. Duke New Smyrna states that it may also enter into an agreement to provide ancillary services to New Smyrna Beach and that, if so, it will make a separate filing consistent with the Commission's then-existing requirements for ancillary services rates. Duke New Smyrna has also filed a tariff to reassign transmission capacity it has reserved for its own use on Duke's transmission system or on the transmission systems of other transmission providers.

Notice of Duke New Smyrna's filing was published in the Federal Register, 63 Fed. Reg. 23,774 (1998), with comments, protests and interventions due on or before May 11, 1998.

Timely motions to intervene were filed by: Sonat Marketing Company, LP (Sonat); New Smyrna Beach; Florida Power Corporation (Florida Power Corp); Florida Power & Light Company (FP&L); and Tampa Electric Company (TECO) (with protest). TECO argues that Duke New Smyrna's application is premature because construction

plans are not finalized, and TECO contends that New Smyrna Beach should be treated as an affiliate because its business arrangements with Duke New Smyrna extend beyond the power sale.

On May 26, 1998, New Smyrna Beach filed an answer to TECO's protest. On that same date, Duke New Smyrna filed for leave to file an answer to TECO's protest, accompanied by its answer to the protest. Neither of these answers object to TECO's intervention.

Discussion

Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1997), the timely, unopposed motions to intervene of Sonat, New Smyrna Beach, Florida Power Corp, FP&L, and TECO serve to make them parties to this proceeding.

We will reject New Smyrna Beach's and Duke New Smyrna's answers to TECO as impermissible answers to a protest. 18 C.F.R. § 385.213(a)(2) (1997).

Market-Based Rates

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. In order for an affiliate of a transmission-owning public utility to demonstrate the absence or mitigation of market power, the public utility must have on file with the Commission an open access transmission tariff for the provision of comparable services. The Commission also considers whether there is evidence of affiliate abuse or reciprocal dealing. 1/

As we explain below, we find that Duke New Smyrna's market-based rate application meets these standards. Accordingly, we will accept the proposed market-based rates for filing, without modification, to become effective upon the commencement of service.

1/ E.g., Progress Power Marketing, Inc., 76 FERC ¶ 61,155 at 61,919 (1996), letter order approving settlement, 79 FERC ¶ 61,149 (1997); Northwest Power Marketing Company, L.L.C., 75 FERC ¶ 61,281 at 61,889 (1996); accord Heartland Energy Services, Inc., et al., 68 FERC ¶ 61,223 at 62,060-63 (1994) (Heartland).

1. Generation Market Power

Duke New Smyrna will own a 500 MW generating facility to be constructed in New Smyrna Beach, Florida. In support of its market-based rate proposal, Duke New Smyrna relies on section 35.27(a) of the Commission's regulations, 18 C.F.R. § 35.27(a) (1997). Section 35.27(a) of the Commission's regulations reads, in pertinent part, as follows:

> [A]ny public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.

Duke New Smyrna has no existing generation and construction of the subject facility has not yet commenced. Under these circumstances, there is no need to consider the generation market power, if any, resulting from construction of the proposed facility. While we noted in Order No. 888 that we would not "ignore specific evidence presented by an intervenor that a seller requesting market-based rates for sales from new generation nevertheless posses generation dominance," 2/ no such evidence is presented here.

In addition, Duke New Smyrna is affiliated with Duke, Nantahala Power and Light Company (Nantahala), and various power marketers and exempt wholesale generators. In Lykes-Duke/Louis Dreyfus, Ltd., 77 FERC ¶ 61,115 at 61,444 & n.3 (1996) (Lykes-Duke); see also Duke Power Company and PanEnergy Corporation, 79 FERC ¶ 61,236 at 62,037-38 (1997), the Commission determined that Duke and its affiliates lack generation dominance. Thus, Duke New Smyrna's affiliation with these companies does not create generation dominance concerns.

Accordingly, we find that Duke New Smyrna meets the Commission's generation market power standard for approval of market-based rates.

2/ Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 at 31,657 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

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2. Transmission Market Power

When an affiliate of a transmission-owning public utility seeks authorization to charge market-based rates, the Commission has required the public utility to have an open access transmission tariff on file before granting such authorization. 3/ Pursuant to Order No. 888, Duke filed an open access transmission tariff in Docket No. OA96-46-000. 4/ For this reason, we find that Duke New Smyrna meets the Commission's transmission market power standard for approval of market-based rates.

3. Other Barriers to Entry/Reciprocal Dealing

Our review of Duke New Smyrna's application satisfies us that there are no other barriers to entry or reciprocal dealing considerations of concern here.

4. Affiliate Abuse

Duke New Smyrna's rate schedule prohibits power sales to or power purchases from Duke and Nantahala absent a separate rate filing under section 205 of the Federal Power Act (FPA), 16 U.S.C. § 824d (1994). In addition, Duke New Smyrna has attached a code of conduct governing affiliate transactions. These commitments satisfy the Commission's requirements as to information sharing, the pricing of non-power goods and services, and separating business activities and operating personnel of the affiliates. With these safeguards, we are satisfied that there are no affiliate abuse considerations of concern here.

5. TECO's Argument That the Application Is Premature

TECO argues that Duke New Smyrna's filing is premature because the facility has not yet been constructed and its construction depends on whether Duke New Smyrna obtains the requisite siting authority. However, the Commission routinely grants requests for market-based rates for power producers whose generating facilities have yet to be constructed and, in fact, early Commission action often is critical to financing. 5/

3/ See Order No. 888, FERC Stats. & Regs. at 31,656-57; accord Southern Company Services, Inc., et al., 71 FERC ¶ 61,392 at 62,536 (1995); Heartland, 68 FERC at 62,059-60.

4/ The tariff covers Duke's and Nantahala's transmission facilities. See Lykes-Duke, 77 FERC at 61,444.

5/ See, e.g., Zond Development Corporation, 80 FERC ¶ 61,051 at 61,151-52, 61,154 (1997).

6. TECO's Argument That the Commission Should Treat New Smyrna Beach as an Affiliate

TECO argues that the Commission should consider New Smyrna Beach to be an affiliate on the grounds that, if Duke New Smyrna provides ancillary services to New Smyrna Beach, it may be provided with preferential information about New Smyrna Beach's transmission system. We find that TECO's concerns are unfounded and speculative, particularly since New Smyrna Beach is not even the control area operator for its system. Moreover, any legitimate concerns about a possible future ancillary services arrangement are, at best, premature because no such agreement has yet been filed. We will review the merits of the agreement if and when it is filed.

Reassignment of Transmission Capacity

Duke New Smyrna states that, consistent with the conditions established by the Commission for reassignment of transmission capacity, 6/ it will reassign transmission capacity at a price not to exceed the highest of: (1) the original rate paid by Duke New Smyrna; (2) the applicable transmission provider's maximum rate on file at the time of the sale to the eligible customer; or (3) Duke New Smyrna's own opportunity costs, capped at the applicable transmission provider's cost of expansion at the time of the Duke New Smyrna sale to the eligible customer. The proposed tariff states that Duke New Smyrna will not recover opportunity costs without making a separate filing under section 205 of the FPA.

We find Duke New Smyrna's request to be consistent with our requirements applicable to the reassignment of transmission capacity. Accordingly, we accept Duke New Smyrna's proposal to reassign transmission capacity.

Reporting and Filing Requirements

Consistent with procedures we have adopted in other cases, Duke New Smyrna may file umbrella service agreements for short-term power sales (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales. For long-term transactions (longer than one year), Duke New Smyrna must submit

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6/ See Order No. 888, FERC Stats. & Regs. at 31,694-97; Order No. 888-A, FERC Stats. & Regs. at 30,219-25; Commonwealth Edison Company, 78 FERC ¶ 61,312 at 62,335-36 (1997).

the actual individual service agreement for each transaction within 30 days of the date of commencement of service. 7/

To ensure the clear identification of filings, and in order to facilitate the orderly maintenance of the Commission's files and public access to the documents, long-term transaction service agreements should not be filed together with short-term transaction summaries.

Additionally, we will direct Duke New Smyrna to inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. These include, but are not limited to: (1) ownership of generation or transmission facilities or inputs to electric power production other than fuel supplies; or (2) affiliation with any entity not disclosed in the filing that owns generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area. 8/ Alternatively, Duke New Smyrna may elect to report such changes in conjunction with the updated market analysis it will be required to file every three years. 9/

Requests for Waivers and Authorizations

Duke New Smyrna requests waivers and authorizations similar to those granted to power marketers with market-based rate authorization: (1) waiver of the accounting and reporting requirements of Parts 41, 101, and 141 of the Commission's regulations; (2) abbreviated filings with respect to interlocking directorates under Part 45; (3) waiver of the filing requirements of Subparts B and C of Part 35, with the exception of sections 35.12(a), 35.13(b), 35.15, and 35.16; and (4) blanket authorization of securities issuances under Part 34. We will grant the requested waivers and authorizations consistent with those granted to other non-traditional entities selling at market-based rates.

7/ See, e.g., Southern Company Services, Inc., 75 FERC ¶ 61,130 at 61,444-45, clarified, 75 FERC ¶ 61,353 (1996); Plum Street Energy Marketing, Inc., et al., 76 FERC ¶ 61,319 at 62,556 (1996).

8/ See, e.g., Morgan Stanley Capital Group, 69 FERC ¶ 61,175 at 61,695 (1994), order on reh'g, 72 FERC ¶ 61,082 (1995); InterCoast Power Marketing Company, 68 FERC ¶ 61,248 at 62,134, clarified, 68 FERC ¶ 61,324 (1994).

9/ We reserve the right to require such an analysis at any time.

The Commission orders:

(A) Duke New Smyrna's market-based power sales and transmission capacity reassignment tariffs are hereby accepted for filing, to become effective upon commencement of service.

(B) Duke New Smyrna is hereby directed to conform with the filing and reporting requirements specified in this order. The first quarterly report of transactions undertaken by Duke New Smyrna under its market-based power sales tariff will be due within 30 days of the end of the quarter in which service commences.

(C) Duke New Smyrna is hereby directed to file an updated market analysis within three years of the date of this order, and every three years thereafter.

(D) Duke New Smyrna is hereby directed to inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. Alternatively, as discussed in the body of this order, Duke New Smyrna may elect to report any such changes every three years with the updated market analysis filed pursuant to Ordering Paragraph (C) above. Duke New Smyrna shall notify the Commission of which option it elects in its first quarterly report filed pursuant to Ordering Paragraph (B) above.

(E) Duke New Smyrna is hereby directed to inform the Commission of the date of commencement of service within 10 days of that date.

(F) Duke New Smyrna's request for waiver of Parts 41, 101, and 141 of the Commission's regulations is hereby granted.

(G) Within 30 days of the date of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liabilities by Duke New Smyrna should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211 and 385.214 (1997).

(H) Absent a request to be heard within the period set forth in Ordering Paragraph (G) above, Duke New Smyrna is hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of Duke New Smyrna, compatible with the public

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interest, and reasonably necessary or appropriate for such purposes.

(I) Until further order of this Commission, the full requirements of Part 45 of the Commission's regulations, except as noted below, are hereby waived with respect to any person now holding or who may hold an otherwise proscribed interlocking directorate involving Duke New Smyrna. Any such person instead shall file a sworn application providing the following information:

(1) full name and business address; and

(2) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(J) The Commission reserves the right to modify this order to require a further showing that neither public nor private interests will be adversely affected by continued Commission approval of Duke New Smyrna's issuances of securities or assumptions of liabilities, or by the continued holding of any affected interlocks.

(K) Duke New Smyrna's requests for waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15, and 35.16, are hereby granted.

(L) Duke New Smyrna is hereby informed of the following rate schedule designations:

Duke Energy New Smyrna Power Company Ltd., L.L.P.
Docket No. ER98-2624-000

	Designation	Description
(1)	FERC Electric Tariff, Original Volume No. 1 (Original Pages 1-2)	Market-Based Rates/ Code of Conduct
(2)	FERC Electric Tariff, Original Volume No. 2 (Original Pages 1-3)	Reassignment of Transmission Rights

By the Commission.

(S E A L)

David P. Boergers

David P. Boergers,
Acting Secretary.

83 FERC ¶ 62,220

EGAT

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE GENERAL COUNSEL

June 9, 1998

Mr. Adam Wenner
Vinson & Elkins L.L.P.
The Willard Office Building
1455 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Re: Docket No. EG98-65-000

Dear Mr. Wenner:

On April 22, 1998, you filed an application for determination of exempt wholesale generator status on behalf of Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. pursuant to section 32 of the Public Utility Holding Company Act of 1935 (PUHCA). Notice of the application was published in the Federal Register, 63 Fed. Reg. 23,773 (1998), with interventions or comments due on or before May 15, 1998. Timely motions to intervene raising no arguments were filed by Sonat Marketing Company L.P., Florida Power Corporation, Tampa Electric Company, and Florida Power and Light Company.

Authority to act on this matter is delegated to the General Counsel. 18 C.F.R. 375.309(g). Based on the information set forth in the application, I find that Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. is an exempt wholesale generator as defined in section 32 of PUHCA.

A copy of this letter will be sent to the Securities and Exchange Commission.

Sincerely,

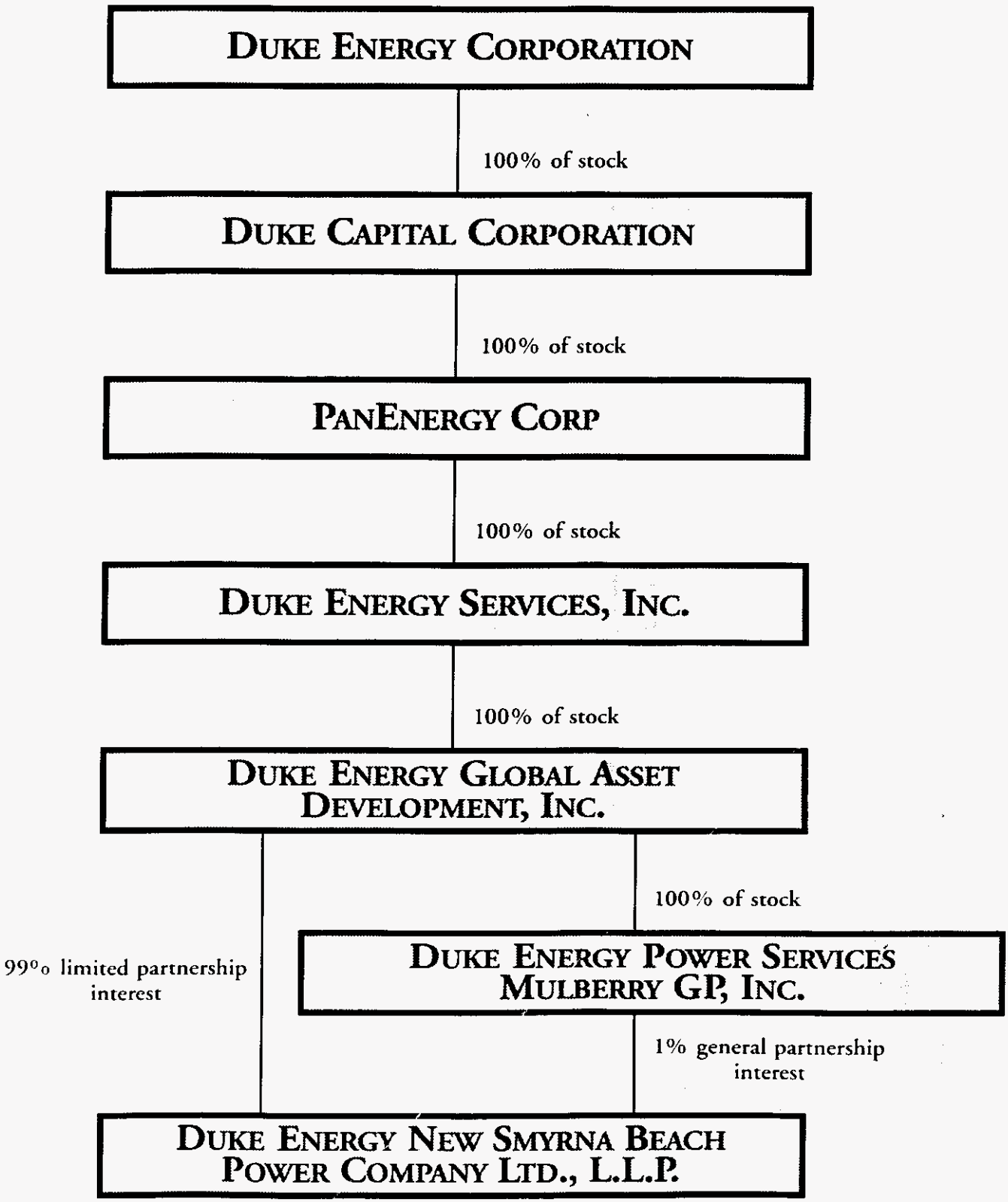
Douglas W. Smith
General Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 981042-EM EXHIBIT NO 17
COMPANY/
WITNESS: Green
DATE: 12-9-98

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Green
Exhibit 17 (MCG-1

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

OWNERSHIP STRUCTURE



83 FERC ¶ 61,316

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

697363

Before Commissioners: James J. Hoecker, Chairman; Vicky A. Bailey, William L. Massey, Linda Breathitt, and Curt Hébert, Jr.

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.) Docket No. ER98-2624-000

ORDER ACCEPTING FOR FILING PROPOSED TARIFFS FOR MARKET-BASED POWER SALES AND REASSIGNMENT OF TRANSMISSION CAPACITY

(Issued June 25, 1998)

In this order, we accept for filing, without hearing or suspension, the tariffs filed by Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. (Duke New Smyrna), under which it proposes to sell power at wholesale at market-based rates and to reassign transmission capacity.

Background

On April 21, 1998, Duke New Smyrna, an indirect wholly-owned subsidiary of Duke Energy Corporation (Duke), filed an application requesting Commission authorization to sell electric capacity and energy at market-based rates. The power is to be produced from a generating facility for which construction has not commenced. Duke New Smyrna states that it has an agreement to sell 30 MW of the 500 MW output of the generating facility to the Utilities Commission of the City of New Smyrna Beach, Florida (New Smyrna Beach) and that Duke New Smyrna will file that agreement once it is finalized. Duke New Smyrna states that it may also enter into an agreement to provide ancillary services to New Smyrna Beach and that, if so, it will make a separate filing consistent with the Commission's then-existing requirements for ancillary services rates. Duke New Smyrna has also filed a tariff to reassign transmission capacity it has reserved for its own use on Duke's transmission system or on the transmission systems of other transmission providers.

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Discussion

Procedural Matters

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We will reject New Smyrna Beach's and Duke New Smyrna's answers to TECO as impermissible answers to a protest. 18 C.F.R. § 385.213(a)(2) (1997).

Market-Based Rates

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. In order for an affiliate of a transmission-owning public utility to demonstrate the absence or mitigation of market power, the public utility must have on file with the Commission an open access transmission tariff for the provision of comparable services. The Commission also considers whether there is evidence of affiliate abuse or reciprocal dealing. 1/

As we explain below, we find that Duke New Smyrna's market-based rate application meets these standards. Accordingly, we will accept the proposed market-based rates for filing, without modification, to become effective upon the commencement of service.

1/ E.g., Progress Power Marketing, Inc., 76 FERC ¶ 61,155 at 61,919 (1996), letter order approving settlement, 79 FERC ¶ 61,149 (1997); Northwest Power Marketing Company, L.L.C., 75 FERC ¶ 61,281 at 61,889 (1996); accord Heartland Energy Services, Inc., et al., 68 FERC ¶ 61,223 at 62,060-63 (1994) (Heartland).

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Accordingly, we find that Duke New Smyrna meets the Commission's generation market power standard for approval of market-based rates.

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Our review of Duke New Smyrna's application satisfies us that there are no other barriers to entry or reciprocal dealing considerations of concern here.

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TECO argues that the Commission should consider New Smyrna Beach to be an affiliate on the grounds that, if Duke New Smyrna provides ancillary services to New Smyrna Beach, it may be provided with preferential information about New Smyrna Beach's transmission system. We find that TECO's concerns are unfounded and speculative, particularly since New Smyrna Beach is not even the control area operator for its system. Moreover, any legitimate concerns about a possible future ancillary services arrangement are, at best, premature because no such agreement has yet been filed. We will review the merits of the agreement if and when it is filed.

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We find Duke New Smyrna's request to be consistent with our requirements applicable to the reassignment of transmission capacity. Accordingly, we accept Duke New Smyrna's proposal to reassign transmission capacity.

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To ensure the clear identification of filings, and in order to facilitate the orderly maintenance of the Commission's files and public access to the documents, long-term transaction service agreements should not be filed together with short-term transaction summaries.

Additionally, we will direct Duke New Smyrna to inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. These include, but are not limited to: (1) ownership of generation or transmission facilities or inputs to electric power production other than fuel supplies; or (2) affiliation with any entity not disclosed in the filing that owns generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area. 8/ Alternatively, Duke New Smyrna may elect to report such changes in conjunction with the updated market analysis it will be required to file every three years. 9/

Requests for Waivers and Authorizations

Duke New Smyrna requests waivers and authorizations similar to those granted to power marketers with market-based rate authorization: (1) waiver of the accounting and reporting requirements of Parts 41, 101, and 141 of the Commission's regulations; (2) abbreviated filings with respect to interlocking directorates under Part 45; (3) waiver of the filing requirements of Subparts B and C of Part 35, with the exception of sections 35.12(a), 35.13(b), 35.15, and 35.16; and (4) blanket authorization of securities issuances under Part 34. We will grant the requested waivers and authorizations consistent with those granted to other non-traditional entities selling at market-based rates.

7/ See, e.g., Southern Company Services, Inc., 75 FERC ¶ 61,130 at 61,444-45, clarified, 75 FERC ¶ 61,353 (1996); Plum Street Energy Marketing, Inc., et al., 76 FERC ¶ 61,319 at 62,556 (1996).

8/ See, e.g., Morgan Stanley Capital Group, 69 FERC ¶ 61,175 at 61,695 (1994), order on reh'g, 72 FERC ¶ 61,082 (1995); InterCoast Power Marketing Company, 68 FERC ¶ 61,248 at 62,134, clarified, 68 FERC ¶ 61,324 (1994).

9/ We reserve the right to require such an analysis at any time.

The Commission orders:

(A) Duke New Smyrna's market-based power sales and transmission capacity reassignment tariffs are hereby accepted for filing, to become effective upon commencement of service.

(B) Duke New Smyrna is hereby directed to conform with the filing and reporting requirements specified in this order. The first quarterly report of transactions undertaken by Duke New Smyrna under its market-based power sales tariff will be due within 30 days of the end of the quarter in which service commences.

(C) Duke New Smyrna is hereby directed to file an updated market analysis within three years of the date of this order, and every three years thereafter.

(D) Duke New Smyrna is hereby directed to inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. Alternatively, as discussed in the body of this order, Duke New Smyrna may elect to report any such changes every three years with the updated market analysis filed pursuant to Ordering Paragraph (C) above. Duke New Smyrna shall notify the Commission of which option it elects in its first quarterly report filed pursuant to Ordering Paragraph (B) above.

(E) Duke New Smyrna is hereby directed to inform the Commission of the date of commencement of service within 10 days of that date.

(F) Duke New Smyrna's request for waiver of Parts 41, 101, and 141 of the Commission's regulations is hereby granted.

(G) Within 30 days of the date of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liabilities by Duke New Smyrna should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211 and 385.214 (1997).

(H) Absent a request to be heard within the period set forth in Ordering Paragraph (G) above, Duke New Smyrna is hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of Duke New Smyrna, compatible with the public

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interest, and reasonably necessary or appropriate for such purposes.

(I) Until further order of this Commission, the full requirements of Part 45 of the Commission's regulations, except as noted below, are hereby waived with respect to any person now holding or who may hold an otherwise proscribed interlocking directorate involving Duke New Smyrna. Any such person instead shall file a sworn application providing the following information:

(1) full name and business address; and

(2) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(J) The Commission reserves the right to modify this order to require a further showing that neither public nor private interests will be adversely affected by continued Commission approval of Duke New Smyrna's issuances of securities or assumptions of liabilities, or by the continued holding of any affected interlocks.

(K) Duke New Smyrna's requests for waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15, and 35.16, are hereby granted.

(L) Duke New Smyrna is hereby informed of the following rate schedule designations:

Duke Energy New Smyrna Power Company Ltd., L.L.P.
Docket No. ER98-2624-000

	Designation	Description
(1)	FERC Electric Tariff, Original Volume No. 1 (Original Pages 1-2)	Market-Based Rates/ Code of Conduct
(2)	FERC Electric Tariff, Original Volume No. 2 (Original Pages 1-3)	Reassignment of Transmission Rights

By the Commission.

(S E A L)

David P. Boergers,
Acting Secretary.

83 FERC ¶ 62,220

COPY

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE GENERAL COUNSEL

June 9, 1998

Mr. Adam Wenner
Vinson & Elkins L.L.P.
The Willard Office Building
1455 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Re: Docket No. EG98-65-000

Dear Mr. Wenner:

On April 22, 1998, you filed an application for determination of exempt wholesale generator status on behalf of Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. pursuant to section 32 of the Public Utility Holding Company Act of 1935 (PUHCA). Notice of the application was published in the Federal Register, 63 Fed. Reg. 23,773 (1998), with interventions or comments due on or before May 15, 1998. Timely motions to intervene raising no arguments were filed by Sonat Marketing Company L.P., Florida Power Corporation, Tampa Electric Company, and Florida Power and Light Company.

Authority to act on this matter is delegated to the General Counsel. 18 C.F.R. 375.309(g). Based on the information set forth in the application, I find that Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. is an exempt wholesale generator as defined in section 32 of PUHCA.

A copy of this letter will be sent to the Securities and Exchange Commission.

Sincerely,

Douglas W. Smith
General Counsel

PARTICIPATION AGREEMENT

Dated: February 17, 1998

by and between

Utilities Commission, City of New Smyrna Beach, Florida

and

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

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EXHIBITS

Exhibit A Description of the Site
Exhibit B Tax Agreement

PARTICIPATION AGREEMENT

This Participation Agreement ("Agreement"), dated as of February 17, 1998, is by and between the Utilities Commission, City of New Smyrna Beach, Florida, a commission ("UCNSB") of the City of New Smyrna Beach, Florida (the "City"), and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P., a limited partnership organized and existing under the laws of the State of Florida ("Duke") (collectively, the "Parties").

WHEREAS, Duke and its affiliates are in the business of developing, owning and operating electric generation facilities throughout the United States;

WHEREAS, in order to meet the power requirements of UCNSB's existing and future customers in a manner that is in the best interest of such customers, and pursuant to a Letter of Intent dated May 21, 1997 (the "LOI") between UCNSB and PanEnergy Power Services, Inc. (now known as Duke Energy Power Services, LLC and an affiliate of Duke), such parties have conducted due diligence investigations regarding the feasibility and economic viability of developing an electric generation facility in New Smyrna Beach, Florida and have reached a definitive agreement for the Parties to proceed with the development of a combined-cycle electric generation facility with a capacity of approximately 240 megawatts or more (the "Facility"); and

WHEREAS, the Facility is to be located on a site presently owned by UCNSB of approximately 20 acres located northwest of the intersection of Interstate I-95 and State Road 44 in Volusia County, Florida and more particularly described on Exhibit A hereto (the "Site"), which Site is adjacent to UCNSB's 115 KV substation (the "Smyrna Substation");

NOW, THEREFORE, in consideration of the mutual agreements contained herein, UCNSB and Duke hereby agree as follows:

1.0 ENTITLEMENT

1.1 General

Duke shall provide to UCNSB an entitlement to 20 megawatts ("MW") of electric capacity (the "Entitlement") from the Facility measured at the ring bus of the Smyrna Substation. The Entitlement shall begin on the commercial operation date ("COD") of the Facility (which is expected to be about 33 months after the date hereof) and continue for the technical and economic life of the Facility (which technical and economic life shall be deemed to be the period during which the Facility, as it is initially constructed prior to the COD, is technically capable (excluding customary outages and force majeure outages) of producing electric energy at a cost that results in a reasonable profit and cash flow to the owner of the Facility when such energy is sold). The Entitlement shall be provided in consideration for UCNSB's contributions to Duke of the Site and certain infrastructure requirements as described in Section 2.0 and UCNSB's other

obligations under this Agreement. There shall be no other charge for the Entitlement.

1.2 Availability

The Entitlement shall be made available to UCNSB for all hours during which the Facility is available. If the Facility is unavailable because of either a scheduled or unscheduled outage, Duke shall have no responsibility to provide for replacement capacity to UCNSB. If the Facility is derated, UCNSB's Entitlement shall be derated proportionately.

1.3 Associated Energy

Beginning at the COD, Duke shall make available to UCNSB, at the ring bus of the Smyrna Substation, 20 megawatt hours ("MWH") of electric energy per hour associated with the Entitlement ("Associated Energy") and UCNSB shall be obligated to take or pay for 18 MWH/hour of Associated Energy for all hours in which the Facility is available. Such amount shall be prorated in conjunction with any derating of the Facility pursuant to Section 1.2. If the Facility is unavailable because of either a scheduled or unscheduled outage, Duke shall have no responsibility to provide for replacement energy. Associated Energy shall be priced at $18.50 per MWH beginning on the COD. On each of the first nine anniversaries of the COD, the Associated Energy price shall be adjusted by multiplying the then existing price by a fraction, the numerator of which is the average of the Weekly Indexes (On-Peak) for the Price of Spot Electricity for the Florida/Georgia Border market as quoted in Power Markets Week published by The McGraw-Hill Companies for the 52 weeks immediately preceding such anniversary, and the denominator of which is the average of such Weekly Indexes for the 52 weeks immediately preceding the COD (in the case of the first anniversary) or the preceding anniversary (in the case of each subsequent anniversary) (or, if such Weekly Index ceases to be quoted, then the Parties shall agree on the publicly quoted index that is the most comparable to such Weekly Index as a substitute therefor); provided, however, that in no event shall the resulting price be greater or less than $18.50 per MWH increased or decreased, respectively, by 3.5% per year (compounded) for each year after the COD (on a cumulative basis). From and after the tenth anniversary of the COD, the Associated Energy price shall be equal to the fair market value of similar quantities of firm wholesale electric energy (including capacity and transmission) delivered by an unrelated third party to another unrelated third party (without any other contractual relationships) at the Smyrna Substation; provided that UCNSB shall be entitled to an annual credit of $1,000,000, one-twelfth of which shall be applied against each month's charges for Associated Energy (which credit shall not reduce any month's charges below zero and shall not be carried forward to future months), to reflect that the new pricing would not be on the same basis as the favorable pricing to UCNSB during the first ten years after the COD. Invoices for Associated Energy provided during a

month shall be delivered by Duke to UCNSB within 10 days after the end of such month and shall be due within 15 days after such delivery.

1.4 Replacement Capacity and Energy

If the Facility is available, but Duke chooses not to dispatch the Facility or the Facility commitments are below the minimum capacity of the Facility as established by Duke, then Duke shall arrange for replacement capacity and energy to be delivered to UCNSB at the ring bus of the Smyrna Substation. There shall be no charge for replacement capacity. Replacement energy shall be priced at the same price as Associated Energy from the Facility as provided in Section 1.3.

1.5 Provision For Modification of Tax Agreement

If at any time during the life of the Facility (which phrase life of the Facility, as used hereinafter, shall include the period of time from the date hereof through the decommissioning and dismantling of the Facility) the Tax Agreement defined in Section 5.2 is modified, is not renewed, or is otherwise affected such that the Facility or Duke incurs City Taxes (as defined in Section 5.2) in excess of $500,000 with respect to the Site and the Facility (and, if applicable, the Additional Capacity as defined in Section 6.1) during any 12 month period beginning on the COD or any anniversary of the COD, Duke shall deliver to UCNSB an invoice or invoices for the amount of such excess and UCNSB shall pay to Duke the amount of such excess within 15 days after delivery of each such invoice.

1.6 Load Following Services

(a) Duke shall furnish load following services to UCNSB that will allow UCNSB to schedule 20 MW for any hour, but take an amount of Associated Energy during the hour which is between 18 and 20 MWH (the "Load Following Services"). Duke shall not be obligated under this Agreement to provide to UCNSB any other ancillary services.

(b) The capacity portion of the Load Following Services will be furnished as part of the 20 MW Entitlement. The energy associated with Load Following Services will be priced pursuant to Section 1.3.

(c) Duke will provide the Load Following Services to UCNSB if the Facility is available. If the Facility is not available, Duke will have no responsibility to provide the Load Following Services. If Duke chooses not to dispatch the Facility or the Facility commitments are below the minimum capacity of the Facility as established by Duke, and if Duke does not arrange for the load following services from a third party, then UCNSB may arrange for the Load Following Services to be provided by another supplier under FERC Order 888 and Duke shall reimburse UCNSB within 15

days of being invoiced by UCNSB for the actual cost of such services minus the energy cost as provided in Section 1.3.

2.0 FACILITY, SITE AND INFRASTRUCTURE

2.1 Facility

Duke shall, at its cost, design, engineer, procure equipment for, construct, finance, own, operate, and market all capacity, energy and ancillary services provided from the Facility.

2.2 Site

UCNSB shall transfer good and marketable title to the Site (free and clear of all liens and encumbrances other than those set forth on Exhibit A hereto) to Duke prior to April 1, 1998. Prior to the commencement of construction of the Facility, Duke shall obtain a Phase I Site Assessment of the Site (to determine real or potential environmental liabilities) performed pursuant to ASTM E 1527-93 guidelines and deliver to UCNSB a copy of the results of such assessment. UCNSB shall indemnify and hold harmless Duke, its affiliates, and Duke's and its affiliates' respective directors, employees and representatives, from and against any and all claims, liabilities, losses and expenses (including costs of suit and attorneys' fees) attributable to the ownership or operation of the Site prior to such transfer or attributable to the condition of the Site at the time of such transfer, regardless of whether same are identified in such assessment. Subject to the foregoing, UCNSB shall not be responsible for, and Duke shall be responsible for, any costs of decommissioning and dismantling of the Facility at the end of its useful life. If, at any time prior to completion of the detailed engineering for the Facility, Duke reasonably determines (based on engineering and technical factors) that the Site is not adequate for the Facility and its related facilities, UCNSB will acquire, at UCNSB's cost and in a timely manner in order for Duke to meet its project schedule for the Facility, and transfer to Duke additional property contiguous with the Site on the same terms as the Site (as described in this Section).

2.3 Make-up Water

UCNSB will, at its cost, complete construction of a wastewater treatment facility (which will include a storage reservoir of at least 2 million gallons for the reuse water) and complete the drilling and equipping of water wells which, together with the reuse water from the water treatment facility, will be capable of supplying all water required by the Facility for the life of the Facility. Such water treatment facility and water wells will be located on land adjacent to the Site and will, contingent on UCNSB's receipt of necessary permits, be completed prior to the commencement of start-up testing of the Facility. From such water treatment facility and water wells, UCNSB will deliver to Duke at the power plant block on the Site all water required by the Facility for the life of the Facility. All of such water shall

be of a quality that meets the technical specifications, prior to demineralization, of the Facility. All of such water will be delivered through a minimum of a 12-inch main with a flow rate of at least 1500 gallons per minute. UCNSB shall charge Duke for all of such water at the lowest rate applicable to major users of reuse water in the area in which reuse water service is provided by UCNSB or by any successor provider (regardless of whether such reuse water is treated at such water treatment facility). Without limiting the foregoing, (a) rate increases will occur only to the extent necessary to meet operation and maintenance cost increases (cost base) associated with the processing of the reuse water, (b) since the Facility will be adjacent to the water treatment facility, capital costs and operation and maintenance costs associated with the transmission of the reuse water will not be included in any rate increases, and (c) Duke shall have the right, through appropriate proceedings, to contest any rate increases. If at any time such water from such water treatment facility and water wells is not sufficient (in terms of quantity or quality) to meet the requirements of the Facility, UCNSB shall deliver to Duke sufficient quantities of potable water as backup water at a price equal to the actual operating costs of pumping such potable water to the Facility (excluding any distribution system costs) and otherwise on the same terms as such water from such water treatment facility and water wells.

2.4 Smyrna Substation

UCNSB shall, at its cost, complete engineering and construction of a modification to the Smyrna Substation's ring bus, associated breakers, relays, instrumentation, etc., to accommodate a position in the ring bus for the Facility prior to the commencement of start-up testing of the Facility. UCNSB shall, at its cost, maintain the Smyrna Substation (including such modification) and provide Duke with access to the Florida Power Corp. and Florida Power & Light Co. transmission grids and with access to use the Smyrna Substation, in each case in a manner that will permit proper operation of the Facility for the life of the Facility.

2.5 Gas Delivery System

Duke shall, at its cost, cause natural gas pipeline service to be made available to the Site prior to the commencement of start-up testing of the Facility and shall also be responsible for any additional gas processing facilities that may be required downstream of the pipeline delivery meter and upstream of the Facility's combustion equipment.

3.0 PERMITS AND APPROVALS

3.1 General

Each Party shall use reasonable efforts to obtain all permits and approvals required to perform its obligations under this Agreement and shall assist the other Party in obtaining its permits and approvals.

3.2 Cost Sharing

Duke and UCNSB will share equally in the first $200,000 of costs approved by Duke (which approval shall not be unreasonably withheld but must be obtained prior to incurring the costs) relating to obtaining and maintaining governmental permits and approvals for the Facility, including charges by Duke's affiliates but excluding Duke, Duke Energy Power Services, LLC and UCNSB staff expenses and excluding the fees and expenses of UCNSB's counsel. Any permitting costs so approved by Duke that are in excess of $200,000 will be the sole responsibility of Duke.

3.3 Sale of Power

The obligation of Duke to provide the Entitlement to UCNSB and to sell Associated Energy to UCNSB, and the obligation of UCNSB to purchase Associated Energy with the Entitlement from Duke, are subject to the receipt of the approval from the Federal Energy Regulatory Commission for the sale of power in a form acceptable to each of the Parties affected thereby in its sole discretion. Recognizing that Duke intends to qualify as an "exempt wholesale generator" under the Public Utility Holding Company Act of 1935, as amended, UCNSB agrees to resell, and not to use for any end use, all of the electric energy provided to it by Duke pursuant to this Agreement.

3.4 Facility and Gas Delivery System

The obligations of Duke under Sections 2.1 and 2.5, including the obligation to construct the Facility and provide for natural gas deliveries to the Facility, are subject to (a) the receipt of all applicable governmental permits and approvals in a form acceptable to each of the Parties affected thereby in its sole discretion, (b) Duke obtaining a reasonably satisfactory agreement for the looping and extension of the existing natural gas pipeline lateral (i.e., the Sanford Lateral) running closest to the Site, (c) Duke obtaining, on or before March 7, 1998, the approval of the Policy Committee of Duke Energy Corporation to proceed with the transactions contemplated in this Agreement, and (d) no circumstance or event existing or having occurred that has had or could reasonably be expected to have a material adverse effect on the feasibility, prospects or business of the Facility. Duke shall give written notice to UCNSB if Duke determines not to complete the Facility as a result of any of the foregoing, in which event neither Party shall have any further obligations under this Agreement;

provided, however, that (i) each Party shall continue to be liable for any breaches hereof occurring prior to such notice, (ii) if at such time the Site has been conveyed to Duke, Duke shall reconvey to UCNSB all of Duke's right, title and interest to the Site, (iii) if such determination is made solely on the basis of the matters described in clause (d) of the immediately preceding sentence, then Duke shall also pay to UCNSB $200,000, and (iv) if within 6 months thereafter UCNSB notifies Duke that UCNSB intends to complete the Facility with another party and requests Duke to transfer any governmental permits and approvals for the Facility and any applications therefor, and if such request is approved by Duke (which approval shall not be unreasonably withheld), Duke will, to the extent legally permissible, transfer to UCNSB any governmental permits and approvals that Duke has received in connection with the Facility and any applications for governmental permits or approvals in connection with the Facility that have not yet been obtained, in each case excluding any confidential or proprietary information of Duke.

4.0 OPERATION AND MAINTENANCE

4.1 General

Duke or its designee (which may, at Duke's option, be or include UCNSB) will be responsible for the Facility's operation and maintenance activities.

4.2 Local Preference for Staffing

Subject to qualifying standards and to the extent commercially reasonable, Duke or its designee will give hiring preference to current UCNSB employees for staff positions at the Facility and will recruit for additional staffing needs from the New Smyrna Beach and Volusia County areas.

5.0 TAXES

5.1 General

Duke will be responsible for the payment of all taxes associated with the sale of capacity or energy from the Facility; provided that UCNSB shall pay (or reimburse Duke on a grossed-up basis for) all taxes (including, without limitation, gross receipts and similar taxes, but excluding (except in connection with a gross-up) federal and state income taxes) associated with the Entitlement or Associated Energy. Except as provided in the preceding sentence or Sections 1.5 or 5.2, Duke will also be responsible for all other federal, state, and local taxes that may be levied as a result of the construction, ownership, or operation of the Facility.

5.2 Special Tax Agreement

Pursuant to the Tax Agreement dated February 17, 1998 by and between the City of New Smyrna Beach, Florida (the "City") and UCNSB (the "Tax Agreement"), the City has agreed to accept an annual payment of $500,000 in lieu of any taxes, fees, user fees, license fees, assessments,

special assessments, or any other charges of any type or nature whatsoever, that the City (or any other special taxing district or instrumentality created by or on behalf of the City) is or may hereafter be in a position to levy, assess, charge, or otherwise impose, either directly or indirectly ("City Taxes", which term includes the payments under the Tax Agreement), regarding sales from, or ownership, construction, operation, decommissioning or dismantlement of, the Facility or the Site. A copy of the Tax Agreement is attached hereto as Exhibit B.

6.0 ADDITIONAL DEVELOPMENT RIGHTS

6.1 General

At any time and from time to time during the life of the Facility, UCNSB shall provide to Duke or its designee, in connection with the development of any additional power generating capacity above 240 MW at or near the Site (which may occur at the same time as the development of the Facility or at one or more subsequent times, and which may be part of the Facility or may be one or more additional facilities), the exclusive right to use the Smyrna Substation (and in such regard, at Duke's request, UCNSB shall provide to Duke, at UCNSB's cost to the extent applicable to the first 260 MW of additional power generating capacity and at Duke's cost to the extent in excess thereof, an additional position on the ring bus at the Smyrna Substation for such additional capacity) and then-currently available land, electric transmission, water treatment and delivery facilities, and other infrastructure at no additional cost. UCNSB shall not provide any such rights to any other parties during the life of the Facility. If, utilizing such rights, Duke develops any such additional power generating capacity above 240 MW that is not merely a modification of the Facility ("Additional Capacity"), then, effective as of the commencement of commercial operations of any Additional Capacity:

(a) Duke shall provide to UCNSB an entitlement to an additional 10 MW of capacity from the Additional Capacity on substantially the same terms as the Entitlement, including a take or pay obligation for 90% of the electric energy from such additional entitlement; provided, however, that (i) if the capacity of such Additional Capacity is less than 240 MW, such additional entitlement shall be adjusted to a number of MW equal to the product (rounded up to the nearest whole MW) of 10 MW multiplied by a fraction, the numerator of which is the capacity of such Additional Capacity and the denominator of which is 240 MW, and (ii) if either the Facility or the Additional Capacity is derated, UCNSB's aggregate entitlement from such two sources shall be derated by multiplying the sum of the entitlements from such two sources by a fraction, the numerator of which is the aggregate availability of such two sources at the time and the

denominator of which is the aggregate capacity of such two sources;

(b) the reference to $500,000 in Section 1.5 shall be revised to be a dollar amount equal to the sum of (i) $500,000 plus (ii) the product of $250,000 multiplied by a fraction, the numerator of which is the capacity of such Additional Capacity and the denominator of which is 240 MW; provided, however, that with respect to any 12 month period beginning on the tenth or any subsequent anniversary of the COD, UCNSB shall not be obligated under Section 1.5 to pay Duke for any ad valorem taxes assessed on the Additional Capacity in excess of the amount described in clause (ii) of this Section 6.1(b), it being understood that, for purposes of allocating ad valorem taxes for this provision between the initial 240 MW of the Facility and the Additional Capacity, the Site and all real and personal property used or useful in connection with such initial 240 MW of the Facility shall be allocated to such 240 MW of the Facility and not to the Additional Capacity (for example, assuming the Additional Capacity is 240 MW, (A) if ad valorem taxes allocable to the Additional Capacity are $250,000 and all other City Taxes allocable to the Additional Capacity are $300,000, UCNSB shall pay to Duke $300,000 with respect to City Taxes allocable to the Additional Capacity, and (B) if ad valorem taxes allocable to the Additional Capacity are $300,000 and all other City Taxes allocable to the Additional Capacity are $250,000, UCNSB shall pay to Duke $250,000 with respect to City Taxes allocable to the Additional Capacity); and

(c) UCNSB shall deliver to Duke all of the water required for such Additional Capacity on the same terms as the water described in Section 2.3 for the Facility, it being agreed that UCNSB shall incorporate into its 5 year capital improvements plan beginning in fiscal year 1998 the capital expenditures required to be in a position to deliver such water for the Additional Capacity.

7.0 REPRESENTATIONS AND WARRANTIES

7.1 Representations and Warranties of Duke

Duke hereby represents and warrants to UCNSB that:

(a) Duke is a duly organized, validly existing Florida limited partnership and is in good standing under the laws of the State of Florida. It has all requisite partnership power and authority to enter into and to perform its obligations under this Agreement.

(b) Its execution, delivery, and performance of this Agreement have been duly authorized, and do not and will not (i) violate any law,

rule, regulation, order, or decree applicable to it, (ii) violate its organizational documents, or (iii) contravene or constitute a default or breach under any instrument, indenture, agreement, or other obligation to which it is a party or by which it is bound.

(c) This Agreement is a legal and binding obligation of Duke, enforceable against Duke in accordance with its terms, except to the extent enforceability is modified by bankruptcy, reorganization and other similar laws affecting the rights of creditors generally and by general principles of equity.

(d) There is no litigation or administrative proceeding (excluding permit applications and similar matters) pending or, to the best of its knowledge, threatened involving Duke that, if adversely determined, could have a material adverse effect on the financial condition, prospects, or business of the Facility or Duke's ability to perform its obligations under this Agreement.

7.2 Representations and Warranties of UCNSB

UCNSB hereby represents and warrants to Duke that:

(a) UCNSB is a duly organized, validly existing commission of the City and pursuant to Section 214 of Chapter 15 of the City's Charter UCNSB has been delegated the authority to manage, operate and control the City's utilities. Pursuant to the authority delegated to UCNSB by the City, UCNSB has all requisite power and authority to enter into and to perform its obligations under this Agreement.

(b) UCNSB's execution, delivery, and performance of this Agreement have been duly authorized, and do not and will not (i) violate any law, rule, regulation, order, or decree applicable to it or the City, (ii) violate its organizational documents, or (iii) contravene or constitute a default or breach under any instrument, indenture, agreement, or other obligation to which it is a party or by which it is bound.

(c) This Agreement is a legal and binding obligation of UCNSB, enforceable against UCNSB in accordance with its terms, except to the extent enforceability is modified by bankruptcy, reorganization and other similar laws affecting the rights of creditors generally and by general principles of equity.

(d) There is no litigation or administrative proceeding (excluding permit applications and similar matters) pending or, to the best of its knowledge, threatened involving UCNSB that, if adversely determined, could have a material adverse effect on the financial

condition, prospects, or business of the Facility or UCNSB's ability to perform its obligations under this Agreement.

8.0 MISCELLANEOUS

8.1 Notices

All notices, requests or consents provided for or permitted to be given under this Agreement shall be in writing, shall be delivered to the recipient in person, by courier or mail, or by facsimile, telex or similar transmission, and shall be effective (a) upon receipt, if sent by personal delivery, mail or courier, or (b) upon the sender's receipt of electronic confirmation of transmission, if sent by facsimile, telex or similar transmissions during regular business hours on a business day (or, if not sent during regular business hours on a business day, on the next succeeding business day). All notices, requests and consents to be sent to a Party shall be sent to the following addresses or such other address as a Party may specify for its address by notice to the other Party:

If to UCNSB:

Utilities Commission, City of
New Smyrna Beach, Florida
Post Office Box 100
200 Canal Street
New Smyrna Beach, Florida 32170
Telephone: 904-427-7100
Facsimile: 904-423-7175
Attention: Director of Utilities

If to Duke:

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.
400 South Tryon Street
Suite 1800
Charlotte, N.C. 28285
Telephone: 704-382-5963
Facsimile: 704-382-1452
Attention: Mr. David Hauser

8.2 Exclusivity

From the date hereof until the COD, each Party shall use reasonable efforts to promote the business of the Facility and shall not solicit or engage in negotiations or discussions with any other party relating to the Facility or any other similar project within the area in which electric service is provided by UCNSB or any successor provider, if such

negotiations or discussions could reasonably be expected to have a material adverse effect on the business or prospects of the Facility.

8.3 Disclosure of Information

The Parties acknowledge that UCNSB is a publicly owned and operated utility and that UCNSB, its commissioners, employees and agents are subject to the provisions and requirements of Chapters 119 and 286, Florida Statutes, regarding the handling of public records and open meetings. Subject to such requirements, each Party shall maintain in confidence all information received from the other Party or its affiliates relating to the Facility; provided, however, that such Party may disclose such information (a) to its affiliates and its affiliates' respective directors, employees, and representatives (it being understood that they shall be informed by such Party of the confidential nature of such information and that such Party shall cause them to treat such information confidentially), (b) with the approval of Duke if such disclosure is reasonably necessary to develop, construct, finance or promote the business of the Facility, (c) if required to do so by applicable laws, rules, regulations, or orders (including any applicable securities exchange rules), (d) if such information was or becomes generally available to such Party on a non-confidential basis, provided that the source of such information was not known by such Party to be bound by a confidentiality obligation, or (e) if such information is generally available to the public.

8.4 Assignment

No assignment of any of the rights or obligations under this Agreement shall be made by either Party other than to an affiliate of such Party unless (a) it can be demonstrated to the reasonable satisfaction of the non-transferring Party that the financial creditworthiness of the transferee party is at least equal to or better than that of the transferring Party and (b) the non-transferring Party has consented in writing prior thereto, which consent shall not be unreasonably withheld; provided that it is understood that no assignment shall relieve the transferring Party of its obligations hereunder unless the non-transferring Party has consented in writing prior thereto, which consent shall be in such non-transferring Party's sole discretion. For purposes of this Agreement, an "affiliate" of a party shall be any other party controlling, controlled by, or under common control with such party. Without limiting the foregoing, if either Party transfers all or substantially all of its assets to another party, such Party shall cause such transferee party to assume all of such Party's obligations under this Agreement.

8.5 Binding Effect; No Third Party Beneficiaries

This Agreement shall be binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns. Except to the extent Section 2.2 (relating to rights of certain parties to be indemnified) provides otherwise, this Agreement is solely for the benefit of the Parties and their respective successors and permitted assigns, and this Agreement shall not otherwise be deemed to confer upon or give to any other party any rights, claims or remedies.

8.6 Expenses

Except as otherwise provided herein, each Party agrees to bear any costs incurred by it in connection with this Agreement and the development of the Facility.

8.7 Indemnification

Each Party shall indemnify and hold harmless the other Party from and against all claims, liabilities, losses, and expenses (including costs of suit and attorneys' fees) that it may incur on account of any breach by the indemnifying Party of any of its representations, warranties or obligations under this Agreement.

8.8 Further Assurances

Each Party agrees to negotiate in good faith and to execute and deliver as soon as practicable after the date hereof a power purchase agreement more fully reflecting the matters described in Section 1.0 hereof. Each Party also agrees to execute such other documents and take such further actions as may be necessary or desirable to effectuate the provisions of this Agreement.

8.9 Compliance with Laws

Each Party shall comply with all laws, rules and regulations applicable to it, the Facility, or the infrastructure described in Section 2.0.

8.10 GOVERNING LAW

THIS AGREEMENT IS GOVERNED BY AND SHALL BE CONSTRUED IN ACCORDANCE WITH THE LAW OF THE STATE OF FLORIDA, EXCLUDING ANY CONFLICT-OF-LAWS RULE OR PRINCIPLE THAT MIGHT REFER THE GOVERNANCE OR THE CONSTRUCTION OF THIS AGREEMENT TO THE LAW OF ANOTHER JURISDICTION.

8.11 Dispute Resolution

In the event of any dispute between the Parties, the Parties shall first attempt to settle such dispute amicably if possible and, failing that, such dispute shall be submitted to the services of a professional mediation service (the cost of which shall be borne equally by the Parties) which shall attempt to mediate the dispute. If the Parties cannot agree upon a mediation service or if the dispute has not been resolved within 60 days after either Party requested mediation services, each Party shall be free to pursue any other means of resolution available to such Party.

8.12 Consequential Damages

Notwithstanding anything to the contrary contained herein, except for actual damages, neither Party shall be liable or have any responsibility to the other Party for any indirect, special, consequential, punitive or other delay-related or performance-related damages including, without limitation, lost earnings, production or profits. Such limitation on liability shall apply with respect to any claim or action, whether it is based in whole or in part on contract, negligence, strict liability, tort, statutory or any other theory of liability. The Parties specifically acknowledge that the benefits each Party contemplates deriving from the provisions of this Agreement reflect such allocation of risk and limitation on liability.

8.13 Remedies

Notwithstanding anything to the contrary contained herein, if UCNSB fails to pay any amounts aggregating over $50,000 for more than 30 days after the due dates therefor, Duke shall have the right to cease providing energy to UCNSB until such failure is cured and, if such failure continues for more than 90 days after the due dates therefor, Duke shall have the right to terminate (upon notice to UCNSB) the Entitlement and all of Duke's obligations under Section 1.0. Subject to Section 8.12, the rights and remedies provided by this Agreement are cumulative and are in addition to any other rights and remedies a Party may have by law, statute or otherwise.

8.14 Waivers

Any waiver, express or implied, by a Party of any right under this Agreement shall be effective only if it is set forth in a written document executed by such Party and shall not constitute or be deemed to be a waiver of any other right, whether of a similar or dissimilar nature.

8.15 Severability

If any provision of this Agreement or the application thereof to any Party or circumstance shall be held invalid or unenforceable to any extent, the remainder of this Agreement and the application of such provision to the other Party or circumstances shall not be affected thereby and shall be enforced to the greatest extent permitted by law. In such event, the Parties agree that the provisions of this Agreement shall be modified and

reformed so as to effect the original intent of the Parties as closely as possible with respect to any such provision held invalid or unenforceable.

8.16 No Partnership

Nothing in this Agreement shall be construed (a) to create or constitute a partnership, agency or similar relationship, (b) to create any joint and several liability on the part of either of the Parties, or (c) to cause the Parties not to be separate legal entities.

8.17 Entire Agreement; Amendment

This Agreement and the Tax Agreement constitute the entire agreement among the Parties and their respective affiliates relating to the Facility and supersede all prior written or oral agreements among any such parties with respect to such matter (including, without limitation, the LOI). This Agreement may be amended or modified only by a written document executed by each of the Parties.

8.18 Headings; References

The headings of the Sections of this Agreement are included for convenience of reference only and shall not be used in construing or limiting the language of any particular Section. All references to a Party shall be deemed to include its successors and permitted assigns. Unless otherwise expressly provided, all references to "Sections" are to the Sections of this Agreement and all references to "Exhibits" are to the Exhibits attached hereto, each of which is made a part hereof for all purposes.

8.19 Counterparts

This Agreement may be executed in any number of counterparts with the same effect as if each Party had signed the same document. All counterparts shall be construed together and constitute the same instrument.

8.20 Limited Recourse Against UCNSB

The obligations of UCNSB under this Agreement shall not constitute general obligations of UCNSB or the City as "bonds" within the meaning of the Constitution of Florida, but shall be payable solely from, and shall be secured equally and ratably by a first lien on and pledge of, the Net Revenues from UCNSB's System on a parity with UCNSB's Series 1992 Certificates, Series 1993 Certificates, Series 1996 Certificates, and any Additional Parity Obligations without any preference, priority or distinction of any such certificate or obligation over any other thereof (with capitalized terms used in this Section but not otherwise defined in this Agreement having the meanings given to them in Resolution No. 28-78, adopted by UCNSB on June 30, 1978). UCNSB hereby grants to Duke such a first lien on and security interest in, and so pledges to Duke, such Net Revenues to secure the payment and performance of UCNSB's

obligations under this Agreement. UCNSB agrees to comply with all of its obligations set forth in such Resolution No. 28-78 as if such obligations were set forth herein.

IN WITNESS WHEREOF, each of the undersigned Parties has executed and delivered this Agreement as of the date first set forth above.

Attest: Helen Simmons

UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH, FLORIDA

By: Ronald Vaden
Name: Ronald L. Vaden
Title: Utilities Director

Approved as to form and correctness:

Counsel to UCNSB: Hal Spence
Hal Spence, Esquire

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

By: Duke Energy Power Services
Mulberry GP, Inc.,
its general partner

By: James M. Donnell
Name: James M. Donnell
Title: Senior Vice President

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EXHIBIT A

Description of the Site

The Site shall be the West 1320 feet of the North 660 feet of the NE 1/4 of Section 21, Township 17 South, Range 33 East, containing 20 acres more or less, but excluding the land covered by the Smyrna Substation.

EXHIBIT B

TAX AGREEMENT

This Tax Agreement (this "Agreement"), dated as of February 17, 1998, is by and between the Utilities Commission, City of New Smyrna Beach, Florida (the "Commission") and the City of New Smyrna Beach, Florida (the "City").

WHEREAS, the Commission, pursuant to Section 214 of the City's Charter, has been charged with the responsibility to manage, operate and control all of the City's utilities and, pursuant to Section 217 of the City's Charter, is authorized to furnish the electricity and power, among other utilities, to private individuals and corporations and in furtherance of said power, the Commission has the right to acquire, construct, maintain, extend, improve and develop electric production and distribution systems and to contract with public bodies, and private corporations, partnerships and individuals for such purposes; and

WHEREAS, the Commission has negotiated and expects to enter into a Participation Agreement (the "Participation Agreement") with Duke Energy New Smyrna Beach Power Company, a Delaware limited partnership ("Duke Energy LP", which term shall include its successors and assigns) for the purpose of developing a combined-cycle electric generating facility on an approximately 20 acre tract of land in Volusia County, Florida (the "Site") with a capacity of approximately 240 megawatts ("MW") or more and including its gas delivery and related infrastructure and any modifications to such facility or infrastructure (collectively, the "Facility"); and

WHEREAS, in consideration for the undertakings as set forth in the Participation Agreement, the Commission will be entitled to 20 MW of electric capacity from the Facility (the "Entitlement") and 20 MW hours of electric energy per hour associated with the Entitlement; and

WHEREAS, entering into the Participation Agreement and this Agreement will serve a public purpose of providing the Commission with an economical and long-term source of electric energy for the benefit of customers of the Commission and residents of the City; and

WHEREAS, as a condition of entering into the Participation Agreement, Duke Energy LP has requested that the Commission and the City enter into this Agreement to set forth the understanding of the parties hereto and Duke Energy LP related to the taxation and the exaction of any fees, charges or assessments by the City (or any other special taxing district or instrumentality created by or on behalf of the City) upon the Site, the improvements to be constructed which comprise the Facility and the electricity to be generated and sold by the owners of the Facility; and

NOW, THEREFORE, in consideration of the mutual agreements contained herein, the parties hereto agree as follows:

1. As provided in the Participation Agreement, Duke Energy LP, or its successors or assigns, has agreed to pay to the City $500,000 payable in twelve equal monthly installments on the first day of each month commencing on the first day of the month following the commercial operation date ("COD") of the Facility and continuing until notice from Duke Energy LP that the Facility is no longer expected to be used for commercial operations. Such amount shall represent the total amount due to the City (or any other special taxing district or instrumentality created by or on behalf of the City) with respect to the Site, the Facility, the construction, ownership, operation, decommissioning and dismantlement of the Facility and the electricity generated, transmitted or sold therefrom. In consideration of such $500,000 per year payments to the City by Duke Energy LP, the City covenants (i) to favorably consider any application to abate (or for exemption from) ad valorem property taxes, as provided by law, (ii) not to levy or impose a franchise fee applicable to the Facility or the electricity generated, transmitted or sold therefrom, (iii) to waive any payments to the city's general fund required pursuant to Section 218 of the City Charter, and (iv) not to directly or indirectly levy, assess, charge or impose (and to cause all other municipal entities not to directly or indirectly levy, assess, charge or impose) any taxes, fees, user fees, license fees, assessments, special assessments, or any other charges of any type or nature whatsoever that the City (or any other special taxing district or instrumentality created by or on behalf of the City) is or may hereafter be in a position to levy, assess, charge, or otherwise impose, either directly or indirectly, regarding the Site, the Facility, the construction, ownership, operation, decommissioning and dismantlement of the Facility, or the electricity generated, transmitted or sold therefrom.

2. In the event Duke Energy LP, or its successors or assigns, constructs additional power generating capacity above 240 MW at or near the Site utilizing the Commission's available facilities and infrastructure at no additional cost to Duke Energy LP (which additional power generating capacity is not merely a modification of the Facility) (the "Additional Capacity"), the amount due the City from Duke Energy LP shall be increased to an annual amount equal to the sum of (a) $500,000 plus (b) the product of $250,000 multiplied by a fraction, the numerator of which is the capacity of such Additional Capacity and the denominator of which is 240 MW, as provided in the Participation Agreement.

3. This Agreement does not relate to, and Duke Energy LP is responsible for, the payment of any and all taxes to be levied or fees, charges or assessment that may now or hereafter be imposed on Duke Energy LP or the Facility by any state or federal governmental unit or agency (other than the City or any other special taxing district or instrumentality created by or on behalf of the City).

4. The provisions of this Agreement relating to exemption from ad valorem tax shall terminate on the date which is 10 years from the COD if and to the extent required by Section 196.1995(6), Florida Statutes, unless renewed based on terms and provisions mutually agreed upon by the parties hereto.

5. This Agreement shall inure to the benefit of and shall be binding upon the City, the Commission, and their respective successors and assigns, and shall be governed by and construed

in accordance with the laws of the State of Florida. Duke Energy LP shall be a third party beneficiary of this Agreement.

6. In the event any provision of this Agreement shall be held invalid or unenforceable by any court of competent jurisdiction, the remainder of this Agreement shall not be affected thereby if such remainder would then continue to conform to the requirements of applicable law.

7. This Agreement represents the entire agreement between the parties. This Agreement may be supplemented, modified or amended only with the prior written consent of Duke Energy LP.

8. This Agreement may be simultaneously executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

IN WITNESS WHEREOF, the City has caused this Agreement to be executed by its Mayor and the seal of the City to be hereto affixed and attested by its City Clerk and the Utilities Commission, City of New Smyrna Beach, Florida has duly caused this Agreement to be executed by its Chairman and the seal of the Commission to be hereto affixed and attested by its Secretary Treasurer, all as of the date first above written.

(SEAL)

UTILITIES COMMISSION,
CITY OF NEW SMYRNA, FLORIDA

By: _____
Chairman

ATTEST:

_____
Secretary-Treasurer

CITY OF NEW SMYRNA BEACH, FLORIDA

(SEAL)

By: _____
Mayor

ATTEST:

_____
City Clerk

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AMENDMENT NUMBER ONE
TO PARTICIPATION AGREEMENT
BY AND BETWEEN
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH, FLORIDA
AND
DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

This Amendment Number One to the Participation Agreement By and Between Utilities Commission, City of New Smyrna Beach, Florida and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. ("Amendment") is made and entered into March 11, 1998, by and between Utilities Commission, City of New Smyrna Beach, Florida ("UCNSB") and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. ("Duke"), collectively, the "Parties".

RECITALS

WHEREAS, UCNSB and Duke are Parties to the Participation Agreement to proceed with the development of a combined-cycle electric generation facility with a capacity of approximately 240 megawatts or more (the "Facility"), dated Feb. 17, 1998, ("Agreement").

WHEREAS, UCNSB and Duke desire to revise the Agreement;

NOW, THEREFORE, in consideration of the foregoing and of the mutual covenants contained herein, the Parties do hereby agree to amend the Agreement as follows:

1. Insert in Section 2.2, Site:

   "and shall transfer back to UCNSB good and marketable title to the Site"

2. Delete in Section 3.4, Facility and Gas Delivery System:

   "Policy Committee" and replace with:

   "Board of Directors of Duke Energy Power Services, LLC, a subsidiary"

3. Add in Section 3.4, Facility and Gas Delivery System:

   "(d) Duke obtaining, within 60 days after all necessary permits are obtained, approval for funding for construction of the project by the Duke Energy Corporation Board of Directors"

   and update subsequent (d) to (e); and add "or (e)" to item (iii).

4. Add to Exhibit B, Tax Agreement, Paragraph 3:

   "Ltd., L.L.P."

   and replace "Delaware" with "Florida".

This Amendment Number One shall be come effective on March 11, 1998.

IN WITNESS WHEREOF, the Parties hereto have caused this Amendment Number One to the Agreement to be executed by their duly authorized officers as of the day and year first above stated.

ATTEST:

By: Lucretia Simmons

UTILITIES COMMISSION,
CITY OF NEW SMYRNA BEACH, FLORIDA

By: Ronald Vaden
Name: Ronald Vaden
Title: Utilities Director

Approved as to form and correctness:

Counsel to UCNSB: Hall Spence

DUKE ENERGY NEW SMYRNA BEACH
POWER COMPANY LTD., L.L.P.

By: Duke Energy Power Services
Mulberry GP, Inc.
its general partner

ATTEST:

By: Sandra Lee

By: James M. Donnell BF
Name: James M. Donnell
Title: Senior Vice President

2.2 Site

UCNSB shall transfer good and marketable title to the Site (free and clear of all liens and encumbrances other than those set forth on Exhibit A hereto) to Duke prior to April 1, 1998. Prior to the commencement of construction of the Facility, Duke shall obtain a Phase I Site Assessment of the Site (to determine real or potential environmental liabilities) performed pursuant to ASTM E 1527-93 guidelines and deliver to UCNSB a copy of the results of such assessment. UCNSB shall indemnify and hold harmless Duke, its affiliates, and Duke's and its affiliates' respective directors, employees and representatives, from and against any and all claims, liabilities, losses and expenses (including costs of suit and attorneys' fees) attributable to the ownership or operation of the Site prior to such transfer or attributable to the condition of the Site at the time of such transfer, regardless of whether same are identified in such assessment. Subject to the foregoing, UCNSB shall not be responsible for, and Duke shall be responsible for, any costs of decommissioning and dismantling of the Facility and shall transfer back to UCNSB good and marketable title to the Site at the end of its useful life. If, at any time prior to completion of the detailed engineering for the Facility, Duke reasonably determines (based on engineering and technical factors) that the Site is not adequate for the Facility and its related facilities, UCNSB will acquire, at UCNSB's cost and in a timely manner in order for Duke to meet its project schedule for the Facility, and transfer to Duke additional property contiguous with the Site on the same terms as the Site (as described in this Section).

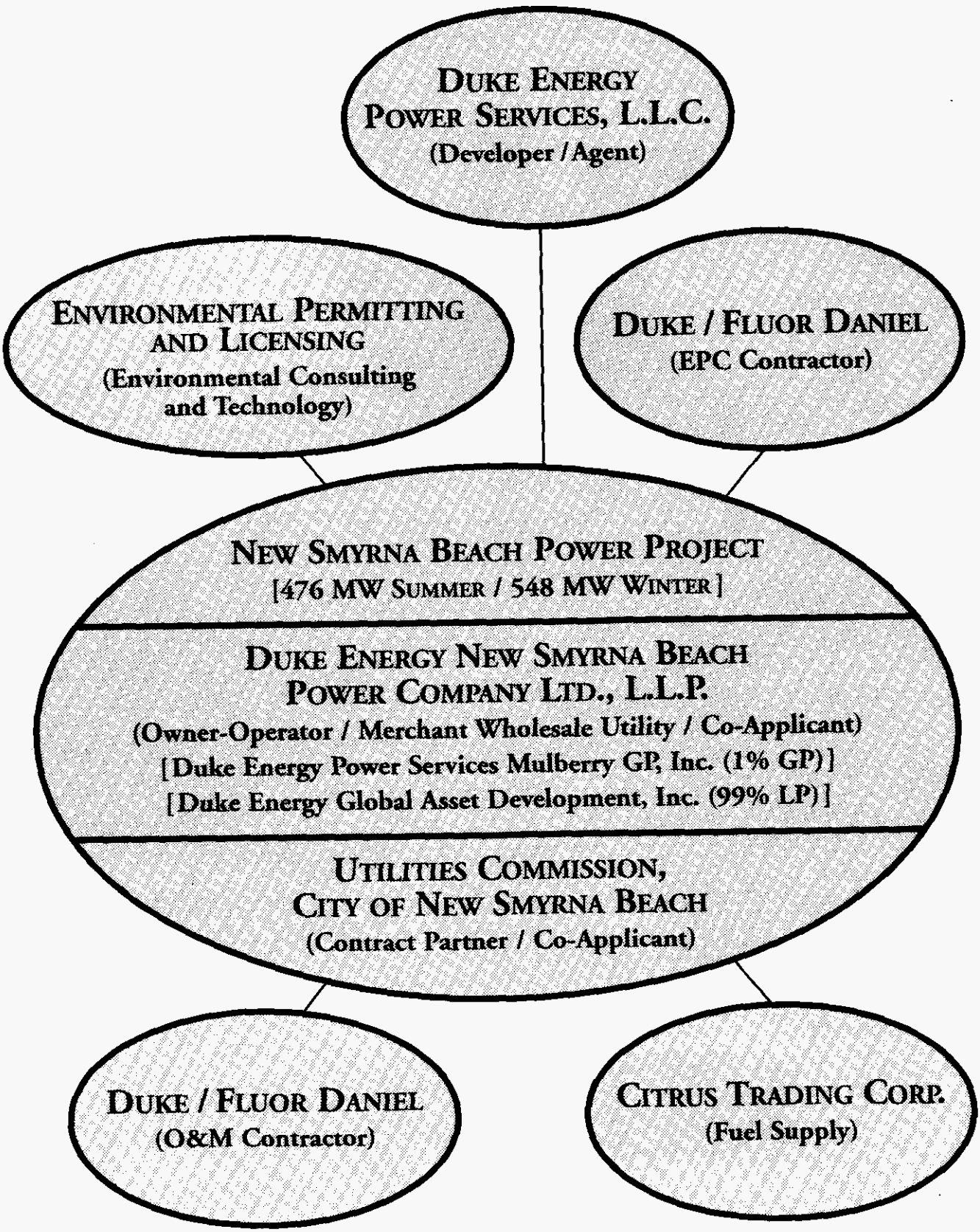
3.4 Facility and Gas Delivery System

The obligations of Duke under Sections 2.1 and 2.5, including the obligation to construct the Facility and provide for natural gas deliveries to the Facility, are subject to (a) the receipt of all applicable governmental permits and approvals in a form acceptable to each of the Parties affected thereby in its sole discretion, (b) Duke obtaining a reasonably satisfactory agreement for the looping and extension of the existing natural gas pipeline lateral (i.e., the Sanford Lateral) running closest to the Site, (c) Duke obtaining, on or before March 7, 1998, the approval of the Board of Directors of Duke Energy Power Services, LLC, a subsidiary of Duke Energy Corporation, to proceed with the transactions contemplated in this Agreement, (d) Duke obtaining, within 60 days after all necessary permits are obtained, approval for funding for construction of the project by the Duke Energy Corporation Board of Directors, and (e) no circumstance or event existing or having occurred that has had or could reasonably be expected to have a material adverse effect on the feasibility, prospects or business of the Facility. Duke shall give written notice to UCNSB if Duke determines not to complete the Facility as a result of any of the foregoing, in which event neither Party shall have any further obligations under this Agreement; provided, however, that (i) each Party shall continue to be liable for any breaches hereof occurring prior to such notice, (ii) if at such time the Site has been conveyed to Duke, Duke shall reconvey to UCNSB all of Duke's right, title and interest to the Site, (iii) if such determination is made solely on the basis of the matters described in clause (d) or (e) of the immediately preceding sentence, then Duke shall also pay to UCNSB $200,000, and (iv) if within 6 months thereafter UCNSB notifies Duke that UCNSB intends to complete the Facility with another party and requests Duke to transfer any governmental permits and approvals for the Facility and any applications therefor, and if such request is approved by Duke (which approval shall not be unreasonably withheld), Duke will, to the extent legally permissible, transfer to UCNSB any governmental permits and approvals that Duke has received in connection with the Facility and any applications for governmental permits or approvals in connection with the Facility that have not yet been obtained, in each case excluding any confidential or proprietary information of Duke.

Figure 1

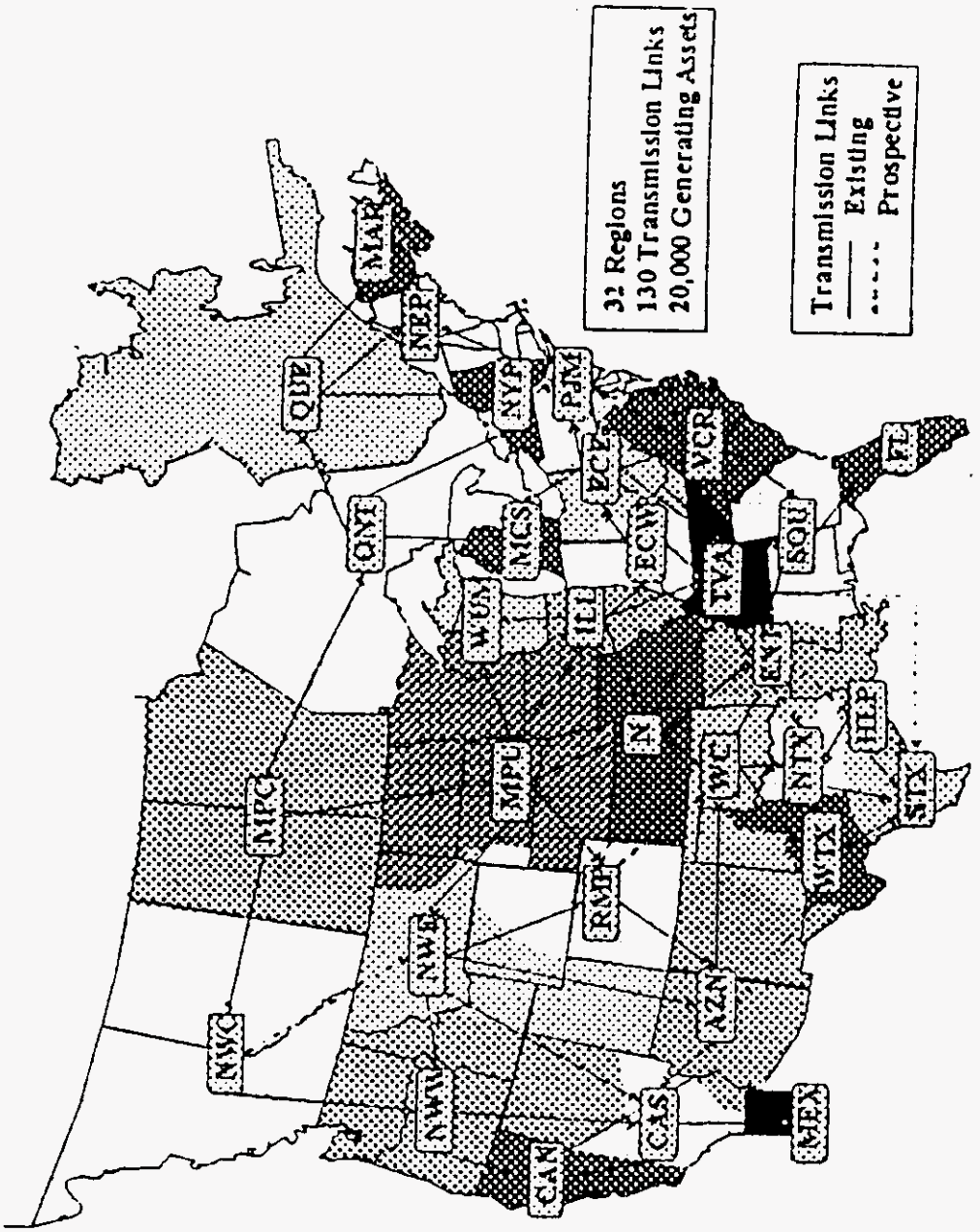
New Smyrna Beach Power Project

Project Structure



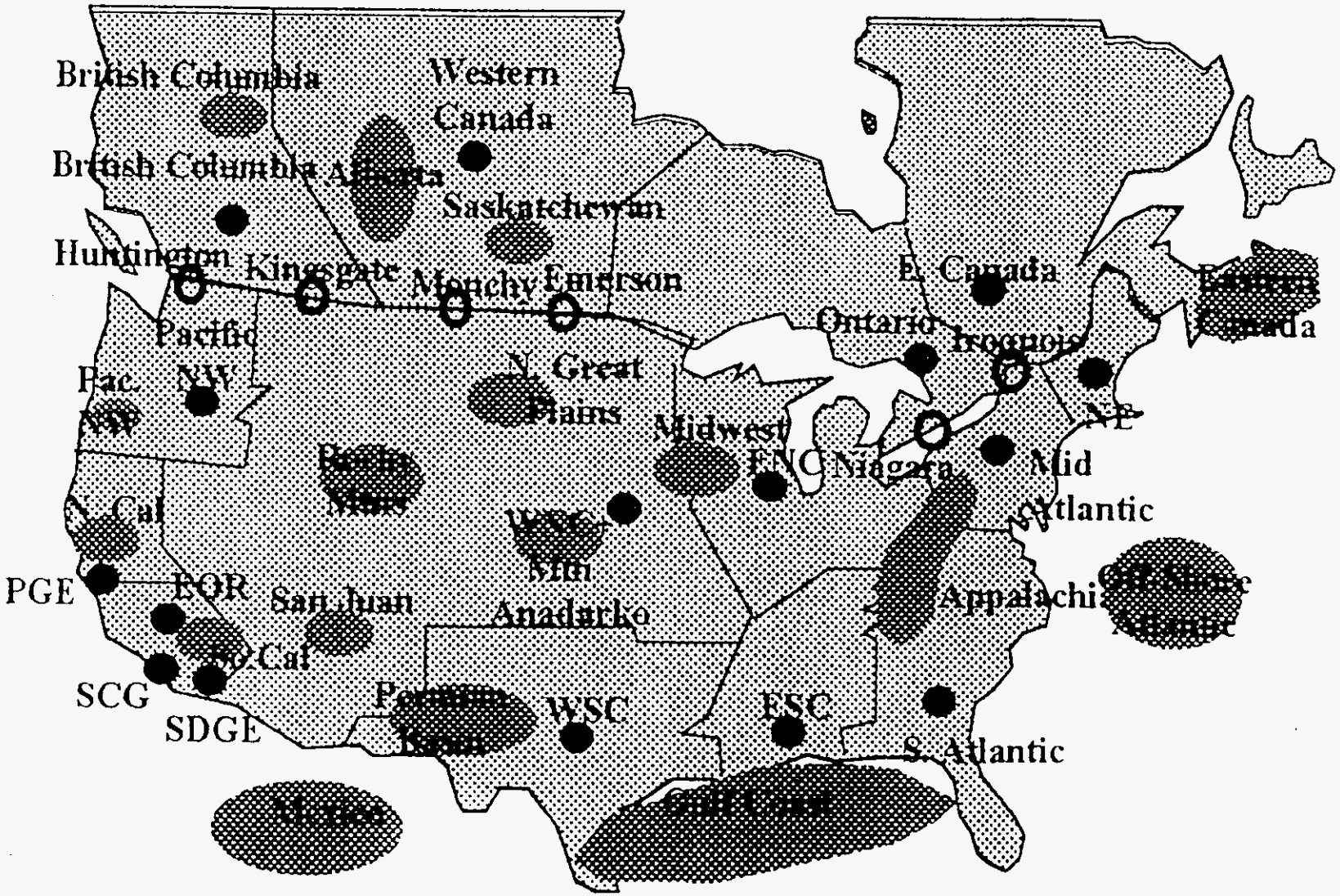
FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-1)

ALTOS NORTH AMERICAN ELECTRICITY MODEL



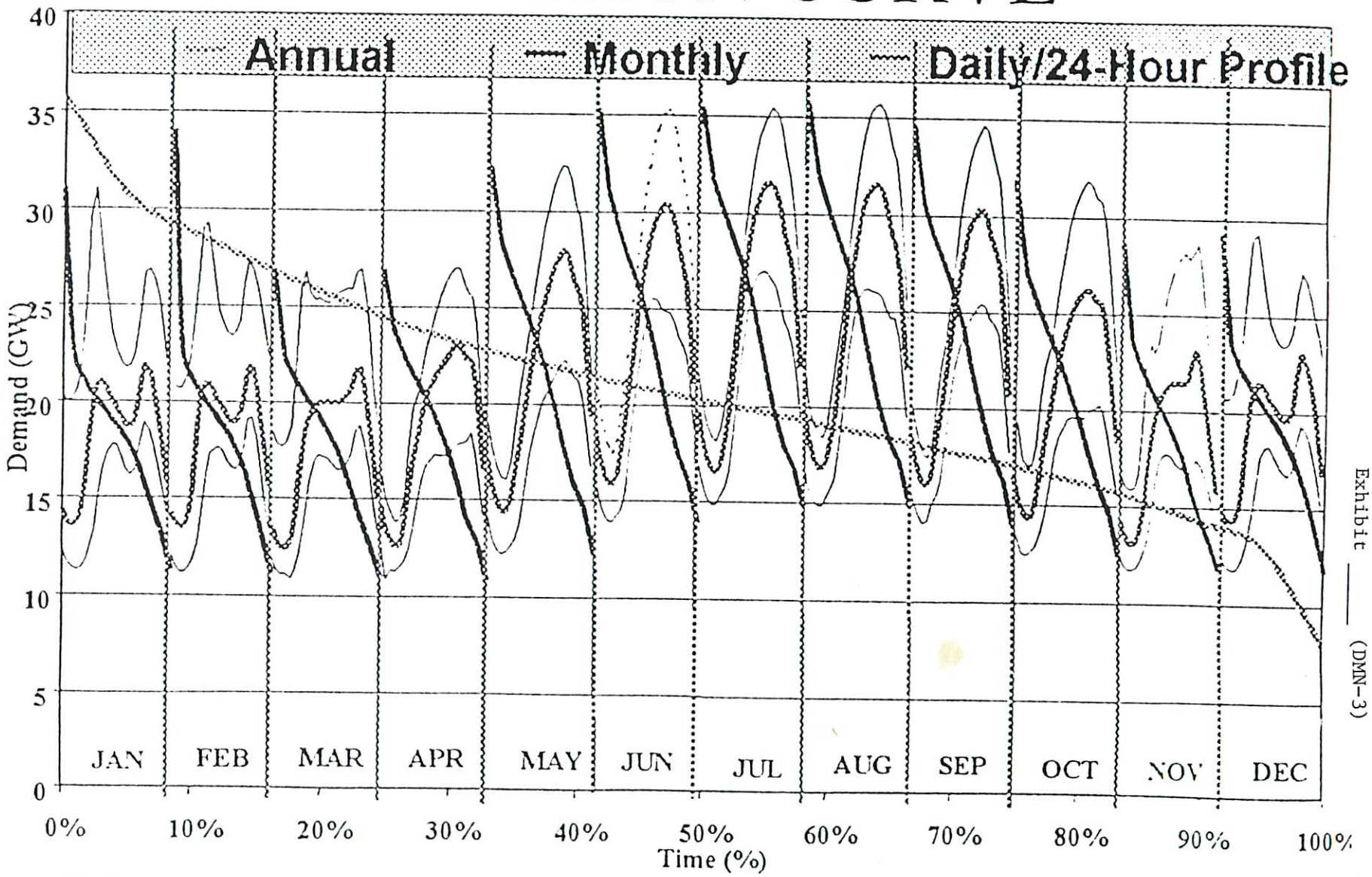
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 18
COMPANY/ WITNESS: Nesbitt
DATE: 12-2-98

NORTH AMERICAN REGIONAL GAS MODEL (NARG)



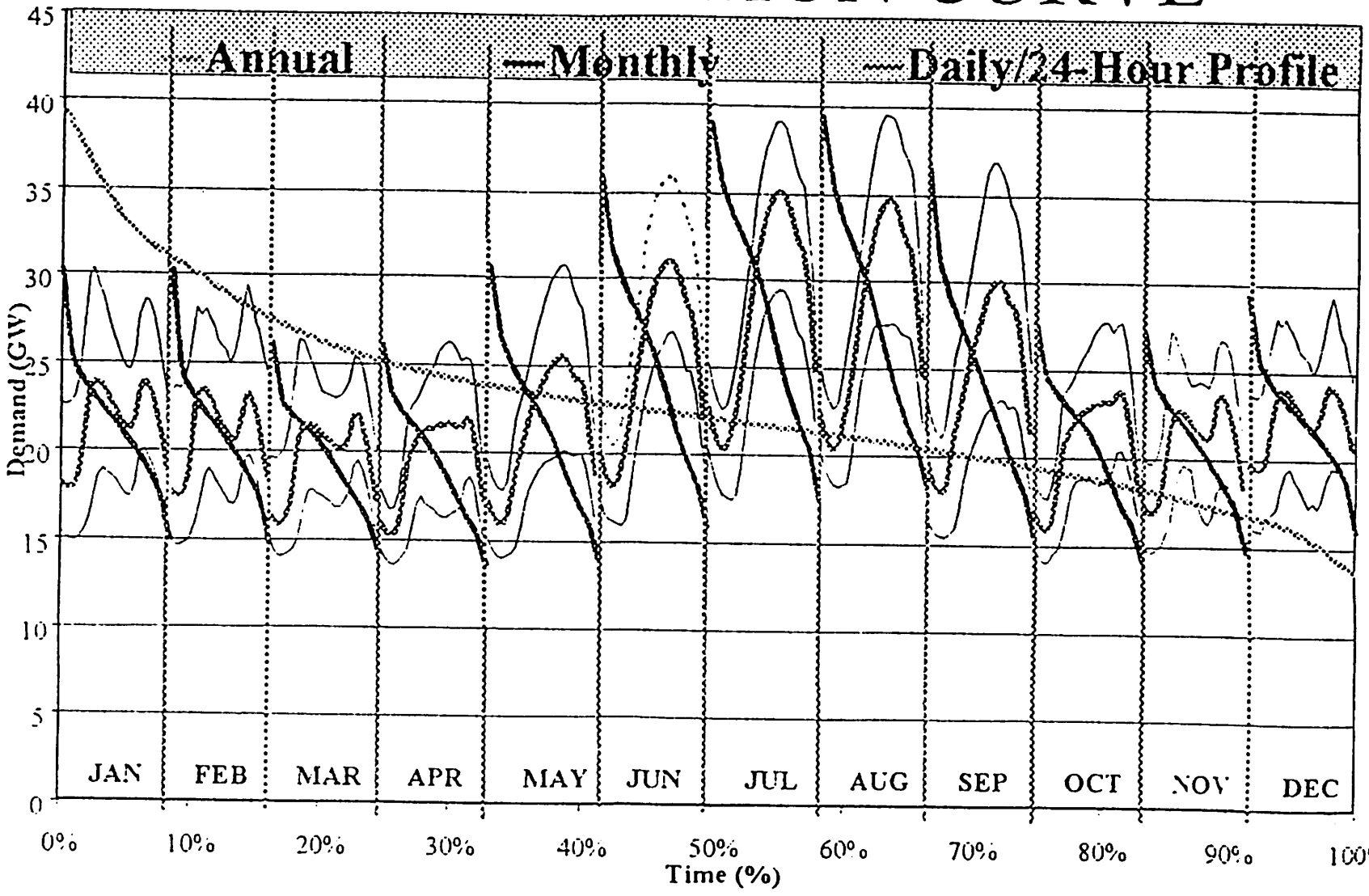
FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-2)

1998 FLORIDA LOAD DURATION CURVE



FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-3)

1998 SOUTHERN LOAD DURATION CURVE



FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ____ (DMN-4)

FLORIDA
CAPACITY PER NERC

	Demand and Capability (MW)		Disposition and Sources (GWH)		Capacity Factors	
	1998	2006	1998	2006	1998	2006
Peak	32,826	38,003	183,281	219,688	63.7%	66.0%
Sales	528	--	--	--	0.0%	N/A
	33,354	38,003	183,281	219,688	62.7%	66.0%
Nuclear	3,876	3,876	29,946	30,094	88.2%	88.6%
Hydro	47	47	25	25	6.1%	6.1%
Coal	9,036	9,036	64,303	67,091	81.2%	84.8%
ST-Oil&Gas	13,761	13,715	33,949	26,130	28.2%	21.7%
CT-Oil&Gas	5,741	5,797	1,919	2,722	3.8%	5.4%
CC-Oil&Gas	2,828	5,711	20,137	43,455	81.3%	86.9%
Other	--	157	1,897	12,692	N/A	922.8%
IPP	2,173	2,173	15,614	14,339	82.0%	75.3%
Subtotal	37,462	40,512	167,790	196,548	51.1%	55.4%
Purchases	2,289	2,405	15,491	23,140	77.3%	109.8%
Total	39,751	42,917	183,281	219,688	52.6%	58.4%
Reserves	6,397	4,914				
Reserve Margin	19.2%	12.9%				

FPSC Docket No. 981042-E
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ___ (DMN-5) (Revised)

SOUTHERN
CAPACITY PER NERC

	Demand and Capability (MW)		Disposition and Sources (GWH)		Capacity Factors	
	1998	2006	1998	2006	1998	2006
Peak	37,367	45,333	199,723	229,510	61.0%	57.8%
Sales	1,598	1,521	10,811	12,311	77.2%	92.4%
	38,965	46,854	210,534	241,821	61.7%	58.9%
Nuclear	5,722	5,748	43,951	44,550	87.7%	88.5%
Hydro	4,434	4,434	7,599	7,562	19.6%	19.5%
Coal	24,970	24,970	145,946	152,019	66.7%	69.5%
ST-Oil&Gas	1,292	1,233	1,412	1,311	12.5%	12.1%
CT-Oil&Gas	3,475	4,034	4,657	6,318	15.3%	17.9%
CC-Oil&Gas	257	257	305	6,575	13.5%	292.1%
Other	--	--	728	829	N/A	N/A
IPP	1,419	7,826	785	18,022	6.3%	26.3%
Subtotal	41,569	48,502	205,383	237,186	56.4%	55.8%
Purchases	1,873	1,028	5,151	4,635	31.4%	51.5%
Total	43,442	49,530	210,534	241,821	55.3%	55.7%
Reserves	4,477	2,676				
Reserve Margin	11.5%	5.7%				
DLC Interruptible Demand	15	3				

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ___ (DMN-6) (Revised)

TABLE 10

NEW SMYRNA BEACH POWER PROJECT
PROJECTED OPERATIONS AND FUEL SAVINGS

YEAR	GENERATION (MWH)	CAPACITY FACTOR %	PRIMARY ENERGY SAVED (MMBtu)	SAVINGS @ 100% NO. 6 OIL DISPLACED (BARRELS)	SAVINGS @ 100% NATURAL GAS DISPLACED (MCF)
2002	3,719,550.72	82.61	13,647,032	5,992,568	13,647,032
2003	3,768,894.72	83.70	13,828,075	6,072,066	13,828,075
2004	3,818,238.72	84.57	14,009,118	6,151,564	14,009,118
2005	3,862,154.88	85.54	14,170,246	6,222,318	14,170,246
2006	3,906,071.04	86.75	14,331,375	6,293,071	14,331,375
2007	3,952,454.40	87.78	14,501,555	6,367,799	14,501,555
2008	3,998,837.76	88.57	14,671,736	6,442,528	14,671,736
2009	4,046,701.44	89.63	14,847,348	6,519,641	14,847,348
2010	4,094,565.12	90.94	15,022,959	6,596,754	15,022,959
2011	4,164,140.16	92.48	15,278,230	6,708,846	15,278,230
2012	4,233,715.20	93.77	15,533,501	6,820,939	15,533,501
TOTALS			159,841,174	70,188,094	159,841,174

NOTES: (1) Primary energy saved estimated as the difference between Btu required to generate MWH in Column (2) in gas/oil steam generators with an average heat rate of 10,501 Btu/kWh and the Btu required to generate the same MWH at the NSB Project's heat rate of 6,832 Btu/kWh.
(2) Oil savings reflects total oil displaced assuming that all of the Project's output displaces oil-fired steam generation.
(3) Gas savings reflects net gas reduction to generate MWH in Column (2).

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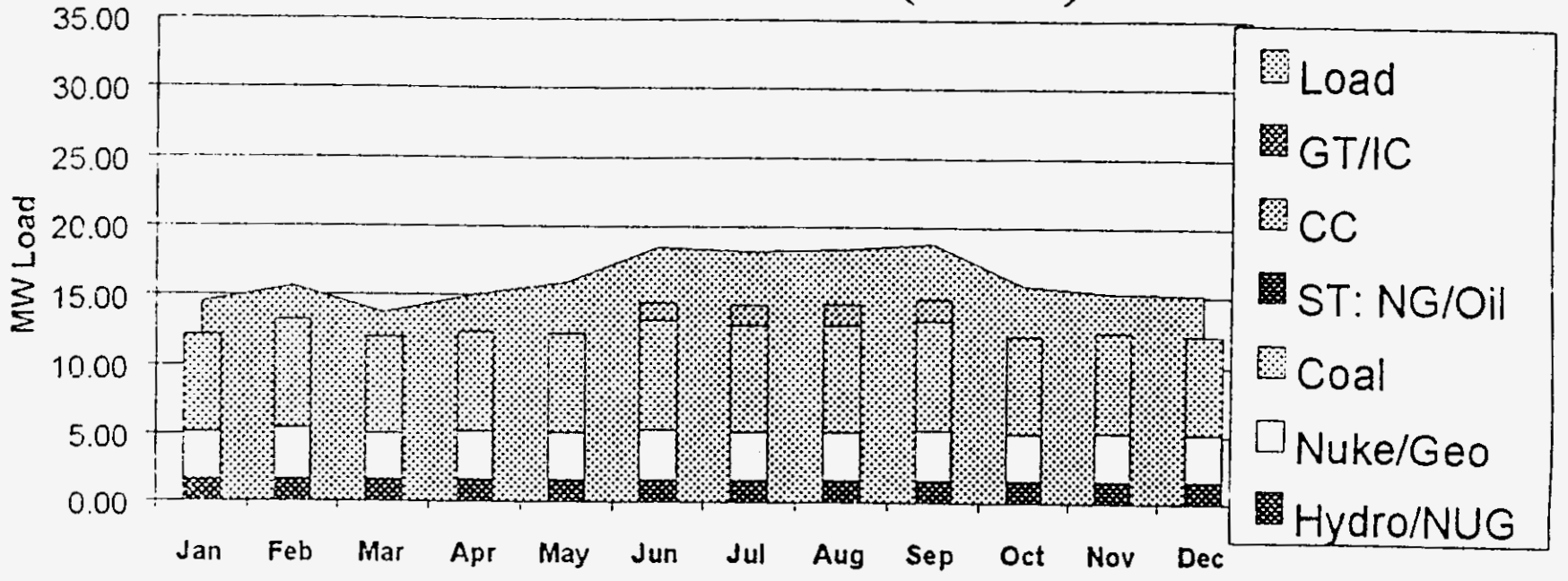
Exhibit _____ (DMN-7)

FLORIDA--1998
BASELOAD (40%)



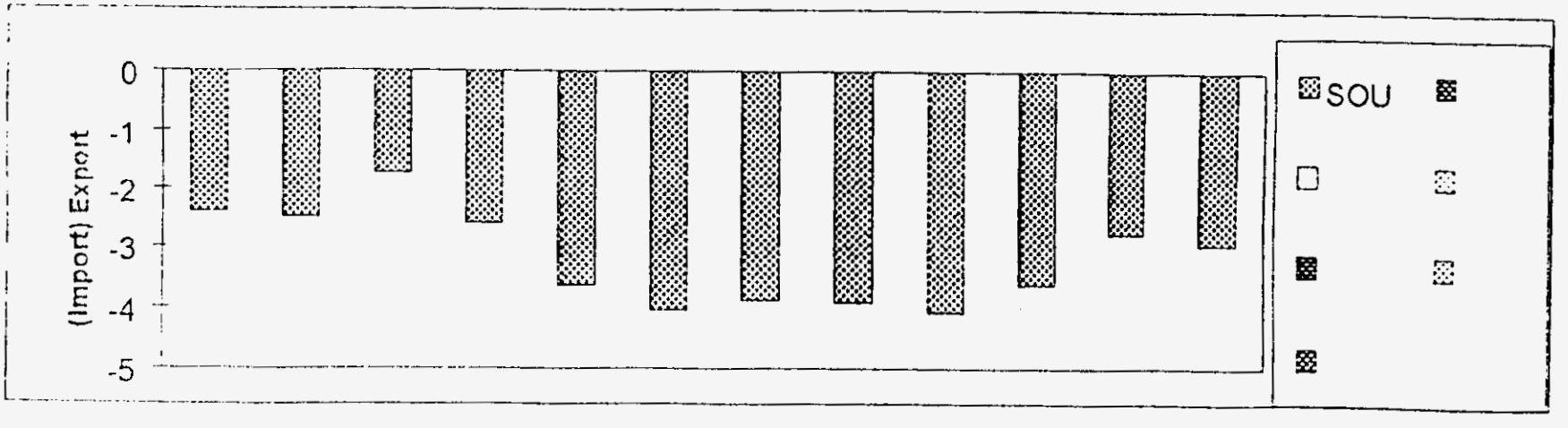


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Exhibit ____ (DMN-8)

FLORIDA DISPATCH--1998
HIGH LOAD FACTOR INTERMEDIATE (25%)

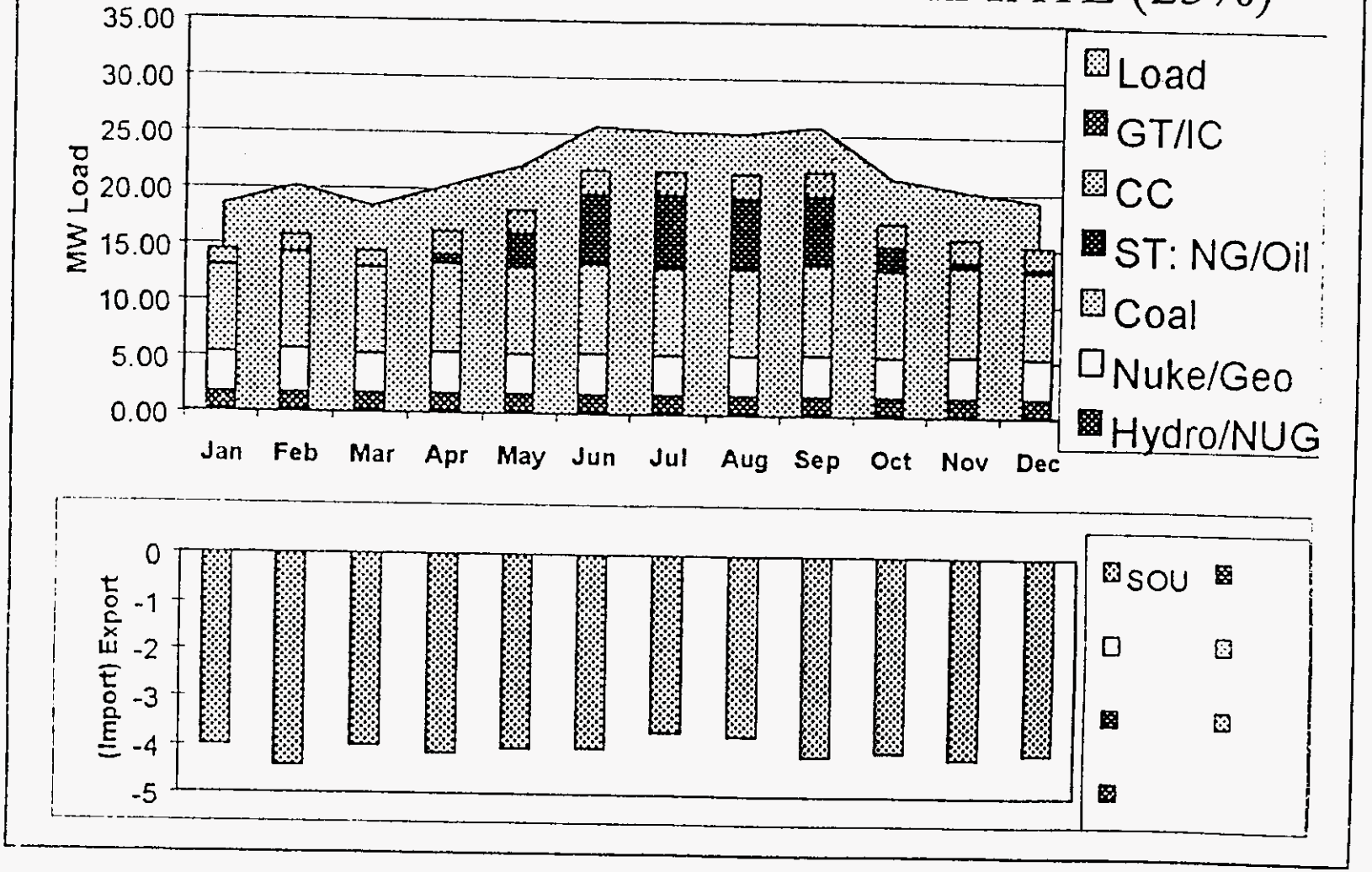

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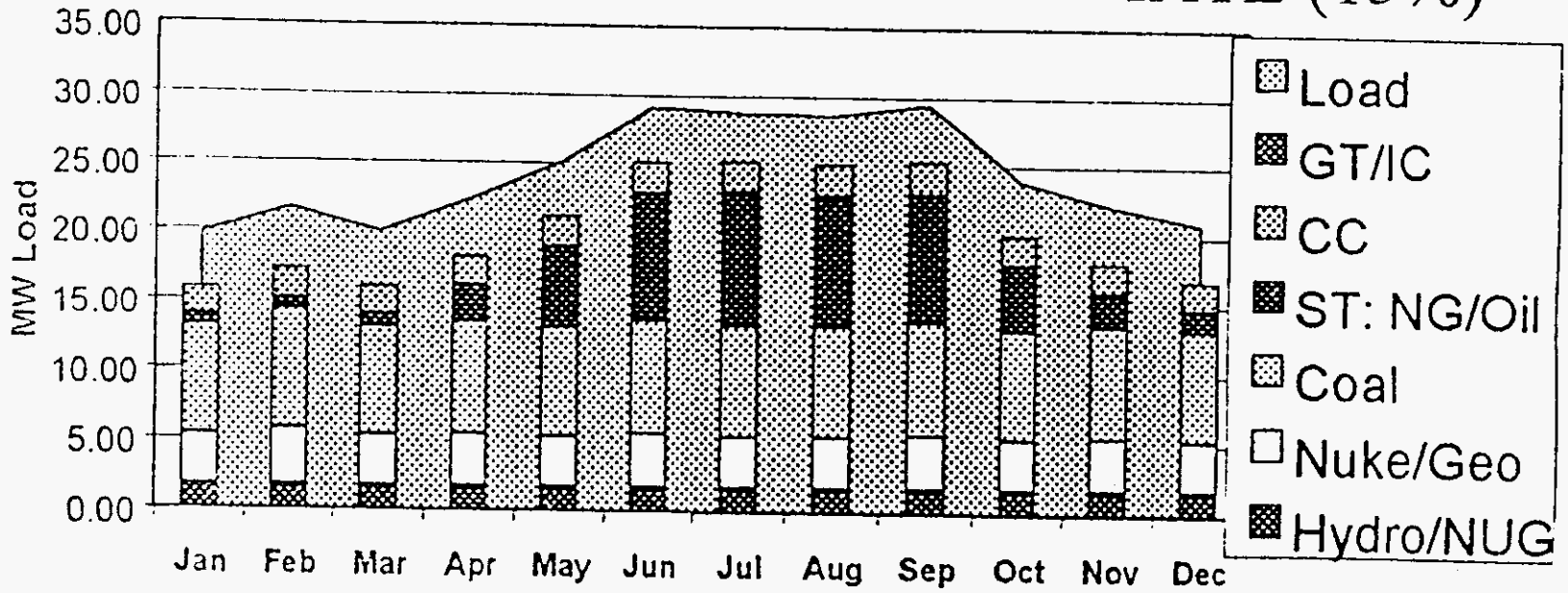
Exhibit _____ (DMN-9)

FLORIDA DISPATCH--1998
LOW LOAD FACTOR INTERMEDIATE (15%)



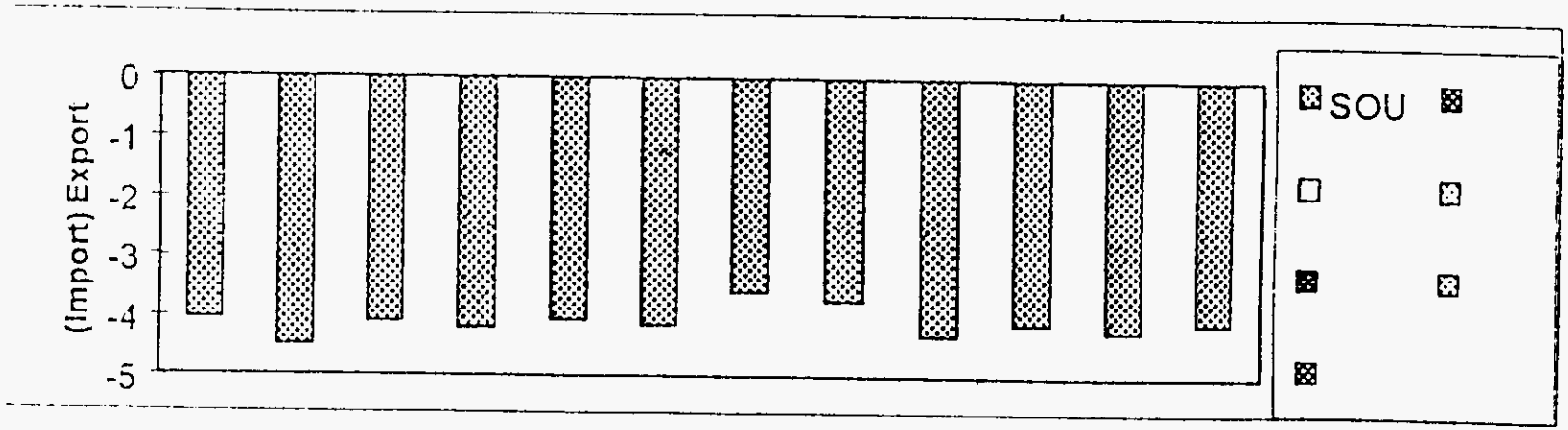


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Exhibit ____ (DMN-10)

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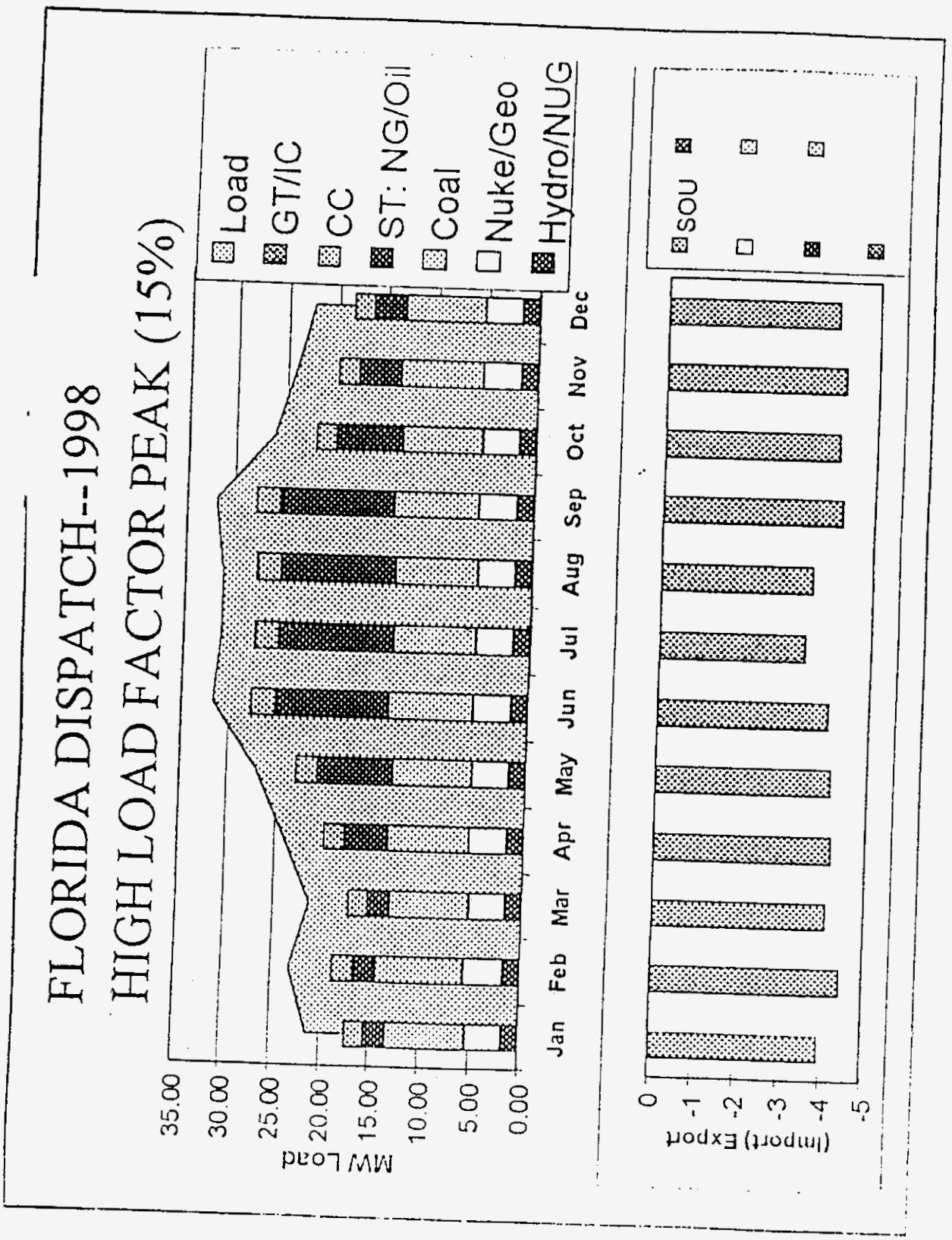
Exhibit ____ (DMN-11)



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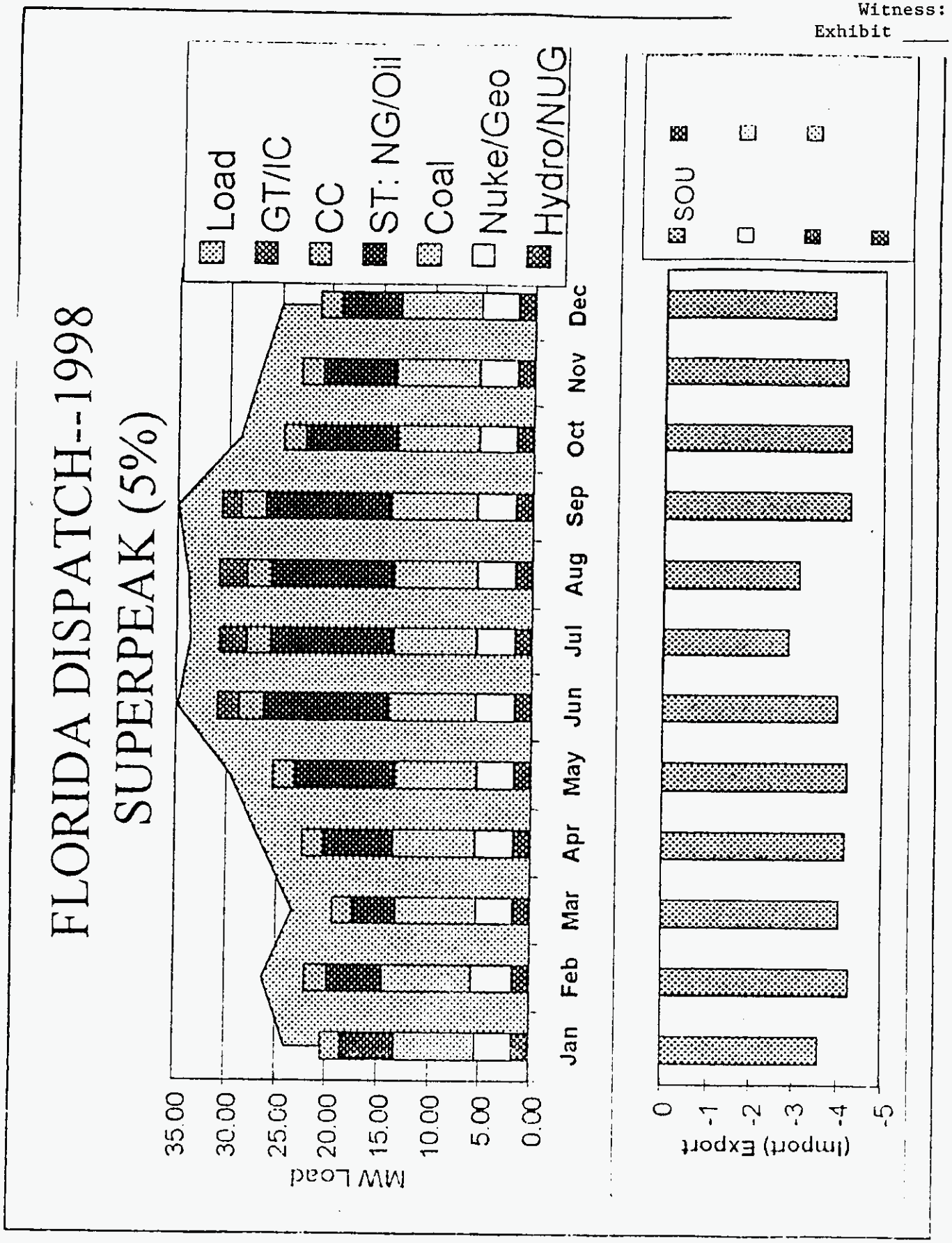
Witness: Nesbitt
Exhibit ____ (DMN-12)



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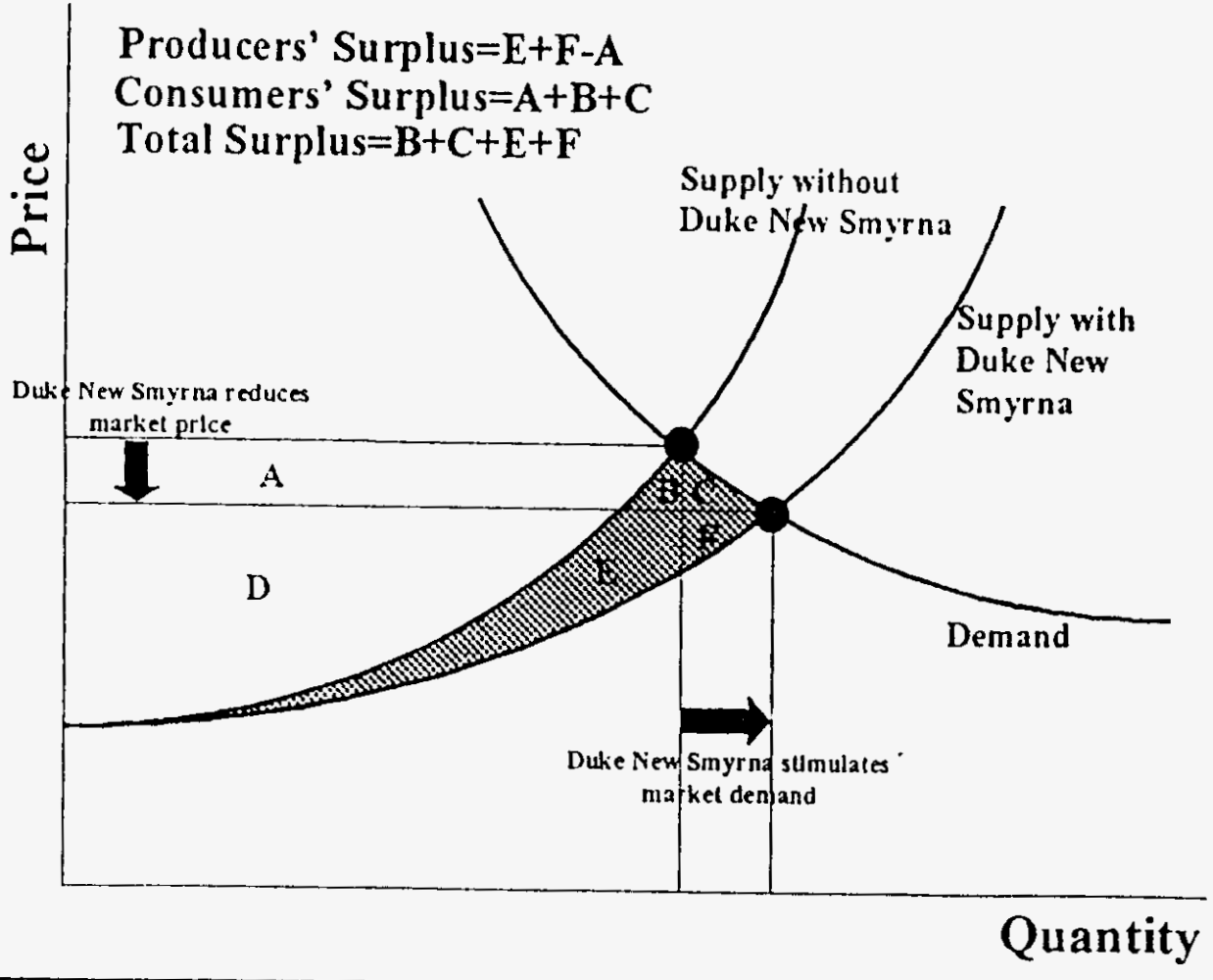
USNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-13)

COMPARATIVE ELECTRICITY PRODUCTION COSTS, SERC & FRCC, 1995-1998

NERC REGION	JANUARY THROUGH DECEMBER			JANUARY THROUGH MARCH		
	1995	1996	1997	1996	1997	1998
SERC						
ELECTRIC GENERATION	555,505	584,329	604,058	145,303	145,980	152,272
PRODUCTION COSTS (¢/KWH)	1.76	1.71	1.68	1.66	1.66	1.58
RETAIL RATES (¢/KWH)	5.89	5.73	5.71	5.67	5.57	5.53
FRCC						
ELECTRIC GENERATION	145,464	142,421	144,669	32,611	31,081	32,633
PRODUCTION COSTS (¢/KWH)	2.41	2.69	2.54	2.71	2.60	2.39
RETAIL RATES (¢/KWH)	7.00	7.27	7.30	7.27	7.41	7.12

BENEFITS OF DUKE NEW SMYRNA PROJECT



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Witness: Nesbitt
Exhibit ____ (DMN-14)

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Witness: Nesbitt
Exhibit ____ (DMN-15

ACHIEVING COMPETITIVE ADVANTAGE THROUGH QUANTITATIVE ELECTRIC ASSET VALUATION

USING THE

ALTOS NORTH AMERICAN REGIONAL ELECTRICITY MODEL

San Jose Jet Center
1250 Aviation Drive, Suite 200C, San Jose, CA 95110
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1. INTRODUCTION AND OVERVIEW

Electricity is not the first commodity to be deregulated. It is not even the first commodity to be deregulated by mandatory unbundling of transmission services away from generation (commodity) services. Electricity is in fact the third such commodity. Telecommunications and natural gas before it were subjected to precisely the same type of forced unbundling between transmission service and commodity. We believe that what the "unbundling" type of deregulation implies for the future is not as arcane or unclear as many would argue. Quite the contrary, disaggregation through forced unbundling subjects electricity markets to precisely the same type of competitive, market, and financial forces to which virtually all other commodities have been subjected for a long time. In building an electricity market model, we combine solid fundamental economic principles together with lessons of learned from recently completed deregulations to help us guide our model design decisions so that we can support asset and marketing and trading businesses in electric power.

Before describing our North American electric model, there are a few realities of the electric power market as it will unfold in the future that need to be articulated:

- First and foremost, electric power plants are destined to become entrepreneurial, merchant elements, not regulated items. Regulators will no longer guarantee forced passthrough of fixed costs. It will be necessary to trade and arbitrage all their inputs and all their outputs in order to truly maximize value from those plants. This single change in the regulatory environment subjects electric generation assets to the vagaries of the market and therefore to unprecedented price uncertainty.

- Second, it will be necessary to carefully and scrupulously manage both the forward cost to market of generating plants as well as the capacity expansion and retirement decisions related to those plants. Plant costs can no longer go unmanaged; they must be scrupulously and carefully understood, measured, and managed. After all, it will be the difference between sales and cost that will dictate profits, not just "cost plus" as in the old days.

- Third, generation owners need accurate and credible forward electricity and fuel price curves in order to manage their asset and trading businesses, more credible and more accurate than their competitors. Portfolio generation companies are in an "arms race" against their large competitors, the company with the best forecast winning out over the worse companies. There is no escape from the need for accurate and credible price anticipation.

- Fourth, price risks may or may not need to be managed. Large, diversified portfolio generators might well be able to shoulder regionally diversified market price risk. They may not want to "give away the upside in order to avoid the downside" as required by most risk management instruments. On the other hand, small to medium sized companies will most definitely want to hedge their generation assets using liquid, traded instruments to do so. In either case, risk management is no better than one's perception of the future MEAN or average price. Forecasting the future MEAN is critical to success.

In building the model described herein, we are helping our clients attack the foregoing needs head on. We help our clients manage price expectations better and more accurately than their competitors and act correctly and decisively based on those better price expectations. No matter what one might hear from efficient market or trading gurus, **it is the company with the best**

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price forecast that will win. Period. Electricity markets will never be sufficiently efficient or complete to allow complete, perfect, frictionless hedging or idealized price discovery. With the paucity of storage and inventorying, electricity will always be volatile and somewhat unpredictable. More so than most other commodities, electricity begs for model-based forward price estimation to complement the imperfect information that will be revealed by markets.

In the discussion to follow, we will put forth the basic structure of our market model and supporting analytical techniques, which we have constructed to assist our clients and their selected partners to develop effective and maximally profitable asset acquisition, marketing, and trading activities. We should emphasize that our modeling system guides decisions related to both physical assets and trading instruments. After all, trading instruments (options, swaps, structured deals, etc.) are fundamentally no different from physical assets. Like physical assets, trading instruments make money based on price differences in the market. In the discussion to follow, we will use the word "asset" to describe physical plants, projects, existing capacity, or financial instruments that are the subject of arbitrage and trading. This document outlines the design of our North American multiregional electricity model and its supporting data base.

We should mention that the method of valuation presented here includes what we term the intrinsic, deterministic value of the asset. The methodology here is based on the notion of valuing the asset based on a cogent and correct but deterministic set of forward prices. There is no attempt in this report to incorporate the effects of uncertainty, i.e., to augment the intrinsic, deterministic value of the plant with the so-called "option value" of the plant. In a companion paper, we have developed a method to extend the intrinsic valuation procedure described here to calculate the full probabilistic value of an asset or a portfolio of assets, i.e., the full option value plus intrinsic value. The companion paper is based on the idea of using the deterministic value presented here as the MEAN of the forward probability distribution over forward price and augmenting it with a sophisticated Markov model of forward price volatility, mean regression, and serial correlation.

2. MEASURING INDIVIDUAL ASSET PROFITABILITY

Evaluation of asset profitability typically begins with a discounted cash flow (DCF) or similar method configured as shown in Figure 1. Into the asset profitability calculator shown in the figure we put the fixed and variable costs of the asset (bottom); the corporate book and tax parameters (top); the corporate time and risk parameters (usually a hurdle rate) designated at the top; the "government takes" or other government royalty, lease bidding, production sharing, or other levies at the top; and projections of the price of the products[1] and the price of the inputs (left). The asset profitability calculator then creates one or more measures of corporate profitability, indicated by the "meter" at the right. Sometimes asset profitability calculators contain detail on asset operations, and other times they are simple, passive DCF calculations implemented on a spreadsheet.

[1] In electric power applications, the problem is more complicated than this simple characterization. The price of the product varies continuously, and the plant must be turned on and off or ramped upward or downward to capture revenues or avoid losses. The revenues captured when the plant is on are related to the market price. The discussions in this paper assume that the plant is turned on and off so as to best capture margins.

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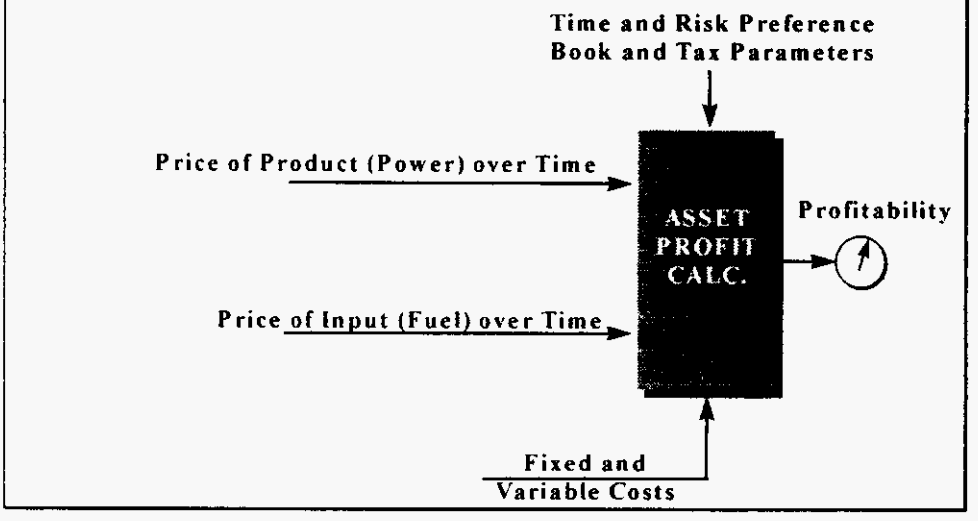
Invariably, when evaluating an asset, the profitability calculator is run through a series of sensitivity ("What if?") cases. Costs are varied, prices are varied, book and tax parameters are varied, corporate measures of time and risk are varied, and the calculator is put through its paces. Not surprisingly, what people find as a result of such sensitivity analysis is this:

- the **DIFFERENCE** between the price of the product and the price of the input is the most important variable affecting asset profitability. Every asset is in effect playing a "basis differential game," being "long" on product and "short" on input. This is fundamental; assets are always long with regard to their product and short with regard to their inputs. Assets are the quintessential "swaps."

- this **PRICE DIFFERENCE** is the least understood of all the inputs, and companies have precious little reliable information upon which to base their estimate of this price difference.

Figure 1: EVALUATION OF ASSET PROFITABILITY



We emphasize the pivotal importance of the price differential across the asset, which we draw conceptually as in Figure 2. Suppose we knew the product price forward into the future beginning at the time at which we initiate possession of the asset (indicated as the product price curve in the figure) and we knew the prices forward into the future of the input factors (indicated as the forward cost curve in the figure). Using that information, we could easily subtract the forward cost from the product price to calculate the contribution to margin from the asset at each point in its future life. This contribution to margin is the contribution to corporate profitability attributable to the asset in each forward year of its life. If we know the contribution to margin in each forward year of the asset's life, we in effect know the shaded area in the figure, and we can calculate the discounted present value of that shaded area as of the time we take possession of the asset. By so doing, we are in effect calculating the discounted present value of the gray area in the figure, and we interpret this as the present value of the future yield to the company that is specifically attributable to the asset. It is the contribution today to corporate wealth that is attributable to the future yield on the asset.

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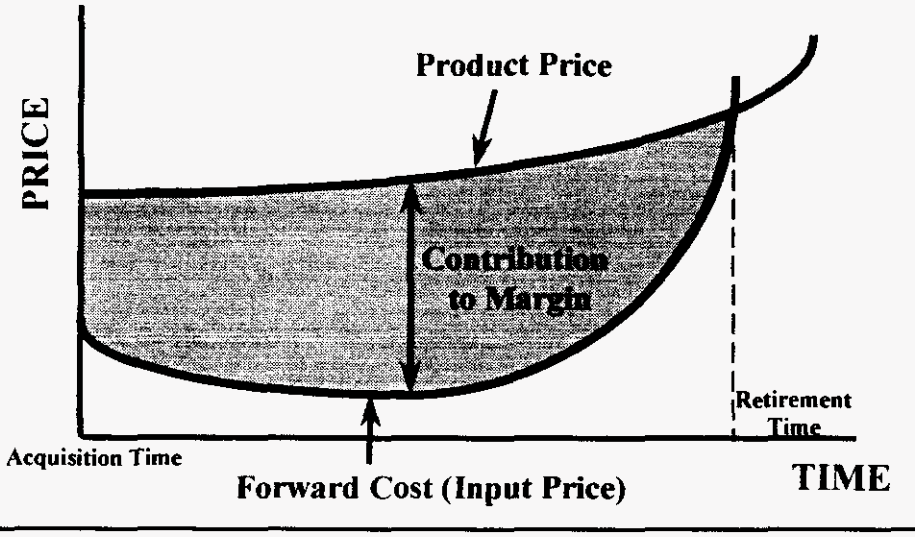
Figure 2: PRICE DIFFERENTIAL ACROSS AN ASSET IS THE MOST IMPORTANT DETERMINANT OF VALUE



The discounted present value of the future margin generated by the asset is the contribution to corporate wealth today represented by the asset. If we already own the asset, it represents the intrinsic value of the asset to the corporation. If we are considering acquiring the asset, it is the benchmark against which we must compare the cost to acquire the asset. If the cost to acquire the asset exceeds the net present future value of the asset, one does not want to acquire the asset. If the cost to acquire the asset is lower than the net present future value of the asset, one will want to consider acquiring it. (Whether we actually acquire it depends on our capital budgeting process, which compares all potential business ventures whose acquisition costs are lower than the present value of future returns and picks the best.) Once we know the discounted present value of the gray area in Figure 2, the decision to acquire the asset is simple—just compare the acquisition cost against the future yield.

Two critically important insights emerge from Figure 2. First, **one cannot escape the need to project forward prices for the products of and the inputs to each and every asset it owns, each and every asset it considers owning, and each and every asset it considers selling**. There is no escape from the need to predict forward prices more accurately and more correctly than one's competitors. The company that makes the better forward price projections wins (statistically speaking) because it has more accurate knowledge of the values of its assets. The company that makes the poorer forward price projections loses (statistically speaking) because other people identify and take the best opportunities first.

Second, **not only is the problem of projecting forward prices critically important to the asset business, so is the problem of projecting forward asset operating costs**. To wit, the bottom curve in Figure 2 is just as important as the top curve in understanding asset profitability. It is the DIFFERENCE between the curves that matters. It is incumbent upon us to understand and anticipate forward cost to market of each and every asset it owns. It is critically important to understand, measure, and project the cost structure of our evolving asset business. We will return

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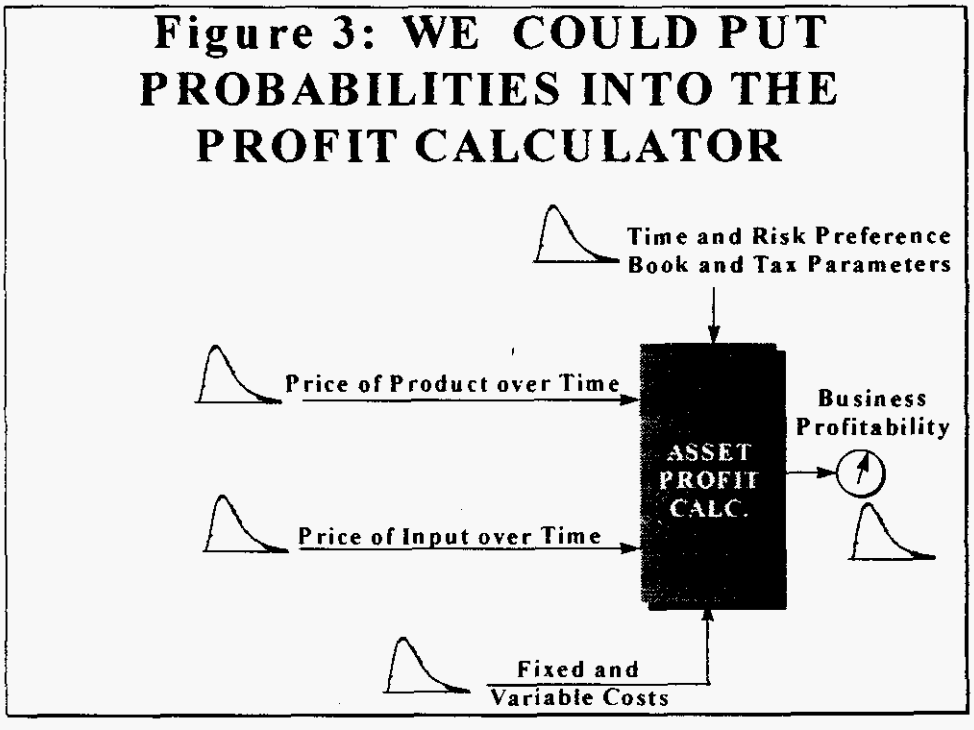
to this theme shortly, articulating how we have approached the cost side of the problem. Before doing so, we will continue discussing the revenue side, i.e., the market side.

3. MEASURING INDIVIDUAL ASSET RISK

In light of the central importance of the price difference across the asset, companies sometimes reason: "We don't really know what the price difference will be, so let's just put in probability distributions for the critical forward variables. Let's put in probability distributions over plant costs. Let's put in probability distributions over book and tax parameters. Let's put in probability distributions over prices or price differences. This will allow us to calculate a probability distribution over asset profitability. We can use this probability distribution to assess the risk-return nature of the asset. This will give us the right answer."

Such a probability approach, often implemented as a "Monte Carlo" simulation, decision tree, influence diagram, or At Risk! Excel add-in, is illustrated in Figure 3. Notice in the figure that probability distributions are placed onto all the input arrows to the profitability calculator. The probability calculator then calculates the probability distribution over profitability from the independent probability distributions over each of the inputs. This procedure is literally fraught with conceptual and practical difficulties, but many managers feel mighty comfortable because they are taking account of uncertainty. Yet the process is usually badly flawed.

Figure 3: WE COULD PUT PROBABILITIES INTO THE PROFIT CALCULATOR



How do people typically implement such a calculation, and why do they get into trouble? They begin by estimating independent probability distributions over each of the individual inputs to the profitability calculator. They then enumerate all possible combinations of settings for all the input variables using probability trees as shown in Figure 4, calculate the probability of each combination of variables, and thereafter run the profitability calculator once for each combination. In this way, they obtain what they interpret as a probability distribution over asset profitability

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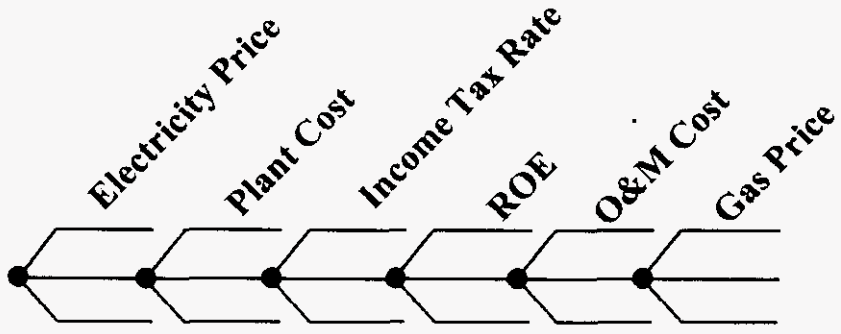
(which we call a profit lottery) as shown in Figure 5. The probability distribution over profitability in Figure 5 depicts the expected profitability of the asset (shown to be slightly positive in the figure), the standard deviation (shown to be rather wide in the figure), the "skewness" of the probability distribution (in the figure, the distribution is stacked toward the left hand or low profitability side, and in fact higher order properties. Parenthetically, in our experience, Figure 5 is typical of individual assets: a high probability of low or negative profits but a "long positive tail," representing the remote possibility of a "home run."

Figure 4: RUN OUT A SERIES OF PROBABILITY-WEIGHTED SCENARIOS



3^6 combinations (=3^6 calculations)
3^6 probabilities

While the approach of estimating probability distributions over asset profitability parameters seems intuitively appealing and correct, it misses the boat in the most important dimension. It does not take into account whether the asset under consideration is correlated or uncorrelated with the rest of one's business or with the rest of the market. It does not consider whether the asset is in point of fact simply one more small addition to the selfsame large lottery the business is already playing, i.e., whether the asset is tightly correlated with the rest of one's business and therefore offers limited diversification benefits. Conversely, it does not consider whether the asset brings new and independent elements of uncertainty to one's asset portfolio and therefore offers systematic diversification advantages. It does not consider whether the asset is anticorrelated with the rest of one's portfolio and therefore offers valuable hedging and risk mitigation possibilities. It simply ignores altogether how the asset fits into one's overall asset portfolio and whether it renders the portfolio better or worse. To illustrate with a simple example, the profitability of a new oil well anywhere in the world is directly and positively correlated with the profitability of every other oil well everywhere else in the world. A new oil well does not diversify risk; it is simply adds to an already large oil price lottery. World oil price strongly ties oil wells' profitabilities together. Is this true of electric generation assets, which can occur in highly Balkanized markets separated by high transmission costs, or is electric generation an intrinsically coupled and correlated business that has the same risks as the oil business? Prospective and current generation owners surely need to understand this.

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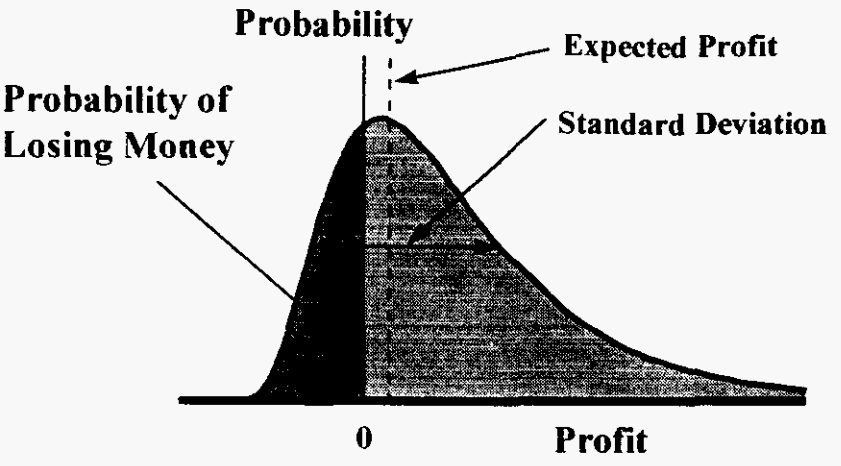
Figure 5: A PROBABILITY DISTRIBUTION OVER PROFITABILITY



The difficult part of managing one's business portfolio is to ensure that the assets in the portfolio are mutually complementary and that their returns are not completely correlated, i.e., that asset profitabilities are not completely contingent on the exact same set of events. We need to be sure that each of the assets in one's portfolio is at least partially independent of the other assets. One needs to be sure that with each new asset we are not simply buying a bigger and bigger piece of the same old lottery unless we are absolutely convinced that each incremental piece offers increasingly attractive returns to compensate for the increasing portfolio risk. (Unfortunately, in the real world, each additional asset tends to offer decreasingly attractive expected returns rather than increasingly attractive prospects. Diminishing marginal returns is an immutable rule of business and economic life.) If we do not manage the correlation characteristics of our asset portfolio, the volatility of our share price will be increased, the price of our stock will not appreciate as rapidly, dividends will not accrue as rapidly, our credit rating will not be as high and our cost of capital will suffer, and our stock's "beta" will be higher than it should be.

Our approach systematically and structurally takes account of the important correlating as well as uncorrelating forces across your portfolio. While our technique, like many others, is able to evaluate the average profitability of each individual asset, it is able to quantify the correlating and uncorrelating forces and thereby give a true representation of the risk-return nature of your asset portfolio. It does not deceive you into thinking that the value of your portfolio is merely the sum of the average returns of each business activity that comprises it. It recognizes the reality that with assets "2 + 2 is not necessarily equal to 4." Indeed, with our correct correlation mathematics, "2 + 2 equals 5 for sufficiently large values of 2 and 2 + 2 equals 3.5 for sufficiently small values of 2!" Portfolio mathematics is critical to the success of any company who owns any assets at all, paper or physical assets.

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4. A MARKET-BASED APPROACH TO ASSET VALUATION

How do we approach the problem of valuing individual assets and portfolios of business assets? The answer is illustrated in Figure 6, a critically important extension of the simple asset calculation in Figure 1. In Figure 6, we make the identical asset profitability calculation as in Figure 1. However, we generate consistent projections of prices of products and inputs using a **full multi-regional market model** as shown at the left. Inputs to the full multi-regional market model are indicated at the bottom of the diagram. They include the full forward cost to market estimates including all variable and fixed costs for all existing and prospective plants and assets in the market, including not only the particular asset being analyzed (indicated at the right) but also all assets that compete with or complement the particular asset being analyzed. By assembling a market-wide asset data base and delivering it to a full multi-regional market model, we ensure that the price calculations indicated in Figure 2 take proper and consistent account of one single collection of technology cost and performance estimates. That is, the price calculations are fundamentally determined by a common and correct set of estimates of all plants in the market, including their forward costs to market (i.e., variable costs and nonsunk fixed costs), all plants that might prospectively enter the market including their full capital and operating costs over their lifetimes, and all plants that might be driven from the market by stronger competitors. By including all capacity currently in place and all capacity that might prospectively enter or exit the market, the price calculation in the full multi-regional market model is able to account for all correlations between plants, technologies, processes, and fuels. The multi-regional market model does not go awry by failing to account for common technologies and processes employed in similar ways everywhere in the market. It does not miss the "zero sum" nature of competitive markets in which similar assets positioned in geographically disparate locations must compete for common markets, winner take all. It does not therefore miss the fact that the electricity market is structurally interconnected and intertwined. It protects our customers from making egregious valuation mistakes and overpaying for assets.

By introducing a structural representation of the market, we are able not only to forecast forward prices on a structural basis but also to systematically correlate the various prices in our markets: electricity versus gas prices, electricity versus coal prices, coal versus gas prices, regional price differences at the wellhead and the busbar, etc. We are also able to calculate the structural relationships between prices at different locations and prices at different points in time. By so doing, the vagaries and naiveté's otherwise involved in direct subjective estimation of prices and price correlations are eliminated. The interrelationships among the assets in our portfolio are properly calculated, and the risk-return nature of our portfolio is properly quantified. Most importantly, we are able to systematically understand and predict the **PRICE DIFFERENTIALS** between products and inputs that dictate the profitability of our assets.

Why are such structural correlations important? The reason, quite succinctly, is that the profitability of an electric power plant is a function of the "spark spread" across that plant, defined in the vernacular as the price differential between electricity and the fuel (e.g., natural gas). Would-be asset owners need to know not only what the spark spread will be but also what variables will affect it. Will higher gas prices widen or narrow the spark spread, or will electricity price rise right along with gas price? If the latter is true, the profitability of the asset is insensitive to gas price. If the profitability is sensitive to gas price, a gas price hedge strategy might ameliorate asset ownership risk. However, if the profitability is insensitive to gas price (i.e., electricity price moves right along with gas price), a gas price hedge strategy would be futile. Rather than being the hedge you thought it was, it is pure speculation. Needlessly adding

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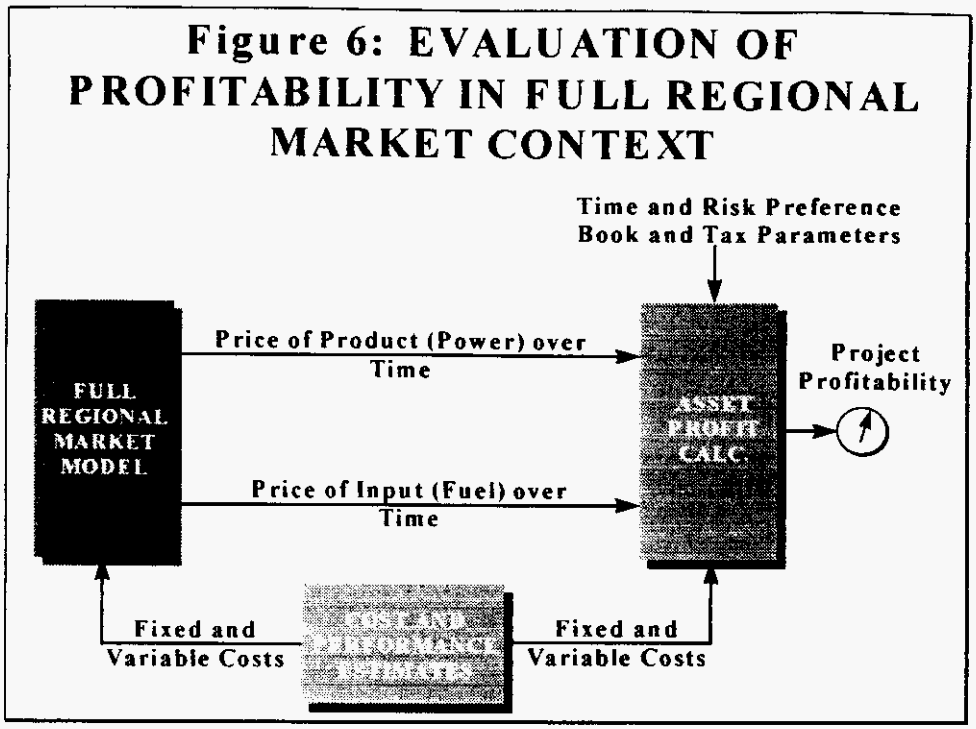
speculation when you thought you were adding hedging devalues one's company and debilitates financial performance.



5. MARKET-BASED APPROACH TO ASSET PORTFOLIO RISK

To add the dimension of uncertainty to our market-based approach is straightforward. In order to evaluate the true riskiness of each asset in our portfolio, all we need to do is postulate probability distributions over the critical inputs to Figure 7 rather than to Figure 1: (1.) Technology cost and performance estimates, (2.) Inputs to the market model, and (3.) Corporate book and tax parameters. The procedure surrounding Figures 4 and 5 can be directly extended to the larger and more comprehensive market modeling context, as Figure 7 summarizes. After inputting such information into Figure 7, our system can calculate a probability distribution over the true profitability of the asset, taking full and explicit account of the correlations between the asset, the rest of one's portfolio, and the market as a whole. Such an approach does not miss the critical correlations between plant and technology cost and performance estimates, market prices, and asset profitability. It gets the inter-asset correlations right and ensures that one is properly measuring the variance as well as the expected return in his overall portfolio. It shelters the asset owner from mistakenly and imprudently buying a hedging instrument he or she does not need and thereby worsening rather than improving risk.

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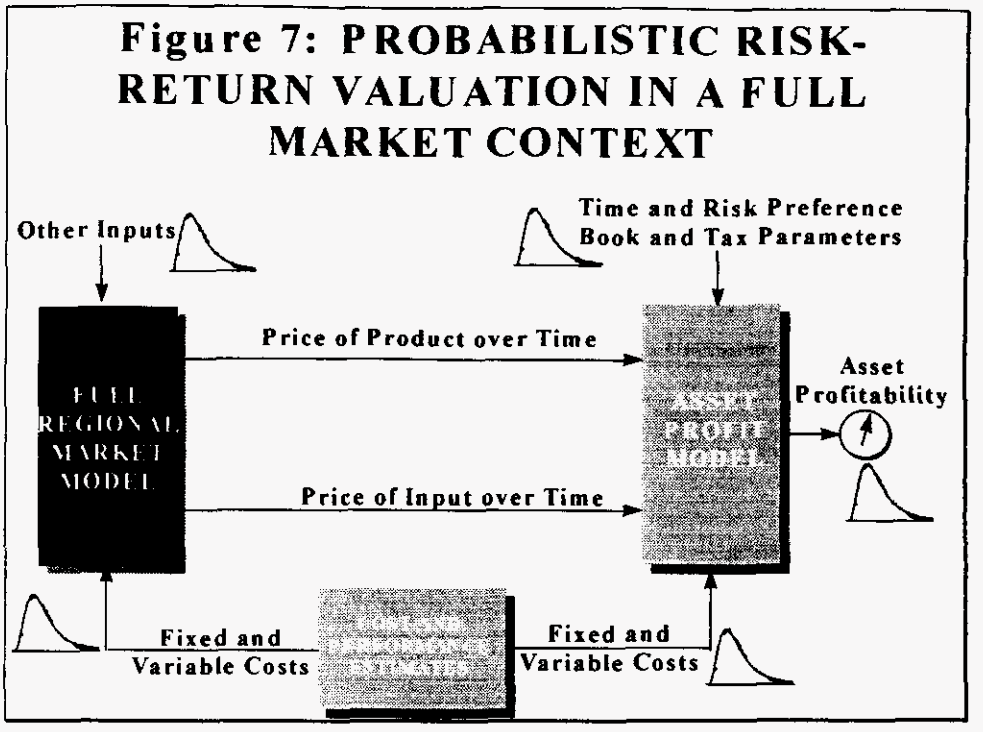

6. STRUCTURE OF THE FULL REGIONAL MARKET MODEL TO PROJECT PRICES AND PRICE DIFFERENCES

Having identified the need to understand prices and price differentials in order to guide our asset strategy, we are faced with the prospect of building a model to assist us in doing so. As we approach the problem of building such a model, we must recognize a few fundamental facts. First, the price differential across an asset is determined by the market. It is not determined by the cost of the individual asset being analyzed. In the coming "merchant electric world," the price differential will no longer be determined by rate base formulas through which fixed as well as variable costs can be imposed downstream on unwitting customers by companies with regulatory complicity. It will not be determined by system lambdas, which reflect the fact that fixed costs were imposed on customers completely apart from energy sales. To be valid, our merchant market model must represent the market at large, not just the individual asset being valued. It must include all assets presently in place combined with all assets that might be built combined with all assets to be retired, and it must consider how those assets jointly and mutually dictate future prices and profits. In the real world, prices are formed from the AGGREGATE of all assets in place, not any individual asset. The premium is on proper representation of the aggregate collection of assets, not on any individual asset.

Second, the price differential across any asset depends on fuel price, heat rate curve (from which we calculate fuel cost), variable cost, operating and maintenance cost, wheeling cost and radius, new equipment installations, future cost evolution, demand variation, and a plethora of economic and cost considerations. Clearly the box in Figures 6 and 7 entitled "Cost and Performance Estimates" must be addressed comprehensively. Later sections in this document outline the difficult problem of assembling the necessary cost and performance estimates for every existing plant in the system and every prospective future plant in the system as we have approached it.

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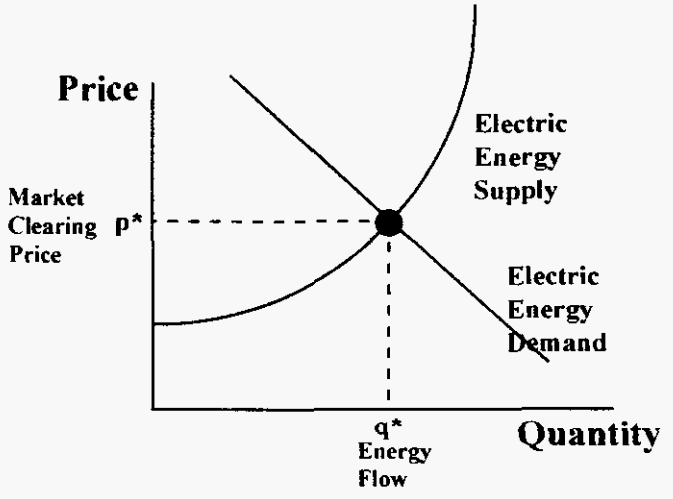
Third, and extremely important, future prices and price differentials cannot be discerned from market observations. For commodities such as electricity, there are simply no spot or futures markets to observe and therefore no market observations to be made. Markets are so distorted by fixed cost passthroughs outside energy markets that those energy prices do not represent the intrinsic cost structure of the industry nor the intrinsic value of the commodity. Even after some semblance of spot and forward markets emerge, they are likely to be so lightly traded (so "thin") that they will provide only the most rudimentary price information but will not support sale or purchase of commodity. What good is observation of a price that will not sustain sale or purchase? It is at best a gross indicator of general market trends, an academic nicety.

Clearly what we need to support our marketing, trading, and asset acquisition and divestiture decisions is a forward projection of electricity, gas, coal, and oil prices that truly represents what those commodities will sell for over the life of the asset. We do not want an academic or hypothetical projection or incomplete market observation, we want a projection of what the actual, real, concrete, palpable market will sustain. Because we cannot look to securities and commodities that trade in broad exchange markets for guidance, what technique should we use? The answer is that we should use "high technology," i.e., state-of-the-art, quantitative economic science, to help us represent what is likely to happen as the future electricity market opens for competition. Economic science, which is becoming and will continue to become increasingly pertinent, is from our perspective represented in Figure 8.

Figure 8: AFTER DEREGULATION, HERE'S THE WAY THE WORLD WILL WORK



If we want to understand and predict present and forward electricity prices, we must quantify the supply curve for electricity, the demand curve for electricity, and (not shown) the transmission grid that interconnects supply with demand. We must extend and extrapolate the simple supply-demand curve pair in the diagram to consider every region of North America and every future time point in sufficient detail so that the consequent projections of prices are sensible and complete. This is the challenge that faces us and that we have met in building our model.

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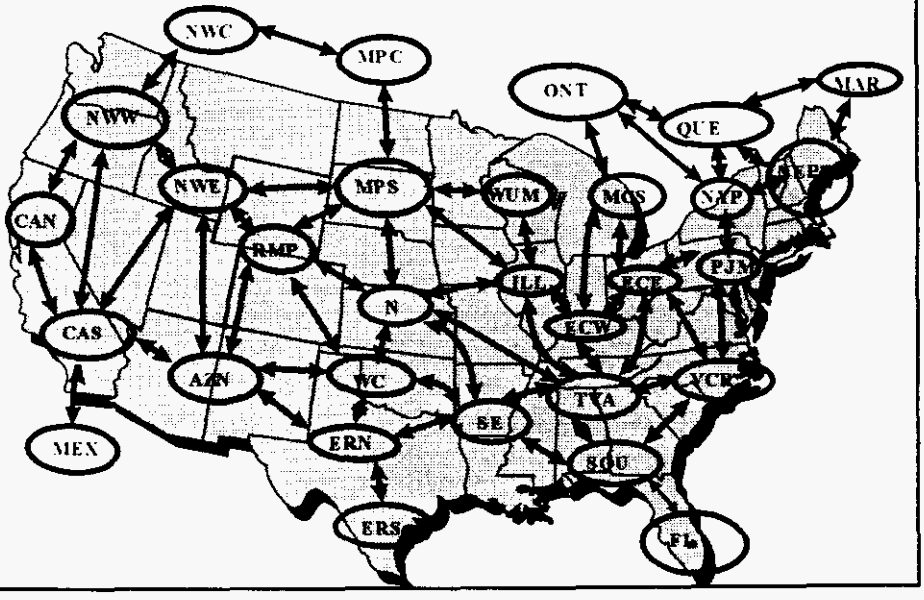
This document will briefly describe the process by which we quantified and integrated the electricity supply situation, the transmission situation, and the demand situation and thereby built our Multiregion North American Electric model. We reiterate that our overriding purpose is to provide accurate and credible projections of future electricity and fuel prices with which to conduct the evaluations summarized above.

6.1. Representation of Electricity Supply

6.1.1. Regionalization

The first step in constructing our model was to regionalize the generation, transmission, and demand regions of the North American electric and fuel markets. Figure 9 provides a schematic representation of the regionalization used. In building our model, we wanted to retain sufficient regional detail so that we could properly represent the capital stocks of generation capacity and fuel supply in each region as distinct from every other region. However, we did not want the model to become so large and unwieldy that it became unrunnable. The regionalization in Figure 9, based in significant measure on the NERC regions and subregions, provided an effective compromise between the objectives of extensive regional detail at one end of the spectrum and workability and usability at the other.

Figure 9: AN INTERCONNECTED MODEL OF THE UNITED STATES



As currently configured, the regionalization of the model can be quickly and easily disaggregated. We can pass a "magnifying glass" over one of the foregoing regions, subdividing and subregionalizing it further than indicated in the diagram.

Within each of the subregional ovals in Figure 9 resides a comprehensive model of indigenous generation, inbound transmission, native load, and outbound transmission. The

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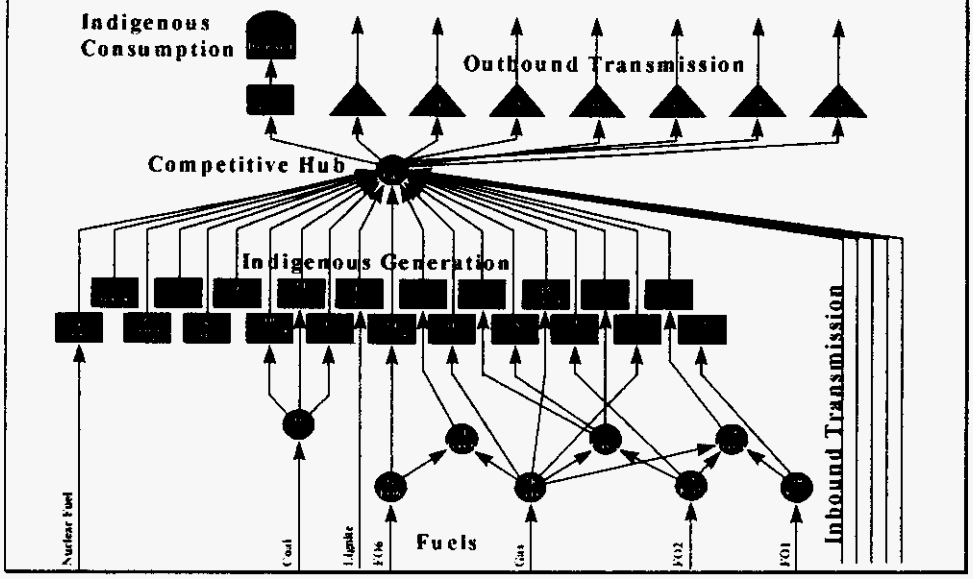
regional network submodel, common for all 30 regions, is depicted in Figure 10. Notice how it enumerates the full range of regional generation options at the lower left, the full range of incoming transmission options at the lower right, the native load (including load shape) at the upper left, and the outbound transmission at the upper right. Our approach is fundamentally tied to network diagrams of the form in Figure 10, just as our North American Regional Gas (NARG) model is tied to analogous regional network diagrams for gas supply, transportation, and demand markets.

Figure 10: REGIONAL GENERATION-TRANSMISSION-CONSUMPTION OPTIONS



6.1.2. Incorporating Forward Cost to Market for Existing Generation Units in a Region

Having regionalized the North American market as in Figures 9 and 10, the next task is to specify the nature of the existing generation mix region-by-region. In the lexicon of the network diagram in Figure 10, we need to "populate the generation nodes" with generation plant data. This has been accomplished according to the logic illustrated in Figure 11. To generate the necessary data, we have estimated the capacity and the forward cost to market for every one of the generation units in a given region—utility-owned units and independently owned units alike. Thereafter, we line up the units in that region in ascending order of forward cost as shown in Figure 11. For each unit in the stack, the width of the supply curve for that unit represents the capacity to produce electricity, and the height of the supply curve represents the forward cost of doing so with that unit. The lower right envelope of this stack (i.e., the lower right boundary of the curve) represents the electricity supply curve available from the aggregate of all the existing generation units in the region. It is the sought-after supply curve based on the capital stocks that exist today.

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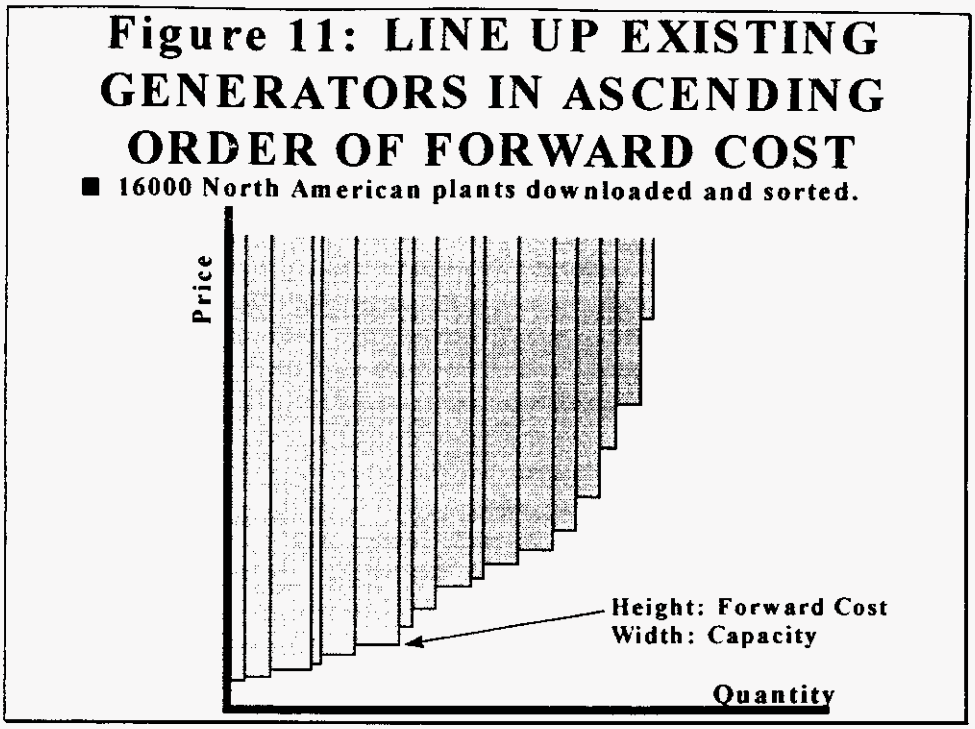

As indicated in the figure, we have downloaded some 16,000 generating plants that comprise North America including capacities and forward costs from publicly and privately available sources. Before arraying them as shown in the figure, it has been necessary to undertake a rather extensive reconciliation and comparison process. We should caution that such downloading has not been conducted as a simplistic, thoughtless, mechanical process. It is much more difficult than that; analysis and "thinking" are required. There is much anomalous cost and capacity information embedded in commercially and publicly available sources (e.g., RDI, ES&D) that has to be ferreted out and adjusted. It has been necessary for us to render judgments and adjustments to many of the plant capacity and forward cost estimates in order to create supply curves that are credible and reasonable. It has also been necessary to adjust them to consider the coal, gas, oil, and nuclear fuel cost projections into the future we want to use. We should emphasize that we have downloaded not only utility-owned, muni-owned, and coop-owned units but also privately and independently owned generation units. In the merchant market of the future, there is fundamentally no difference or distinction between utility-owned and non-utility-owned units. We have access to proprietary data bases that enumerate all independently owned as well as utility-owned generation units in North America.

What types of judgments and adjustments have been necessary to craft the supply stack in Figure 11? The answer lies in a brief description of how one must think about forward cost to market for each of the existing generation plants. Figure 12 summarizes what we have included and not included in each element of the generation supply stack in Figure 11. Beginning at the bottom, notice that we have included as part of the forward cost all fuel-related costs (bottom) and all variable costs (e.g., consumables). Variable cost is assumed to include costs that will be incurred if the plant operates but will NOT be incurred if the plant does not operate. Variable costs are those that need not be borne if the plant does not operate. They are avoidable. The

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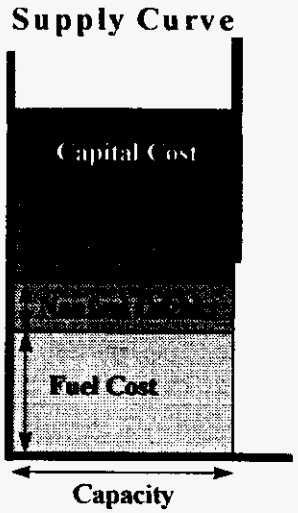
second from the bottom element of the diagram is understood to include all nonfuel costs that can and will be foregone and avoided if the plant is not run.

Figure 12: QUANTIFICATION OF FORWARD COST TO MARKET



- **FORWARD COST EXCLUDES**
  - ✓ Capital cost
  - ✓ Some Fixed O&M
- **FORWARD COST INCLUDES**
  - ✓ Some Fixed O&M
  - ✓ Nonfuel variable O&M
  - ✓ Fuel cost
- **WIDTH OF SUPPLY CURVE IS CAPACITY**

Turning to the most difficult element of the forward cost stack, designated fixed operating and maintenance cost in Figure 12, it is clear that a portion of the fixed O&M cost must be included in forward cost because it can be avoided if the plant does not run. For example, the basic, minimum, prudent maintenance cost necessary to keep the plant in service can be avoided by shutting down the plant. In a competitive market, such cost will have to be repatriated through energy sales; otherwise, plant owners will be obliged to permanently shut down the plant because it loses money with every KWh of operation. In the figure, therefore, a portion of the nonvariable O&M cost must be included in the forward cost of the plant and therefore included in the height of the supply curve.

It is also true that because fixed O&M costs are presently being repatriated largely through fixed cost passthrough as part of the regulatory compact, completely apart from energy sales, they have been arguably been substantially higher than would be sustained in a competitive market. (Such argument is similar to but not identical with the Averch-Johnson effect, which argues that if utility companies are paid to make risk free investments, they will over invest relative to an economically efficient level.) The portion by which fixed O&M costs are too high and will not be repatriated through energy sales in the forthcoming competitive electricity market must be excluded from forward cost to market. They must appear above the horizontal line in Figure 12 and they must be viewed as sunk costs (if they are incurred at all). The question of fixed O&M costs is a difficult problem, one that has consumed a great deal of debate and analysis related to this model. We are convinced ours is the correct approach, but analysis and revision must continue.

There is another interpretation of forward cost to market, which is equivalent to the foregoing, that merits extended discussion. Using the analogy of a jet aircraft that is owned by an

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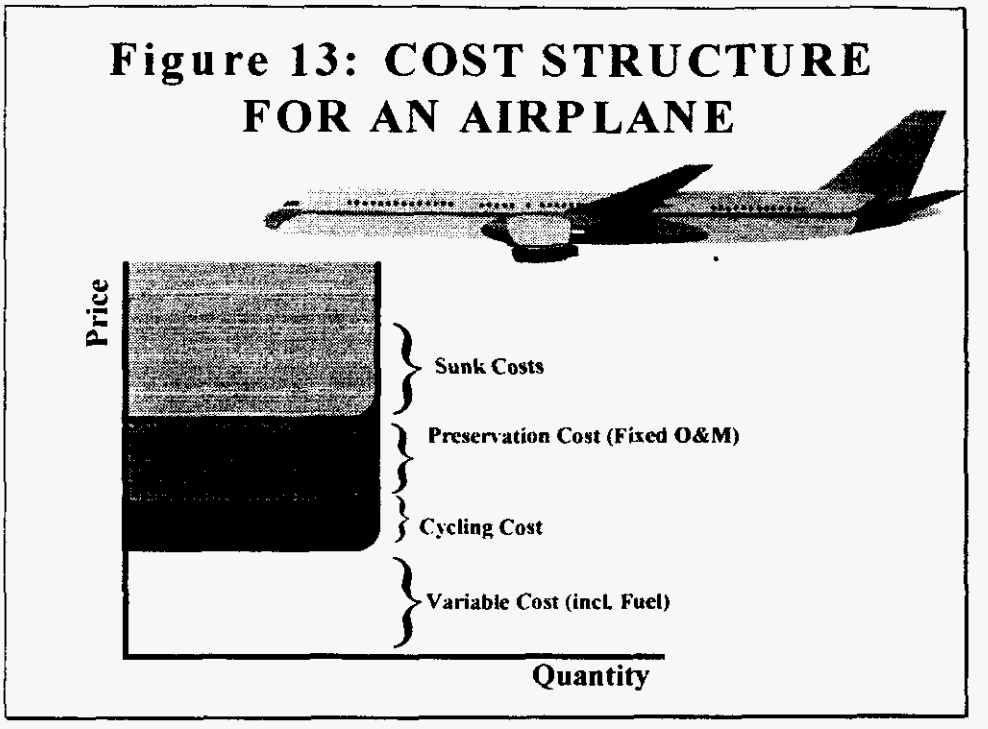
airline company, we see in Figure 13 that its cost structure is comprised of four fundamental elements: variable operating cost, cycling cost, preservation cost, and all sunk costs. Variable costs include fuel, consumables, crew, etc. Cycling costs include incremental costs necessary to provide the specific time schedule of services demanded by their market. Preservation cost represents the lowest prudent cost required to maintain the aircraft in serviceable form so that it can carry passengers and generate revenue. It can be regarded as mileage- or flight hour-dependent maintenance costs and other such fixed maintenance items. Finally, there are a number of sunk and/or allocated costs that can be attributed to ownership of the airplane (e.g., depreciation, gate leases, airport fees). These sunk costs are truly sunk and are independent of the operation or the airplane.



In assembling a forward cost curve for an airplane, we would argue that it should be composed of the variable cost plus the cycling cost plus the preservation cost. These three categories of cost, and only these three categories, can be considered avoidable if the airline company were to sell their plane to Air Ghana, Air Nigeria, etc. or simply decommission it. To wit, variable cost, cycling cost, and preservation cost are avoidable by simply divesting the asset. If the market fails to repatriate such cost through ticket sales, the airline company can and will choose not to incur those costs. The decision not to incur any of these three categories of cost—variable cost, cycling cost, or preservation cost—is tantamount to a decision to divest the airplane. Whether or not to operate the airplane is a function of the SUM of all three of these forward costs to market. It is critically important to realize that the market must repatriate ALL forward costs—variable cost, cycling cost, and preservation cost—or the asset will be retired and removed from the North American asset mix. Precisely the same is true for power plants, semiconductor plants, steel mills, and all other capital assets. If the market (or some government agency that provides an equivalent subsidy) fails to repatriate variable cost, cycling cost, and preservation cost, electric plants will be decommissioned and abandoned.

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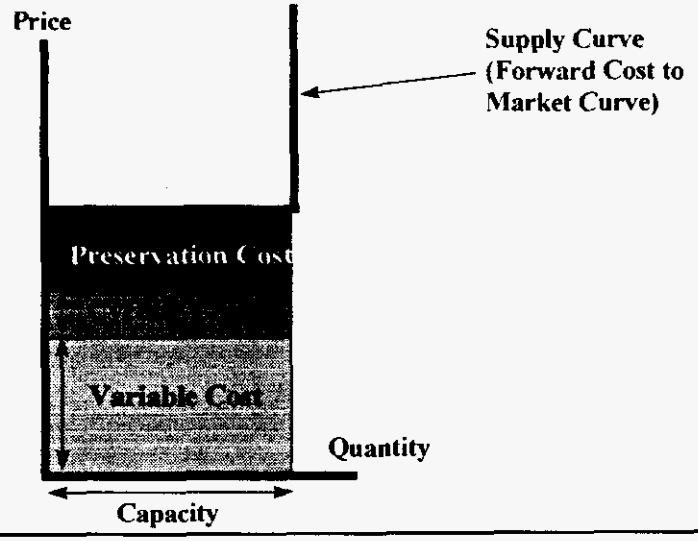
The curve in Figure 13 must be recast in terms of variable cost, cycling cost, and preservation cost. Figure 14 illustrates. Clearly, the forward cost to market for any electric plant must, in the absence of full cost passthrough via regulatory formula, include each of these three categories. The forward cost estimates we apply in our model have taken great effort to embed the view implicit in Figure 14. Given this view, it is absolutely clear that forward prices will NOT be equivalent to "system lambdas." System lambdas reflect only fuel costs and nonfuel pure variable operating cost. They systematically exclude those elements of cost so important to the forthcoming merchant world—cycling and other service costs and preservation costs. Any model that purports to equate forward price with forward system lambda is both incorrect and misleading. We should also note in passing that the cycling and preservation costs of much of the older capacity resident within the North American generation plant inventory is quite high. There is large difference between pure variable cost and total forward cost to market for these older plants. This large difference imperils the competitiveness of these older plants and attracts entry, a phenomenon our model is uniquely able to model. This is a critically important point. Old plants must compete against all other plants in the generation inventory, and those old plants must carry the heavy disadvantage of high nonvariable O&M cost. When those plants are transformed from their present highly protected state of fully regulated plants with full cost passthrough to merchant plants that face market prices for both fuel and power, their high O&M costs will become increasingly daunting.

Figure 14:
RECATEGORIZATION OF PLANT FORWARD COSTS



Turning to the last cost category, all embedded capital costs and capital recovery factors must be viewed as sunk costs and will not be repatriated or repatriatable through energy sales. Gone with the demise of fixed cost passthrough is the notion of "return on and return of rate base." Gone is the notion of guaranteed repatriation of embedded capital outside energy sales. Gone in the forthcoming merchant era is the notion of fixed cost passthrough downstream to unwitting customers who are forced to accept it. In the coming merchant world, there are no customers who can be forced to do anything! Just like other industries ranging from gold, oil, semiconductors, or agriculture, yesterday's capital costs and cash flows deriving therefrom are

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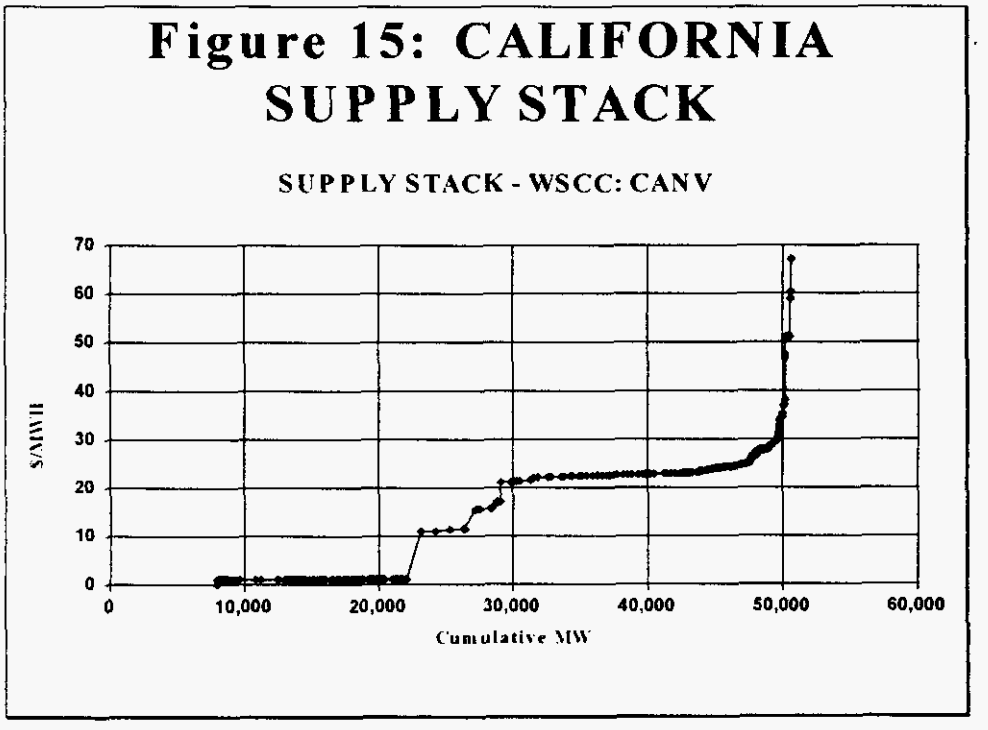
sunk and unaffected by future plant operation. Those costs must not be included in forward cost to market estimates necessary to run a market model. While we want to consider the possibility of embedded costs (i.e, stranded costs) being repatriated in transmission or distribution tariffs within the electric power system, we also will want to consider the possibility that they will either be recovered totally outside the energy system or not recovered at all by electric utility shareholders.

The most difficult aspect of measuring forward cost to market has proven to be estimating what magnitude of formerly fixed operating and maintenance costs should be included as a forward cost and how much it contributes to the height of the supply curves? What portion of historical preservation costs will actually be borne by and repatriated to generation owners in the competitive market? We have made such estimates for each of the units in each of the 30 regions of North America and incorporated them into our estimates of the heights of the supply curves. This is not a job for the fainthearted—estimating forward in time what cost it will REALLY require in a fully competitive market to preserve capacity for intermittent use.

We have implemented our plant data management system within a proprietary software system known as MarketPoint. One of the outputs of that system is the region-by-region supply stacks discussed in detail in this section. Figure 15 puts forth the supply stack calculated for the WSCC:California-Southern Nevada generation region.

Figure 15: CALIFORNIA SUPPLY STACK



MarketPoint is configured as shown in Figure 16. The system contains plant data for every utility-owned and independently owned generation unit in North America as shown on the left. It compares and reconciles all the publicly and privately available data source and develops a single, consistent, reasonable set of generation data.

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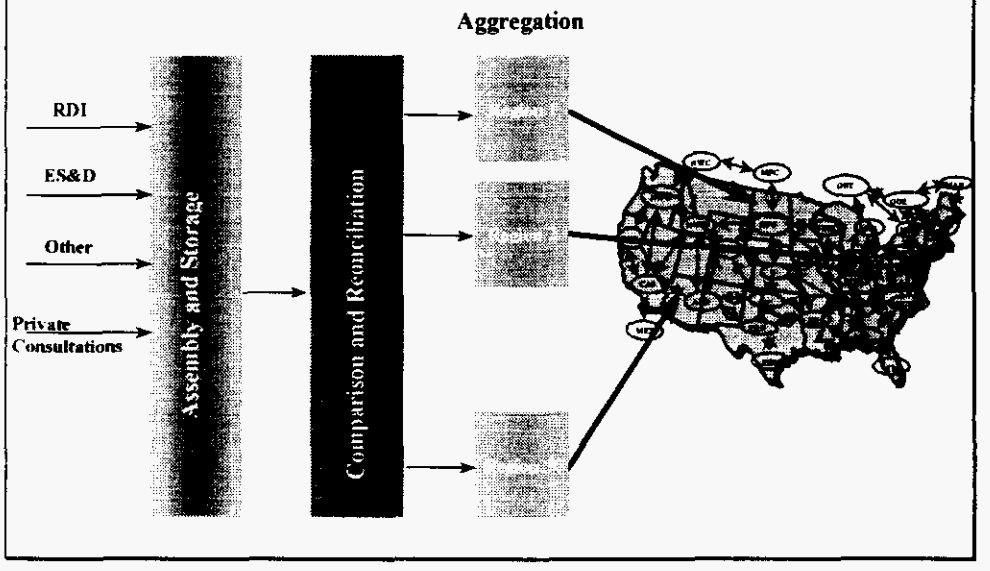
Figure 16: MARKETPOINT™ GENERATION DATA



6.1.3. Cost Reduction and Performance Improvements for Existing Units in a Given Region

As we have observed in every industry that has deregulated, "the good get better and the bad become moribund." There is tremendous incentive immediately following deregulation for existing plants to reduce their forward cost to market over time. Darwinian natural selection (survival of the fittest) virtually guarantees that it will occur. Such cost reductions obviously include reducing fixed O&M, both the market repatriatable portion and the nonrepatriatable portion. As a directly relevant example, consider that airlines (and maintenance contractors) have reduced prudent and mandatory maintenance costs for their 747s as far as they prudently can, and those reduced costs have been repatriated through airline ticket revenues. Airlines have also reduced or eliminated altogether excess or imprudent fixed O&M they may have been charging before deregulation. In short, they have learned to repatriate that portion of maintenance cost that is required by them and their competitors to remain airworthy, and they have eliminated redundant or unnecessary costs. Competitive forces compel them to be constantly vigilant in seeking out and eliminating fixed O&M costs that can be prudently eliminated.

Figure 17 represents the inexorable downward pressure against forward cost to market experienced by the presently existing generation capital stocks. The stack of supply curves represented in black represents presently existing capacity and forward cost embedded in presently existing vintages of plant and equipment. The downward-shifted gray stack represents the downward migration in forward cost to market for each individual vintage of plant currently in place and collectively for the entire set of vintages. Keep in mind, this downward shift occurs as plant owners simultaneously and/or individually reduce the three important elements of costs—variable cost, cycling cost, and preservation cost. We have carefully considered and represented this downward evolution in our model.

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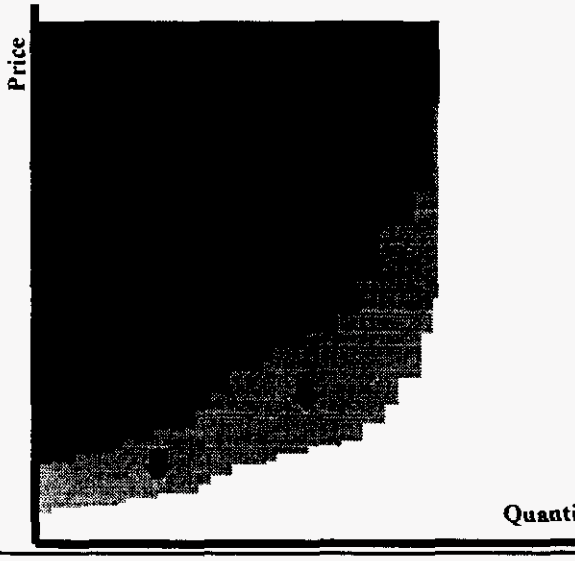
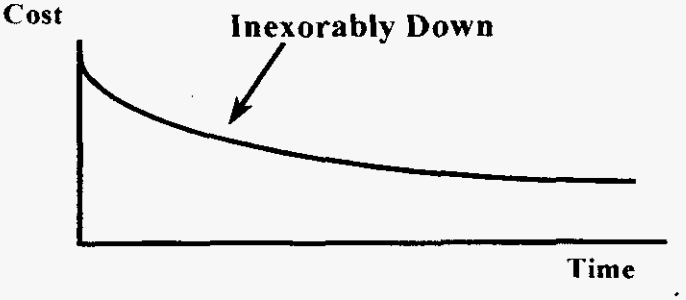
Figure 17: COMPETITIVE PRESSURE REDUCES FORWARD COST



Based on empirical observation of every industry that has been deregulated, it is absolutely unacceptable to hold the cost structure for the existing capital stock of plants constant and static at today's level. We have rendered difficult judgments regarding the most likely future evolution of forward cost structure of the existing mix of plants in place, and we have embedded that judgment in our model. We believe that plants that do not reduce costs are likely to exit the market and only plants that reduce costs will remain in the mix. We characterize this inexorable cost reduction as shown in Figure 18. In effect, we have placed existing vintages of plant on a "learning curve" through the future to reflect our judgment as to what is possible and/or likely.

Figure 18: COMPETITION PUSHES COSTS DOWN

Cost reduction never fails in a competitive economy.



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6.1.4. Retirements of Existing Units in a Given Region

Alas, notwithstanding the inexorable pressure for cost reduction, many existing plants simply cannot hope to survive. Competition is quintessentially Darwinian, the weak, the old, and the sick do not survive. Some economists have dubbed capitalism a system of "graceful obsolescence." Plants retire because they age, and their operating and maintenance costs escalate to noncompetitively high levels. It is well to consider that the average age of electric generation capital stocks is over 20 years in North America, older than at any time in the past. Cost escalation in the older plants resident within that mix is inevitable. Cost escalation in plants currently in cold shutdown is inevitable, and it is likely that few or none of those plants will ever reenter the market.

What does aging mean? How is it manifest in terms of forward cost to market for a given plant? The answer is obvious when one considers his or her personal automobile. When the car is new, its forward cost to market (fuel cost plus maintenance cost) is low and flat, remaining so until the car hits a certain age. After a certain age, the sum of fuel cost plus maintenance cost begins inexorably to appreciate. Maintenance becomes more frequent and more costly. Whereas maintenance used to mean an oil change, it now means a transmission overhaul or a valve job. Whereas outages used to mean running out of gas, outages now mean two weeks in the shop while the user commits to a rental car. We can plot the phenomenon of plant aging conceptually as in Figure 19. The top right portion of the black supply curve (the old, high cost plants in place today), can be expected to shift over time to the left as companies abandon those old plants in favor of new plants or imports via transmission from contiguous areas. We have given a great deal of attention in our electricity model to the problem of quantifying which plants are likely to escalate in forward cost to market the most quickly and thereby be the most quickly "out of the money." On a region-by-region basis, we have made an assessment of the rate of escalation of forward cost to market escalation due to aging and an estimate therefore of how far the leftward shift in Figure 19 might indeed be.

As a parenthetical note, it is well to consider that the most underestimated and underpredicted phenomenon in other industries that have experienced deregulation was the rate and extent of shutdown and retirement of capital stocks rendered economically obsolete and noncompetitive by deregulation. In particular, commodity prices fell, and formerly cost-competitive production facilities or processes were instantly rendered noncompetitive and driven out of the market. Without a regulatory safety net to repatriate the higher-than-market costs of these plants, they were quickly retired and written off. (Recall how quickly rotary phones left the scene, how quickly Alaskan and Canadian frontier gas were abandoned, and how quickly synfuels projects were terminated.) Our model strives not to understate plant retirements that might occur under future deregulation of electricity. Instead, we have estimated the rate and extent of plant aging so that we can predict which vintages and types of plants on a region by region basis are likely to exit the generation mix as shown in Figure 19.

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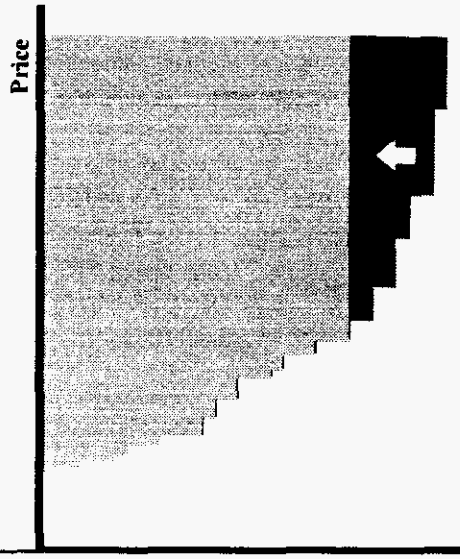
Figure 19: COMPETITIVE PRESSURE RETIRES OLD PLANTS



6.1.5. Ingress and Egress of Transmission to and from Each Generation Region

As if cost evolution in existing plants were not a difficult enough problem, deregulation opens the Pandora's box of "competition from afar" via long distance electric transmission. While in the halcyon days of rate of return regulation, utility companies could generate exclusively for their own accounts, staving off transmission and generation entrants into their service territories through franchise control, they now face the prospect of transmission entering their service regions and competing with their generation assets. That is the "bad news." There is, however, offsetting "good news." Generation companies can compete with plants in contiguous service territories by exploiting outward bound transmission, thereby augmenting the markets they can serve. The logistics of inbound and outbound transmission add a degree of competition and a degree of analytical complexity to the electric power industry that has not been present historically. The historical types of models used in the industry, particularly production simulation dispatch models, were and are absolutely unequipped to represent the inbound and outbound transmission issues that will begin to affect the industry in the future. Production simulation models have gone the way of the dinosaur, representing an industry environment that is long since gone.

How do we represent the emerging open access transmission system and its implications for electric power? The answer is apparent from the structure of the map in Figure 9 and the subregional network diagram in Figure 10. We have represented existing and prospective transmission linkages among all the contiguous regions and subregions in the diagram, we have represented all the indigenous generation alternatives within each region and subregion, and we have represented electricity demand within each region and subregion. To wit, we have used "brute-force enumeration" to characterize all the existing and prospective generation, inbound transmission, outbound transmission, and native consumption options within each region and

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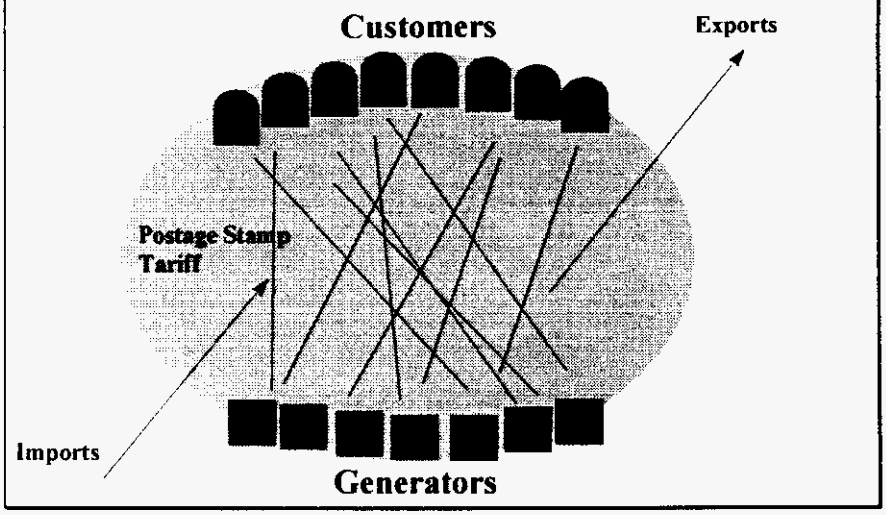
between each pair of contiguous regions. Focusing on transmission, within each of the regions and subregions in Figure 9 and Figure 10, we have represented generation, transmission, and consumption as shown in Figure 20.

Figure 20: TRANSMISSION CONVENTIONAL WISDOM



The title of Figure 20 is significant, the "conventional wisdom" of the electric transmission business. The "conventional wisdom" suggests that generators in a particular region will generate power and wheel it to their own customers (which we term intra-regional wheeling), ship it to customers in contiguous regions, and receive it from generators in contiguous regions. It is usually further conjectured that such transactions will all occur at a single tariff, a "postage stamp tariff." A postage stamp tariff or rate is a single, common rate for point to point transmission service, but the rate is independent of the entry point and the exit point. Postage stamp rates charge a shipper to "get on and get off the train" but do not levy a distance-dependent charge. Postage stamp rates have the property that wheeling costs are the same, absolutely identical, for all entry and exit points on the transmission system. Wheeling power 300 yards costs the same as wheeling it 350 miles. While we want to admit into our model the possibility of postage stamp transmission rates for both intra-region and inter-region wheeling, we also want to admit the possibility of market-sensitive rates, distance dependent rates, and zone rates in electric transmission, just as we have seen evolve in the gas and telecommunications businesses. There is no earthly region why rates should equilibrate to a single postage stamp rate. On the contrary, postage stamp rates hurt certain transmission linkages, and the owners of those linkages can be expected to reset their tariffs as a competitive measure. We have retained the ability to consider the widest possible range of transmission rates and infer what particular set or sets of rates are likely to be market-sustainable.

Motivated by our ambitious goals for modeling electric transmission, we have proceeded as follows. We have implemented the structure in Figure 20 for each of the 30 regions and subregions in Figure 9, but we have connected them together as shown in Figure 21.

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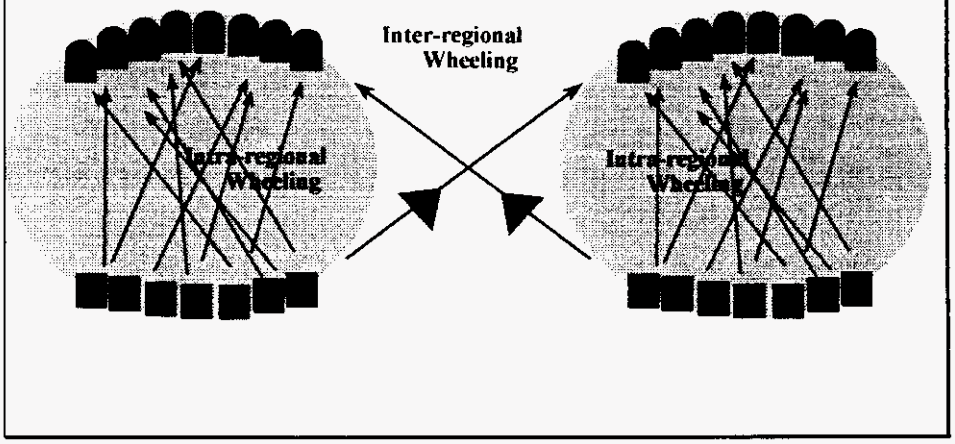
Figure 21: WE REPRESENT INTERCONNECTED WHEELING LINKS



The reason for the interconnection indicated in Figure 21 is that we want to allow the possibility that the transmission tariff from the left region to the right region is DIFFERENT from the transmission tariff from the right region to the left region. We also want to allow the possibility that the intra-regional wheeling tariff in the left region is DIFFERENT from either of the two inter-regional tariffs, and that all are DIFFERENT from the intra-regional tariff on the right. This is not to say that we dismiss the possibility that they might all be the same. On the contrary, the structure we have built allows us to set them all equal to represent prospective postage stamp wheeling. However, it is to say that we want to preserve the possibility of setting them all to be different and thereby to represent scenarios whereby owners of transmission strive to price at market rates and strive to extract whatever rents they can whenever they can extract them. We also strive to represent the possibility that transmission might enter on an unregulated, unguaranteed, greenfield way at some time in the future. (The example of privatized highways argues that merchant entrepreneurs might build transmission if there is sufficient rent earning possibility they can glean from such entry.)

There is one other critically important aspect of our transmission submodel that merits discussion here. Referring to the inter-region and intra-region wheeling links, they have a fixed maximum capacity today. We have made a great deal of effort to estimate and input today's transmission system maximum capacities in the model. We have attempted to represent maximum inter- and intra-regional capacities so that we can identify near term bottlenecks caused by transmission capacity limitations. In addition, however, just as with generation, it is possible to reinforce existing transmission infrastructure to increase inter-regional and intra-regional transmission capacity. It is also possible to implement greenfield transmission capacity, adding lines that are either parallel to existing lines or lines along fundamentally new routes. Our model considers existing transmission capacity, the cost and capacity of augmenting existing capacity, and the cost and capacity of building new, greenfield transmission capacity. Just as with other commodities, prospective new electric transmission competes against old, and the combination of prospective new and old transmission compete against indigenous generation.

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Figure 22: INCOMING TRANSMISSION ADDS SUPPLY AND REDUCES COST

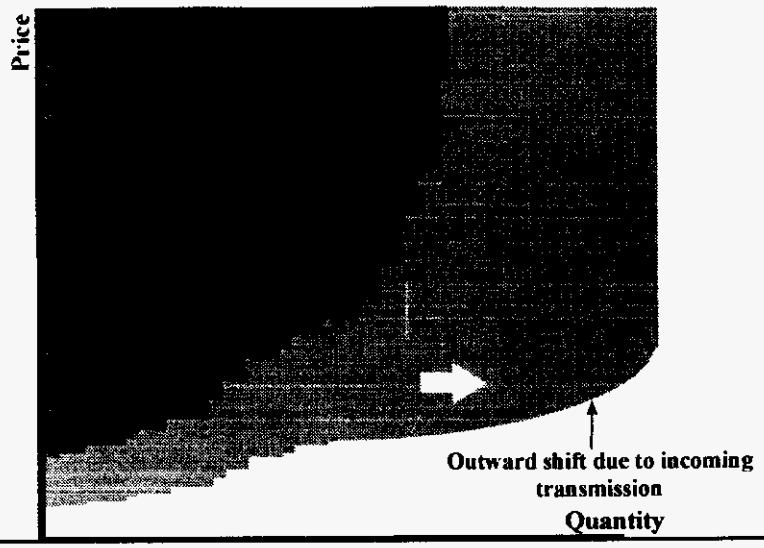

Figure 22 represents economically what the combination of cost improvements in existing plants combined with incoming transmission can do to the original supply curve that characterizes only the existing capital stocks (black in the figure). Intuitively, there is a large increment of energy supply from incoming transmission that can materialize at or near a given price. This increment of incoming transmission energy competes "one-up" against the existing generation mix within the region. Furthermore, the existence of this transmission increment, because it drives the lower right boundary of the supply curve downward and to the right, has the prospect to dramatically depress market clearing prices of electricity in the region. In effect, it creates additional supply to chase a fixed level of demand. When additional supply chases a fixed level of demand, prices cannot help but fall (relative to what they would otherwise be). Indeed, incoming transmission depresses prices in the region into which it enters. Always.

By implementing the transmission increment as shown in Figure 22, we are able in the power model to represent the true effects of inter- and intra-regional wheeling. We will not naively miss the prospective effects of incoming transmission buoyed by generators in contiguous regions who are striving to increase profits. We will not inadvertently miss "competition from afar," directed as it will assuredly be to high margin business. We will not inadvertently overvalue indigenous assets in any given region because we fail to consider the possibility of aggressive incoming transmission into the region.

By the same token, however, we will not fail to properly represent the fact that outbound transmission can create heretofore-unavailable energy markets for existing plants in certain regions. Our model considers the fact that outbound transmission can be an attractive business alternative for existing and prospective new generators in certain regions. Outbound transmission means that plants need not necessarily be sited contiguous to markets. Plants can be sited many miles away more contiguous to attractive fuel supplies and the electricity transported on an increasingly competitive transmission system to new markets. The more transmission that leads

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away from an existing plant, the larger the prospective market that plant sees. Larger prospective market available to a given plant means a higher selling price for the output from that plant. The model strives to balance (in the economic sense) the price-stimulating influence of outbound electric transmission against the price-suppressing influence of inbound electric transmission. We believe we have the tools and the emerging data to do so, and we have carefully employed them in valuing a rather broad range of assets and business prospects thus far.

Before leaving the issue of transmission, we need to represent what transmission implies for contiguous regions. Figure 23 illustrates two regions, one a region (at the left) with excess generation capacity relative to demand and one (at the right) with tight capacity relative to demand. Notice that the region with excess capacity at the left evidences a lower market-clearing price than the tight region in the absence of interconnecting transmission. As illustrated in the figure, if the incremental cost of transmission is smaller than the price differential that would be sustained in the market between the two regions if they were isolated, transmission will enter. As it enters, the critical insights are those shown in the figure:

- Price in the region where the transmission originates will INCREASE. Outbound transmission stimulates market-clearing price because it provides more demand against a constant generation mix.

- Price in the region where the transmission terminates will DECREASE. Inbound transmission decreases market clearing price because it provides more supply against a constant customer mix.

- If the cost of transmission happened to be higher than the price differential between regions in the absence of transmission, there would be absolutely no transmission between the regions. Transmission will have absolutely no effect on the price in either region or the flow between them.

- In the absence of transmission limitations, the price differential between the two regions will shrink to the point at which it equals the transmission cost between the regions. In other words, transmission capacity will enter up to the point at which the price differential between the regions is exactly equal to the marginal transmission cost between regions.

- If there exists an immutable upper bound on transmission, the price differential between the two regions will remain larger than the transmission cost between the regions. Transmission will depress the price differential, but it will not be sufficient in size to depress the price differential all the way to marginal transmission cost.

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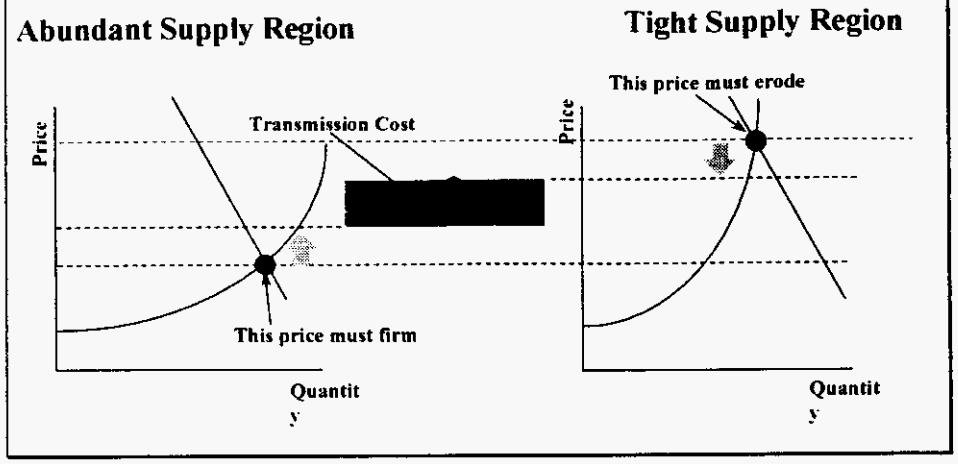
Figure 23: TRANSMISSION DICTATES PRICES AND DIFFERENTIALS



Transmission is difficult to model because one does not know priori which regions will have low prices during which periods and which regions will have high prices during which periods. The only way to accurately model transmission is through "brute force," systematically enumerating every existing and prospective transmission link complete with cost and capacity between every pair of regions in the model. This is precisely why dispatch-oriented production costing models have completely "fanned" on transmission. They have absolutely no hope of modeling transmission, for they require that one input an a priori estimate of what transmission assets are present in each region. It is not physically possible to have an asset from region A available in region A as a generation asset and simultaneously in region B as a vertically integrated generation-transmission asset, as dispatch models would force you to assume. Our approach is the only dynamic approach we know of that can represent the simultaneity of transmission implicit in Figure 9.

6.1.6. Prospective Entry of New Generation Units into a Given Region

As if the foregoing issues were not sufficiently daunting and difficult, it is true that if the price of electricity rises to the point at which that price is capable of repatriating the full capital cost plus the full operating cost of a new, greenfield facility plus a minimum market-level rate of return necessary to draw capital from financial markets into that new, greenfield facility, we must expect such new, greenfield facilities to be built and enter the market. In effect, the full capital and operating cost of a greenfield facility must "cap" the price of energy in each of the 30 generating and consumption regions. There is no way that long term prices should exceed the full cost of a greenfield facility for very long. Increasingly easy entry will guarantee that it will not.

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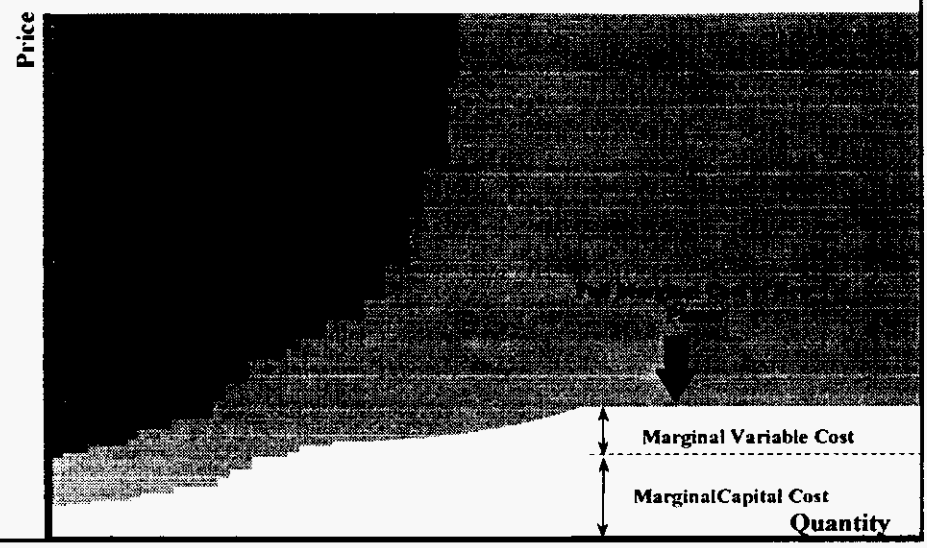
Figure 24 represents the fact that new greenfield units can be expected to enter if the prices rises sufficiently to draw them into the market. Notice at the right hand side of the diagram that if the full fixed and variable cost of a greenfield unit plus a return to its owners will be repatriated by electricity prices, that greenfield unit will enter. Furthermore, there is no limit in each region on the entry of greenfield units. Gas combined cycle plants are literally commodities in their own right and can be added wholesale on a consistent and common basis. Recognizing

Figure 24: NEW PLANTS ENTER AT FULL MARGINAL COST



the fact that entry is very easy and relatively quick, we must represent the fact that the supply curve becomes horizontal at an electricity price necessary to fully repatriate all fixed plus variable costs of a new greenfield unit. It is this flattening of ultimate electricity prices that inevitably obsoletes and shuts down old electric generation capacity. Old capacity is replace by the entry of new, whose full fixed plus variable cost undercuts the variable cost of the old, decrepit units.

We should note in Figure 24 the use of the terms marginal variable cost and marginal capital cost. What we are attempting to indicate in the figure is that the price of electricity is capped by the "marginal new unit," the unit that offers the best sum of fixed plus variable cost. What the precise configuration of this unit is given local fuel costs, altitude, temperature, and other characteristics varies from region to region. We have gone to great effort to estimate the capital cost, operating cost, and heat rate of each and every prospective new unit that could conceivably enter the market in each region. This information is part of the model database. New units enter if the price rises to the point where it crosses the flat portion of the supply curve at the extreme right of the figure. In the Altos model, new equipment costs have been estimated from developers, equipment vendors, and cognizant electric power professionals by our staff and represents an important judgmental assumption to the model.

Greenfield entry is important in the sense that the rate and magnitude of capital stock rollover and new equipment entry in other industries that have deregulated has been colossally underestimated. The telecommunications industry was rife with stories of overcapacity during Judge Greene's Modified Final Judgment to break up AT&T, yet North America experienced a

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literal explosion of capacity. The gas industry was rife with stories of excess reserves and a gas bubble during FERC Order 436, yet in spite of prices falling by almost ½ in real terms since then, North America still experiences massive drilling, reserve additions, abundance of supply, and low prices. We have given special attention to the question of greenfield entry because we do not want to repeat the mistakes of other deregulating industries. Furthermore, we want to identify specific greenfield entry opportunities for our clients.

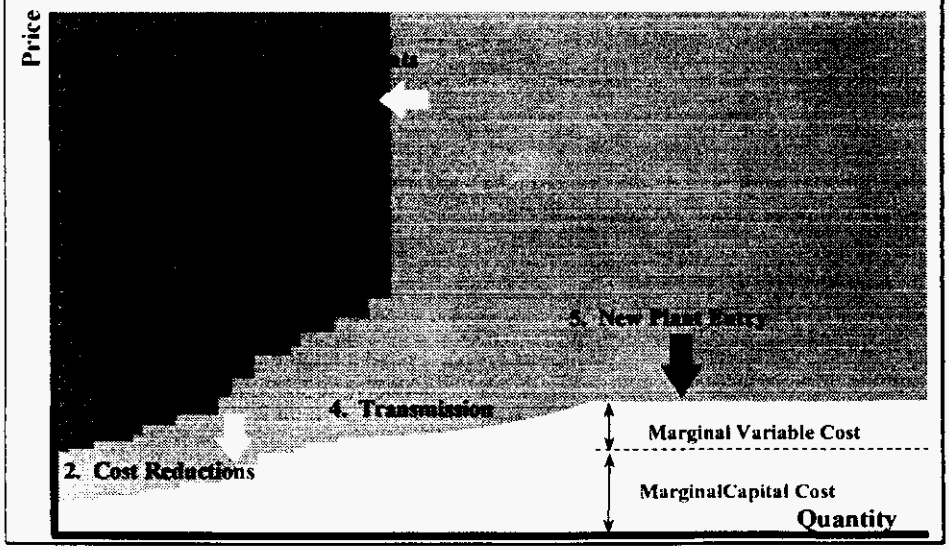
6.1.7. Summary of Supply Representation (Generation Plus Transmission)

It is important to summarize the issues we have accounted for related to electric energy supply. Figure 25 does so. Notice in the figure, we have taken great effort to represent on a region by region basis the following five supply- and transmission-related phenomena:

- Cost and capacity of existing generation capacity
- Cost reduction that will evolve in existing generation capacity
- Imminent retirements in noncompetitive generation capacity
- Ingress and egress of transmission capacity to and from every North American region
- Entry of new, greenfield capacity based on the full fixed and variable forward cost to market.

The figure summarizes our endeavors to represent each of these phenomena individually and collectively. We are unaware of any analytical framework save ours that systematically and formally represents each of these five supply phenomena, collectively or individually.

Figure 25: FIVE KEY PHENOMENA



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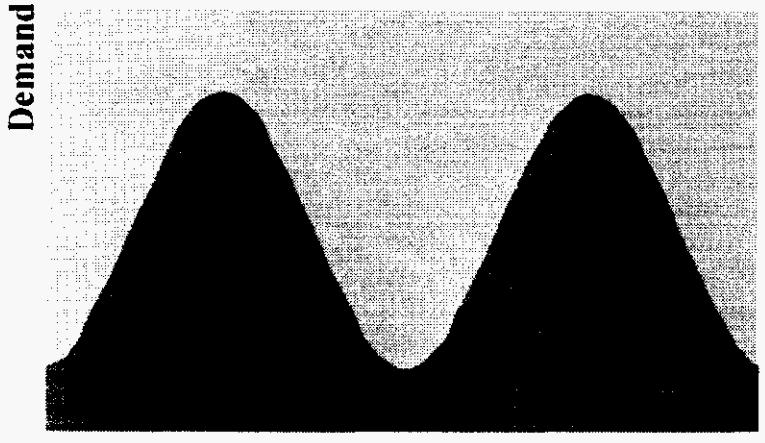
6.2. Representation of Demand

Having completed our generation and transmission overview in the previous section, we now turn to the question of incorporating electric energy demand into our model(s). Electricity demand varies by hour of day, day of week, week of year, and year. Furthermore, because electricity is not storable, it is the ultimate in "just in time" (JIT) manufacturing product. Literally 100 percent of all inventory must be embedded in standing capacity to produce, not in inventory that can be stored and resold upon demand. With today's technology, one cannot store electrons for later use. They flow and are used when they are generated. Generation units are like flashlights. When one turns on the switch, the flashlight produces light. When one turns off the switch, the flashlight immediately ceases to produce light. Like a flashlight beam, one cannot turn on the light during times when he does not need it and inventory it for when he does need it.

Projecting electric energy demand is akin to predicting demand for light from the flashlight. We need to project the hour by hour, day by day, week by week, and year by year demand for the beam of light, i.e., the aggregate stream of electric energy required by the customers in a given region. Figure 26 recognizes that the hourly demand for electric energy must be projected region by region throughout the 30 regions we use to comprise the North American electricity market.

Figure 26: DEMAND VARIES BY TIME OF DAY, WEEK, SEASON AND YEAR



How can we determine what the hourly load variation is, and how can we project it 10 or more years into the future? To do so, we have accessed the hourly demand reports by every utility and other reporting entity in the country. We have accessed this voluminous information in automated form by hour by reporting entity over a complete three year historical period. It is our intention in so doing to be comprehensive, generating histories of demand by hour for every reporting entity in North America over the past three reporting years. By so doing, we are able in effect to develop a historical load duration curve for every hour of the year. This highly detailed information will allow us to build comprehensive models of demand at different levels of detail over different time horizons for our model.

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What is the demand side methodology we have used? The raw, reported data alluded to above represents a historical demand schedule, which varies by time of day, week, season, and year. Figure 26 provides a conceptual illustration of the time-varying historical data we have assembled to populate our demand model. The figure emphasizes that electricity demand is different for every historical hour reported in every region at every reporting point in North America. Indeed, there is a time-varying schedule of demand of the form in Figure 26 stretching over the past three years at every point in North America.

The next step is to aggregate the raw information hour-by-hour, region-by-region to create 30 regional aggregates of hour-by-hour electric energy consumption. To wit, we have taken the curves of the form in Figure 26 and aggregated them hour by hour according to the geographic subdivisions in Figure 9. After such aggregation, we can develop an overall curve of the form in Figure 26 for each of the 30 regions that comprise our model.

Once we have assembled this hour-by-hour load pattern over the three year historical period for the 30 regions of our model, we need to aggregate this data to the level required by the market model we wish to use. We can either maintain the hour-by-hour chronological form of the data, or we can use it to calculate daily, weekly, seasonal, and/or annual representations of load and load duration. Before discussing exactly how we have processed and aggregated the hourly demand data, it is worthwhile to define unequivocally what we mean by a load duration curve. To develop load duration curves, we begin with the hour by hour demand schedules for each of the 30 regions as depicted in Figure 26 and reorder them in sequence from highest demand to lowest demand in the given year. This demand reordering process can be used to create regional load duration curves as depicted in Figure 27. Such load duration curves represent total demand that occurs during a year, and they represent the total demand that occurs in every individual hour of the year. However, by reordering demands from highest hour to lowest hour, we lose the chronology of hourly demand by day, by week, and by season. All we would have is a highest-to-lowest snapshot of annual demand as distributed throughout the hours of the year. Whether this reordered series of demands is sufficient for a given need depends on whether we are studying hourly and daily load following. If not, the unordered representation of loads is sufficient. If so, we need to retain the chronology.

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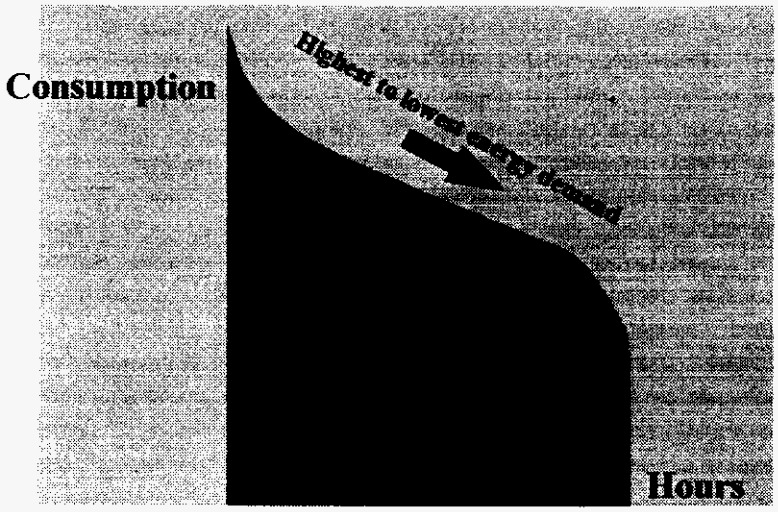
Figure 27: CALCULATION OF LOAD DURATION CURVE BY REGION



Using the WSCC, California and Southern Nevada as an example, Figure 28 illustrates three different analyses of the demand data we have undertaken. To begin, the figure depicts the average daily demand pattern for each of the twelve months of the year, which is termed "Monthly Average Hourly Demand" in the figure. The average daily load shapes are the solid curves that embody the characteristic double peak in the winter and the characteristic single peak in the summer. They are derived from three year average hour by hour demand by month as derived from the Altos demand data base. Such daily load shape information is used to simulate daily operation in our models. Referring again to Figure 28, we have crafted 12 monthly load duration curves and a single annual load duration curve. The 12 monthly load duration curves are used to populate our monthly models, and the annual load duration curve is to populate our longer run annual models. The comprehensiveness and hour-by-hour chronology of our demand side information is critical to developing demand side data of the type shown in Figure 28.

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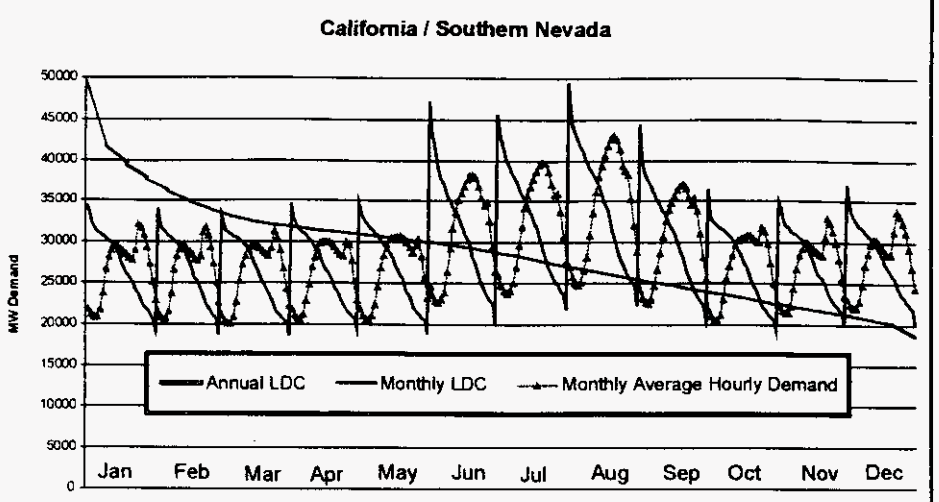
Figure 28: DEMAND INFORMATION SUITABLE FOR MODEL INPUT



Referring initially to the annual load duration curve, which serves as the basis for our annual, long term model, we must disaggregate the curve and place it into the model to characterize time-varying electricity demand. Having developed each load duration curve, we first discretize each curve into specific load periods. For our long term model, we have used three load periods, which we have designated base, intermediate, and peak. For our monthly model, we have used five load periods: base, high intermediate, low intermediate, high peak, superpeak In the longer term model, we have defined base load as that demand that persists 100% of the time, i.e., the bottom block in Figure 29. Intermediate load is that load that persists 50% of the time. It corresponds to the middle block in the diagram. Peak load demand persists 15% of the time in the current version of the Altos model, and it corresponds to the top block in the diagram.

Once we have created the regional load duration curves of the form in Figure 29, we then normalize them so that each curve represents the annual load variation for 1 GWh of total energy demand. That is, the area under the normalized load duration curve is 1.0; the sum of the areas of the three rectangles in Figure 29 is 1.0. Following such normalization, we are then able to multiply the normalized load duration curve by a long run electric energy projection such as that produced by NERC to obtain a ten or twenty year, load dependent, electric energy demand projection. This is precisely what we have done on a region by region basis throughout North America, multiplied the normalized load duration curves derived from historical data by projections of electric energy demand derived and extrapolated from FERC.

Our electric energy demand projection combined with a normalized load duration curve calibrated to historical load shapes constitutes a forward demand schedule in the electric model. In the lexicon of economic theory, this demand projection represents an "inelastic" projection of electric energy demand. We have the capability on a load category by load category basis to specify a price elasticity of demand so that the actual projected demand for electricity by the model is price sensitive. This capability is represented schematically in Figure 30. Notice in the figure that we specify price-sensitive demand curves for each of the discrete increments of load.

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There is a peak load demand curve complete with price sensitivity, an intermediate load demand curve complete with price sensitivity, and a base load demand curve complete with price sensitivity. We believe this price sensitivity to be potentially important as the true marginal cost of on peak power becomes increasingly exposed to electricity customers for the first time. In the past, customers have been insulated from the true marginal cost (i.e., the true price) of peak load power because of regulatory cross subsidies of peak load prices by base load prices and of residential customers (who cause the peak to a significant degree) by industrial customers. Our price sensitivity feature has not yet been fully studied or exploited, but it promises to be important to asset valuation and trading in some regions during some periods of time.

Figure 29: DISCRETE APPROXIMATION TO LOAD DURATION CURVE

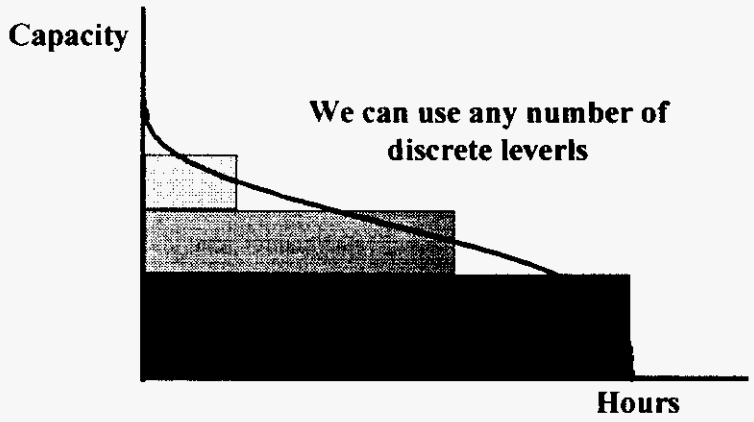
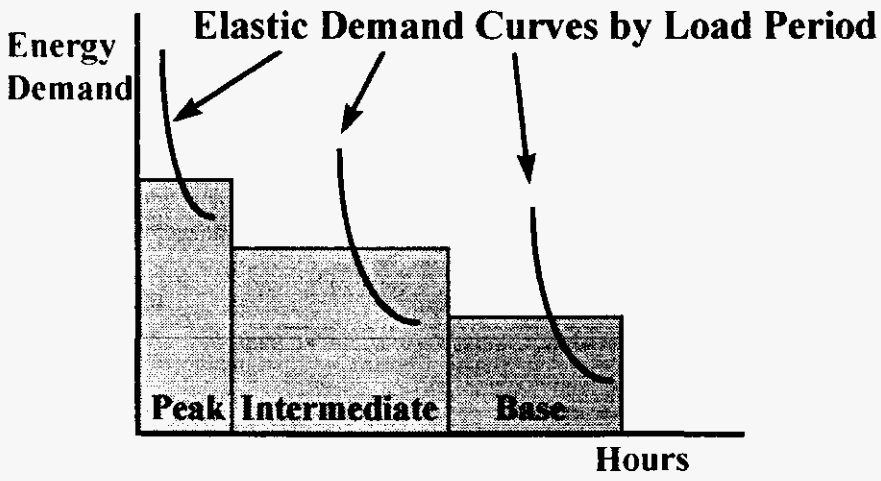


Figure 30: DISCRETIZE TO CALCULATE PRICE IN EACH LOAD PERIOD



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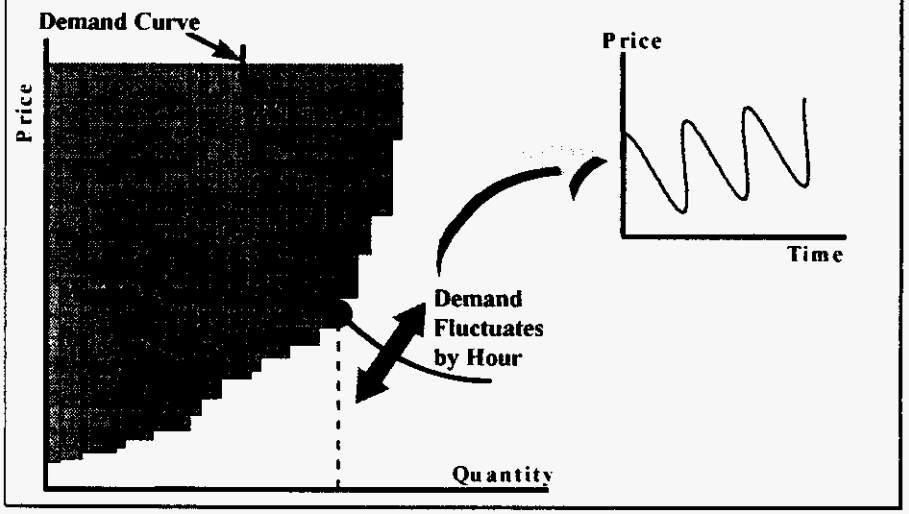
7. SUMMARY OF MODEL STRUCTURE

To summarize, the Altos North American Electric Power Model can be represented schematically as shown in Figure 31. The model contains a complete representation of supply including

- generation as it presently exists,
- cost reduction in present capital stocks,
- retirement of present and future capital stocks,
- existing and new increments of inbound transmission,
- existing and new increments of outbound transmission, and
- prospective entry of new plants and new technologies.

Figure 31: A DYNAMIC INTERREGIONAL PRICING MODEL OF ELECTRICITY



The model contains a complete representation of inbound and outbound inter-regional transmission that can accommodate not only postage stamp transmission tariffs but also a rich and complete range of distance-based, zone-based, value-based, monopolistic, or other tariff structures. On the demand side, the model is capable of representing demand on a chronological basis, but the present implementation used to support long and short run decision is based on a discretized load duration curve approximation. Viewed as an integrated whole, the model represents changing supply and changing demand and finds the market clearing price and quantity. In our lexicon, the model finds the "magic crossing point" between supply and demand. The market clearing price represented by this magic crossing point varies throughout the year as shown in the figure.

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We have developed increasing confidence in the general results of the model, and more companies are becoming increasingly committed to using it to guide their asset valuation decisions and our marketing and trading decisions. We believe that the model can generate competitive advantage, allowing us to increase profits and reduce risks of our asset and trading businesses and to coordinate and marry them at the most fundamental level.

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FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ____ (DMN-16)

OVERVIEW OF THE NORTH AMERICAN REGIONAL GAS (NARG) MODEL

by

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August 1998

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1. OVERVIEW AND SUMMARY OF NARG

1.1. General

The North American Regional Gas (NARG) model[1] is an economic model of the natural gas industry of North America that represents how regional interactions between supply, transportation, and demand determine price, quantity, and reserve additions. The objective herein is to describe the NARG model works. We have provided enough detail to illustrate rather comprehensively how the model works, yet we have omitted the detailed mathematics. Readers desiring a more mathematical description are referred to Nesbitt, Haas, and Singh, The GRI North American Regional Gas Supply-Demand Model, Decision Focus Incorporated report to the Gas Research Institute, 1988. The balance of this initial section discusses the time horizon and time period conventions resident within the model. Section 2 characterizes the resource model in depth. Section 3 describes the demand side of the model, and Section 4 outlines the pipeline transportation component of the model. Collectively, these sections provide enough methodological information to characterize rather completely how the NARG model works and why it represents North American gas markets in the best possible way.

1.2. Time Period Structure Of The NARG Model

The NARG model and the Generalized Equilibrium Modeling System (GEMS) approach upon which it is based are neither short- or long-term in nature. The GEMS approach is fully the most general approach in existence with regard to its dynamic assumptions. In particular, GEMS assumes that the future price schedule is a continuous, nonlinear function. (It makes a similar continuous assumption for flowing gas volume, reserve additions, and capacity additions.) The GEMS user specifies the time interval over which he or she wishes to sample from the continuous price (or other function) by specifying the following three parameters:

- Number of Time Points, i.e., the number of samples from the continuous future nonlinear price curve the user wishes to consider.

- Time Interval Between Time Points, i.e., the inter-time point interval the user wishes to consider.

- Number of Intra-Year Time Points, i.e., the number of subannual time points within each year the user wishes to consider. For example, in the short run gas model, we specify 36 monthly time increments. Time variation of core and noncore demand across these monthly time increments allows us to take account of seasonal demand variation and storage injection/withdrawal to fulfill it. GEMS allows us to specify as many intra-year periods as we like, including months (January, February, March,...) or others.

Armed with these inputs, which are "data" to the model and are not hard-wired into the computer code, GEMS creates the specified number of time points separated by the specified time interval. The long term version of the NARG model specifies ten (10) time points separated by a five (5) year interval with a single intra-year time increment. This creates a 45-year future model horizon,

[1] NARG and GEMS are tradenames owned by Decision Focus Incorporated.

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sampling from the continuous nonlinear future price curve ten times, and considering only annual gas demand.

2. THE SUPPLY SIDE OF THE NARG MODEL

This section puts forth a rather complete description of the supply elements of the NARG model. We will discuss not only the rationale and details of the supply side calculation but also fully characterize the supply side data, where we get it, and why it is the best and most accurate descriptor of North American supply.

2.1. Regional Structure

The NARG model is a multiregional supply, transportation, and demand model. The reasoning underlying the supply regionalization is central to a full understanding of NARG. This section discusses how and why we have regionalized North America to take account of the resource deposition.

2.1.1. Regional Structure Of The United States

It would not be useful to subdivide the supply regions in the NARG model according to political or demographic boundaries (e.g., states, provinces, census regions). Rather, it is more useful and appropriate to subdivide the supply regions according to existing and prospective natural gas producing potential, i.e., to subdivide on a geological basis. In making such subdivision, consideration must be given to the structure of the existing and prospective future pipeline system. In particular, supply regions must be associated with the upstream ends of existing pipelines and with the upstream ends of anticipated new pipelines. The supply regions in the NARG model were selected with several considerations in mind.

First, when it is necessary to distinguish differences among gas producing basins in terms of transportation costs to demand regions that compete for that gas, those basins have been associated with distinct supply regions. That is, transportation cost differentials dictate supply regionalization.

Second, for those sources that will require new pipeline or gathering capacity, regional supply distinctions have been made. If a particular resource producing basin relies on the addition of new pipeline or gathering capacity to become economically viable, that supply region is distinguished from other supply regions. Indeed, in such cases, the supply region and the outward-bound pipeline are inextricably linked, and we must model them in effect as a pair. Proper consideration of the relationship between pipeline segments and resource production regions was one of the primary considerations that has in recent months motivated the disaggregation of the Texas intrastate portion of the natural gas system and disaggregation of the Gulf Coast and Gulf-to-Northeast pipeline links. To wit, we needed to disaggregate the Gulf Coast gas-producing region in order to represent in more detail its configuration relative to the supply basins it exploits and the interim or final demand centers it serves.

Third, when it is necessary to distinguish resource endowment and cost differences among producing basins, those basins are distinguished by region. In general, there are substantial differences among resource producing regions with regard to extent, cost, and distribution of the natural gas resource base. Some would argue that such heterogeneity of the resource base motivates an extremely detailed representation of natural gas supply. Countering such argument is

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the observation that much supply side aggregation is dictated by the specific structure of the pipeline system. We have sought to balance the desire for more supply side regional and technological detail with the desire to realistically represent the transportation corridors for delivering gas to market. However, it has become clear over time that it is increasingly necessary to disaggregate the Louisiana and Texas region of the Gulf of Mexico, both onshore and offshore. The region is that recently unfolding resource deposition information related to the onshore and offshore Gulf resource indicates substantially higher potential located in specific locations. Our disaggregation of the Gulf of Mexico resource base was designed to capture those newly emerging realities.

Fourth, many supply or pipeline projects have direct effects only in localized regions of the United States or Canada, yet the indirect effects proliferate broadly throughout all supply and demand regions of all countries represented. In effect, prices carry economic signals from the single directly affected region to all other regions of the country along all the paths of the pipeline network. The representation of the pipeline network must contain sufficient detail to represent all important existing and prospective future paths. Noting that pipeline connections cause adjacent markets to communicate, we are motivated to incorporate a larger rather than a smaller number of pipelines and pipeline corridors into NARG.

Fifth, government policy can be region-specific. Excessive aggregation across regions would obviate the ability of the model to properly represent government policy. For example, there are significant tax, financial, and other differences among regions, necessitating regional distinctions in the model. A specific illustration is the argument that the Alliance pipeline might use liquid sales to subsidize gas transportation. In such a scenario, the transportation cost along Alliance would be smaller than "normal" gas pipeline economics might otherwise dictate. The NARG model can represent such phenomena related to Alliance as well as a wide range of policy and other similar phenomena.

With regard to the conventional and deep natural gas resource base, the Potential Gas Committee (PGC) regions and designations were adopted and incorporated into the model. There are several reasons for this regionalization. First, much of the resource data is reported in geological and geographic zones consistent with the PGT regions. The PGC, the United States Geological Survey (USGS), and similar resource base reporting organizations have given a great deal of much thought to the appropriate degree of regional disaggregation of the conventional resource base. We have sought to incorporate that thought by adopting their regions.

Unconventional gas (tight sands, methane from coal deposits, and Devonian shale), which are commonly called "continuous deposits," are associated in the model with conventional gas supply regions and are distributed among the conventional gas supply regions as dictated by their actual physical location. The unconventional gas resource base is distinguished in the same degree of regional detail as the conventional gas resource base, but the realities of where it occurs are properly represented. Using the same regional distinctions for unconventional as well as conventional gas is particularly convenient and we think proper because the unconventional gas resource must enjoy the same access to the transportation system as conventional. Furthermore, the unconventional resource base is further down the economic ladder than the conventional resource base, meaning that the pipeline infrastructure built to exploit the lower cost conventional resource base is likely to dictate the exploitation pattern of the higher cost unconventional resource base.

Synthetic sources (e.g., coal gasification) are regionalized according to coal producing

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regions of the United States. The major coal producing regions of the United States have been associated with the various PGC supply regions and have been placed into the corresponding aggregate NARG model gas supply regions. For example, the North Dakota coal region (where minemouth coal gasification might occur) is considered to lie within the Northern Great Plains supply region. Small, exotic sources such as methane from waste or biomass are positioned within the various demand regions, representing the fact that they use only the distribution system, not the transportation system.

2.1.2. Regional Structure Of Canada

The regional structure of the Canadian gas system and the supporting resource data are distinguished as follows. The Western Canadian Sedimentary Basin has been disaggregated into the three provinces in which it resides, and the balance of the Canadian resource base has been distinguished regionally:

- British Columbia
- Alberta
- Saskatchewan
- Eastern Canada
- MacKenzie Delta
- Canadian Arctic (Beaufort Sea, Arctic Islands)

As with the United States, the particular regional disaggregation for Canada was chosen with several purposes in mind. First, we need to properly position the primary gas deposits in Canada. It is known that the vast majority of economic Canadian gas occurs within Alberta in the Western Canadian Sedimentary Basin. Yet, that there are significant gas deposits in British Columbia and Saskatchewan and that the latter deposits are positioned differently with regard to the Canadian transportation system.

Second, the Canadian resource base must be distinguished at a level of geographic detail necessary to support analysis of existing and prospective Canadian border import locations to the United States: Huntington/Sumas (Westcoast), Kingsgate (PGT), Monchy (Northern Border), Alliance, Emerson (Great Lakes), Niagara, and Iroquois. The level of border import and demand detail within the United States dictates the level of resource base disaggregation needed for Canada.

Third, it was necessary to distinguish key demand patterns in Canada, which in the past have influenced not only delivered gas prices in Canada but also export economics and government policy. In particular, much of Canadian gas demand occurs within Ontario, which is Canada's most populous and most politically influential province. However, Ontario demand must be served through long distance pipeline from Alberta either indirectly through the Great Lakes system or directly through TransCanada.. In recent years, Ontario has imported gas across the St. Claire lake from Detroit, thereby experiencing competition from the United States. Alberta and points intermediate (i.e., Saskatchewan) must therefore be distinguished.

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Fourth, it is necessary to distinguish the more Northern, Arctic gas resource base in sufficient detail; otherwise, one cannot predict what is the most economical resource base exploitation pattern and what will be its impact on gas price throughout North America if any.

Finally, the eastern Canadian resource producing basin contiguous to the Sable Island has grown in importance. We have distinguished the Eastern Canadian, Sable Island resource base as well.

2.1.3. Geographic Representation Of Gas Import Alternatives

Border import locations are positioned at various points along the United States-Canadian border and the United States-Mexico border. There are two prospective border import locations from Mexico represented in the model. LNG import locations are positioned along the east, Gulf, and west coasts at various existing and prospective future locations. The NARG model is embedded within a World Gas Trade Model that explicitly calculated the LNG import point prices based on world supply-transportation-demand considerations. This is necessary to ensure that the prospective and existing interconnections to the rest of the world are credible.

2.1.4. Overall Regional Structure

The NARG model, which is the North American portion of the World Gas trade model, distinguishes three geographic regions, the United States, Canada, and Mexico. Alaska is represented as part of the United States, but the colossal transportation system that would be needed to move Alaskan gas to the Lower 48 United States and its interconnection with Canada is represented. The NARG model contains the following regional detail

- North Alaska (1)
- South Alaska (2)
- San Juan/Raton Basins (3)
- Rocky Mountain Basins (4)
- Northern Great Plains Basins(5)
- Anadarko/Arkoma Basins (6)
- Permian Basin (7)
- Gulf of Mexico Basins (8)
- Midwestern Basins (9)
- Appalachian Basin (10)
- Offshore Atlantic Coast (11)
- LNG Import Terminals (12)
- Canadian Border Import Locations (13)
- Mexico Border Import and Consumption Locations (14)
- Pacific Northwest Demand and Supply Region (15)
- West North Central-Mountain Demand Region (16)
- West South Central Demand Region (17)
- East North Central Demand Region (18)
- South Atlantic Demand Region (19)
- East South Central Demand Region (20)
- Middle Atlantic Demand Region (21)
- Oil Region (22)

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- Southern California Supply Region (23)
- Northern California Supply Region (24)
- Pacific Gas and Electric Demand Region (25)
- Southern California Gas Company Demand Region (26)
- San Diego Gas and Electric Demand Region (27)
- EOR Demand Region (28)
- New England Demand Region (29)
- Gulf-to-Northeast Pipeline Corridor Transportation Region (30)
- Canada: British Columbia Supply Region (C1)
- Canada: Alberta Supply Region (C2)
- Canada: Saskatchewan Supply Region (C3)
- Canada: Northern Canada Supply Region (C4)
- Canada: Eastern Canada Supply Region (C5)
- Canada: Western Canada Demand Region (C6)
- Canada: Ontario Demand Region (C7)
- Canada: Canadian Oil Region (C8)
- Canada: Eastern Canada Demand Region (C9)
- Canada: British Columbia Demand Region (C10)

The indexes we have associated with each region correspond to the NARG model indexes used internally.

The regionalization of the NARG model is embedded in the network "tinkertoy" diagrams that will be provided under separate cover. In reviewing those diagrams, it will become immediately obvious just how the foregoing regions have been represented and what level of detail is contained within each region.

2.2. The Depletable Resource Supply Hexagons--How Do They Work?

This section outlines how the supply nodes in the NARG network operate. Implicit in this discussion are a number of critical dimensions of the NARG technique:

- What is the economic logic and rationale that underlies NARG?

- What is the data necessary to support the supply nodes? How should it be interpreted? How should it be assembled?

- What are the characteristics of supply-demand equilibrium in an economic system containing depletable resource processes? How can the supply-demand-balancing concept be applied to markets with depletable resource processes within?

- What is the right way to represent depletable resource production? There are so many incorrect or naïve ways to represent depletable resource production. There is only one right way. What is it?

- What is the right way to represent equilibration between resource markets (e.g., gas) and financial markets? Financial markets provide such variables as the cost of capital, which is related to returns on equity in broad financial markets and interest rates on debt in broad markets. How do we represent the fact that at supply-demand equilibrium, there can be no

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possibility of arbitrage between financial markets and gas markets? In a modeling sense, how can we be sure that the forward price and cost of gas are properly related to discount rates that represent costs of capital?

This section answers those questions in summary form. We have prepared much more detailed documentation elsewhere and can make copies available to our NARG customers upon request.

To begin this discussion, consider the simply notion of an economic supply curve. Figure 1 is a traditional static economic supply curve. It is static in the sense that it represents a single point in time, i.e., a "snapshot" in time. The simple static supply curve answers the following question: "If the market price were p, how much supply would the producer voluntarily and profitably deliver to the market?" Such a supply curve can be derived fundamentally by appealing to the notion of a price-taking, profit-maximizing producer doing the best he can given that everyone else in the economy is simultaneously doing the best they can. We have interpreted the supply curve as a price-taking, profit-maximizing producer elsewhere in our NARG documentation. (See Nesbitt, Haas, and Singh, The Gas Research Institute North American Regional Gas Supply-Demand Model, Decision Focus Incorporated report to the Gas Research Institute, 1988.) Keep squarely in mind, the notion of a supply curve is tantamount to the notion of a price-taking, profit-maximizing producer. In NARG, just as in the real world, producers are assumed to be striving to maximize profits. The notion of a price-taking producer is depicted in the simple static supply curve in Figure 1 by reading a price off the vertical axis and using the curve to find the corresponding quantity on the horizontal axis. The quantity on the horizontal axis has the property that it represents the very last Mcf in the market that can be produced profitably at the given price p. (The very last Mcf is termed the marginal Mcf.) All Mcf's less than the very last Mcf will be produced at a strictly positive profit; their cost will lie below that of the marginal Mcf. The very last Mcf can be produced at "breakeven," i.e., zero profit. Economists use the term "direct supply curve" for Figure 1 to indicate the fact that the market is specifying a price and the producers are deciding how much to produce at that price.

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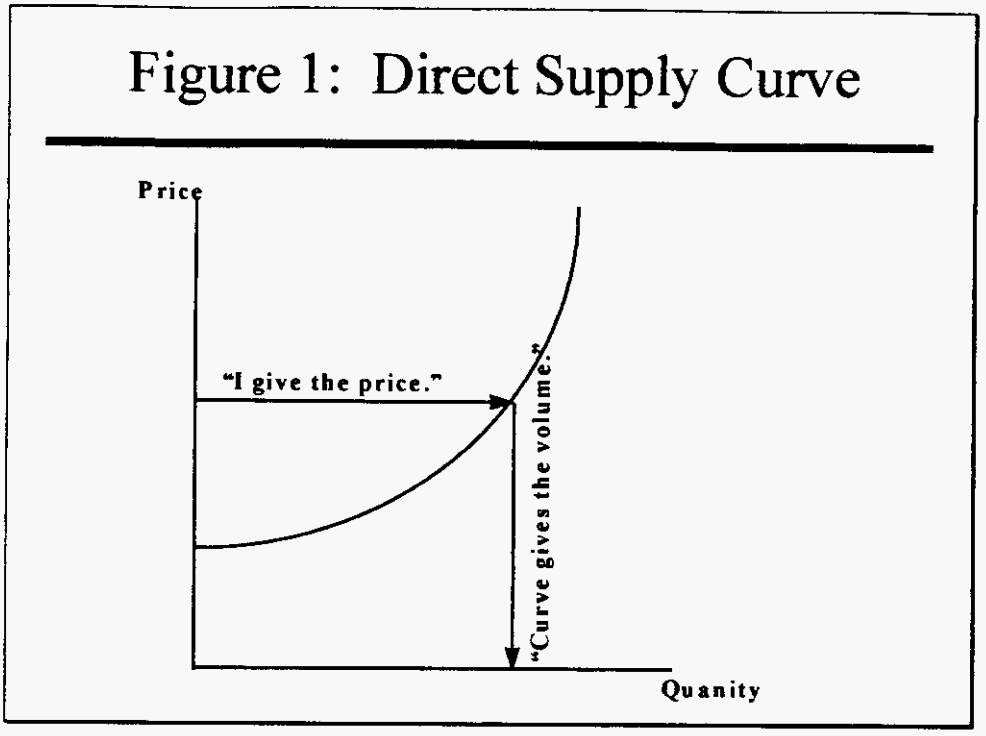

NARG uses the inverse of the direct supply curve, which is depicted in Figure 2. In particular, NARG specifies a quantity on the horizontal axis and uses the supply curve to read the corresponding price off the vertical axis. As indicated in Figure 2, the inverse supply curve as it is termed by economists begins by specifying a quantity or volume to be delivered to the market on the horizontal axis and then uses the inverse supply curve to read the price off the vertical axis necessary to motivate producers to voluntarily and profitably produce and deliver that specified quantity to the market. The notion of an inverse supply curve in Figure 2 is quintessential to the NARG calculation procedure in a way that will be made clear shortly. To reiterate, NARG will be asking the question: "If the market wanted me to deliver the quantity q, how high a price would the market have to sustain in order to induce me to voluntarily and profitably deliver that quantity?" The inverse supply curve is exactly the same as the direct supply curve; they are precisely the same curve. With the inverse supply curve, one reads the price from the vertical axis at a prespecified quantity from the horizontal axis by following the arrows in Figure 2 rather than the reverse direction in Figure 1.

Using the notion of an inverse supply curve, how does NARG work? The answer is simple. NARG successively executes the following set of steps:

1. Guess the supply volume, i.e., guess a quantity on the horizontal axis of Figure 2.
2. Read the price necessary to elicit that supply volume from the inverse supply curve by following the upward and leftward arrow in Figure 2.
3. Pass the price thus determined to the demand curve, i.e., to the portion of the market that lies downstream from the supply processes.
4. Determine the market demand that would occur at the price specified in step 3 by reading it from the demand curve. Figure 3, which represents the demand curve, illustrates how this is done.
5. Pass the demand quantity back to the supply curve.

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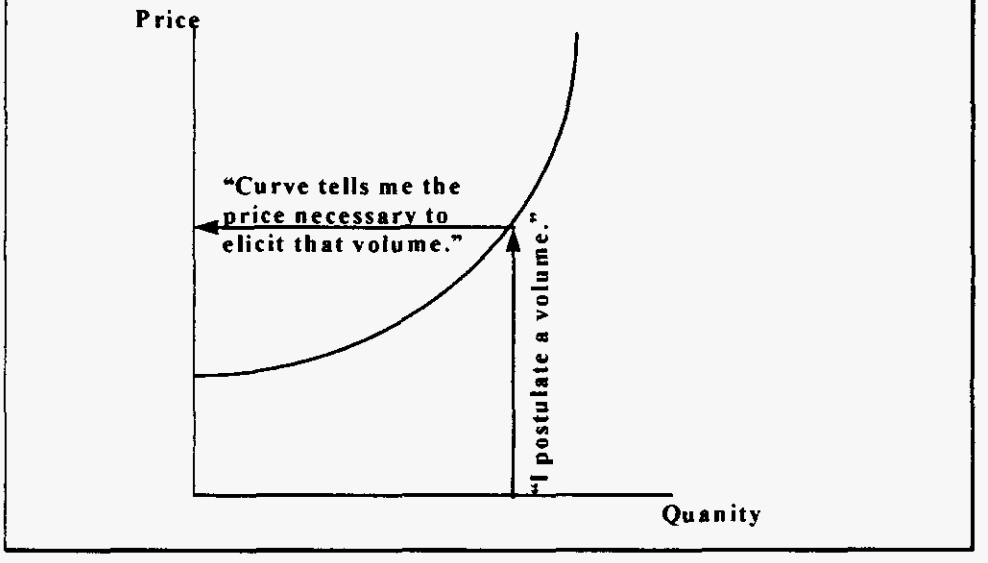
6. If the demand passed back to the supply curve in step 5 is the same as the supply volume that was initially guessed in step 1, NARG is complete and can quit. If the demand from step 5 is different from the supply volume that was initially guessed in step 1, NARG replaces the guess in step 1 with the calculated volume from step 5 and repeats. NARG will have to execute this series of steps a number of times until the step 1 guess is the same as the step 5 guess. When the two successive guesses are equal, NARG has achieved supply-demand equilibrium. The NARG method is no more than a simple supply-demand cobweb method commonly seen in the economics literature and is illustrated in Figure 4.

Figure 2: Inverse Supply Curve



NARG works as a supply-demand cobweb procedure that finds the "magic crossing point" between supply and demand. The inputs to the NARG model are the two curves in Figure 4, the supply curve and the demand curve. The outputs from the NARG model are the price and the quantity where the two curves cross each other. To emphasize, **inputs are curves, and outputs are magic crossing points.** The magic crossing points represent market clearing prices and quantities traded at those prices. What is needed to create and run NARG is the supply curve and the demand curve. The remainder of this section describes how we conceive and assemble the supply curves basin by basin for natural gas supply and region by region for natural gas demand.

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Figure 3: Demand Evaluation

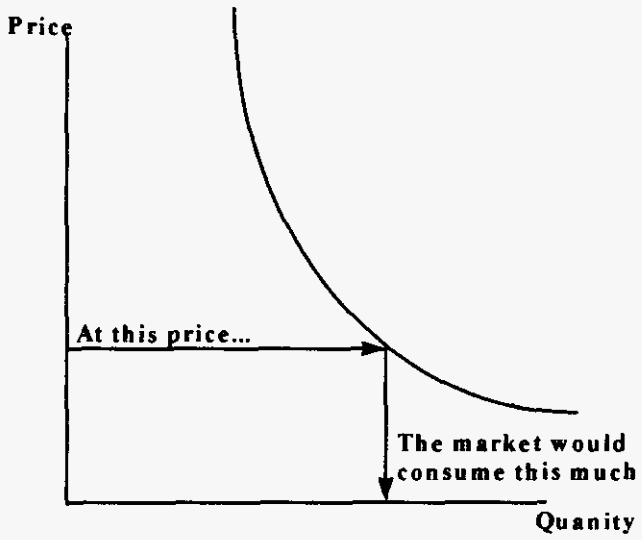
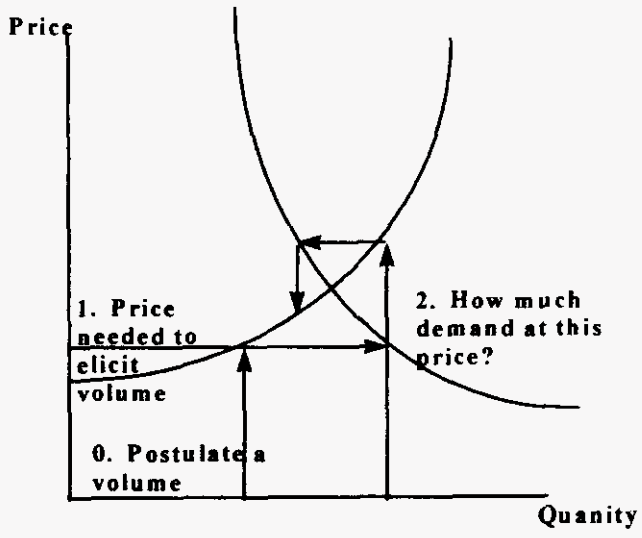


Figure 4: NARG's Iterative Supply-Demand Calculation



We should emphasize that representing primary resource production is not as simple as assembling a static, time-independent supply curve of the form in Figure 1 or Figure 2.

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Depletable resource supply is most definitely NOT a static issue; it is an intrinsically dynamic issue. Depletable resource supply must specifically account for such phenomena as

- Production dynamics for each well, including the maximum possible level of production and the degree of cost escalation beginning from the time production from each vintage of well is initiated until the time that well is exhausted. The full life cycle production profile and cost of each well are intrinsically dynamic and must be considered.

- Successively ongoing exploration and production across a given basin. Successive, cumulative exploration and production is what causes a resource to be depleted in a given basin. Capital and operating costs and dry hole probabilities change as depletion exhausts resource deposits in descending order of attractiveness across each producing basin, and we must represent the dynamics of that process.

- Technological innovation, including 3D seismic, horizontal drilling, advanced drilling such as spiral drilling, etc. Such technological innovation has in the past decade stimulated aggregate volumes available in each basin and has depressed the cost of exploiting any given volume. Technological innovation has created an important dynamic force that we must carefully and explicitly represent.

- Retirements of existing capacity. As old wells are retired, the fundamentals of short run supply change. This too is an important dynamic issue that NARG represents.

- Addition of new reserves and subsequent production from those reserves. NARG focuses on the process by which a market draws in new reserves and new production from those new reserves over time. In economists' jargon, NARG gives a great deal of attention to "entry" and "exit" in the primary resource producing sector.

NARG represents each of these elements in ways we are about to describe.

The analogy in Figure 2 of "start with a guess at quantity q; read the price p off the supply curve" will be preserved as we extend to a fully dynamic model. However, we have to carefully extend the notion so that it remains robust and correct. To do so, we have used the analogy "start with a guess at the production schedule q(t) forward through time; read the corresponding price schedule p(t) forward through time" off the supply curve. Rather than beginning with a scalar quantity q and reading off a scalar price p, we start with a time-vector q(t) and determine a time-vector p(t). To begin the NARG supply node calculation, therefore, we guess a gas production schedule q(t) forward through time. The forward gas production schedule q(t) extends forward throughout the entire time horizon of the model. Figure 5 illustrates what such a gas production schedule q(t) might look like.

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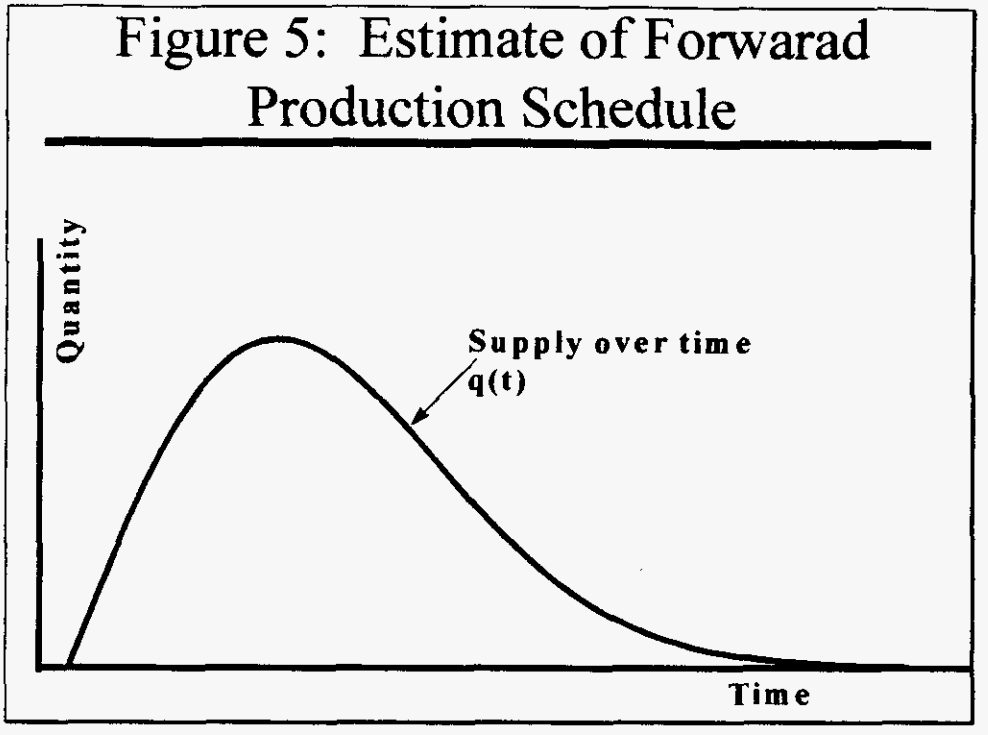

Beginning with the postulated schedule of gas production forward in time q(t) as indicated in Figure 5, we must first determine the schedule by which proved reserves must be added in order to sustain and meet the specified gas production schedule q(t). To wit, how much and when would reserves have to be added to meet the production schedule q(t) in Figure 4? The answer is found by first recognizing that each well, i.e., each vintage of well, experiences a geometrically declining level of production during its life. The production schedule from a well decays geometrically (exponentially) as shown in Figure 6. We use the convention that the area under what we call the "facility decline profile" (the exponential curve) is 1 Mcf. The facility decline profile therefore tells us what is the time pattern of future production that will derive from each Mcf of proved reserves today. For example, if there were 6.87 Tcf of proved reserves in place today, the production from that 6.87 Tcf of proved reserves will follow the shape of the facility decline curve in Figure 6 normalized to a total shaded gray area of 6.87 Tcf. Geometric facility decline curves are the fundamental building blocks of primary resource production, i.e., the fundamental relationship between proved reserves in the ground and flowing gas into the gathering and interstate pipeline system. The facility decline curve relates deliverability to proved reserves.

The facility decline curve is one of the fundamental data inputs to the NARG resource model. For each hexagonal tinkertoy in the model, i.e. for each increment of resource in each producing basin, we input a geometric decline rate for that tinkertoy. The reciprocal of the geometric decline rate is commonly known as the "reserves-to-production ratio." If we want a 10 year R/P ratio, we simply input a geometric decline rate of 0.1. This creates the following equation for the facility decline curve in Figure 6: $prod(t)=0.1*(1-0.1)^t$. Summation of this equation from 0 to infinity verifies that the area under the curve is indeed 1 Mcf. Annual production in the first year is 0.10 Mcf, production in the second year is 0.09 Mcf, production in the third year is 0.081 Mcf, and so forth.

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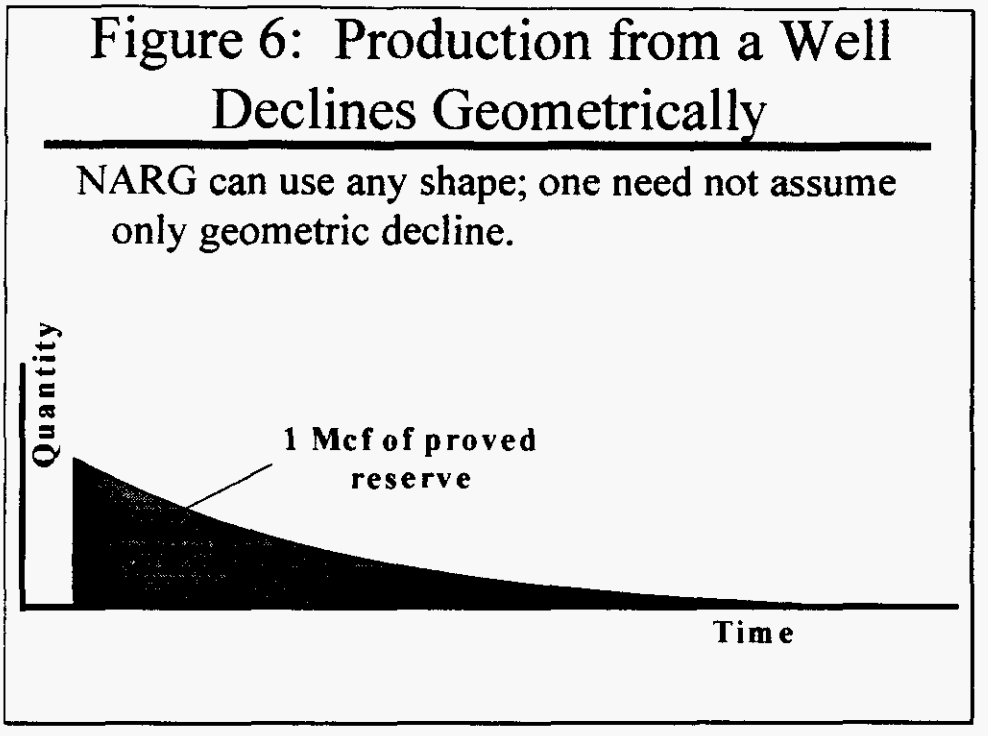
As noted in Figure 6, the facilities decline curve is not restricted to be exponential in form. Indeed, one can specify any shape one wishes. For the current version of NARG, however, we have assumed that every resource node in the model has a geometric decline profile. R/P ratios in the current version range from 5 years on the low side (for deep water Gulf of Mexico gas) to 15 years on the high side for coalbed methane and tight sands. In practice, relatively little is lost by assuming geometric facility decline. Notwithstanding the fact that some resource "techies" made a big deal out of nuances in facility decline curves, sensitivity analysis in NARG will quickly confirm that it is changes in the R/P ratio, not detailed nuances, are what matter.



Given the facility decline profile, how do we calculate the rate of proved reserve additions necessary to sustain the postulated quantity schedule q(t) in Figure 5? The answer is simple; we simply stack "exponential bricks" under the quantity schedule q(t). Figure 7 shows how. If we consider a given year t in the middle of the postulated forward production schedule q(t), we notice that reserves have to be proved before, during, and after time t. Before year t in the figure, there are five periods during which reserves have to be added to sustain the production schedule q(t) before year t. The quantity of reserves that have to be added in year t, indicated by the light gray exponential curve at the top, is that quantity necessary to make up the shortfall in production in year t and ensure that q(t) units are flowing to market.

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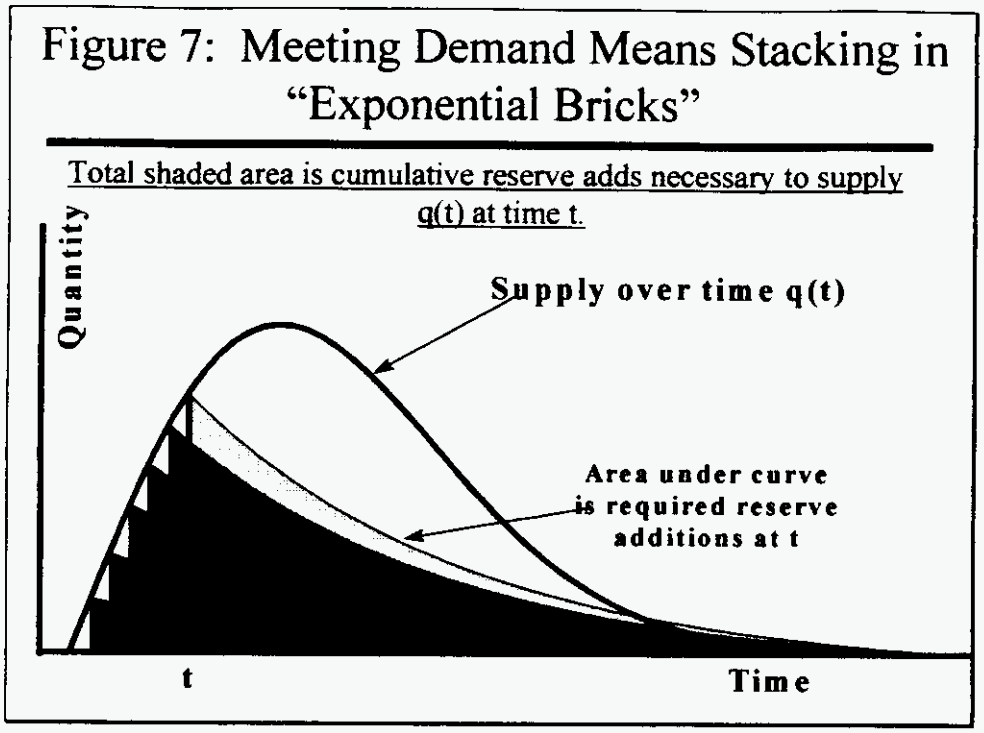

The process of "stacking in" exponential bricks to satisfy the postulated production schedule is rather simple mathematically and rather revealing graphically and economically. If we keep track of the CUMULATIVE quantity of reserves proved since the beginning of time, we will have a plot of the total shaded area in Figure 7 as it grows over time. The total shaded area begins at zero when the postulated production schedule q(t) is zero. The shaded area grows to be equal to the area under the first exponential brick at time t=1. It grows to be equal to the sum of the areas under the first two exponential bricks at time t=2. It grows to be equal to the sum of the areas under the first three exponential bricks at time t=3. By the time we reach period t in the figure, the cumulative additions to reserves is equal to the entire shaded area in the figure. Cumulative additions to proved reserves is simply the growing gray area in Figure 7 over time. In a critically important sense, cumulative additions to proved reserves characterizes cumulative depletion and exhaustion of a given resource basin. Cumulative additions to proved reserves represents cumulative exploitation of the resource base in a given basin, i.e., cumulative extraction and exploitation of the resource base in that basin.

The concepts in Figure 7 contain some critically important elements and some critically important terminology. By reshading various portions of Figure 7, we can define and illustrate some critically important resource base concepts. At the left, we see in the most darkly shaded area that portion of previously proved reserves that have been delivered to market and burned as of time t. They are reserves that have been expended as of time t. They are gone forever and are not available for future consumption; they kept someone warm last winter. The medium gray area in the middle of the figure represents proved reserves in place as of time t. The total medium gray area represents reserves that are in existence as of time t and will be produced at time t or in some future time. They are "reserves" in the sense they are destined for market at some future time; they will not be withheld because their forward cost to market is low. They will not all come to market at once because they are constrained by their facility decline curve. The light gray area represents the quantity of new reserves that must be provided as of time t. In order to sustain the

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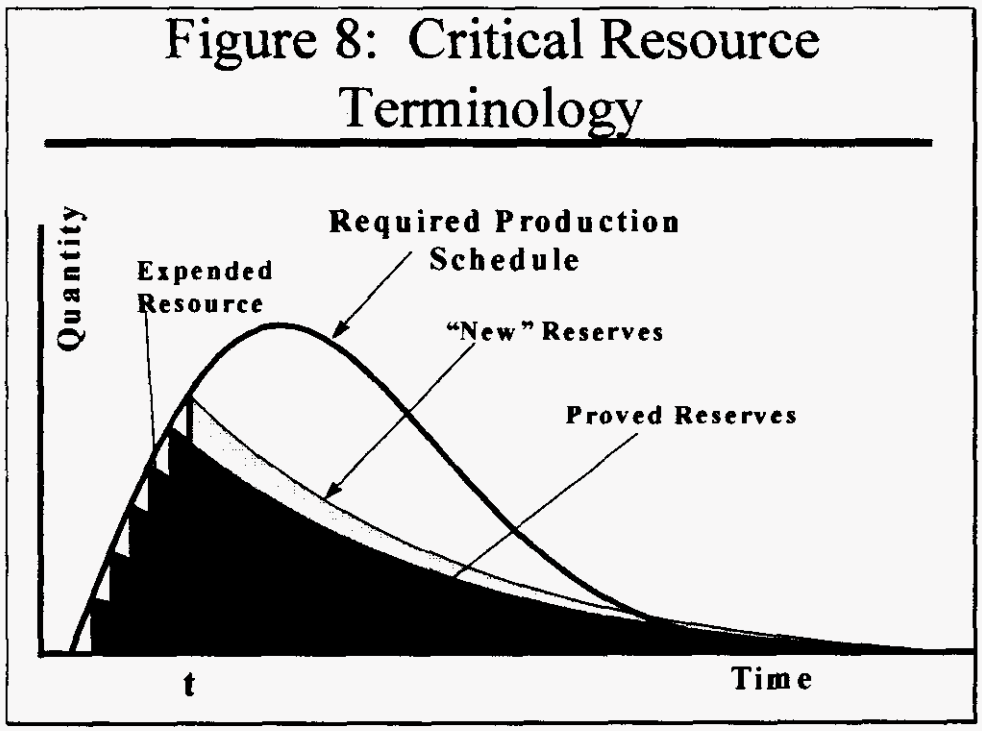
given production schedule q(t) through and including time t, producers must add reserves equal in magnitude to the light gray area at the top at time t. Clearly, as indicated in the figure, reserves must be added well ahead of production. Our clients tell us that Figure 8 has greatly clarified what in the heck people are talking about in the resource business. The figure makes clear what we mean by proved reserves; it is the middle gray shaded area. It is resource to be produced in the future but constrained by the remainder of the facility decline profiles for every vintage of well in place. It makes clear how much new reserves must be added in year t in order to sustain a given production schedule. To add fewer reserves is to fall short of the production schedule q(t).



The critical datum from Figure 8 that must be specified to the model is first year proved reserves, i.e., the middle gray area in the figure as of the first model year. NARG requires that the user specify how much proved reserve exists in every producing basin region by region throughout North America. This middle gray area is an important, user-specified input to the NARG model. NARG then adds new reserves during the forward horizon of the model according to the logic of the light gray area.

If we make a plot of cumulative reserve additions using the logic in Figure 8, i.e., the growing total shaded area, over time, it will have the monotonically increasing shape shown in Figure 9. Cumulative reserve additions will grow at a substantial rate initially or during some point in the production horizon of the basin and then will flatten out as little or no additional exploration and production occurs. Keep in mind, the curve for cumulative future reserve additions in Figure 9, denoted Q(t), is derived directly and unequivocally from the postulated schedule q(t) of future production.

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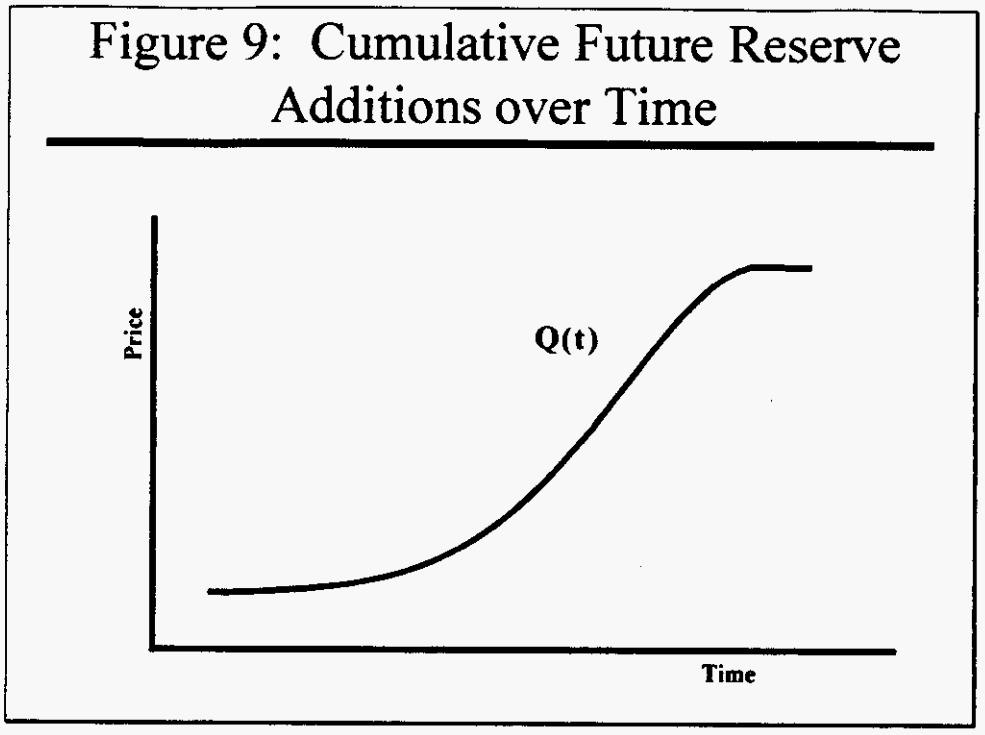

Let us now turn to the question of how much the cost of each successive unit of reserves might change as the basin is exploited according to the cumulative reserve addition schedule in Figure 9. To do so, let us consider the resource producing basin as a "warehouse" that contains every Mcf of gas resident in the given somewhere on a shelf in that warehouse. Let us suppose further that the owner of the warehouse has lined up every Mcf of gas in his warehouse in ascending order of full fixed plus variable cost beginning at the door and extending inward further and further from the door as total costs go up. If we plot the cumulative volume of all gas in his warehouse against the cost of each successive Mcf of gas in his warehouse, we will obtain the curve in Figure 10. We term the curve in Figure 10 the resource marginal cost curve. In our experience, the resource marginal cost curve so defined is the most fundamental and most correct characterization of the resource deposition in a basin. It contains an unequivocal representation of BOTH the cost and the volume of reserves that can be proved and produced in a basin. It is not limited to volume, and it is not limited to cost. It explicitly couples volume with cost. We are very enamored of the representation in Figure 10 for several other reasons:

- It is unequivocal. There are no mistakes of interpretation. We know precisely what we mean. We must enumerate every Mcf of gas and attach a cost to every Mcf.

- The underlying definition of "technology" is unequivocal. If we want to impose technological learning, we must specifically extend the curve outward and to the right or downward in a way that simulates the application of the new technology. Alternatively, we must distort the curve outward and downward to simulate advancing technology.

- It is not confounded by dynamics. Dynamics, i.e., how fast reserves might be proved, are superimposed ex post facto from the outside, not embedded arbitrarily in the supply curves as they are in other models. By separating the dynamics from the resource deposition, we are able to make accurate characterizations of the resource in place and thereafter accurate

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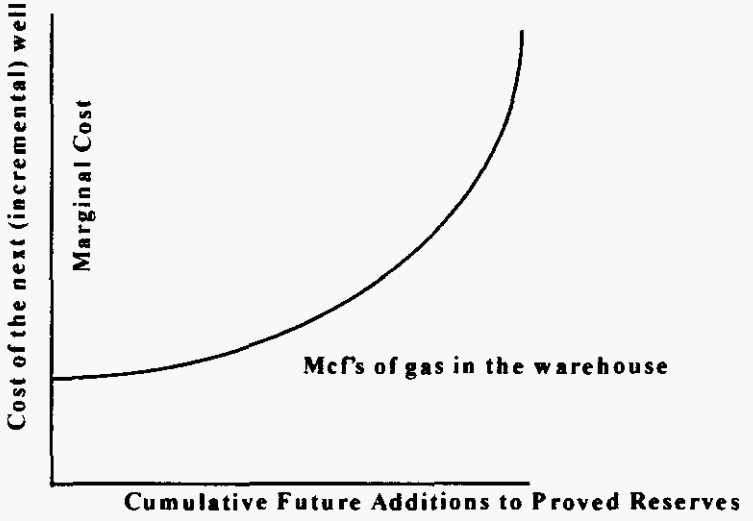
characterizations of the dynamics and technology of exploration and production. We see this as a major strength of NARG. By contrast, the GRI/EEA Hydrocarbon model completely misses the boat because of its confounding of resource deposition with finding rate dynamics. By extrapolating historical finding rate trends, the model simply cannot escape from historical dynamic issues completely unrelated to the deposition of the resource itself. This is why the Hydrocarbon model has been so remiss at predicting forward production schedules and forward prices. Hydrocarbon model price projections have been a sad joke in the industry, an embarrassment, because they continue to confound the issue of total resource supply with the issue of the dynamics of extraction.

- It is not confounded by price. Price is explicitly entered as one variable, namely the variable on the vertical axis. The discussion of the shortcomings of the Hydrocarbon model pertain to this issue as well. That model confounds price and cost with they dynamics of production and intertwines it with the total volume available. As many of our customers have commented, the particular strength of this approach is that it allows one to put in the proper forward shape of the supply functions and thereby ensure that you do not miss the proper market price behavior.

Figure 10: Resource Marginal Cost Curve



The resource marginal cost curve in Figure 10 is the fundamental input to NARG that characterizes the volume and cost of resource deposits in each of the basins of NARG. Because we recognize that resource production requires both fixed (capital) and variable cost, we have actually input to NARG a pair of curves similar in concept to the single aggregate curve in Figure 10. The leftmost curve represents that capital cost necessary to prove each successive Mcf of reserves, and the rightmost curve represents the variable cost necessary to produce from each successive Mcf of reserves. Figure 11 illustrates. The fundamental resource inputs to NARG are the pair of curves in Figure 11. In particular, each hexagon in the NARG network requires precisely the pair of curves in Figure 11. When we deliver NARG, we deliver a complete and

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fully documented set of such pairs of curves for every increment of gas, onshore and offshore, deep and shallow, conventional and unconventional, foreign and domestic, throughout North America.

Even though the model contains the pair of supply curves in Figure 11, we will continue the discussion of how the resource model works by using the simplified curve in Figure 10. Given the schedule Q(t) of cumulative additions to proved reserves necessary to sustain the postulated schedule q(t) of production, which is depicted graphically in Figure 9, suppose we plot it on the horizontal axis of Figure 10 and read the corresponding marginal cost MC(t) from the marginal cost curve as indicated in Figure 12. That is, for each level of cumulative reserve additions Q(t), we proceed upward from that point on the horizontal axis, then proceed leftward from that point at which that vertical curve intersects the supply curve to the vertical axis. By so doing for every point Q(t) in the forward horizon of the model, we are in effect using the marginal cost curve to determine the schedule of marginal cost over time, i.e., MC(t). The forward schedule of marginal cost MC(t) is interpreted as follows. "If the production schedule q(t) were followed, the full cost of the last well to be drilled in year t, i.e., the marginal well in year t, would be MC(t). The schedule MC(t) is truly a schedule of the marginal well and its cost over time. It represents the full cost of the last Mcf to be added in each year. It is the worst well that is competitive in each future year.

Figure 11: Fixed Cost and Variable Cost of Resource Exploitation

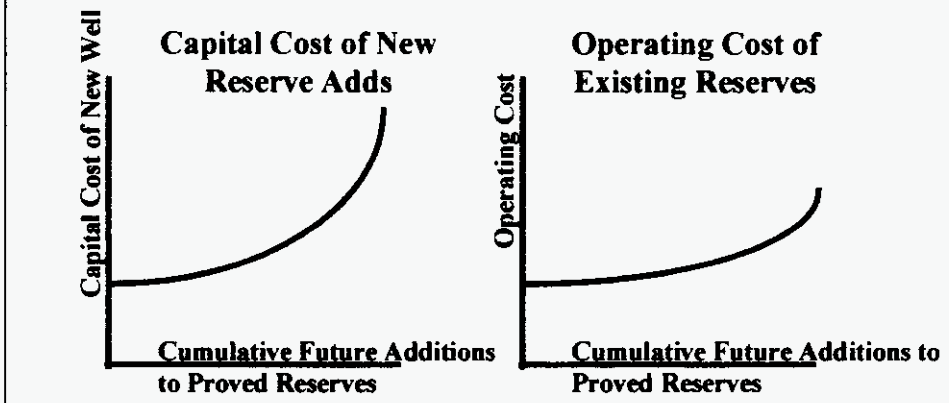

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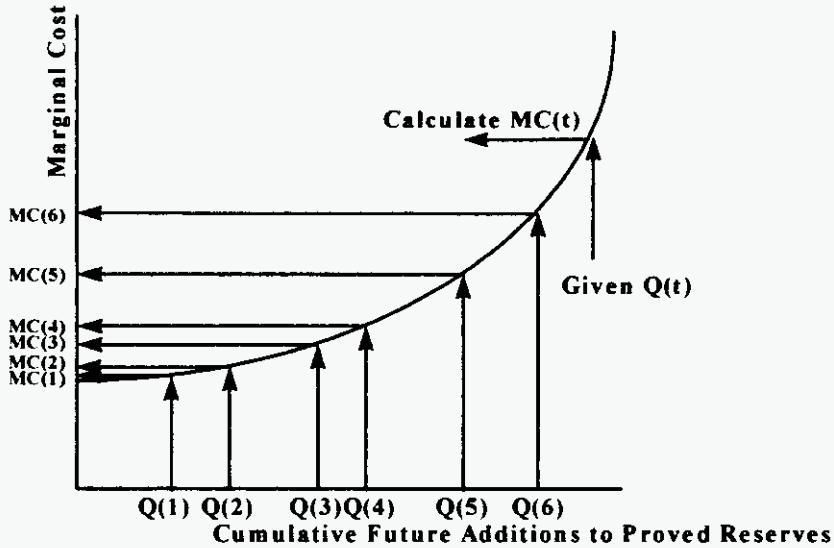
Figure 12: Calculating Marginal Cost over Time



The time schedule of marginal cost MC(t) derived from the foregoing procedure has the form in Figure 13. If the supply curve is upward sloping, the marginal cost curve will likewise be upward sloping because the cumulative reserve addition schedule Q(t) is monotonically increasing. The only way the marginal cost curve can be downward sloping over time is if technological innovation and cost reduction reduces cost faster than depletion as represented by the supply curve in Figure 10 escalates cost. This has probably occurred during certain periods of the 1980s and 1990s; however, it is unlikely to persist forever. Inexorable depletion will ultimately set in. The question, however, is when. The supply data embedded in the current version of the NARG model result in rather flat real supply curves for the next 30 years or more.

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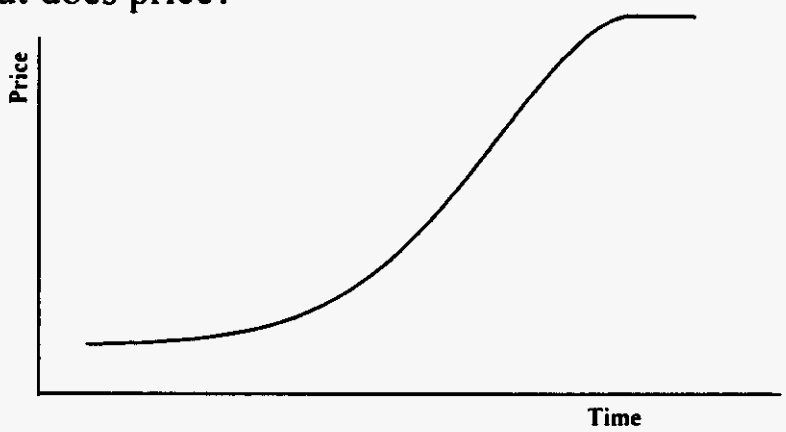
Figure 13: Cost of the Marginal Well (Marginal Cost) Over Time

- Marginal cost rises with cumulative depletion, but does price?



Once we have calculated the marginal cost schedule over time, are we done? Isn't price equal to marginal cost? The answer is an unequivocal NO! There is one critically important step left to go. Producers would not necessarily be willing to deliver wells to market at the postulated rate q(t) if the price they got was the schedule MC(t). To see why, consider the situation in Figure 14. A producer holding the marginal well at time t would receive the price p(t+1) if he waited until time t+1 to deliver his marginal well. His cost would remain constant at MC(t) if he delayed the marginal well to time t+1. Hence, the profit he would get by waiting would be p(t+1)-MC(t). However, he would not receive the money until time t+1. Its discounted present value as of time t would be {p(t+1)-MC(t)}/(1+r) where r is the producer's discount rate. As indicated in the figure, the profit margin received one year into the future but discounted one year back to the present would be a lower bound on the profit the producer would expect to get in the current year t. (The producer could get that much money by simply delaying the marginal well by one year, so the market would have to compensate him or he would not deliver the marginal well in year t and the production schedule q(t) would not be met.) Indeed, the price p(t) would have to be greater than or equal to $p^*(t) = MC(t) + \{p(t+1)-MC(t)\}/(1+r)$. The price necessary to elicit the production schedule q(t) in year t would be $p^*(t)$, not MC(t). It is this calculation of $p^*(t)$ that is made within NARG.

Why is this the correct model of resource pricing in a competitive market? The reason is simple. Under this simple equilibration between discounted present value of margins that can be captured over time, there is absolutely, unequivocally no incentive for arbitrage between the physical market for gas and the financial market as represented by the discount rate r. There is no incentive for people to convert their gas to money, secure in the knowledge that the money will escalate in value faster than the gas would have escalated had they left it in the ground. Likewise, there is no incentive to withhold gas from market, secure in the knowledge that gas prices will escalate fast enough so that you make more money on gas price appreciation than you would have made in the financial markets. There must be absolute, lockstep equilibration between gas

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markets and financial markets as represented by discount rates. Otherwise, the postulated forward price solution from the model will not be stable in the real world and cannot be advocated as a valid, reasonable, sustainable projection of forward gas price. The reasoning in Figure 14 assures that the "gas in the ground-money in the bank" tradeoff does not favor one over the other. All possible arbitrage between the two will have been completed so that there is stable, sustainable equilibration. This is absolutely critical to valid, reasonable forward price forecasting.

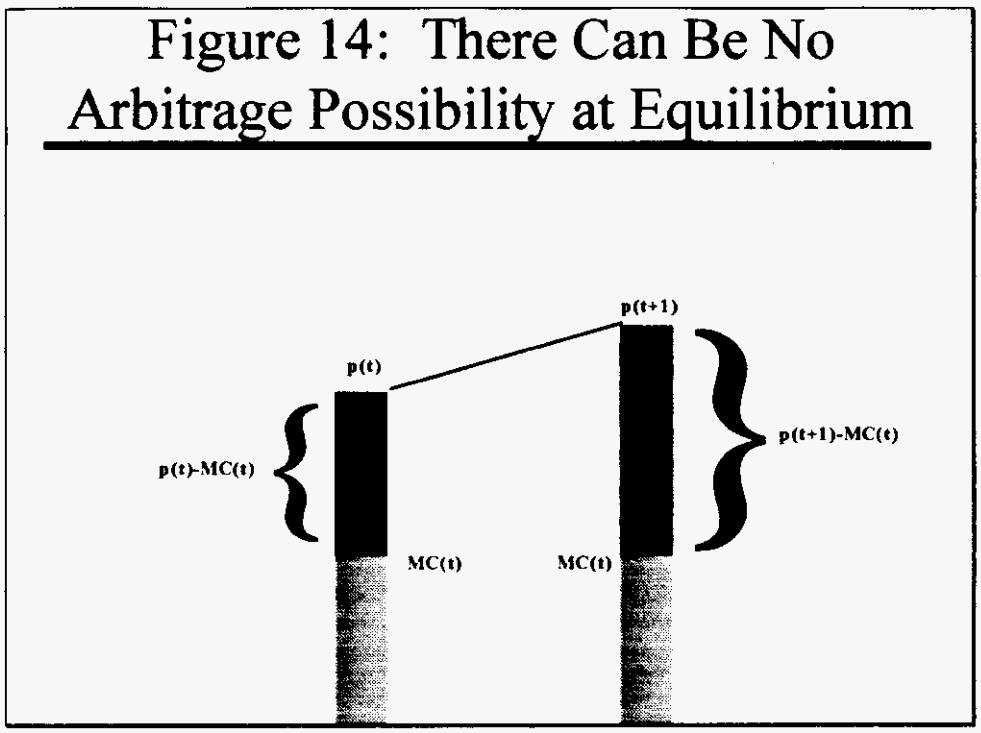

Figure 15 summarizes this notion that there must be complete equilibration between gas in the ground and money in the bank at equilibrium. The price schedule that is reported by the resource hexagon to the demand portions of the model must be the higher of the two curves, not the lower marginal cost schedule MC(t) in the diagram. The price reported to the demand portions of NARG must be such that no producer has any incentive to change his production schedule over time. If producers have incentive to change, assuredly, they WILL change. If they have incentive to changes, assuredly the price that contains such incentives will not be sustainable in the market. It cannot be a market-clearing price; it must not be reported to the demand side of the model for equilibration. This is a critically important feature of NARG not to be underemphasized. The price that is reported to the demand sectors from the supply models is such that no producer has any incentive to reschedule his production over time given that price schedule.

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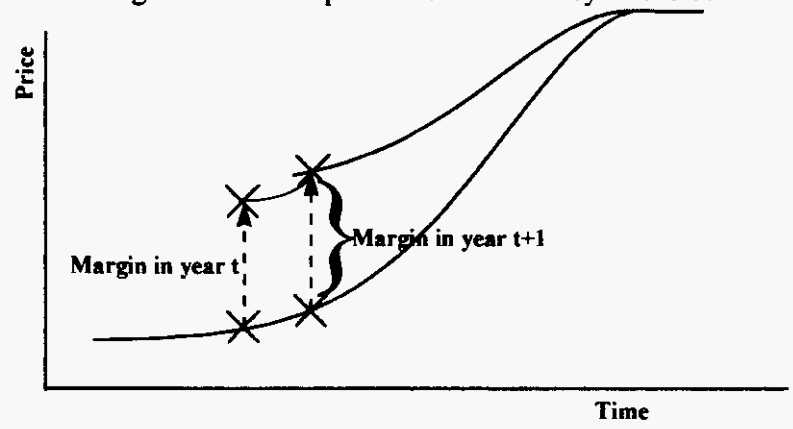
Figure 15: Price Must Not Allow Financial Arbitrage Over Time

Margin in year t at least as high as discounted margin from year t+1.

Gas in the ground must equilibrate with money in the bank.



Why go to all this trouble to equilibrate gas markets with financial markets? The answer is that we want to eliminate hockey stick and other "stupid" forward price projections. Hockey stick price forecasts are indeed stupid; they cannot be sustained in a market. To see why, consider Figure 16. During periods of rapid price de-escalation at the front end of the hockey stock price forecast, gas is crashing in value. Producers would face very strong incentives to drill their prospects and liquidate their resource holdings before their value deteriorates dramatically. Incentives to liquidate one's gas in the very short run would create strong market force to drop near term price and therefore flatten out the downward trend at the front end of the hockey stick forecast. To wit, there is systematic force that flattens an otherwise declining price trend. The front end of the hockey stick experiences forces that tend to flatten it. Similarly, during the period of rapid price escalation at the back end of the hockey stick price forecast, gas is soaring in value because of gas price appreciation. Producers would face very strong incentives to hoard their resource until after its price had escalated to new heights and liquidate it only thereafter. As producers hoard their gas at the front end, there would be shortage conditions and near term prices would escalate, tending to flatten out the escalating portion of the hockey stick. Therefore, there are strong, systematic forces that tend to flatten out the price-escalating portion of the hockey stick forecast. Obviously, hockey stick price forecasts of the type we see from the Hydrocarbon model as unequivocally wrong. They do not properly consider arbitrage between financial and physical markets. Such price forecasts cannot possible serve as the basis for cogent strategy and pipeline analysis.

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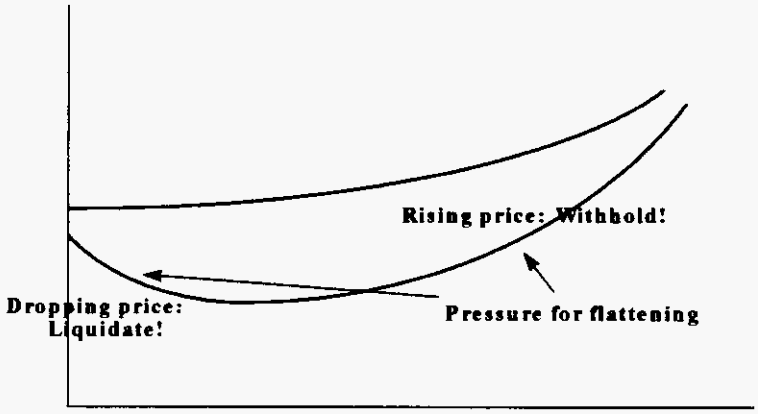
Figure 16: Hockey Stick Price Forecasts Are Wrong

- The market arbitrages Hockey Sticks.



How might we summarize our resource module? We will do so from two perspectives. The first is the flow of logic beginning with a postulated production schedule forward in time q(t) and ending with a price schedule forward in time p(t). The second is to summarize the data that are needed to execute the resource process. The logical sequence of operations employed in the resource model is the following:

STEP	VARIABLE CALCULATED	OPERATION REQUIRED
1	Guess q(t)	Make a guess at production schedule
2	Calculate Q(t)	Calculate cumulative reserve additions necessary to sustain production schedule q(t)
3	Calculate MC(t)	Read marginal cost off resource marginal cost curve
4	Calculate p(t)	Calculate price p(t) from marginal cost MC(t) to eliminate intertemporal arbitrage
5	Report p(t) to demand model	Deliver the price schedule p(t) to the demand portion of the model
6	Get demand d(t)	Read demand d(t) from demand curve given price p(t) from resource process
7	Compare d(t) and q(t)	Determine whether supply and demand quantities are the same. If so, quit. If not, substitute d(t) for q(t) and repeat

The data required to implement the resource model are the following:

1. Reserves to production ratio, allowing us to calculate the facility decline curve in Figure 6.

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2. Initial year proved reserves, i.e., the middle gray shaded area in Figure 8. This represents the inventory that exists in the first model year, an inventory that will be produced to market during the model horizon.

3. The pair of resource supply curves in Figure 11, which characterizes aggregate resource deposition in each resource producing basin.

4. The discount rate used to make the "no intertemporal arbitrage" equation in Figure 14. This discount rate must represent the market-determined cost of capital that directs resource exploitation decisions in the energy business. It is NOT a hurdle rate; it is a market-observed and market-determined cost of capital that faces energy producers.

These four elements fully comprise the NARG resource base. Keep in mind, we need each of these four elements for every increment of resource for every producing region in North America. That is, there is a separate reserves to production ratio, initial year proved reserves, pair of resource supply curves, and discount rate specified for every hexagon in the NARG model. To reiterate, we deliver the data resource data assumed for the current version of NARG to our customers and licensees so that they review, evaluate, and customize it.

A final note on the resource process is related to the age-old question: What is the output of the resource model? Based on the discussion herein, the outputs of the resource model are simple

- The equilibrium price schedule p(t) forward in time over the model horizon.
- The equilibrium production schedule q(t) forward in time over the model horizon.
- The equilibrium schedule of reserve additions Q(t) forward in time over the model horizon.

In short, model outputs are price, production, and reserve additions over the forward horizon.

3. THE DEMAND SIDE OF THE NARG MODEL

Having completed our discussion of supply, this section turns to the question of representing natural gas demand on a regional basis throughout North America. This discussion begins with how we have regionalized the demand side and thereafter puts forth our demand modeling technology.

3.1. Regional Structure

The degree of regional disaggregation on the demand side of the NARG model is governed by the census regions of the United States. There is much historical precedent to disaggregating gas demand by census region, and there is much accepted data. Furthermore, climatic distinctions among census regions are usually deemed adequate to reflect different weather and usage patterns throughout the United States. Two of the standard census regions have been aggregated. We have aggregated the West North Central census region with the Mountain census region to create the single, aggregate West North Central-Mountain region. The Pacific region has been substantially disaggregated. In particular, we have broken California away from the Pacific Northwest. Within California, we have represented PG&E, SoCal Gas, San Diego Gas and Electric, and the EOR demand region. Within Canada, the model aggregates the thirteen

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provinces and territories into four aggregate demand regions. Western Canada contains all provinces to the west of and including Manitoba except for British Columbia, which is represented as a separate and distinct region. Eastern Canada includes all provinces east of the Ontario/Manitoba border excluding Ontario, which is represented as a separate and distinct region.

3.2. How Do We Represent Gas Demand?

Inside each of the fifteen demand regions, the NARG model is structured to take account of key demand-side phenomena including demand stimulation at lower prices, demand suppression at higher prices, and interfuel substitution between oil and gas. In order to represent such phenomena, it is necessary to recognize the segmented nature of gas demand. To properly characterize gas demand, it is important to distinguish at least two types of consumers in gas markets. The first, sometimes termed the "core market," is largely captive and exhibits relatively inelastic gas demand. The remainder, termed the "noncore market," is possessed of an immediate alternative such as fuel oil. As long as gas price remains below that of the alternative, noncore gas demand is relatively firm. If gas price rises to or above the price of the alternative, noncore gas demand will switch away from gas toward the alternative.

A simple network characterization of gas demand can be represented in network form as in Figure 17. In the figure, energy is assumed to flow along the links through the processes from bottom to top. The figure depicts two demand "tombstones," one for core demand and one for noncore demand. Each tombstone contains a demand curve, i.e., a price-quantity relationship that specifies the quantity of gas (or gas-equivalent) that will be consumed at every possible price. Notice in the diagram that noncore demand can be satisfied either by gas or by the substitute (assumed to be oil in the diagram). Core demand can be satisfied only by gas. Gas moves from wholesale at the lower left through a core distribution process to core customers, and it moves through a noncore distribution process to the burnertip point of competition at which it must compete against oil.

Economists characterize the simple core/noncore network representation of demand using a demand curve such as that in Figure 18. The figure delineates the size of the core and noncore markets and shows the assumed oil price. In the figure, gas demand is shown to be equal to core demand for gas prices above the oil price and to be equal to core plus noncore demand for gas prices at or below the oil price.

In reality, core gas demand is somewhat elastic, and noncore gas demand is highly segmented, each segment facing a slightly different substitute price. Therefore, in reality, the demand graph in Figure 18 should be "rounded off" as shown in Figure 19. The demand curve in Figure 19, very characteristic of gas demand, has an inelastic portion at high gas prices, a very elastic "shoulder" for gas prices in the vicinity of oil price, and an inelastic portion at low gas prices. Results generated by the NARG model rely heavily on the distinctive pattern of gas demand in Figure 19.

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Figure 17: Network Representation of Gas Demand

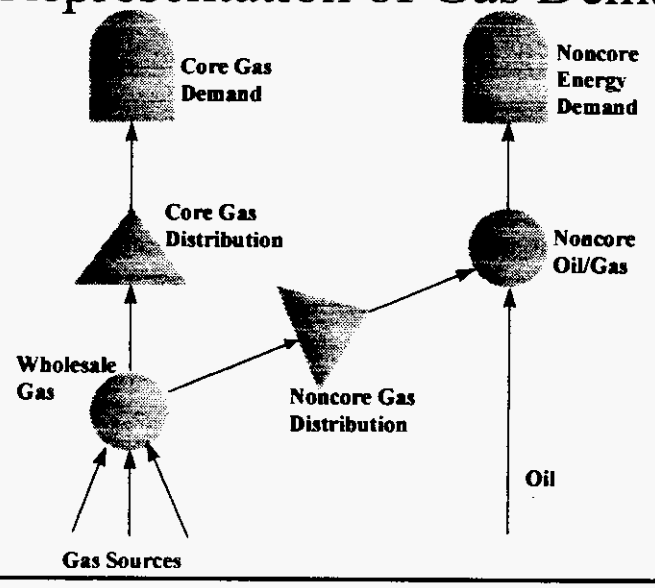

Figure 18: Segmented Representation of Gas Demand

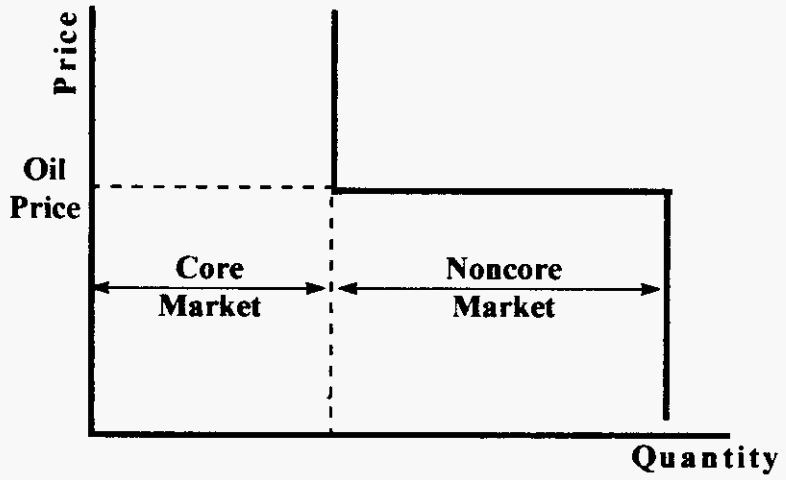

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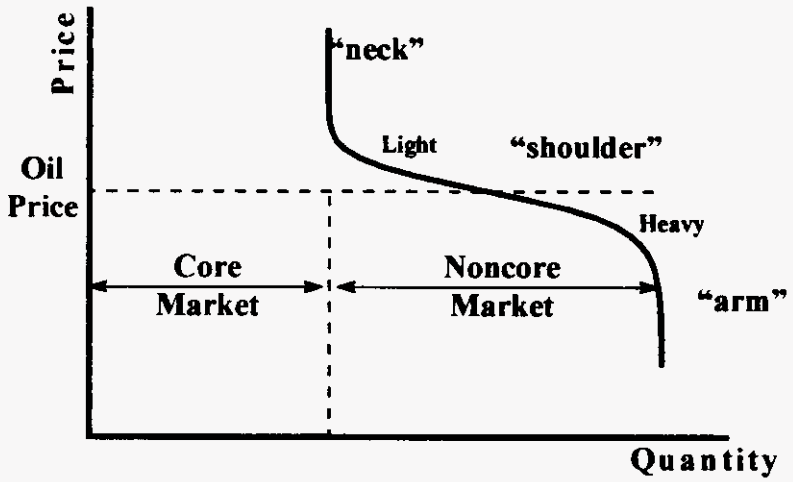
Figure 19. Wholesale Gas Demand Curve is Rounded Off



It is interesting to note that the width of the shoulder in Figure 19 has diminished during the past two decades as the industrial sector of the United States has emigrated or shrunk. What used to be a relatively broad shoulder in our formerly industrialized economy has now become a much narrower shoulder in our service economy. Such narrowing has vital consequences for the relationship between the market clearing price of gas relative to the price of oil, implying a much weaker degree of coupling between the two than was true historically.

Every demand region in the model contains the network structure in Figure 17 and therefore the demand curve structure in Figure 19. Thus, every demand region in the model represents demand stimulation/repression at different prices as well as substitution at the exogenously given price of the substitute. The data needed for the demand side of the NARG model is the demand curve in Figure 19 itself. In order to construct the demand curve in Figure 19, we need its constituent elements, which are best seen by referring to the "caricature" of demand illustrated in Figure 18:

- a demand curve (price versus quantity versus time) for noncore use. We need to place a demand curve into the core demand tombstone. Most often, we simply use a projection forward in time of noncore demand and assume that overall noncore demand is inelastic at that level.

- a demand curve (price versus quantity versus time) for core use. We need to place a demand curve into the noncore demand tombstone. Most often, we simply us a projection forward in time of core demand and assume that core demand is inelastic at that level.

- an estimate of noncore distribution cost, which is needed in order to properly represent burnertip gas pr ices relative to oil prices.

- a projected time schedule of the price of oil against which gas must compete.

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- an estimate of core distribution cost.

- lag parameters that simulate adjustments in capital stock necessary for gas/oil substitution.

In particular, we need a projection of core and noncore market size, the price of oil, and the core and noncore distribution costs. We deliver to our NARG customers comprehensive analysis of how these data are conceived and assembled for NARG.

The two demand curves within the demand tombstones for each demand region have been inferred from GRI's 1996 Baseline forecast. In particular, we have divided GRI's sectoral gas demand projections into a core (nonsubstitutable) and a noncore (substitutable) component. We should emphasize that undue attention on demand is probably not warranted. In light of the bullish and escalating projections of natural gas supply in the Gulf Coast and elsewhere, gas supply has increased in importance relative to gas demand. This is not to say that demand issues are unimportant. It is to say, however, that gas demand is less important than gas supply.

3.3. The "Answer" Given By The Model – Market Clearing Prices And Quantities Flowing At Those Prices

Equilibrium models such as the NARG Model plot gas supply and demand curves on the same graph and seek to find the intersection. The intersection specifies a market-clearing price at which the market will tend to operate. Indeed, there are economic forces that drive the market toward that price. The intersection also specifies a quantity that will be traded in the market at the market-clearing price. Using the characteristic pattern of demand in Figure 19, we can make some rather profound and far-reaching conclusions about the nature of the regional supply-demand equilibrium. In particular, we see that there are three possible supply-demand cases that can occur, each of which has distinctive and important properties:

Case 1: The gas supply curve intersects the demand curve above the shoulder, as shown in Figure 20. The market clearing price (denoted p*) of gas is seen to exceed the price of oil. Furthermore, in this ease,

- gas supplies will be "tight."

- noncore users will be driven to the substitute.

- a core user will be the marginal gas user.

- core users will be obliged to buy gas at a premium over oil.

Case 1 will occur if oil prices are low (that is, low shoulder in the demand curve), gas supplies are tight (that is, high gas supply curve), or gas demand is high.

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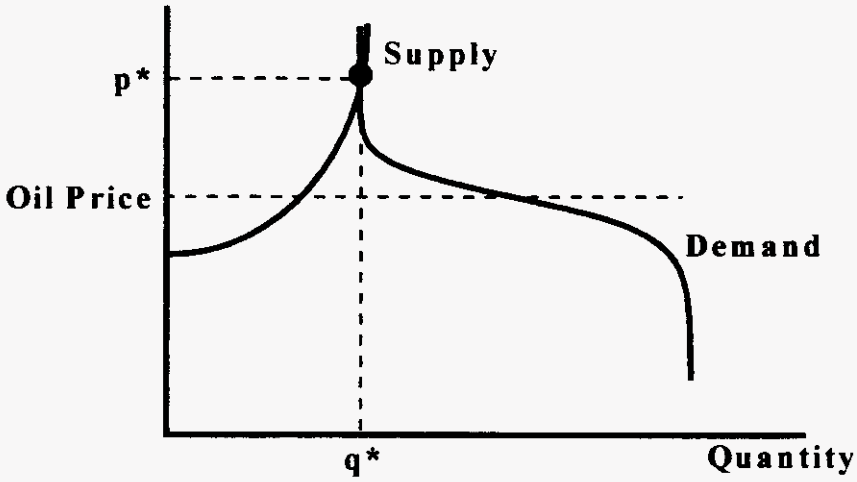
Figure 20: Case 1--Gas Price Clears on "Neck;" Gas Price Above Oil Price



Case 2: The gas supply curve intersects the demand curve along the shoulder as shown in Figure 21. Notice that

- the market clearing price of gas will be equal to the price of oil.
- some noncore customers will use gas, while some will utilize the substitute.

This is the case that so many people implicitly assume ALWAYS applies to gas. Many people lazily and incorrectly assume that oil and gas prices must equilibrate. As we have seen in Case 1, this is not necessarily true. It is quite coincidental when Case 2 rather than Case 1 occurs.

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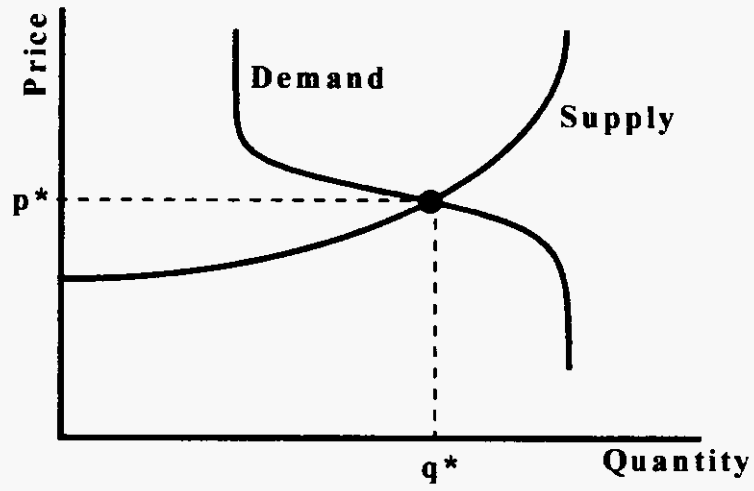
Figure 21: Case 2--Market Clears on "Shoulder;"--Gas and Oil Price Equal



Case 3: The gas supply curve intersects the demand curve below the shoulder as shown in Figure 22. The market-clearing price of gas is seen to be below that of oil. In this case

- gas supplies will be "abundant."
- noncore users will be attracted to gas.
- a noncore customer will be the marginal source
- both core and noncore users will buy gas at a discount relative to oil.

Case 3 will occur if oil prices are high (that is, high shoulder in the demand curve), gas supplies are abundant (that is, low gas supply curve), or gas demand is low.

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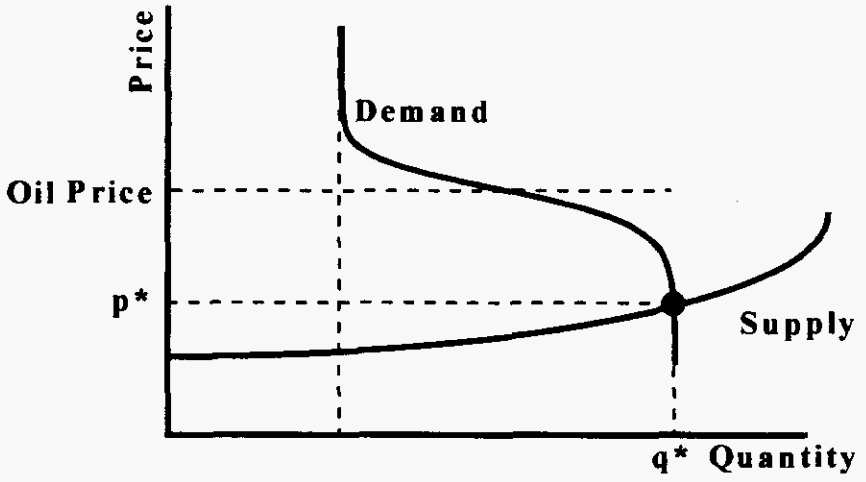
Figure 22: Case 3--Gas Market Clears on "Arm;" Gas Price below Oil Price



A conspicuous observation in Figures 20 through 22 is that in general **THE MARKET CLEARING PRICE OF GAS WILL NOT BE EQUAL TO THE PRICE OF OIL**. Gas and oil prices will not be at parity. Indeed, only if the supply curve intersects the demand curve precisely through the shoulder, that is, on the flat portion of the demand curve as in Figure 20, will the price of gas be equal to the price of oil. As we have already argued, the shoulder has narrowed substantially over the past two decades, rendering it decreasingly likely that Case 2 will occur.

Different supply-demand scenarios will in general correspond to one of the three cases discussed earlier. For example, a base case scenario might correspond to Case 3 (gas supply intersects demand below the shoulder so that gas price is below oil price). However, a low resource base scenario, all else equal, would shift the supply curve upward and to the left so that in fact Case 1 rather than Case 3 pertains; gas supply would intersect above the shoulder.

Comparison of high versus low gas resource base scenarios (and in fact almost any pair of scenarios involving different supply curves and/or different demand curves) leads to a critical conclusion:

THE MARKET CLEARING PRICE OF GAS WILL BE DIFFERENT BETWEEN DIFFERENT DEMAND, SUPPLY, AND OIL PRICE SCENARIOS.

This finding has profound ramifications:

- In general, the customary assumption of oil/gas price parity at the burnertip is wrong. To assume such parity is to get the wrong answer both for burnertip market clearing price and quantity consumed.

- In general, the customary practice of equating gas wellhead prices to oil price "netbacks"

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From the burnertip through the pipeline system is wrong. To calculate oil price netbacks is to get the wrong answer both for wellhead market clearing price and quantity produced.

- Oil and gas prices are likely to move farther away from parity as the noncore market decreases relative to the core market. Conversely, the larger the noncore market, the nearer to parity oil and gas prices are likely to be.

We conjecture that the customary (and increasingly incorrect) procedure of netting back burnertip-equivalent oil prices to the wellhead originated in the days when the United States had a large industrial sector, that is, a large noncore market relative to the core market. Although not technically correct even in those days, oil price netbacks were serendipitous; there existed a broad noncore "shoulder" in the economy that virtually ensured that Case 2 would apply. However, now that the industrial sector has declined in size relative to the residential and commercial core sectors, Case 1 or Case 3 is much more likely to pertain today. Oil price netbacks are inevitably destined to be wrong today and in the future.

The alternative to assuming oil/gas price parity at the burnertip and calculating netbacks to the wellhead is to enumerate all present and potential future supply regions using supply curves, all present and potential future demand regions using demand curves with noncore shoulders, and all present and potential future transportation links connecting supply regions to demand regions and thereafter to explicitly compute the prices and quantities at which all supply and demand curves simultaneously intersect. This is precisely what the NARG model does.

We should also point out that the Case 1-Case 2-Case 3 configurations change during the year as well. In the winter, we often see a Case 1 world in the Northeast and Midwest. Gas demand accelerates because of the cold weather, while gas supply stays constant because the pipeline supply system is fixed. In the summer, we see a Case 3 world persisting in the Gulf of Mexico. There are no heating demands, meaning aggregate demand is small and implying that the demand curve is pressed toward the left axis. During the course of the year, the demand curve oscillates from left to right, while the supply curve remains relatively fixed. As shown in Figure 23, this means that the market clearing price during the year moves upward and downward in a relatively predictable fashion. While the longer term version of the NARG model considers only average annual demand, the NARG model contains the logic to make the seasonal calculation illustrated in Figure 23.

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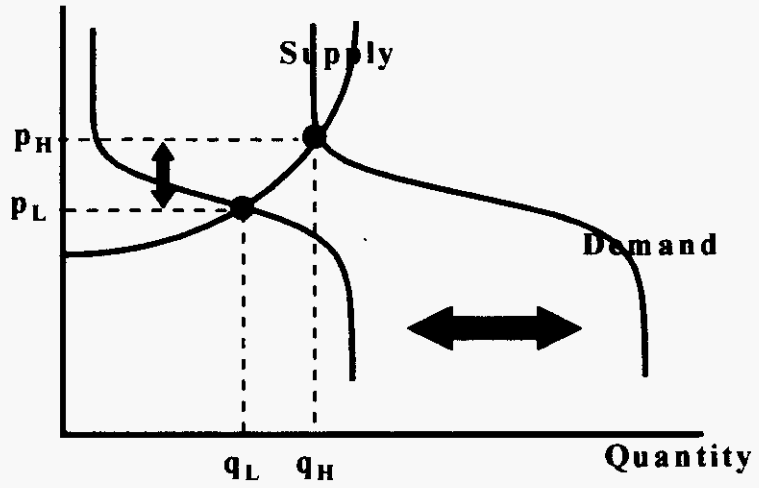
Figure 23: Gas Demand "Wiggles" During the Year, Taking Price with It



Finally, many have argued that the simple oil-for-gas substitutability model that led to the "neck-shoulder-arm" demand curve pattern in Figure 19 is oversimplified. In particular, gas does not substitute for oil at a single oil price. Rather there are many different types and qualities of liquid fuels (No. 1 fuel oil, No. 2 fuel oil, Low sulfur No. 6 fuel oil, High sulfur No. 6 fuel oil, etc.), and there are a number of different segments that consume either those fuels or consume gas (e.g., electric generation using steam turbines, electric generation using combustion turbines, industrial process head, industrial boilers). Each segment and each fuel represent a different regime of oil-for-gas substitution, and the model needs to represent some or all of these segments. Such demand side disaggregation is quite easy to accomplish in NARG by simply expanding the network diagram in Figure 17 to consider additional segments and additional substitution commodities. In doing so, one would develop a demand curve that looks not like a "neck-shoulder-arm" pattern in Figure 19 but rather has a series of substitution zones as shown in Figure 24. This subsegmented representation of demand might or might not be important in certain applications. If it is, it can be easily accommodated by expanding the segmented network representation in Figure 17 to create the demand curve in Figure 24.

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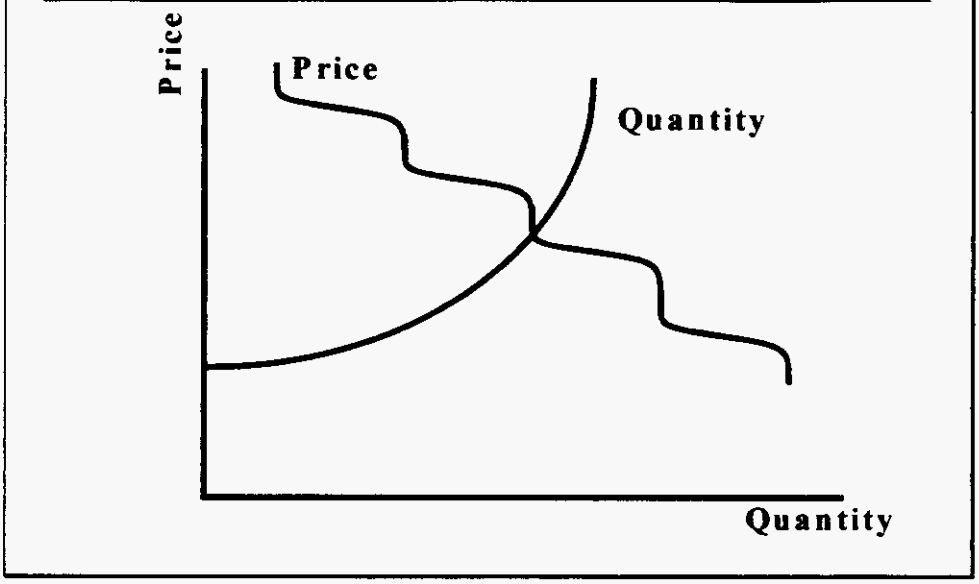
Figure 24: Demand Curve May Be Sub-Segmented



4. THE PIPELINE COMPONENT OF THE NARG MODEL

Turning from the supply and demand elements of the NARG model, we note that the degree of pipeline detail must be consistent with the degree of supply and demand detail elsewhere in the model as discussed earlier in this section. In particular, while we could enumerate and distinguish every individual pipeline in the United States, we have instead sought commonalities among supply regions, pipelines, and demand regions that allow aggregation. In fact, rather than representing individual pipelines, we have instead represented pipeline corridors from our supply regions to our demand regions. Indeed, these corridors are quite explicitly defined by the characterization of our supply and demand regions and by the configuration of the United States and Canadian pipelines systems that exist today.

Embracing the notion of pipeline corridors, we begin by considering the network of existing pipelines. Each of the existing pipeline corridors begins in a given supply region, extends perhaps through intermediate supply and demand regions, and terminates in a demand region. The network of existing pipeline corridors interconnects all currently producing regions with all currently consuming regions. We have given a great deal of attention and effort to representing the existing pipeline system, including capacity and cost. To our NARG customers, we deliver the pipeline data for existing pipeline routes throughout North America used in the NARG model.

Because the NARG model predicts the evolution of the North American gas system over the next 40 years, we cannot stop with existing pipeline corridors. Rather, it is necessary to enumerate all prospective future pipelines that might be built in the next 40 years. These prospective future pipelines connect new producing regions (or subregions) with various demand regions, and they connect Canada and Mexico to the United States. NARG enumerates the pipelines that can be prospectively built within the time horizon of the model. We will discuss shortly how we have characterized prospective new pipelines and pipeline expansions.

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The prospective new pipelines in NARG are just that--prospective. They will be built only if they become economic. They will be built only if supplies at the upstream end, marked up to account for the cost of the new pipelines, constitute the most competitive source at the downstream end. We will discuss nuances of capacity expansion below (e.g., looping or compression augmentation for existing capacity). In the model, looping is considered as an option for all existing capacity as well as for the existing links of the new corridors.

Because the linkage between Canada and the United States is potentially so important, we have distinguished in some detail the pipelines in Canada that directly or indirectly lead to the lower 48 United States. These Canadian pipelines, should they be built, provide a route for hundreds of Tcf into United States markets should those Tcf become economically competitive.

In reviewing the Canadian export situation in the NARG model, the prospective routes from North Alaska through Alberta and ultimately to the United States and from Northern Canada (MacKenzie and Beaufort Sea) through Alberta and ultimately to the United States must be represented. The former pipeline represents the upstream leg of the ANGTS system while the latter pipeline represents the pipeline that will have to be built in order to exploit Canadian Arctic gas (the Polar project and prospective expansions). Competition between these two pipelines will in part determine the competitive viability of the various Arctic supply regions and of the pipeline projects proposed to serve them.

Once we have enumerated all the existing pipelines and pipeline corridors, we must represent the cost and the capacity of those corridors. How do we think about the supply curve for pipeline service? The answer is rather clear. If we knew the maximum annual throughput for a pipe and we knew the forward cost to market borne by the owner of that pipe from its origin to its destination, we could make a plot of the supply curve for that pipe as in Figure 25. The height of the supply curve is the forward cost to market, i.e., the variable cost the owner of the pipeline would have to bear in order to provide service. The width of the supply curve is the capacity, i.e., the annual throughput, of the pipe. The width represents the physical size of the facility, and the height represents the forward cost to continue to provide service. In the most fundamental sense, the supply curve for transportation service in Figure 25 is the economic representation of the cost and capacity of the pipe in question. It is completely devoid of the regulatory baggage of the past. There is no embedded or historical cost in the curve; there is only forward cost to market. There is no guarantee that the owner of the pipeline facility can or will recover any embedded historical cost; there is only the forward cost the owner has to bear in order to continue to provide the transportation service.

For every existing pipeline corridor in the NARG model, we have created a supply curve for pipeline service of the form in Figure 25. The data necessary to characterize such pipeline service includes

- The forward cost to market, i.e., the height of the pipeline supply curve. We have used pipeline costs specified by our customers and contractors over the years to characterize the cost along each existing pipeline link.

- The capacity of the pipe, i.e., the width of the pipeline supply curve. We have used estimates of capacity, i.e., maximum annual throughout, specified by our customers and contractors over the years to characterize the annual capacity of each existing pipeline link in the model.

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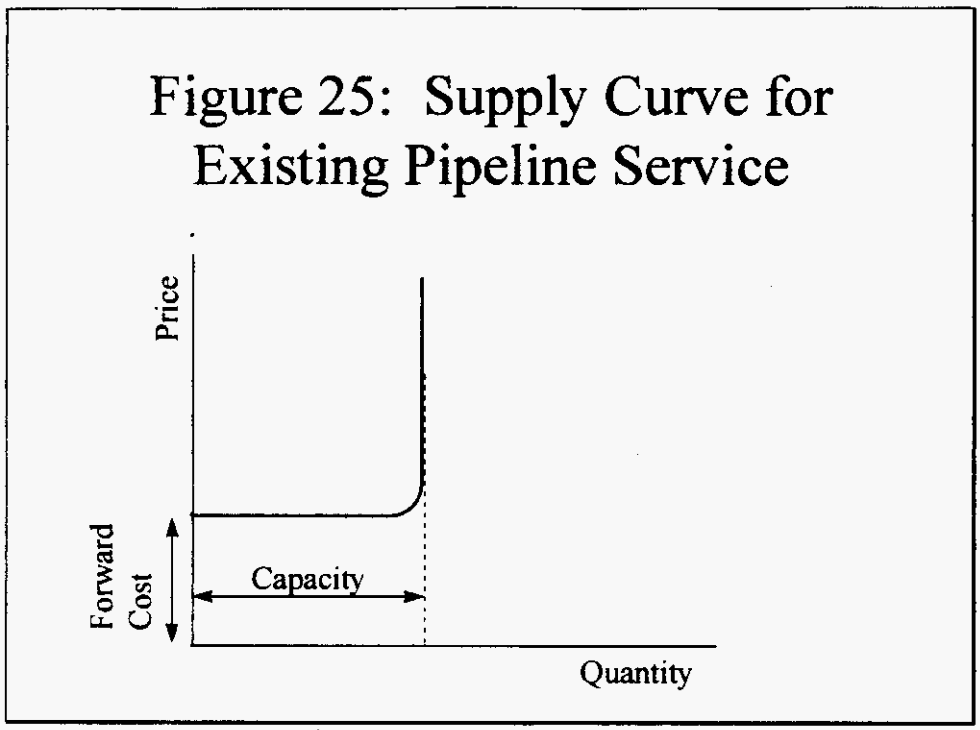
The pipeline database delivered to our NARG customers contains such estimates for every pipeline link the North America as estimated for use in NARG.



There are several generic types of pipeline capacity expansion that can be implemented:

- expansion of capacity of a given pipeline by such actions as looping or increasing pressure.
- expansion of capacity along a given corridor by adding a new pipeline.
- Addition of an entirely new, greenfield increment of pipe

We represent each of these types of capacity addition in the same fashion. We input an estimate of the full forward cost to market—capital cost plus operating cost—and graft it onto the right hand side of the existing capacity curve in Figure 25. Thus, the logic for adding new pipeline capacity within NARG is represented graphically as shown in Figure 26. Notice that once the market hits the full capital and operating cost of new capacity, such new capacity can enter without bound. The aggregate supply curve for existing plus new pipeline capacity in Figure 26 is estimated along every pipeline corridor, existing or prospective, in the NARG model. Therefore, in addition to the foregoing cost and capacity data for new pipes, we need an estimate of the full forward cost of expansion for new transportation capacity along that corridor.

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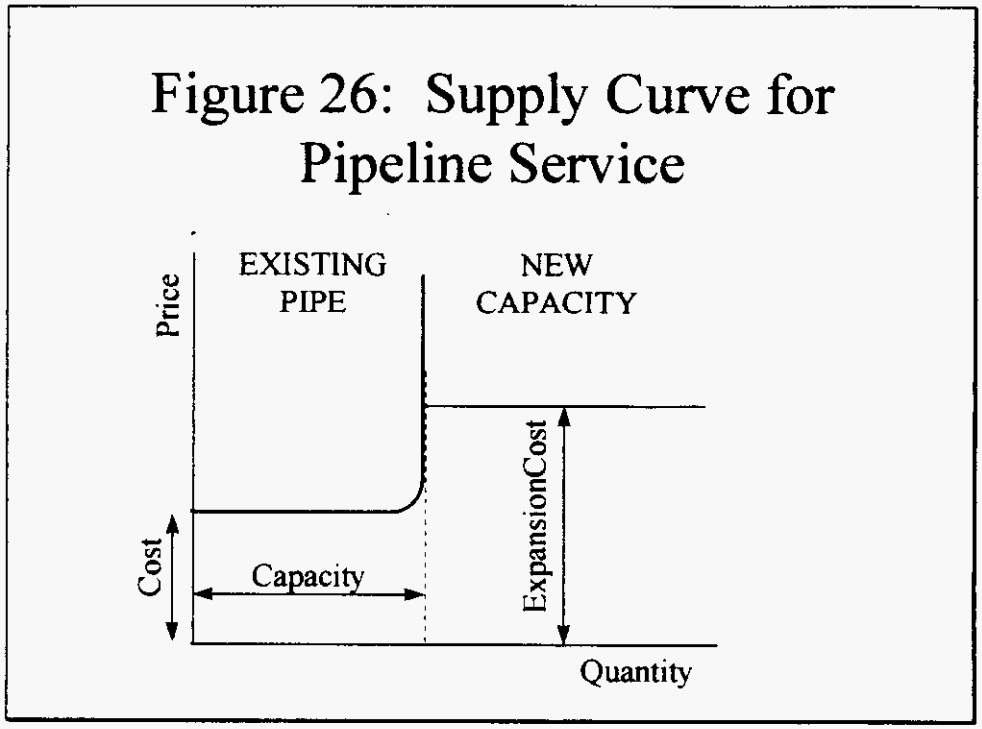

5. CONCLUDING REMARKS

NARG has become the industry-leading model of North American natural gas price and basis forecasting, asset valuation, pipeline addition, investment, abandonment, and long run marketing. It has outlasted most or all of its competition over the past 20 years. In the past year, we have been working assiduously to complement the long run annual structure of NARG with a short term (36 month) monthly model that can guide short term price and basis forecasting and can guide a broad range of trading and marketing decisions. The short run model, which has not yet been fully documented, will be ready for commercial use in the third quarter of 1997 and will be offered and licensed under the same terms as NARG.

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The Need for and Viability of the Duke New Smyrna Beach Project

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December 3, 1998

FLOBIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 19
COMPANY/ WITNESS: Duke Energy
DATE: 12-3-98

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The Duke New Smyrna Beach (DNSB) Project is Needed Now and Is Economically Viable Now

Methodology

- ✓ Model
- ✓ Data
- ✓ Analysis

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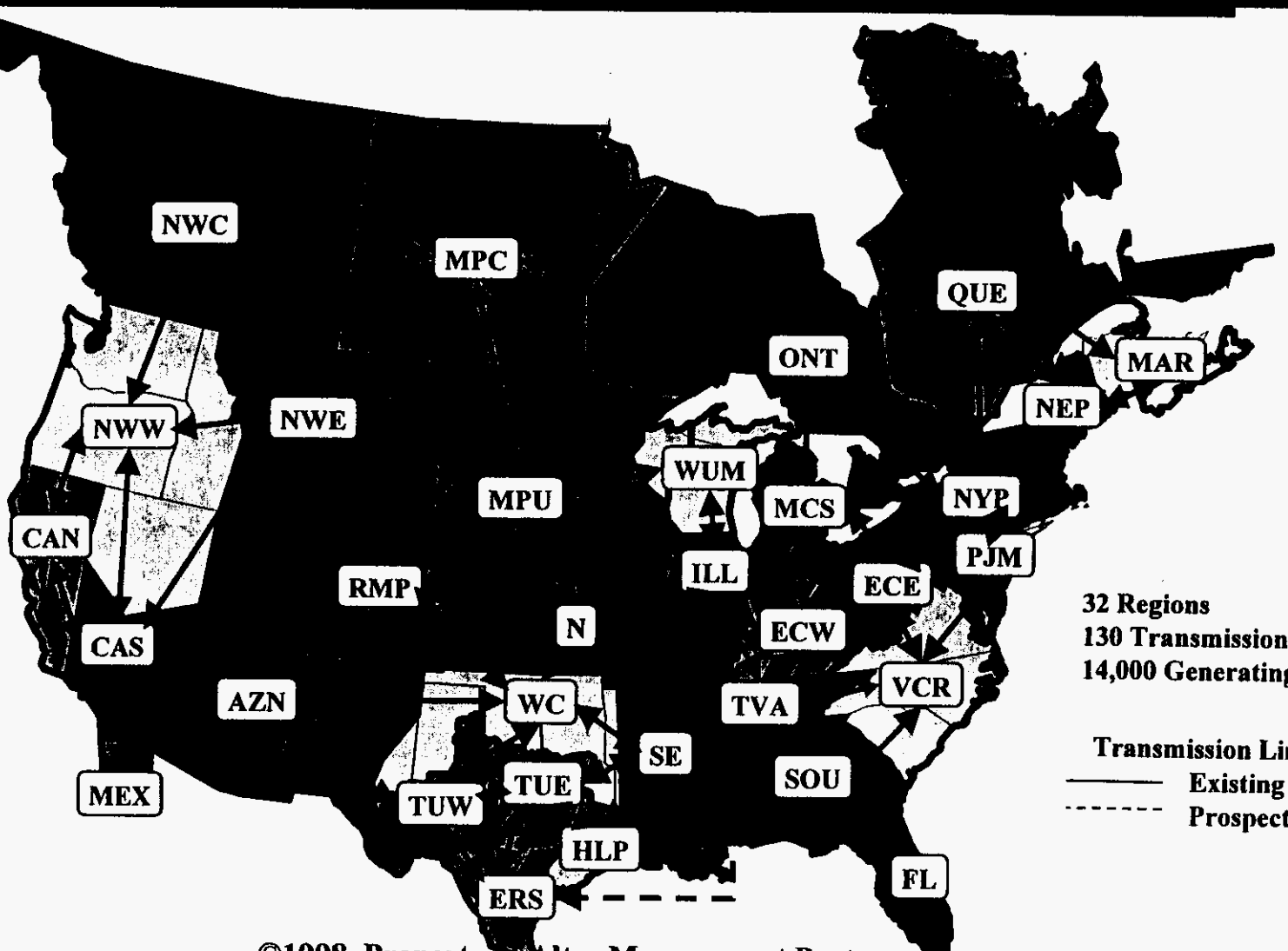
Altos Market Model with North America-Wide Scope



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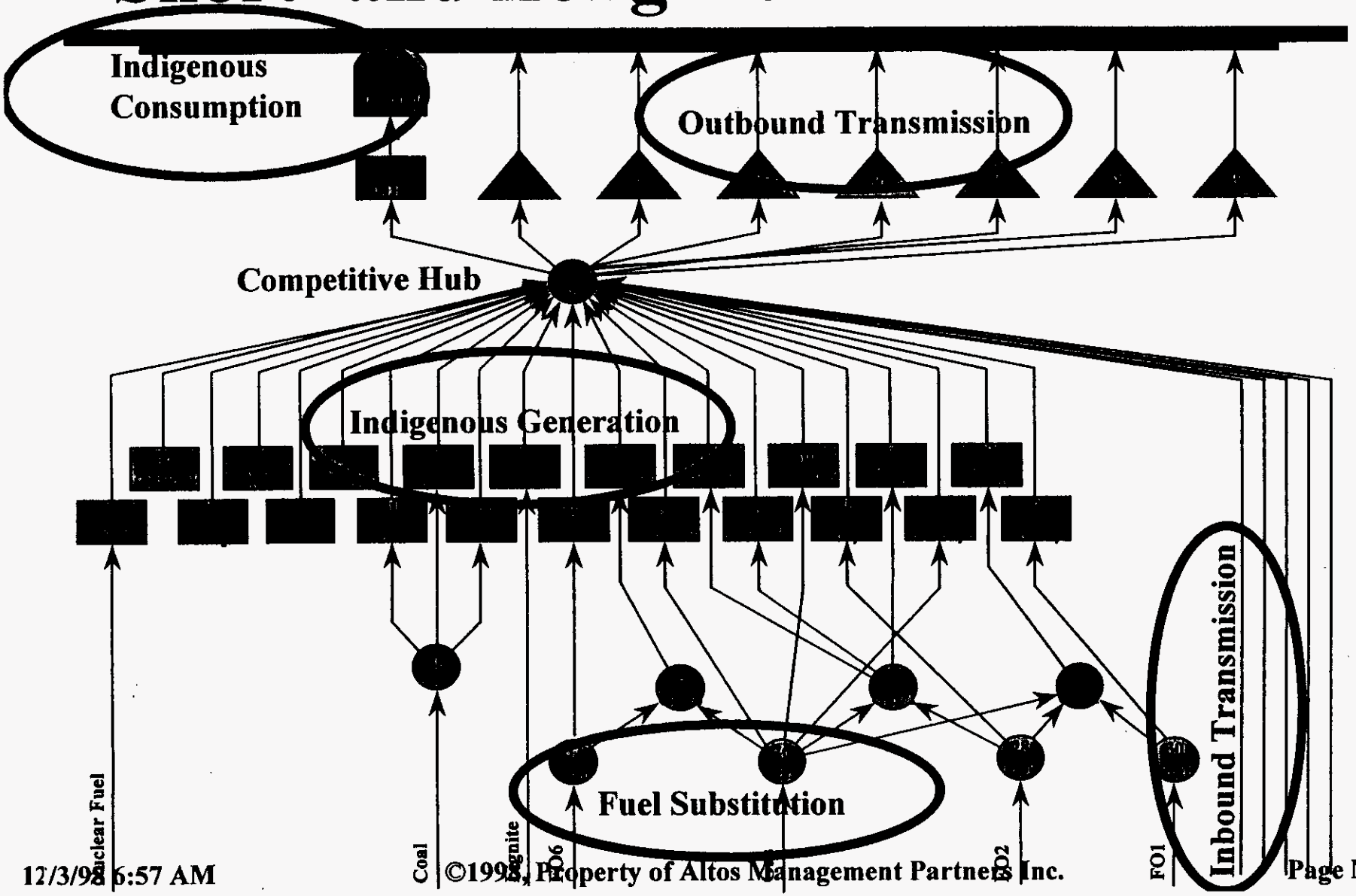
Altos Model Addresses the Important Short- and Long-Run Market Issues



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Gas Prices Come from Altos North American Regional Gas Model (NARG)

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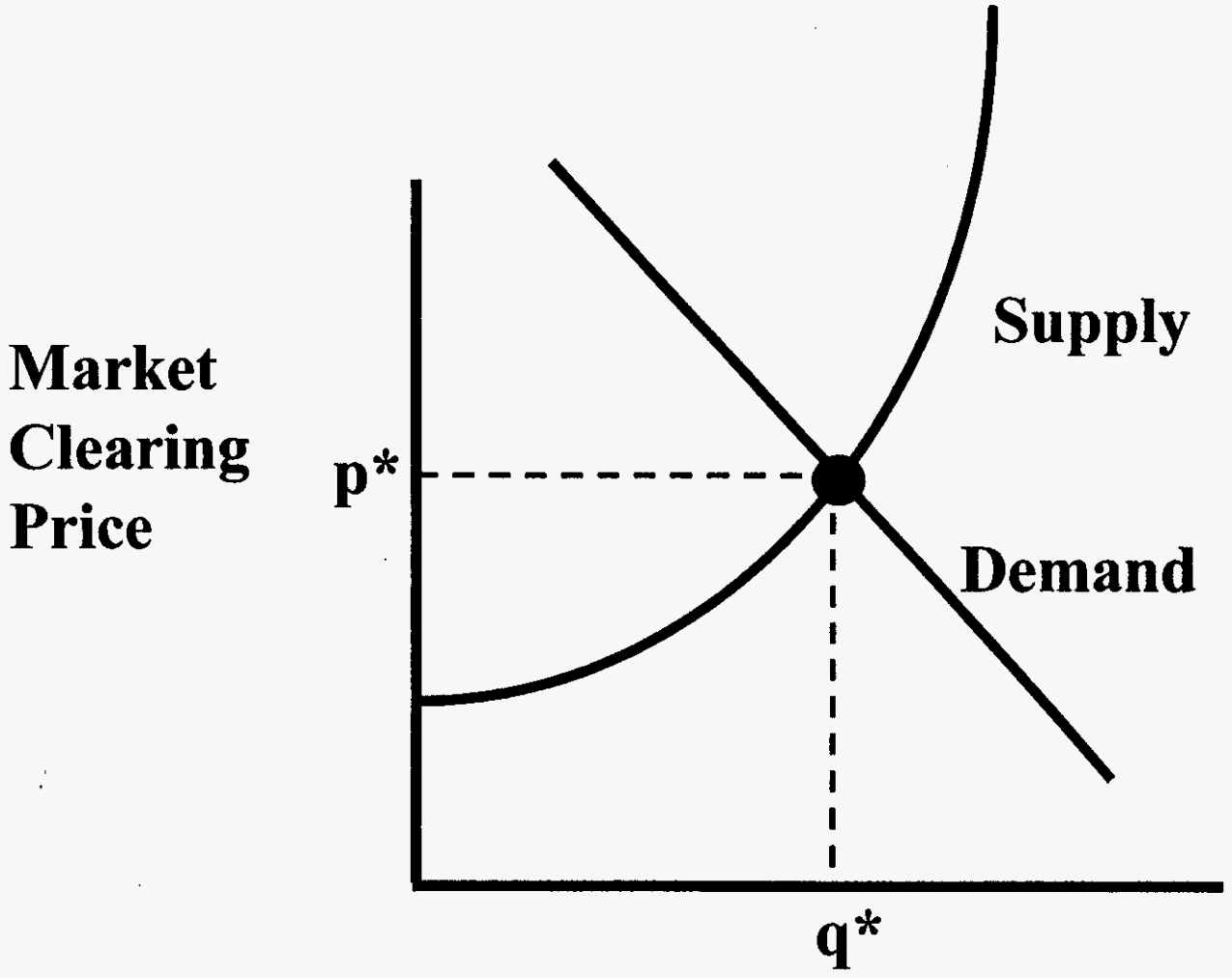
Both Models Balance Supply and Demand and Thereby Calculate Price



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1. There Is a Direct and Immediate Economic Need for DNSB

- ❶ DNSB displaces generation from high cost plants that would otherwise have to be maintained and run with a new, lower cost, cleaner plant (p. 14, L 24).
  - ✓ Florida ratepayers need the lower prices that displacement of inefficient generation will cause (p. 34, L 10).
  - ✓ Displacement of high cost plants by low cost plants equals direct augmentation of Florida producers' plus consumers' surplus. (p. 35, L 14).

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1. There Is a Direct and Immediate Economic Need for DNSB

❷DNSB beats the marginal source for 83-94 percent of the hours of the year; whether it beats an inframarginal source is unimportant. (p 22, L 23)

❸When DNSB enters, wholesale energy prices in Florida will be directly reduced as a result of such entry. (DMN-12)

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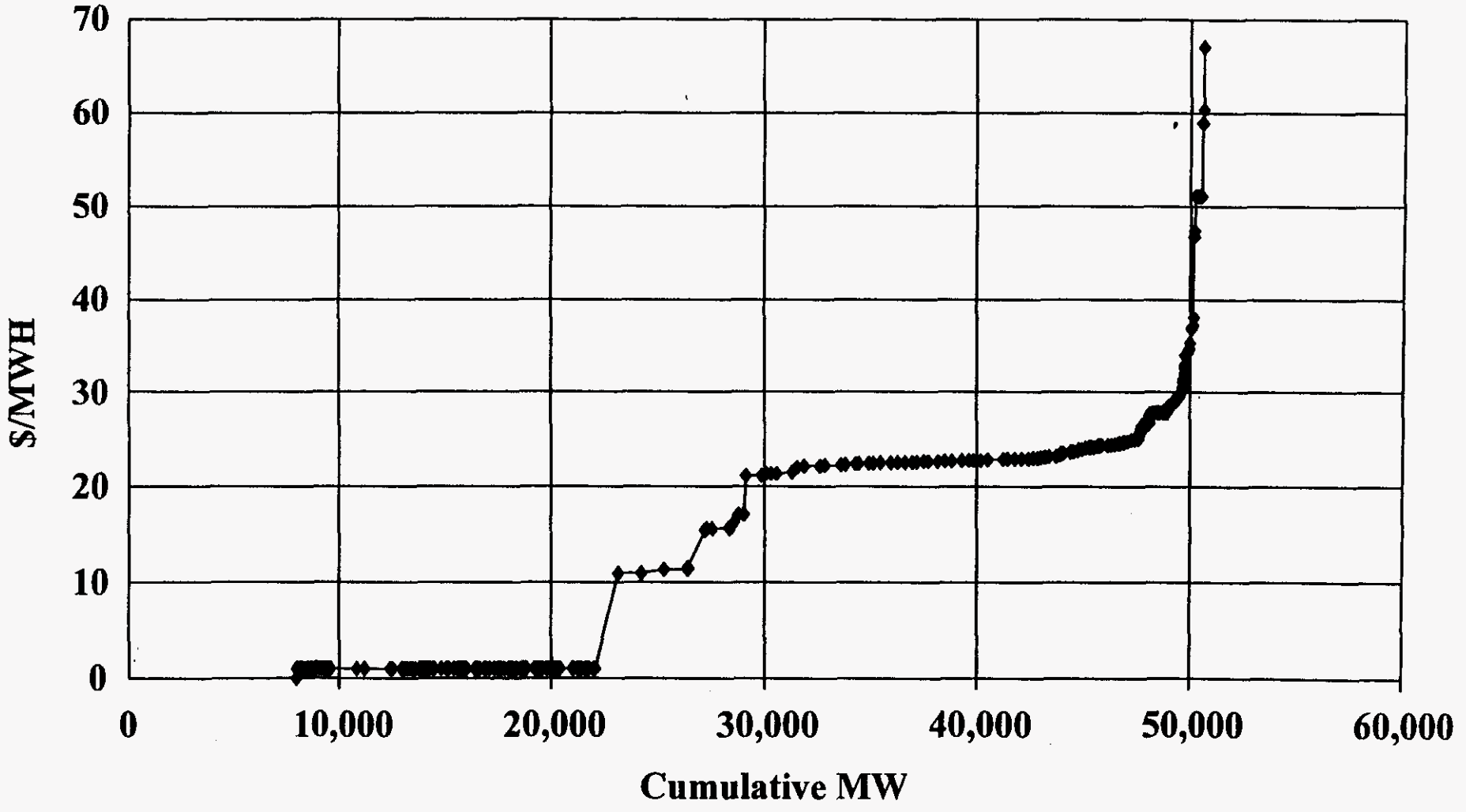
California Supply Stack
WSCC--CA/NV (DMN-15, p. 20)



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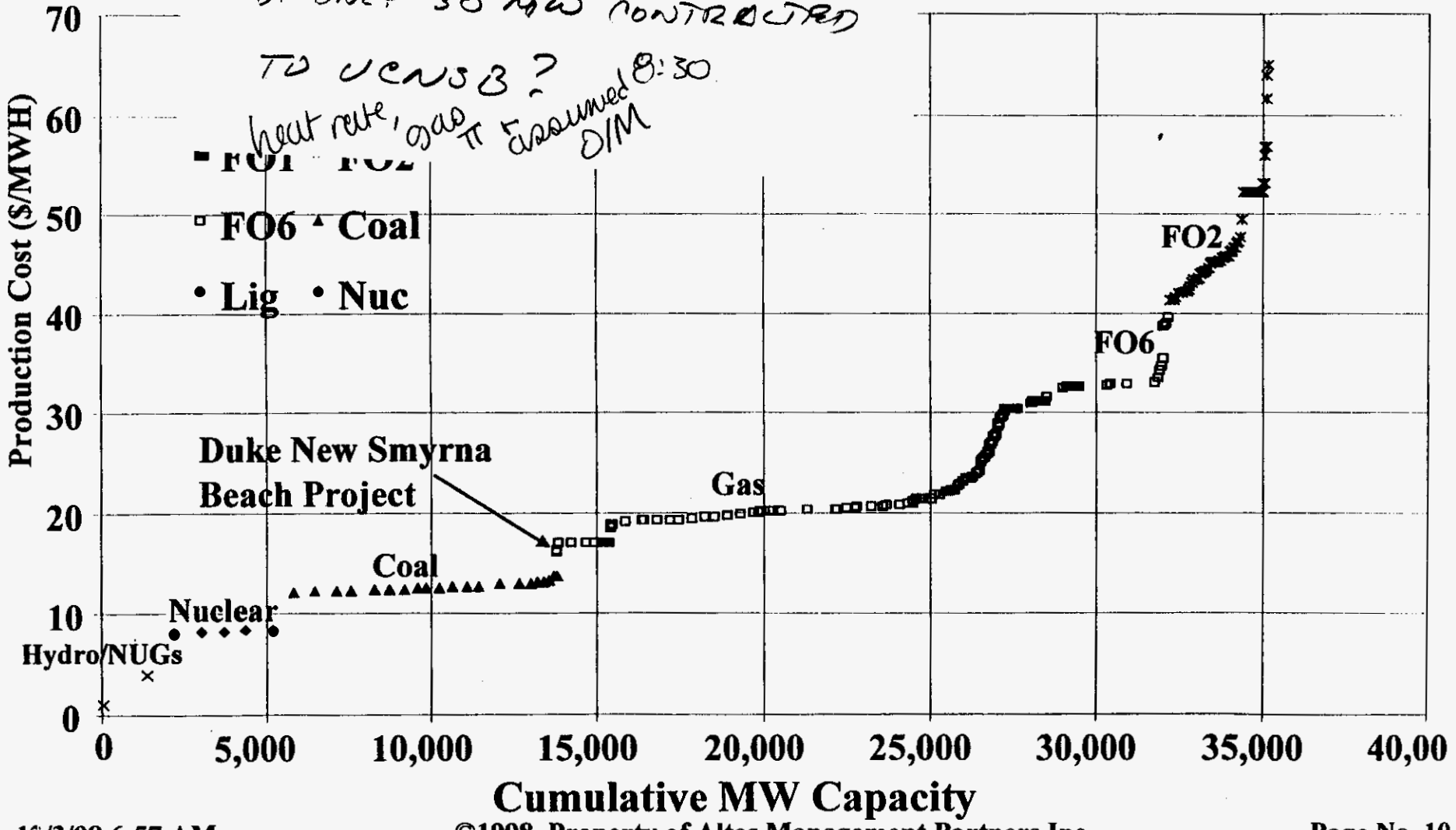
THE PRODUCTION PRICE YOU'VE ASSUMED FOR THE TOTAL 500 MW IS THE PRICE OF ONLY 30 MW CONTRACTED TO UCNSB? heat rate, load ? Assumed O/M 8:30

ly Stack



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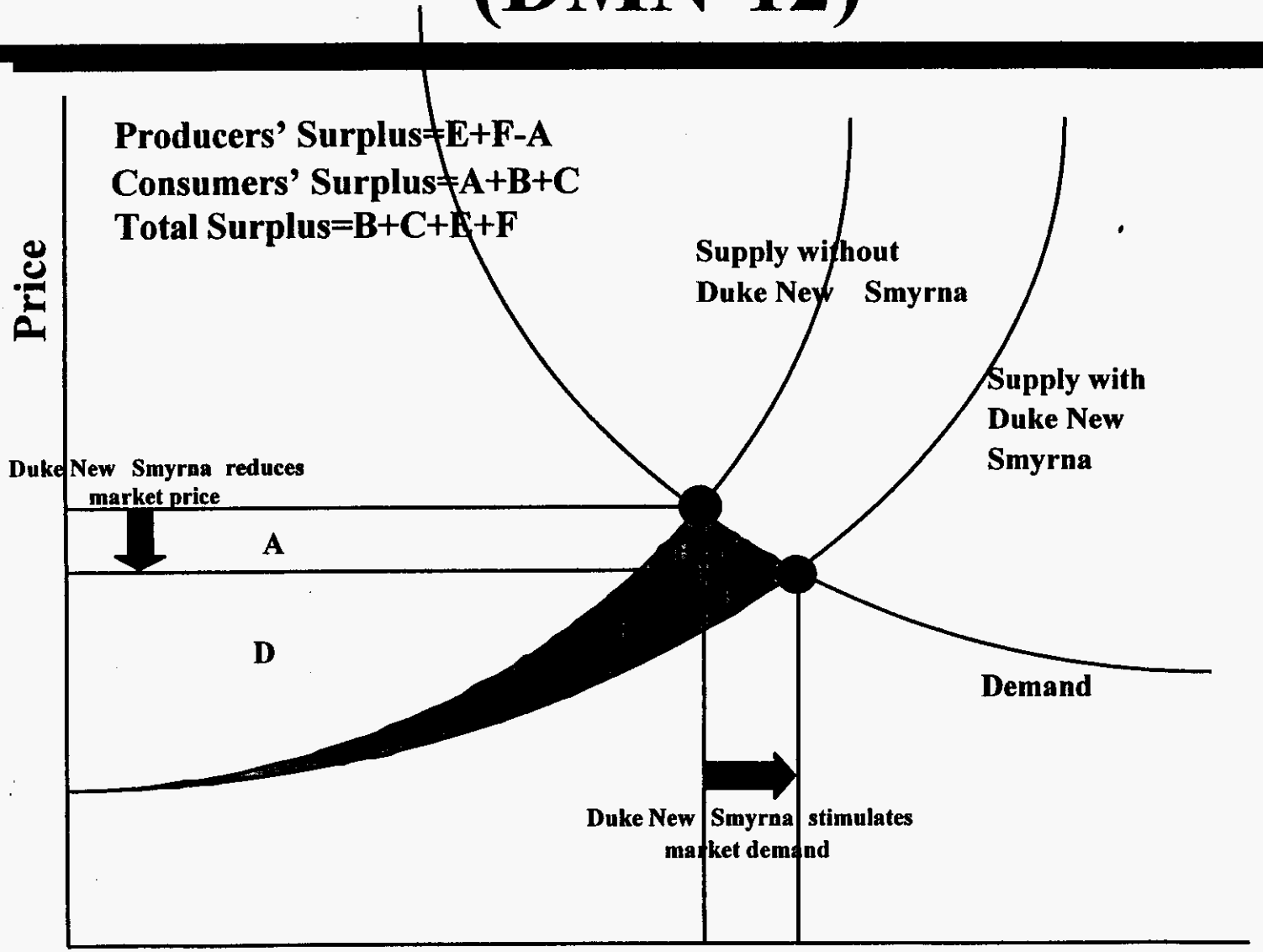
Benefits of Duke New Smyrna Project (DMN-12)



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2. The Model Projects that the FRCC Wholesale Market Needs...

❶5400 MW of new gas CC capacity immediately (p. 13, L 23)

❷The Florida market fully absorbs this capacity (p. 29, L 4). (We will return to this point later.)

❸At most, an inconsequential amount of energy from DNSB would ever be sold out of state (p. 38, L 19)

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3. DNSB Project Saves Fuel (DMN-7)

❶ DNSB is highly efficient (6,832 heat rate)

❷ DNSB displaces low efficiency units that would otherwise have to be used(10,510 heat rate)

❸ DNSB reduces the number of Btus of fuel that need to be consumed in Florida to generate the same number of MWH (13.674 TBtu)

❹ Reduction of the number of Btus of fuel consume per MWH leads to

- ✓ economic benefits (lower fuel cost per MWH)
- ✓ environmental benefits (more efficiency, oil displacement)
- ✓ MCF of gas savings per MWH generated

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4. DNSB Pays Environmental Benefit

❶ **Efficient low heat rate plant configuration reduces environmental emissions relative to what would otherwise occur. (p. 30, L17)**

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5. DNSB Directly Reduces Potential Exercise of Market Power (p. 31)

❶ DNSB diminishes prospective exercise of market power

- ✓ DNSB dilutes market concentration
- ✓ DNSB creates small competitive merchant fringe that limits prospects for market power and price flyup

❷ DNSB does NOT have market power

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6. DNSB Increases Ability to Meet Load Growth

❶ Demand growth is inevitable in Florida (p. 15, L 12).

❷ When DNSB enters, there is incrementally more capacity chasing a fixed demand (p. 34, L 22).

❸ While I have not quantified the impacts, the DNSB project will improve reserve margin and loss-of-load-probability (p. 14, L 13-20)

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7. DNSB Provides Direct Risk Reduction to Florida Ratepayers (p. 30, L 13-17)

❶100 % of price and marketability risk is borne by DNSB project owners

❷No price risk is borne by Florida ratepayers or wholesale market participants

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9. Imports from Points North of Florida Will Decline in the Future (p. 18, L 14)

- ❶ Southern will evolve from net exporter to net importer from its neighbors other than Florida.
  - ✓ Off Peak: Southern's low cost coal units will be increasingly dedicated to local Southern markets. (p. 26, L 9)
  - ✓ On Peak: There is declining economic incentive to transmit summer power. (DMN-12)

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The Duke New Smyrna Beach (DNSB) Project is Needed Now and Is Economically Viable Now

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 981042-EI EXHIBIT NO. 20
COMPANY/
WITNESS: FPL
DATE: 12-2-98

20

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	**DOCKET NO. 981042-EM** **DATE: October 13, 1998**

FLORIDA POWER & LIGHT COMPANY'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-13) TO DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

Pursuant to Rule 28-106.206, Florida Administrative Code, and Rule 1.350, Florida Rules of Civil Procedure, Florida Power & Light Company ("FPL"), by and through its undersigned attorney, hereby serves the following Request for Production of Documents upon Duke Energy New Smyrna Beach Power Company LTD., L.L.P.

Please produce the following documents at Steel Hector and Davis, LLP, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, not later than fourteen days after service of this request, for purpose of inspection and copying.

DEFINITION

As used herein, the word "documents" shall mean the original and any non-identical copies of any writing or record, including but not limited to a book, pamphlet, periodical, letter, memorandum, telegram, report, study, interoffice or intraoffice memorandum, memorandum reflecting an oral communication, handwritten or other notes, working paper, draft, application, permit, chart, paper, graph, survey, index, tape, disc, data sheet or data processing card, computer printout, or any other written, recorded, transcribed, filed or graphic matter, however produced or reproduced.

FLORIDA POWER & LIGHT COMPANY'S
FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO
DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY
LTD., L.L.P. (NOS. 1-13)
DOCKET NO. 981042-EM

DOCUMENTS REQUESTED

1. Please provide all documents and analysis in which it is assumed or projected that the Project with its heat rate of 6,832 Btu per kWh (HHV) will displace generation from less efficient gas-fired steam boiler units or from even-less-efficient CTGs.

2. Please provide all documents and analyses in which it is assumed or projected that the Project will displace oil-fired generation.

3. Please provide all documents and analyses supporting the Project's projected equivalent availability factor of 96 percent, planned outage factor of 3%, forced outage factor of 1%, and a capacity factor ranging from approximately 83 percent in 2002 to 94 percent or more by 2012.

4. Please provide all documents supporting Table 2 of the Joint Petition Exhibits.

5. Please provide the "preliminary site screening analyses commissioned by Duke New Smyrna [which] indicate that the Project is consistent with the overall zoning and plan of development for the area in which the Project will be located, and that no significant problems are anticipated in connection with the environmental permitting process for the Project site." (Joint Petition at 8).

6. Please provide the complete and unredacted gas supply and transportation contract between Duke Energy Power Services, L.L.P. and Citrus Trading Corp. pursuant to which the Project will have sufficient gas to operate for initial term of twenty years.

7. Please provide all analyses and other documents showing the volume of gas necessary for the Project to operate at full capacity for an initial term of twenty years.

8. Please provide all load flow studies prepared for Duke New Smyrna and the UCNSB regarding the Project. This would include but not necessarily be limited to the load flow studies discussed in the paragraph at the top of page 9 of the Joint Petition.

9. Please provide all the supporting documentation for the statement at page 10 of the Joint Petition that the Project will displace "generation from less efficient units and units that burn fuels that produce more pollution than is produced by the natural gas fuel used in the Project."

10. Please provide the Joint Power Agreement for the Project.

11. Please provide all documents supporting the statement in the Joint Petition at page 17 that, "the Project is demonstrably cost-effective relative to virtually all other gas fired combined cycle power plants proposed for Florida over the next 10 years."

12. Please provide the load flow studies referred to on page 24 of the Joint Petition at paragraph 36.

13. Please provide all analyses which indicate the Project would displace electric energy produced from either or both oil fired and less efficient gas fired generation facilities.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's First Request for Production of Documents to Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. (Nos. 1-13) in Docket No. 981042-EM was served by Hand Delivery (when indicated with an *) or mailed this 13th day of October, 1998 to the following:

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By: Charles A. Guyton
Charles A. Guyton

TAL/26146-1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	))))))	**Docket No. 981042-EM** **Filed: October 13, 1998**

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY Ltd., L.L.P. (NOS. 1-13)

Florida Power & Light Company ("FPL") gives notice of serving its First Set of Interrogatories to Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. (Nos. 1-13), with a copy thereof to all counsel on the attached Certificate of Service, this 13th day of October, 1998.

Respectfully submitted,

STEEL HECTOR & DAVIS
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Suite 601
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(904) 222-2300

Attorneys for Florida Power
& Light Company

By:
Charles A. Guyton

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's Notice of Serving First Request for Production of Documents to Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. (Nos. 1-13) in Docket No. 981042-EM was served by Hand Delivery (when indicated with an *) or mailed this 13th day of October, 1998 to the following:

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By: Charles A. Guyton
Charles A. Guyton

TAL/26144-1

EXHIBIT NO. _____

DOCKET NO: 981042-EM

WITNESS: Dale M. Nesbitt, Ph.D.

PARTY: The Utilities Commission, City of New Smyrna Beach, Florida and Duke Energy New Smyrna Beach Power Company LTD., L.L.P.

DESCRIPTION: Transcript of the Deposition of Dale M. Nesbitt, Ph.D., Taken at the Instance of the Staff of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 21
COMPANY/ WITNESS: Nesbitt
DATE 12-2-98

PROFFERING PARTY: STAFF

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	DOCKET NO. 981042-EM

DEPOSITION OF: Dale M. Nesbitt

TAKEN AT THE INSTANCE OF: FPSC Staff

DATE: Tuesday, November 10, 1998

TIME: Commenced at 9:00 a.m.
Concluded at 10:25 a.m.

PLACE: Steel, Hector & Davis
215 South Monroe Street
Suite 601
Tallahassee, Florida

REPORTED BY: NANCY S. METZKE, RPR, CCR

BUREAU OF REPORTING
RECEIVED 11-18-98

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APPEARANCES:

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DOUGLAS HALL, ESQUIRE, Florida Power Corp., Carlton, Fields, 215 South Monroe Street, Fifth Floor, Tallahassee, Florida 32301.

ALSO PRESENT:

JIM BREMAN, FPSC Staff.

MIKE BLAHA, Altos.

* * * *

STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

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DALE M. NESBITT

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Whereupon,

DALE M. NESBITT

was called as a witness by the FPSC Staff and, after being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. JAYE:

Q All right. As we begin this morning, I'd like to make sure everyone understands the stipulations. We stipulate that this deposition is taken pursuant to notice in accordance with the Florida Rules of Civil Procedure. All objections except as to form of question will be preserved until the hearing. Reading and signing are not waived, and off-the-record conversations are with the consent of the deponent. Are there any other things?

(NO RESPONSE)

Q Seeing none, we will get started.

Good morning.

A Good morning.

Q My name is Grace Jaye. I am counsel for the Florida Public Service Commission. I have a few questions for you.

First of all, would you please state your name and business address for the record?

A My name is Dale M. Nesbitt, N-e-s-b-i-t-t. Business address is 1250 Aviation Avenue, Suite 200-C, as

in Charlie, San Jose, with a J, California, 95110.

Q By whom are you employed and in what positions?

A I'm employed with Altos Management Partners, and I'm the president and CEO.

Q And what are your duties with Altos?

A My duties with Altos include internal management issues, working on client projects externally, marketing, public relations, software development, data assembly, pretty much the full range of professional activities that our firm does.

Q Could you please summarize your employment history and work experience?

A Sure. Let me start with my first professional job, if you don't mind.

Q That's fine.

A That was in 1972 with Xerox Corp at the Palo Alto Research Center. At that time I was hired as a -- it was called a research analyst. In 1974 I went from Palo Alto Research Center at Xerox to Stanford Research Institute which is now called SRI International. At SRI International I began as an analyst and worked there until January of 1977 in the decision analysis department in their management systems division. When I left there, I was the manager of their decision analysis, dash, energy program.

In January of '77 I and three colleagues founded a firm named Decision Focus Incorporation, which is abbreviated DFI. I'll use that term subsequently. DFI grew to be 150, 200 people by 1995 when I sold my position in DFI and co-founded Altos Management Partners with several other individuals. And that's where I am today, at Altos Management Partners.

Q So Altos was founded in 1995?

A Yes.

Q Okay. Great.

Would you give a brief summary of your educational background?

A Yeah. I attended the University of Nevada in Reno from '65 to '69 and received a bachelor of science degree in engineering science. In 1969 I went to Stanford. In 1970 I received a bachelor's degree in mechanical engineering. In 1972 a master's degree in engineering, hyphen, economic systems. In 1975 I received a Ph.D. in engineering-economic systems. All the latter three at Stanford.

Q Do you have your own copy of Staff's first request for production of documents to Duke New Smyrna Beach Power Company, Limited, L.L.P., Numbers 1 through 23?

A I don't have it before me.

Q I'm going to hand you a copy of the first

question and the response to it. I have copies for everyone else. I'll give you a moment to look that over.

A Thank you.

(WITNESS REVIEWED DOCUMENT)

MS. JAYE: We'll go ahead and get that marked as Deposition Exhibit 1.

(SO MARKED EXHIBIT NUMBER 1)

A Okay, I've reviewed it.

BY MS. JAYE (Continuing):

Q Are you the appropriate witness who will address questions related to this particular Request for Production of Documents Number 1 at hearing in this docket?

A Yes, I am.

Q Was this answer prepared specifically to address this request for production of documents?

A Yes, it was.

Q Is this response to this request for production of documents a composite of preexisting documents?

A No, I wouldn't say that. What it is, primarily, is paper copies of the Excel spread sheet that contains the fuel price forecast. So it's paper copy of an electronic file by and large.

Q Okay. Who provided the information used in the electronic file, Altos or Duke New Smyrna?

A All of the documents -- all of the numerical

values here were provided by Altos; none were provided by Duke New Smyrna.

Q Did you sponsor Duke New Smyrna's response to Request for Production of Documents Number 1?

A Did I sponsor this?

Q This answer, yes, sir.

A Let me answer that this way: I prepared this answer, and it does come from the Altos model and the data base that was used to drive it. Does that -- is that what you're after?

Q Yes.

A Okay.

Q Okay. Looking at the question for Request for Production of Documents Number 1, does this request complete copies of each fuel price forecast used?

A Yes, there was only one fuel price forecast used, and it was common to the models and to the runs, and this was it.

Q Okay. Which fuel types are included in this response?

A The fuel types that are included in this response included -- it's in the first page, natural gas; three types of oil, FO6, FO2, Number 2 fuel oil, Number 6 fuel oil, and FO1 Number 1 fuel oil. You'll see that coal is included, nuclear fuel and lignite.

Q Okay. Is it your testimony that petitioners evaluated eight generating alternatives listed in Table 15, Page 67 of the petition exhibits? Now this will be in the bound volume of petition exhibits. Do you have this with you?

A I don't have that, no.

Q Okay. Let me turn to that for you. I'll let you take a look at that one.

MR. McGLOTHLIN: Would you repeat your question please, Grace?

MS. JAYE: Yes.

BY MS. JAYE (Continuing):

Q Is it your testimony that the petitioners evaluated the eight generating alternatives listed in this table on Page 67, Table 15 of the exhibits to the petition?

A Yes, we did, and let me clarify that. Within the Altos North American Regional model, each of those eight technologies is considered and is allowed to compete against each other technology and all in-bound transmission options.

Q Now do these evaluations of the eight alternatives listed on Table 15, Page 67 of the petition exhibits include the fuel price forecasts that are appended to the answer to POD 1?

A Yes, they do. Each of the generation plant types

takes as its fuel input the prices that are in the answer to Question 1 that you've provided.

Q Does the response to POD Number 1 contain fuel prices for 1998 and no other year, or are other years involved?

A Let me check that. Subject to check, I believe that these were the fuel prices expressed in 1998 dollars but describing fuels in the year 2000.

WITNESS NESBITT: Is that correct, Mike?

I might ask Mike which years these fuel prices correspond to.

MR. BLAHA: I can't say exactly.

A We'd have to look in the model.

Q So can you tell me looking now at Table 15, Page 67 of the petition exhibits what years were used in the evaluation of these eight alternatives?

A Yes, I can tell you that. We evaluated competition among those eight and other alternatives in the year 2000, 2002, 2004, 2006, out to I believe the year 2014. So each of these alternatives was competed against each of the other alternatives in each of those subsequent future years beginning in the year 2000 and separated by two-year intervals.

Q For each of these two-year intervals, do you have a fuel forecast?

A For each of those two-year intervals we do have a fuel forecast, and the document, the response to Question Number 1 is for one of those years, which I would -- I'll be glad to check exactly which one it is; but there is a fuel forecast in each future year, yes.

Q Okay. Could you provide us a late-filed exhibit detailing those fuel price forecasts out through the year 2014?

A Yes.

Q And we'll call that a late-filed exhibit, fuel forecasts through 2014.

Looking again at the response to POD 1, are all of the fuel prices that are contained in this POD in 1998 constant dollars?

A Yes, they are all expressed in constant 1998 dollars.

Q Okay. And turning again to Table 15, Page 67 of the petition exhibits, were all of these generation alternatives, these eight alternatives, evaluated in 1998 constant dollars?

A Yes. In the model each of these technologies are characterized by costs that are expressed in 1998 dollars.

Q Okay. What is the planned in-service year for the proposed project?

A I'd have to check what that is.

WITNESS NESBITT: Mike, do you recall what that was, the planned in-service year?

MR. BLAHA: I believe it was 2001 or 2002. I'm not --

A We'd have to check. 2001 or 2002.

Q Could you explain how a constant 1998 fuel price was used to evaluate an in-service date for this project which would be in 2001 or 2002?

A Certainly. It's a fairly standard procedure. If you look at a fuel price going forward in dollars of the day, year 2002 dollars, and discount it by the inflation factor that is projected to pertain between the year 2002 and the year 1998, you will have the fuel price as it will exist in the year 2002 but expressed in dollars of the day in 1998.

Q All right. Do you have your direct testimony with you?

A Yes, I do.

Q Would you please turn to Page 13? I ask you to read into the record, beginning at Line 4 of the sentence beginning "To wit," through the end of that paragraph ending with the word "projections."

A To the end of the paragraph?

Q Yes, sir.

A "To wit, the forward price calculations and their

implications for the project are drawn from Atlos's models, data, analyses and personnel. They are not drawn from proprietary or confidential data from Duke New Smyrna, the UCNSB, or any of their affiliates, nor are they drawn from analysis or data provided by Duke New Smyrna or the UCNSB. My objective has been to apply and put forth my and Altos's best professional analysis and judgment based on our best available technology, experience, and data, not to mirror Duke New Smyrna's or the UCNSB's analysis or projections."

Q Was your analysis wholly separate and apart from Duke's or UCNSB's?

A Yeah, I think as the paragraph says, our analysis is based on Altos's input, Altos's model and Altos's judgment; and in that sense it's separate from Duke's and UCNSB's.

Q Would any information provided concerning fuel prices by Duke New Smyrna and UCNSB then reflect Altos's models?

MR. McGLOTHLIN: I'm sorry. Could I hear that again?

MS. JAYE: Yes.

BY MS. JAYE (Continuing):

Q Would any fuel price information provided by Duke New Smyrna or UCNSB then be based upon Altos models?

MR. McGLOTHLIN: Provided by Duke --

A Could you clarify the question please?

Q Yes. Any information received from Duke New Smyrna or UCNSB then in this petition would be based upon information provided by Altos as far as fuel price forecasts are concerned?

A I wouldn't know what Duke or UCNSB's fuel prices were based on.

Q Okay.

A I would simply note that the fuel prices that were used in my evaluation are based on Altos's judgment.

Q So then looking, again, Page 67, Table 15 of petition exhibits, these evaluations of the eight options are based upon Altos information?

A Yes, they are, the evaluations, the eight options are based on Altos's cost information for the plant and Altos's fuel information.

Q It appears that the 1998 monthly prices were used in preparing the answer to POD 1. Were these actual or estimated prices?

A These prices that are in the answer to POD 1 are estimated prices. They are prices that are based on output of our North American Regional Gas model.

Q When was the fuel price forecast attached to this POD response actually finalized?

A The fuel price forecast was finalized, I would

say, second quarter of 1998, approximately; so in the spring, early summer of 1998.

Q Were more than one year of fuel prices used in preparing the answer to this POD?

A Well, the POD puts forth one year's worth of fuel prices, but the evaluation, as I said a minute ago, was based on an exactly analogous set of fuel forecasts for each of the forward years in the model horizon.

Q Okay.

A So the answer to your question is, this is for one year, and I'll check which year it was. I believe this is the year 2000.

Q Were any historic years used in preparing this fuel price forecast?

A No, historical years were not used in preparing the Altos fuel price forecast.

Q Were all of the fuel prices used in the Florida forecast on the model?

MR. McGLOTHLIN: I'm sorry, could you repeat?

Q Were all of the fuel prices used in the Florida forecast in the model?

MR. McGLOTHLIN: Do you understand her question?

WITNESS NESBITT: No.

A Do you mean were all of the fuel prices in this POD 1 response?

Q Yes, sir.

A Yes, every fuel price in this response was placed into the model that was used to make the Florida evaluation.

Q Was a well-head commodity only price used or a fully delivered price as burned?

A As burned. These prices that you see here are delivered prices, and based as they are on outputs of the North American Regional Gas model, that model integrates all the well-head prices at the various producing basins in North America with all of the pipeline transmission costs to all the various end-use regions. So implicitly, these prices contain all the well-head information and all the transmission information in the natural gas markets of North America.

Q We would like to request another late-filed deposition exhibit. Under the natural gas run for fuel prices on answer to POD 1, looking at the line for Florida, I would like to see the transportation cost assumptions broken down and see those along with the actual cost of natural gas side by side.

A Okay. Let me tell you what form that's in, and you tell me if that's appropriate.

Q Okay.

A I've got well-head projections from the model for

each of the various well-heads, one would be Henry; and I have these forecasts for prices in Florida. And the basis differential, the differential between those represents the transportation cost from Henry to Florida. Is that appropriate?

Q That is. That is very appropriate. We'll call this Late-filed Deposition Exhibit Number 2, natural gas transportation component for Florida.

Looking again at POD 1, if you could turn over to the coal prices, Page 5 I believe it is. Could you explain what the coal prices for the FL region include, again, the Florida region?

A Okay, the coal price in the Florida region represents the price of coal delivered to the coal burning facilities in Florida, so it's the all-in delivered price on a dollar per million BTU basis. And what it represents is Altos's projection of the market clearing price of coal in Florida.

Q Okay. What type of coal is assumed?

A In the analysis done for Florida we assumed one aggregate type of coal. We did not distinguish among various types of coal or qualities of coal. It's coal, one aggregate type.

Q Okay. We are going to need another late-filed deposition exhibit. What we would like to see is a

breakdown of delivered coal prices as they are shown on what we call our 423 forms that are required for the investor-owned utilities in Florida where a transportation component and the type of coal are both specified. We would like to see that compared to a breakdown of your coal price forecast. If you would like, we can go off the record and I can have my staff member explain to you how that would work.

A Please do that.

MR. McGLOTHLIN: That would be a good idea.

MS. JAYE: Let's go off the record a minute.

(DISCUSSION OFF THE RECORD)

MS. JAYE: All right. Back on the record.

All right. We'll have a deposition Late-filed Exhibit Number 4, called 423, 1997, expressed in 1998 constant dollars compared with the Altos model.

BY MS. JAYE (Continuing):

Q Doctor Nesbitt, could you please explain the difference in the FERC Form 423 price forecast and the Altos model?

A Let me tell you what the Altos model forecast is based on. I'm not familiar enough with the FERC 423 forecast to pass judgment. The Altos price forecasts for coal are based on Altos's judgment of how future market clearing prices of coal are likely to evolve in each of the

regions indicated on the left-hand side. These are explicitly forecasts of what the market price is likely to be. They are not based on history. They are based on our judgment of how the future coal markets are likely to evolve.

Q Then, Doctor Nesbitt, would market price on a forward going basis be like a spot market price as far as your projections?

A Let me clarify what a market clearing price is. It's the price at which, the cash price at which buyers and sellers voluntarily trade coal. So in that sense it's a cash spot price.

MR. HALL: I'm sorry, I didn't hear. It's a cash?

A Cash spot price. However, the cash spot price and the futures prices equilibrate in a merchant market, so there is really no difference, okay, between some sort of terming and some sort of spot price when you are looking forward in time and projecting market clearing prices. This is basically the price of a BTU of coal in the Florida, SBP, West central, et cetera, markets as they are laid out up and down the side of the table that you referred to.

Q Looking again at the table in POD 1, have Florida-specific fuel prices in all of these forecasts been compared with any other Florida-specific forecast made by

other sources? And those could be utilities, agencies, other consulting firms.

A For purposes of this evaluation, we've not made any historical comparisons, nor have we compared with other consulting firms. The reason being, we've taken ours from our own models; and the accuracy of our own models and the history of our own models compels us to use those given that we want our judgment to be at the heart of this evaluation.

Q Should the current project developers in your opinion be concerned if Florida Power and Light, Florida Power Company and Tampa Electric Company's fuel price forecasts are substantially different from the ones used in the current project fuel forecast evaluations?

A No, they should not. Fuel price forecasts really don't matter to the viability of this project. It's actual fuel prices that you are going to have in the future. Let me clarify that. You know, the forecast is irrelevant; it's what the fuel prices are going to actually be.

Q In your opinion, should the Florida Public Service Commission be concerned that Florida Power and Light, Florida Power Corporation and Tampa Electric Company's fuel price forecasts are substantially different from the ones used in the current project fuel forecast evaluations?

A In my view, no.

Q Would the Commission be better informed if it could see a comparison of your fuel price forecasts as they are contained here in this POD and those which it has already reviewed and on which it has already formed an opinion?

A I don't think that that provides better information. The history of fuel price forecasts that don't come from models has been a very checkered and poor history indeed, and I don't think that provides meaningful information to make better decisions.

Q Doctor Nesbitt, if you would, please, turn in your direct testimony to Page 14. Would you please clarify for me how you approached the question of need as it relates to the Duke New Smyrna petition?

A Yes. The way I think of need and the way that I've used it in this analysis is the following: If a new plant, such as the proposed Duke New Smyrna Beach plant, is lower in cost than the marginal plant, the last plant out, and that marginal plant can change over time, then it's needed. Plants are needed for two reasons: One reason is to add to the supply stack to meet low growth; but equally important, you need new plants entering the system to retire old high-cost plants and avoid the cost that would have to be paid to maintain and run those old high-cost

plants. To summarize, need to me means the need for a lower cost option that displaces a higher cost option out of the Florida market, thereby reducing the market clearing price, thereby increasing the reliability and redundancy of the system.

Q Is it your testimony then that need should be defined, at least in part, as displacement of older less efficient capacity?

A In my view need should be defined, yes, in terms of displacement of older -- I wouldn't say more inefficient; I would say more costly capacity. The need for new is the need to displace old in an important sense.

Q Is this displacement then -- let me back up.

Is the choice to displace this older capacity on an energy basis or capacity basis?

A The choice to displace this capacity is both. It's -- The way we think of need is, is the total fixed plus variable cost of the new lower than the total fixed plus variable cost of the old in a present value sense. That's not directly dependent on whether you are talking about capacity, energy or any other tariff structure; it's the cost. Is the cost on a total basis of the new lower than the cost on a total basis of the old? In the case of the Duke New Smyrna Beach project, most definitely the cost of the new is lower than the cost of the old, and that's

why it's needed.

Q If you would, please turn to Exhibit DMN-15.

A I'm with you.

Q Okay. In looking at this what I would appreciate you doing is explaining to me if it is your testimony that the need for displacing the older expensive units is based upon an assumption of retail electric deregulation.

A No, it is not. It is not based on the assumption of retail electric regulation. It's based on an assumption of a robust competitive wholesale electricity market.

Q The next question is based upon a hypothetical. For purposes of this question, please assume that all of Florida demand is being adequately met by existing generation and transmission facilities. Would you please explain in this context how the proposed Duke New Smyrna plant would avoid uneconomic duplication of existing generation and transmission facilities?

MR. McGLOTHLIN: Would you repeat that last part of your question, please?

MS. JAYE: Yes.

BY MS. JAYE (Continuing):

Q Please explain in the context of adequate demand, adequate transmission and adequate generation how the proposed Duke New Smyrna plant in your opinion would avoid uneconomic duplication of existing generation and

transmission facilities?

A Let me talk just for a moment about the thesis of your question. The thesis for your question is "adequately met." I would not accept the thesis that demand is adequately met if you're meeting it with a higher cost alternative than you need to meet it with. We can push this to an absurd level. Suppose that the last plant is two thousand dollars per megawatt hour. Is that adequately meeting Florida customers' needs? Perhaps. Do you need something to replace it? I would argue you certainly do.

Okay, it's not appropriate in my view, and it's not appropriate in the view of the analysis we did, to add up the megawatts of supply and compare them to the megawatts of demand. That's just plain wrong. What you've got to do is look at the cost of those megawatts of supply and assure yourself that the need is being met based on the lowest cost mix of options that you have.

So the thesis of the question is faulty in my view. Needs are not adequately met if you are using higher cost options than you need to use. So there will be no duplication of facilities. There will be retirement of uneconomic facilities or scaling back of uneconomic facilities as cost effective new facilities enter the state.

Q Under the scenario as you have revised it, would

the scaling back or retirement of older facilities cause an increase in your view in stranded costs?

A No, it would not. The scale back and retirement of old facilities would induce the owners of those facilities not to make otherwise uneconomic future investments that they would make if you didn't have the New Smyrna Beach plant entering, so it would save uneconomic costs from being made and forced on the ratepayers of Florida. That's not a stranded cost issue. That's an avoidance of future uneconomic cost issue.

Q Okay.

MS. JAYE: That's the end of my questions. Thank you, sir.

EXAMINATION

BY MR. McGLOTHLIN:

Q Doctor Nesbitt, staff counsel asked you some questions about the fuel forecast that you chose and asked among other things whether you would compare that to other forecasts, and in response you said based upon the history of the model that the model compelled you to use your own forecasts. Would you explain further why you chose the forecast you used to the exclusion of others?

A Yeah. The, particularly the natural gas price forecast having come out of the North American Regional Gas model. That model has been used in pretty much every, I

will say every pipeline decision in North America in the last 15 years. It's called every one of them right. It's got a very good historical track record on forecasting basis differentials between various regions. The reason it does such a good job is it's got a lot of care and a lot of effort in the primary resource supply basin by basin throughout all of North America; and, in fact, it's linked into a model of the world, and so basin by basin throughout the world which gives you import prices everywhere in North America.

It's got a detailed representation of the existing and the prospective pipeline grid so it competes existing pipe against prospective new pipe adds. It's got a relatively detailed representation of segmented demand by region throughout North America. So what it -- It doesn't make inconsistent judgments of supply in one region versus demand in one region. It doesn't make inconsistent judgments between price formation in one region and price formation in another region. And as I said, it's been used extensively in regulatory proceedings as well as in private decision making on the natural gas business over the last almost 20 years and done a mighty fine job.

As I've reviewed other consultants' price forecasts or public domain bodies, I've seen the track record a lot worse. As I've seen history being used to

make future price forecasts, it's done a terrible job, relatively speaking. So I've decidedly chosen to use model based outputs for our fuel price forecast to project the market price of gas in Florida and everywhere else in North America and to project the basis differentials between and among the regions.

Q Staff counsel also asked some questions about the forecast of coal price and whether it was done on a contract or spot basis, and your answer, as I understand it, was that for your purposes there was no difference. Would you elaborate on what you mean?

A Yes, and let me elaborate a bit by analogy. If we were going to talk about a commodotized commodity such as gold, gold has the same price whether it's contract or spot. Okay, fully commodotized commodities such as coal in a merchant environment such as we are trying to simulate, there is no difference. There is no arbitrage possibilities between spot and long-term contract.

What you have to understand is the fair market value of the commodity, and that's the philosophy we have embedded in these price forecasts for the commodities. What's the fair market value, the one number that represents the value of that commodity in Florida, the Southern, et cetera, markets that are articulated in the column of the response to Request Number 1.

Q My last question based upon staff's is this: You referred a moment ago to the merchant world as you did earlier. Who proposed to bear the risk of the proposed plant in this case?

A In the case of the Duke New Smyrna Beach proposal, all of the risks of the plant, both the energy risk and the capacity risk, is going to be borne by the owners of the plants, namely Duke and New Smyrna Beach. None of that under the current proposal will be thrust downstream on to any customer within the State of Florida or anywhere else who doesn't voluntarily want to have it. So if it's cost effective, people will voluntarily buy it. If it's not cost effective, nobody in Florida will be forced to pay for it.

Q Does the fact that the petitioners propose to bear the risk bear on staff's question regarding the avoidance of uneconomic duplication of facilities in your view?

A Could you repeat that question back, please?

(WHEREUPON, THE COURT REPORTER REREAD THE QUESTION)

Q Let me ask it again. If the petitioners propose to bear all the risk, will the project result in uneconomic duplication of facilities?

A No, in that case it will not, and I would repeat

the answer that the fact that the petitioners are proposing to bear all of the cost risks and all the price risks means that otherwise uneconomic expenditures that would have to be made in the future and thrust upon Florida ratepayers don't have to be made.

MR. McGLOTHLIN: Those are my follow-up questions.

EXAMINATION

BY MR. GUYTON:

Q Doctor Nesbitt, in response to Mr. McGlothlin just a minute ago and Ms. Jaye earlier, you spoke of the plant having the consequence of avoiding uneconomic future costs by Florida utilities. Do you recall that?

A I do recall that.

Q What are those uneconomic future costs by Florida utilities that you have in mind, sir?

A Those uneconomic future costs by Florida utilities are fuel costs, variable costs, cycling costs and preservation costs, and capital reinvestment costs, if any, in the marginal plant that would have to be used in the absence of the Duke New Smyrna Beach project. So it's in the highest cost, the oldest, the least-efficient asset that would have to be used in Florida in the absence of this project. Okay, and if those costs were made, they

would have to be forced on Florida ratepayers because the market would not voluntarily accept those costs when and if the Duke New Smyrna Beach unit is in.

Q Now does your model quantify those cost avoidances?

A The model quantifies the cost structure of every plant or aggregate of plants in Florida, and as it substitutes low-cost options for high-cost options, it quantifies the cost savings and the price reduction that results, yes.

Q You say your model quantifies the cost for every plant or aggregate plant. What do you mean by aggregate plant?

A If you look at the structure that we've used for the model in Florida, you will see Florida coal generation. That's the sum of the coal generation units in Florida, their costs and their capacities. In calculating the market clearing price in Florida, you don't need to look at every individual plant. You can aggregate those plants into an aggregate producing unit because what you're trying to identify in this modeling technology is who is at the margin. So there are individual plants represented or aggregates of plants represented.

Q Well, did you take each technology and aggregate them for purposes of your model?

A Each technology? Would you clarify?

Q Each generating technology.

A Let me summarize what we did, and then let me ask Mike Blaha to elaborate on this, if I might. What we did was we have an estimate of every plant in Florida, its capacity and its cost. Okay, then what we did was we aggregated those capacities and those costs into some 15 or 20 categories, if you will, of generation units in Florida. Then we competed those categories of generation units one against the other to ascertain the market clearing price of power, given the market clearing prices of the fuels that we've seen in the earlier exhibit in Florida.

WITNESS NESBITT: Mike, do you have anything to add to that?

MR. BLAHA: If I could paraphrase what Doctor Nesbitt just said. The answer to the question is yes and no. Yes, on the primary technologies, and technologies are defined by prime mover and primary fuel and secondary fuel; and, no, in the sense that we don't break out everything, solar, wind, a lot of the other types of technologies.

BY MR. GUYTON (Continuing):

Q What are the categories or aggregates of generation, the 15 or 20 that compete in your model?

A I'd have to sign on to the model and look at

exactly what those are. Let me summarize: Several of them. There is nuclear. There is coal. There is Hydro/NUGs must-run units. There is natural gas combined cycled. There is natural gas or oil steam turbines. There are combustion turbines fired with either natural gas or oil.

MR. BLAHA: Maybe I could make this a little simpler. We have high efficiency coal and low efficiency coal which is defined.

MR. GUYTON: Give me a minute to keep up with you, sir. High efficiency coal?

MR. BLAHA: And low efficiency coal.

MR. GUYTON: Two different categories?

MR. BLAHA: Correct. Divided by 10,500 heat rate which means anything above 10,500 heat rate would be aggregated together to be low efficiency, and anything beneath 10,500 would be high efficiency coal.

On the combined cycle side, we have natural gas only and natural FO2 switchable and IG/CC which in essence is another coal technology. We have lignite as another coal.

MR. GUYTON: I'm sorry, I'm falling behind here. Three types of natural gas, did you say?

MR. BLAHA: Three types of combined cycle.

MR. GUYTON: Natural gas, natural gas switchable and IG/CC?

MR. BLAHA: Correct.

MR. GUYTON: The natural gas switchable being switchable to oil?

MR. BLAHA: Two oil.

MR. GUYTON: Okay. Number 2 oil?

MR. BLAHA: Number 2.

MR. GUYTON: So those are three separate categories of combined cycle?

MR. BLAHA: Correct.

MR. GUYTON: Okay.

MR. BLAHA: Steam turbines. We have natural gas, natural gas 6 oil, which is residual oil; residual oil only; natural gas 2 oil; and 2 oil only. So there are five steam turbine classifications.

MR. HALL: Now I'm falling behind. Would you run through those again?

MR. BLAHA: It's natural gas only, natural gas 2, number 2 only, natural gas 6, number 6 only. So there are three types of natural gas.

MR. GUYTON: Okay. And those three would be natural gas only, or a unit that could burn either natural gas or number 2 oil?

MR. BLAHA: Correct.

MR. GUYTON: And a unit that could burn either natural gas or number 6 oil?

MR. BLAHA: Correct. And throughout the country number 6 also includes 3, 4 and 5 oil, which applies to other areas of the country.

MR. GUYTON: But not Florida?

MR. BLAHA: I don't believe you burn anything other than six here.

MR. GUYTON: And the other steam turbine types you have are?

MR. BLAHA: Two only.

MR. GUYTON: Two only.

MR. BLAHA: Diesel only and residual only, residual is FO6.

MR. GUYTON: Okay.

MR. BLAHA: And then we have the combustion turbine that's going to make it even more complicated. In the combustion turbines we have gas only, FO2 only, and FO1 only, and gas FO2.

MR. GUYTON: Dual fuel gas FO2?

MR. BLAHA: Dual fuel gas and diesel, and dual fuel gas and FO1. And we have a waste, steam turbine waste, which would be wood, municipal solid waste, et cetera.

MR. GUYTON: And to develop each of these technologies that you model in your model, you aggregate Florida units to fit within these specific categories?

MR. BLAHA: Correct.

MR. GUYTON: Okay. So you develop an aggregate heat rate?

MR. BLAHA: Weighted average heat rate.

MR. GUYTON: Okay. How is the weighted average heat rate developed?

MR. BLAHA: Take the heat rate from the individual units, multiply that by the rate of capacity of the unit, sum that product, and divide by the sum of the total capacity.

MR. GUYTON: For that type unit?

MR. BLAHA: For that aggregation of units, yes.

MR. GUYTON: You develop a weighted average variable cost for each of these types of units?

WITNESS NESBITT: Mike, you might address how you got the variable cost for the units.

MR. BLAHA: The variable cost of the units, what we did was pull the large plant statistics from the FERC Form Ones and form twos, and because it's large plant statistics there are a lot of smaller plants that aren't necessarily reported.

MR. GUYTON: Which year FERC Form Ones were used?

MR. BLAHA: 1978 to 1987, I believe. Ten years. Basically to cover -- tried to cover two overhaul cycles.

MR. GUYTON: 1978 to 1987?

MR. BLAHA: Excuse me, 1987 to 1990 -- 1980. Let me start over. 1988 to 1997, excuse me. I'm in the wrong decade.

MR. GUYTON: Were the FERC Form Ones for the Florida utilities pulled to calculate the variable O&M costs?

MR. BLAHA: Correct.

MR. GUYTON: Okay. Now you suggested that that was done by large plant statistics. What do you mean by large plant statistics?

MR. BLAHA: The large plant statistics are separate pages, and I think they are the E-400 pages in the FERC Form 1 that specify all of the various FERC chart of accounts, disaggregates the cost by those account numbers; and we classified those accounts numbers between variable O&M, cycling costs, preservation costs.

MR. GUYTON: Okay. I may come back to that, but I want to get back to the fuel because we have staff. The fuel price for units was developed by multiplying whatever weighted heat rate you had for a particular aggregation or type of unit times the fuel price forecast that Altos developed out of the NARG model?

MR. BLAHA: The fuel price? I'm sorry, I don't understand.

MR. GUYTON: The fuel cost for the unit.

MR. BLAHA: My understanding is that the fuel costs, and correct me if I'm not answering this, answering your question, but the fuel costs, basically the fuel price that we at Altos derived and inserted into the model, would be multiplied by the heat rate, the aggregate heat rate of -- or the heat rate of the aggregated classification plants.

WITNESS NESBITT: Right.

MR. GUYTON: So --

MR. BLAHA: Wait a second, that's fuel cost.

WITNESS NESBITT: That's fuel cost. I think your answer to the question is correct. What the Altos model does is it takes the heat rate of the aggregated units as previously defined by Mr. Blaha and multiplies those by the fuel prices that you've seen in the answer to our Request Number 1 from staff to get fuel costs, and that's part of the cost structure of each of those plants.

MR. GUYTON: Okay.

MR. BLAHA: Yeah.

MR. GUYTON: So in the Altos model there were no Florida units which were modeled individually, instead they were all aggregated into one of these categories that you mentioned earlier?

MR. BLAHA: Correct, unless there is a specific type unit that would be -- stand by itself in the

classification of technology.

WITNESS NESBITT: That's right. Let me amplify that. That is true. In order to calculate market clearing prices, it is appropriate to aggregate. It not only does not compromise the accuracy of the method, it actually enhances it because it improves the computation time and allows you to find the marginal unit a lot easier. I've found in my practice you are better off to aggregate, not to disaggregate.

Let me also amplify the earlier answer. In DMN-15, Page 15, there is a diagram of the plants and their competitive position in the Florida market that is indicated there. We can make a little built larger picture available to you so that you can see the plants and the fuel types, the configurations and how they compete, DMN-15, Page 15.

BY MR. GUYTON (Continuing):

Q That actually shows your aggregation of units?

A No, what that shows is what categories of units are there and how are they competing in the Florida hub, one of your earlier questions.

Q But it's just too small to read here?

A Yeah, it's just too small to read.

Q Okay. When you were being questioned by staff counsel about your fuel forecasts, you made reference to

how you used 1998 fuel prices -- or let back up -- that you used 1998 constant dollars for your fuel price forecast, and you made mention of inflation factors that you would use to discount. Have you provided in response to staff those inflation factors?

A No, I have not, and the reason that I haven't is that we made all of our projected fuel prices in constant dollars. We don't make them in current dollars, and we don't need the inflation factor, therefore. All the workings are done in constant 1998 dollars.

Q So the late-filed exhibit that you are going to provide for staff of the fuel forecasts each year will be stated in 1998 constant dollars?

A That's correct.

Q If one wanted to escalate those to the dollars in the year for which they are forecast, one would need the inflation factors?

A One would need the inflation factors, and one would need to know the basis upon which he or she selected the inflation model that he or she decided to select. The two most popular inflation factors would be GNP deflator and consumer price index.

Q Which do you use?

A I've used the consumer price index most often.

Q Which index for CPI?

A I didn't know there was more one. The straight CPI as reported by Ibbottsen and Associates I used.

Q You were asked by staff counsel how you approached the question of need, and in your answer you said that there were two ways to look at need: One was to look at it in terms of stacking supply-side resources, and the other one was to look at it in terms of replacing higher cost options with lower cost options. Is that a fair approximation of what you said?

A I don't think I said there were two ways. I wouldn't accept that thesis.

Q Okay. From your perspective, need is measured by the need to displace old higher cost capacity with newer lower cost capacity?

A That's an important component of need. Let me articulate what I think need is, if that's the question. I need to replace expensive stuff with cheap stuff. That's the quintessential definition of need. If it costs too much, I don't want it. If it costs less, I do want it, okay, with regard to generation technologies. That definition of need cuts to what I also said earlier, the heart of I need to avoid future uneconomic payments. I need to avoid future uneconomically high price. I need to avoid higher prices than otherwise would have to occur. What I really need is the lowest possible price for the

commodity that I have to buy. That's what I need. The need for the Duke New Smyrna Beach project derives from the need to drive power prices as low as they can possibly be driven maintaining the same integrity or better integrity of the system as you already have.

Q So need from your perspective is market driven?

A Need is market driven in large measure.

Q Okay. It's not at all reliability driven?

A It is reliability driven in part, but the reliability is a market-driven phenomenon itself.

Q So the market will take care of reliability?

A The market has in every industry that has been deregulated to date taken care of reliability quite nicely, and in my view the market is likely to take care of reliability here as well.

Let us consider what will happen to reliability if the Duke New Smyrna Beach five hundred megawatts are added. Reliability is going to get better, because you have more supply chasing the same demand. We haven't quantified that. That makes the plant even more positive than it is now. You get a reliability benefit since the plant is economically so attractive. That would only make it better.

Q And your model attempts to quantify the amount of new capacity which is -- which the market would say is

needed?

A The model quantifies what the market says is needed, yes, where the market is both the entrepreneurs who build the capacity as well as the customers who take the energy from the market and consume it, yes.

Q And your model would quantify as need the amount of capacity which could be added and be economically viable or profitable?

A Could you read the question back, please?

(WHEREUPON, THE COURT REPORTER REREAD THE QUESTION)

A The model calculates the amount of capacity that can be profitably added, and it adds that much capacity. As soon as it's not profitable to add it any more, it doesn't add it.

Q Now in your model, when you employ a fuel forecast from your -- I know the acronym -- the NARG model, if you will --

A Yeah.

Q -- do you use that fuel forecast for all units, both existing and additional units that are competing?

A Yes, we do. There's -- in the case of Florida, there's one price of gas that represents the aggregate Florida market, and that one price of gas is common to all the units in Florida, old and new.

Q Okay. So your model doesn't attempt to capture existing contractual prices in relationships?

A No, what our model does is marks gas to market. Whether or not there is a contract, it marks the gas to market, and it values the gas at the market price.

MR. GUYTON: Okay. I think that is all the follow-up I have of staff.

MR. HALL: And I don't have any questions at this point.

MR. McGLOTHLIN: I have no more questions.

(WHEREUPON, THE DEPOSITION WAS CONCLUDED)

* * * *

ERRATA SHEET

DOCKET NUMBER 981042-EM
DALE M. NESBITT
NOVEMBER 10, 1998

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that DALE M. NESBITT personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 10th day of November, 1998.

NANCY S. METZKE
Notary Public - State of Florida

Nancy S. Metzke
MY COMMISSION # CC677518 EXPIRES
September 13, 2001
BONDED THRU TROY FAIN INSURANCE INC.

CERTIFICATE OF DEPONENT

This is to certify that I, DALE M. NESBITT, have read the foregoing transcription of my testimony, Page 1 through 45, given on November 10, 1998 in Docket Number 981042-EM, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the errata sheet attached hereto.

_____

DALE M. NESBITT

Sworn to and subscribed before me this
_____ day of _____, 19_____

_____
NOTARY PUBLIC
State of _____
My Commission Expires:

REPORTER'S DEPOSITION CERTIFICATE

STATE OF FLORIDA)
COUNTY OF LEON)

I, NANCY S. METZKE, Certified Shorthand Reporter and Registered Professional Reporter, certify that I was authorized to and did stenographically report the deposition of WALTER S. REID; that a review of the transcript was requested; and that the transcript is a true and complete record of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 14th day of ~~January~~ November, 1998.

NANCY S. METZKE, RPR, CCR

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Kennie Sanford, Jr
Principal Design Engineer

EDUCATION:

B.S., Mathematics and Physics, Stephen F. Austin
B.S., Electrical Engineering, University of Houston

PROFESSIONAL LICENSE/CERTIFICATE:

Registered Professional Engineer TX NO 51296

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SUMMARY OF EXPERIENCE:

Electrical Engineer with 25 years of experience preparing construction drawings, construction subcontracts, engineering and construction cost estimates, engineering schedules, specifications, calculations, and protective relay coordination for electrical power generation, distribution, lighting, grounding, generator and motor controls, and instrumentation for cogeneration, refinery, and petrochemical plants. Also, experience preparing inquiries, purchase requisitions, and technical quotation summaries and also doing factory inspections for electrical equipment and material. In addition, field experience doing checkout and startup of electrical systems for cogeneration facilities.

INDUSTRIES/TECHNOLOGIES EXPERIENCE:

SIGNIFICANT EXPERIENCE:

FLUOR DANIEL, INC., Sugar Land, TX (1996 - Present)

PRINCIPAL ELECTRICAL ENGINEER

Chevron FEBPX, Chevron, Thailand, (1997 - Present)

Lead electrical engineer for the "Front End Engineering" work to establish a Lump Sum Turn Key (LSTK) contract for the detailed engineering, procurement, and construction of an aromatics plants, including a co-generation facility. Plant electrical load was estimated at 55MW. My work included preparing an estimate, developing the scope of work and one-line diagrams, layout of substations, and preliminary electrical system analysis.

Terminal Upgrade Project, Amoco, Trinidad, West Indies (1996 - 1997)

Lead electrical engineer for the replacement of the electrical facilities at an onshore crude oil processing terminal facility. My work included preparing an estimate, developing the scope of work and one-line diagrams, layout of new substations, and requisitioning of new equipment to replace the 15KV and 480V electrical distribution systems at the facility. Work also included replacement of the existing manual generator controls with new PLC automated controls.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 22
COMPANY/ WITNESS: Sanford
DATE: 12-2-98

Metaxylene No. 2 Unit, Amoco, Texas City, TX (1996 - 1997)

Engineer responsible for preparing the relay coordination, load flow analysis, and short circuit analysis, and short circuit analysis for a new process unit as well as the addition of a 25KVA, 138KV-13.8KV transformer and 145KV SF6 circuit breaker to an existing 138KV outdoor substation.

KVAERNER JOHN BROWN, Houston, TX (1994 - 1996)

PRINCIPAL ELECTRICAL ENGINEER

Lead electrical engineer for a new ethylene vinyl alcohol unit. My work included preparing an estimate, developing the scope of work, one-line diagrams, area classification, layout of new substations, and requisitioning of new 13.8KV-4.16KV transformer, new 13.8KV-480V transformer, switchgear, motor control centers, and variable speed drive-controllers for the facility.

DESTEC ENGINEERING, INC., Houston, TX (1986 - 1994)

LEAD ELECTRICAL ENGINEER

Lead electrical engineer for a 465MW cogeneration facility:
The major components of the facility consisted of (3) gas turbine/generator skids with HRB's, (1) steam turbine/generator system, and (1) utility furnished 52.5KV GIS. I prepared the generator and utility interface one-line diagrams to show relaying, metering, synchronizing schemes, and DCS interface for a Phase III engineering package.

Lead Electrical Engineer for a 424MW cogeneration facility:
The major components of the facility consisted of (3) gas turbine/generator skids, (1) steam turbine/generator system with 18KV generator breaker, (3) HRB's, (1) six bay cooling tower, water treatment system, and (3) lineups of 1500MVA, 15KV switchgear. I wrote specifications, assisted with equipment vendor selections, and checked vendor drawings. I supervised preparation of design drawings, relay coordination study, and short circuit, load flow and motor starting calculations. I spent ten months at the jobsite assisting with construction, checkout, and startup of the electrical systems, including preparing field test requirements for all equipment and generators, and evaluating construction change orders.

Lead electrical engineer for (3) 50MW congeneration facilities and associated produced water system:
The major components of each facility consisted of (2) gas turbine/generator skids, (2) HRB's and one prefabricated metal control building housing indoor electrical equipment. I issued the material requisitions for all electrical equipment, which was shop wired and shipped to the jobsite in a prefabricated building. I checked the relay coordination and the three line-diagrams, prepared the short circuit and load flow studies, and assisted with checkout, startup, and utility pre-paralleling of the facilities.

FLUOR ENGINEERS, INC., Sugar Land, TX (1973 - 1986)

SENIOR ELECTRICAL ENGINEER

Standard Oil Chemical Co., Lima, Ohio (1986)

My work included revising and updating SOCC standards specifications for electric motors, electrical design and installation, prefabricated electrical equipment building, power transformers, low voltage switchgear, motor control centers, switchracks, instrument and power cable, neutral grounding resistors, uninterruptible power supplies, packaged equipment electrical requirements, electric heat tracing, cable tray, power conditioners, and automatic transfer switch; developing the inspection and testing procedure for existing electrical equipment to be used in a new service; requesting quotations for electrical equipment, preparing quotation summaries, and making technical recommendations for vendor selection; and preparing the electrical construction cost estimate

($2.7 million). The contract was postponed at approximately 20% of engineering completion.

Amoco Oil Co., Texas City, TX (1985)

I participated in the following: performing a field survey of instrumentation presently in operation, updating of process and instrument diagrams to reflect field survey, revising P&ID's to incorporate a Foxboro Distributed Control System, preparing an instrument index on the IBM PC (using Dbase III), and preparing specifications for differential transmitters, temperature transmitters, thermocouples, and RTD's, pressure switches, solenoid valves, current switches, transducers (I/P, I/I, & E/I), level controllers (pneumatic) and local indicators.

Texaco, Inc., Convent, LA (1983 - 1984)

Systems included: new 13.8KV, 1000MVA Main Substation No. 3 and 18 new area substations (4160V, 2400V, and 480V); tow 13.8K, 3000A distribution lines from the L.P.&L. Bagatelle Substation to Main Substation No. 3 to 23 new area substations (both offsites and onsites), modifications to existing Main Substation No. 2 and 8 existing area substations; one new 480V, 1050KW and one new 480V, 1200KW standby generator systems; one new control house designed for a distributed control system, modifications to add process computers to one existing control house, employee/gate house, addition to existing lab building, firehouse, tank farms, pipeways, blending and treating unit, loading docks, cooling towers, instrument air compressor, export fuel gas compressor, sour water disposal area, general waste water treating area, clarifier, flare, maintenance office, equipment storage room, Texaco office building, and electric heat tracing for piping in Pipeway 21. Total cost of the offsites portion of the project was $171 million.

Work included: preparing a feasibility and cost study for determining voltage distribution level for routing power from Louisiana Power and Light's substation to Texaco's Main Substation No. 3; preparing a feasibility and cost study to add capacitors at main Substation No. 3 for power factor correction; specifying, requisitioning, and inspecting switchgear, motor control centers, power transformers, switchracks, power cables, variable speed drive controllers, reactors, capacitors, electric heat tracing, and generators; preparing protective relay coordination study, short circuit calculations, motor starting calculations, cable derating calculations for cable installed underground, sag and tension calculations for overhead distribution lines, cable pulling calculations, and maximum allowable control circuit length calculations; preparing detailed estimate for engineering and material cost (electrical totaling $10.3 million); and reviewing and approving approximately 1100 electrical plan drawings, details, and wiring diagrams. I supervised (10) electrical engineers and (30) designers who performed the above listed work. Engineering was completed approximately (6) months ahead of the original schedule and within budget.

Gulf Science and Technology, Baytown, TX (1982)

My work included: writing specifications for electric motors, general electrical, electrical requirements for packaged mechanical equipment, and oil-immersed transformers; recommending limits for classifications of hazardous areas; and preparing the construction cost estimate. The project was postponed at approximately 10% engineering completion.

Shell Oil Co., Martinez, CA (1981 - 1982)

My work included: supervision of (5) electrical engineers who specified and requisitioned power transformers, bus duct, motor control centers, power and control cable, instrument cable, variable speed drive controllers, and UPS systems; preparation of detailed construction cost estimate (electrical totaling $6.0 million); checking vendor drawings, factory inspections for a 250KW, 480V steam turbine generator set, and (4) 50KVA, 120V, single phase output UPS's, reviewing and approving approximately 600 electrical plan drawings, details, and wiring diagrams; and calculating maximum allowable run length of 120VAC control wiring for remote control of 480V starters to confirm that no voltage drop problems existed for lengths less than 1700 feet. Engineering was completed on schedule and within budget.

Imperial Chemical Industries Americas, Inc., Baton Rouge, LA (1980)

The subprojects were: (a) a clarified water make-up system including the installation of two 40HP cooling water pumps (estimated electrical cost was $10,000); (b) the uprating of (4) existing 600VDC rectifier systems (estimated electrical cost was $650,000); and (c) the rehabilitation of a cell renewal building so that ICI cells could be renewed. My work included: preparing a work description for each subproject; preparing the electrical requirements for packaged equipment and 480V motor control centers; and specifying and requisitioning 480V outdoor starts, diodes and fuses for rectifiers, Halmar DC metering system, control panels, and motor control centers.

I was reassigned as the Lead Electrical Engineer for the upgrading of the existing chlorine production facility. Work included: reviewing engineering and design of a new 230KV substation (estimated cost of $4.1 million); approving design drawings for modification of bus duct (estimated cost of $0.5 million); checking and approving the 60,000 amperes shorting switches for use during change-out of ICI cells. Total indicated cost of the project was $34 million. The plant was sold by ICI after engineering completion. Construction was never started.

Arco/Polymers, Inc., Port Arthur, TX (1979)

My work included: revising and updating ARCO standard specifications for electrical motors, general electrical, electric grounding, instrument electrical, electrical testing and inspection, and outdoor power transformer; requisitioning electrical equipment and material; compiling office man-hour and construction cost estimates; reviewing and approving approximately (75) detailed design drawings for grounding, power, lighting, and instrumentation; and preparing detailed description of work for the electrical subcontract, then making technical recommendations for subcontractor selection. Electrical construction cost was approximately $900,000, including labor, equipment, and material. Engineering was completed on schedule and within budget.

ELECTRICAL ENGINEER

Cities Service Company, Lake Charles, LA (1978)

Electrical Engineer for the design and construction of a single train unit (K-Line) for a low density polyethylene plant. My work included: checking the one-line diagrams; preparing the electrical construction cost estimate (totaling $1.1 million for material and equipment, and $1.1 million for labor); and requisitioning the extruder driver, fly knife cutter motor, switchgear, motor control centers, transformers, and lighting panelboards.

National Petrochemical Co. of Iran, Bandar Shahpur, Iran (1978)

Electrical Engineer for preparing an electrical base engineering package for an NGL fractionation facility. My work included: writing specifications for hermetically sealed transformers, industrial and flameproof motors, high voltage switchgear, general electrical, 400V switchgear, neutral grounding resistor, generator control benchboard, UPS system, and electrical generators; prepared area classification recommendations based on IEC standards, and designed the electrical distribution system which included four 10000KW, 11KV gas turbine generators. Distribution level was recommended at 11KV with utilization voltages at 3.3KV and 380KV. System was designed using IEC standard voltage levels. All substations were double-ended for reliability to maintain operation of critical loads.

Marathon FCCU Addition, Garyville, LA (1977)

Electrical Engineer for checking the design of a 230KV substation of two 40MVA, 230-13.8KV transformers and a line-up of 13.8KV switchgear located inside a Powell power control room (PCR) type building.

Union Texas Petroleum, Rayne, LA (1977)

Lead Electrical Engineer for a $5.6 million expansion of an NGL fractionation facility. My work included reviewing the general electrical specification and 480V motor control center specification; writing specification for electrical requirements for packaged mechanical equipment; scheduling, requisitioning, expediting all electrical equipment and material (totaling $80,000); reviewing and approving approximately 50 electrical plans, details, schematics, and wiring diagrams; calculating load requirements for the new unit and recommending addition of 1500 KVA at 480V more capacity; compiling schedule for completion of design drawings; compiling engineering man-hour estimate and construction cost estimate; checking motor control schematics for motors ranging in size from 3HP to 200HP.

Arco/Polymers, Inc., Port Arthur, TX (1976 - 1977)

Lead Electrical Engineer for the design and construction of a high density polyethylene plant, HDPE-3 (totaling $34 million). Electrical system consisted of an incoming 69KV, 10MVA substation with a 4160V secondary and (3) 1000KVA, 4160 - 480/277V substations. My work include: reviewing ARCO specifications; revising the 4000HP extruder motor specification to ensure compatibility with a Werner-Pfleidereer extruder; writing and issuing specifications for a 69KV outdoor substation, cathodic construction estimate (totaling $2.1 million); preparing area classification study for approval by ARCO; technical evaluation subcontracts evaluating quotations and issuing purchase requisitions; preparing detailed description of work for electrical subcontracts and evaluating quotations and change orders; reviewing and approving approximately 275 electrical design drawings; factory inspections of all major equipment; calculating short circuits of system, performing relay coordination study, and tabulating relay settings.

My work at the jobsite included: performing checkout of all control circuits, performing run-in test of motors, and performing electrical functional check of the deluge and gas detection systems. Engineering and construction was completed on schedule and under budget.

ASSOCIATE ELECTRICAL ENGINEER

Union Carbide Corporation, Taft, LA (1975)

Electrical engineer acting as coordinator between design and engineering for the "Energy System" phase of the project. System included a 230KV overhead line looped throughout the plant with (4) main substations for stepping down to the utilization voltages of 2400V and 480V. My work included: reviewing the design of the 230KV substations (design by Commonwealth Associates); requisitioning transmission line material; checking all motor control schematics for process and utility pumps; checking approximately (15) 480KV one-line diagrams, and (4) overall plant distribution one-line diagrams; and checking vendor drawings.

ASSISTANT ELECTRICAL ENGINEER

Union Carbide Corporation, Taft, LA (1975)

Electrical Engineer for modification of the acrylics unit. My work included: specifying and requisitioning additional components for 480V starters for reuse in a new service; reviewing all electrical specifications and evaluating comments on specifications; and preparing the electrical estimate (project totaling $3.6 million).

St. Croix Petrochemical Co., St. Croix, Virgin Islands (1974)

Acting design supervisor for designing and drafting of connection diagrams for installing all process instruments, and performing field checkout of the electrical controls for the Erie City boilers at St. Croix.

ELECTRICAL DESIGNER

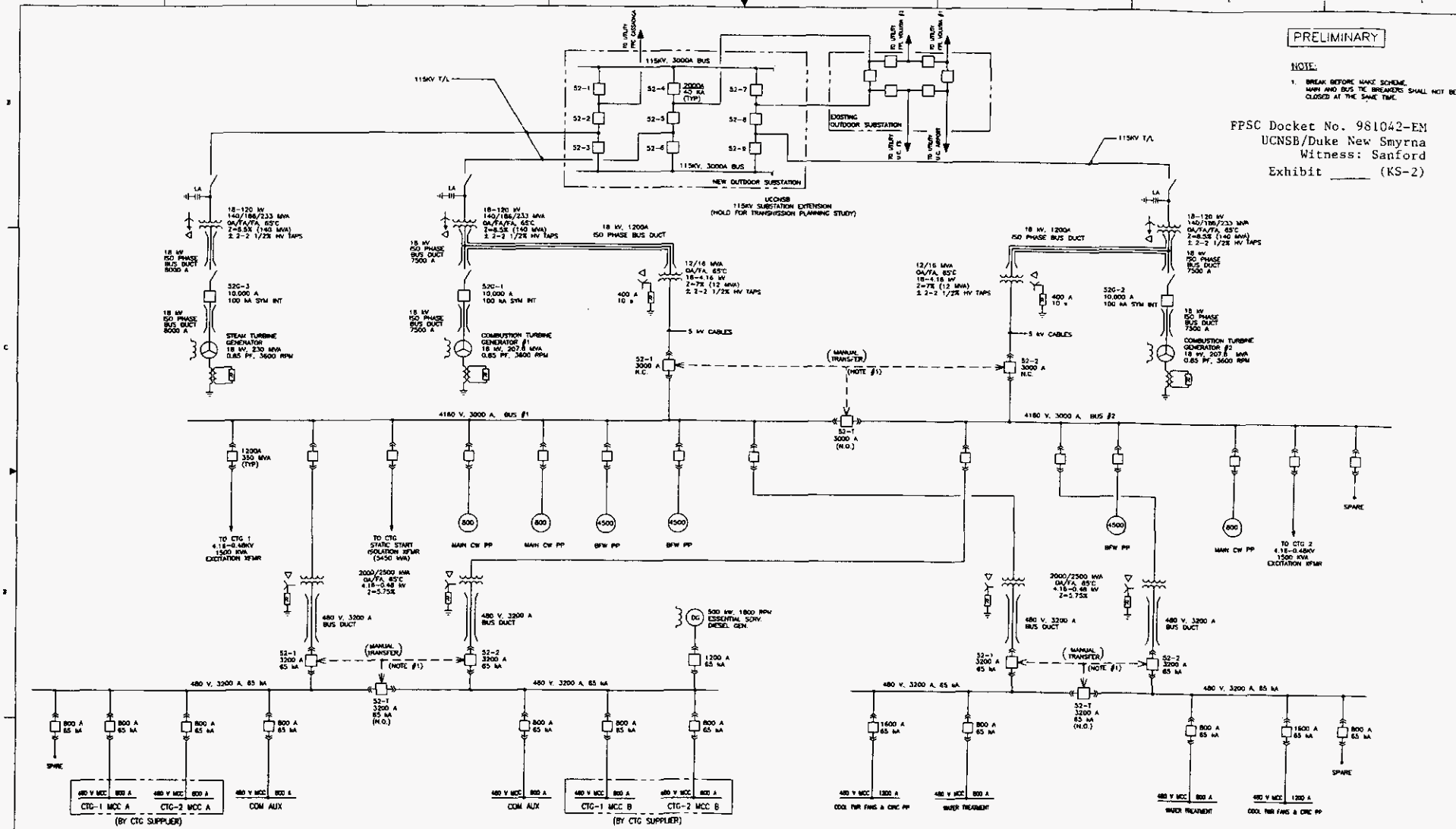
St. Croix Petrochemical Co., St. Croix, Virgin Islands (1973 - 1974)

PRELIMINARY

NOTE:

1. BREAK BEFORE MAKE SCHEME. MAIN AND BUS TIE BREAKERS SHALL NOT BE CLOSED AT THE SAME TIME.

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Sanford
Exhibit ____ (KS-2)



REV.	DATE	REVISION DESCRIPTION	CHK.	APPROVED
A	1/98	ISSUED FOR INT. REVIEW	DB	
B	2/98	ISSUED FOR INFORMATION	DB	
C	4/98	ISSUED FOR INFORMATION	DB	
D	6/98	ADDED AUX. DIESEL GENERATOR	DB	
E	7/98	UPDATED GEN. RATINGS PER REF. PLANT	DB	

DUKE FLUOR DANIEL

POWER ENGINEERING • CONSTRUCTION • OPERATIONS & MAINTENANCE

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DESIGNED BY: R. FELDI
DRAWN BY: P. SCHWARTZ
CHECKED BY:
APPROVED BY:
LEAD DISCIPLINE: E. SANFORD
PROJECT: 06877401
CLIENT: DEFS
APPROVAL: 4/6/98

NEW SMYRNA BEACH POWER PROJECT
OVERALL ONE LINE DIAGRAM

SCALE: NOT TO SCALE
DRAWING NUMBER: 06877401-6-603A
REV: E

*DATE*TIME* MANUAL CHANGES MADE - YES ☐ NO ☐ | DWG. FILE UPDATED - YES ☐ NO ☐ | MISC. UPDATED - YES ☐ NO ☐

CAD DRAWING No. 00603AE.DWG

CONTRACT PKG
VEN. PKG.
DISCIPLINE

NEW SMYRNA BEACH POWER PROJECT

Project Electrical Facilities Description

1 PROJECT ELECTRICAL SYSTEM OVERVIEW

The project is a natural gas fired combined cycle facility consisting of two (2) Combustion Turbine Generators (CTGs), two (2) Heat Recovery Steam Generators (HRSGs), one (1) Steam Turbine Generator (STG), and cooling towers with a nominal output of 500 MW (514 MW at ISO temperature and humidity conditions). Plant electrical generation will be at 18kV. A step-up transformer will be provided for each generator for connection to new 115 kV transmission lines. Three 115kV overhead transmission lines will connect the new power plant facility to the "Interconnection Point" at the load side of the 115kV New Smyrna Beach Substation. Additions, modifications, and/or upgrades to the existing transmission networks, are described in the Results of Power Flow Studies prepared by Resource Management International Inc., dated July 2, 1998.

2 ELECTRICAL SYSTEM DESCRIPTION

The electrical system for the facility as described below is required for operating and interconnecting of the CTGs and STG to the 115kV transmission grid.

2.1 Electrical System Major Components

° New 115kV Take-off Towers

New 115kV take-off towers for the step-up transformers and disconnect switches will be installed next to the power plant. The main step-up transformers will be connected to the 115kV grid using 115kV disconnect switches and one take off tower located next to each transformer. New metering and relaying panels for the new plant switchyard will be housed in a new control building.

° New Overhead 115kV Transmission Lines.

Approximately 150 feet of new overhead 115kV transmission line for each generator. The 115kV transmission line will be installed for interconnecting

the generation unit step-up transformers with a new 115kV substation (furnished and installed by New Smyrna Beach Utilities Commission).

° New breaker bays at the new 115kV Utility Substation.

New substation will consist of new breaker bays (breaker and half scheme) for each new 115kV transmission line, including surge arresters, bus support structures, and disconnect switches for connection to the existing 115kV transmission network. New metering and relaying panels for each new 115kV transmission line will be housed in a new substation relay room.

° Main Generator Step UP (GSU) Transformers.

The main generator step-up transformers will be oil filled, two winding transformers each sized for the maximum output rating of each combustion turbine and steam turbine. GSU transformers will be provided with NLTC and surge arresters for each generator.

° Isolated phase bus (IPB) system.

The IPB will connect each generator with the main step-up transformer, the generator circuit breaker (where applicable), the static frequency converter, and the auxiliary transformers.

° High Current Isolated Phase Generator Circuit Breakers

Circuit breakers will be installed on all the CTGs and STG to allow for start up power to be back fed from the 115kV system through the GSU Transformer to the Station Auxiliary Transformers.

° Station Auxiliary Transformers with NLTC.

Transformers rated 18-4.16kV will be connected to 5kV switchgear in a secondary-selective radial configuration.

° 5kV and 600V switchgear.

5kV switchgear will provide auxiliary power to the CTGs and STG starting system, 4kV motors, and 4.16-48kV auxiliary transformers. 600V switchgear will provide

auxiliary power to the 480V motor control centers, 460V motor loads, and miscellaneous low voltage power, lighting, and electric heat tracing loads.

° Plant unit 480V motor control centers ("MCCs").

The CTGs and STG 480V MCCs will be supplied with the CTG and STG package. The plant unit 480V MCCs will be used to feed the balance of plant unit loads, i.e., water treatment loads, cooling tower loads, and other miscellaneous loads.

° 120VAC UPS Inverter feed from the unit 125VDC system.

Each unit will be provided with one 120VASC UPS inverter feed from the unit 125 VDC system to provide reliable power to the DCS and other critical instrumentation and power supply loads. UPS power will be provided for all DCS components, CTG controllers, STG controllers, JRSG burner management system, CEM analyzers and all critical instrumentation. Provision for alternate power to the UPS will be included in the design. UPS malfunctions will be alarmed at the operator station.

° 125 VDC Station Service Batteries with redundant Battery Chargers.

Each unit will be furnished with 125 VDC station batteries with two battery chargers to provide 125VDC power to the switchyard equipment, MV and LV circuit breakers, and provide battery power to the UPS inverters.

° Generators

The combustion turbines and steam turbine will drive synchronous generators. Each generator will be hydrogen cooled. Controls, excitation systems, voltage regulators, metering, and protective relays for the generators will be integrated into the combustion and steam turbine packaged control equipment.

2.2 Starting Means for the Power Plant

2.2.1 Normal Starting of CTG Single Shaft Combined Cycle Unit

Normal starting of the CTG is by a Load-Commutating Inverter (LIC) adjustable frequency drive, which uses the generator as a synchronous motor for variable speed control during start of the CTG system. The LCI start system ramps the turbine to a self sustaining speed required for purge, light-off, waterwash, etc. One LCI inverter will be supplied for two CTGs, which will prohibit simultaneous starts of the CTGs.

2.2.2 Normal Starting of STG Unit.

The turbine governor contains all functions necessary for automatic run up from standstill to nominal speed, loading and operation. The steam control valves are equipped with hydraulic servo motors and are positioned via electro-hydraulic servo valves.

2.3 Black Start Capability

No black start capability is provided for this project. Standby power for start-up of the new power facility is assumed to be available from the UCNSB. Standby power for operation of controls and operations of equipment for maintenance and preservation systems during emergency shutdowns and extended downtime of the new power facility is assumed to be available from the UCNSB.

2.4 Emergency Power Requirements

A 500 kW diesel engine driven generator is furnished for standby power for backup to the UPS system and other critical loads. Standby power is required during an unsuccessful full load rejection, when the hot units come to a complete stop and heat must be removed from the hot areas of the turbines, such as bearings. Electrical loads include seal oil pumps, cooling lube pumps, and control loads. Power to these loads is normally provided by batteries and the UPS system.

3 ELECTRICAL DESIGN CONSIDERATIONS

3.1 The electric system will be designed per the applicable provisions of the following Codes and Standards:

- American National Standards Institute (ANSI)
- Institute of Electrical and Electronics Engineers (IEEE)
- National Electrical Manufacturers Association (NEMA)
- American Society for Testing and Materials (ASTM)
- Insulated Cable Engineers Association (ICEA)
- National Fire Protection Association (NFPA)
- National Electrical Safety Code (NESC)
- National Electrical Code (NEC)
- Illuminating Engineering Society (IES)

4 CONTROL SYSTEMS

4.1 Scope

4.2 The Instrumentation and Control systems will be designed to provide state of the art monitoring and control of the operation of the plant. Optimization of the control system for a high level of automation will provide all necessary process information and operational controls for start-up, normal operation and transient or shutdown conditions of the plant operations via CRTs in the control room.

4.3 The control system will consist of a Distributed Control System (DCS) with microprocessor base controllers, Operator Console and Engineering Console.

4.4 Field instrumentation will be standardized as much as possible as to type, manufacturer and model in order to simplify the plant design and reduce spare parts.

4.5 Control of Subsystems

4.5.1 The DCS will provide the main control functions of the plant. The DCS will also interface with mechanical equipment controllers to provide supervisory control functions and to obtain critical operations parameters for overall plant performance monitoring.

4.5.2 The various subsystems will be controlled from the operator console. The Operator console will consist of color CRT monitors, functional keyboards, alarm panels and alarm printers. Graphic and faceplate displays will be provided to enable the operator to have full visibility and control of the process. Alarm displays and alarm print-outs will be provided to alert the operator of plant disturbances and to maintain a historical log of these disturbances. In addition, the alarm printer will document all operator initiated changes.

4.5.3 Combustion Turbine/Steam Turbine Generator (CTGs and STG).

4.5.3.1 Control of the CTGs and STG will be performed by a vendor supplied packaged control system. The packaged control equipment will e located in an enclosure adjacent to the system. Primary control will be from the CTGs and STG packaged control equipment located at the operator console. From this station the operator will be able to perform setpoint and monitoring functions of the CTGs and STG. Local CTGs and STG packaged control equipment will provide local control capability.

- Start
- Stop
- Raise load
- Lower load
- Raise vars
- Lower vars
- Load hold
- Duct burner start permissive
- Start permissive
- Ready to start

4.5.3.2 Control via the DCS will consist of hardwired signals to and from the CTGs and STG controller. These signals typically consist of the

following: The DCS will also be interfaced to the CTGs and STG packaged control equipment via a datalink to obtain all operating parameters of the system. These data will be displayed on the operator console and will also be used for performance monitoring, alarming, logging, trending, etc.

4.5.4 Electrical Systems control

Status of the 4160 volt breakers, transformers and selected switchyard signals will be monitored and controlled by the DCS. These signals will be hardwired to the DCS racks.

FLORIDA PUBLIC SERVICE COMMISSION
981042-EM EXHIBIT NO. 23
COMPANY Locascio
DATE 12-2-98

DUKE/FLUOR DANIEL

PROFESSIONAL SUMMARY

MARK LOCASCIO

PRINCIPAL PROCESS/SPECIALTY ENGINEER

EDUCATION:

B.S., Engineering, Harvey Mudd College, Claremont, California
M.E., Chemical Engineering, Carnegie-Mellon University, Pittsburgh, Pennsylvania
M.B.A., University of California, Irvine, California

Registered Mechanical Engineer, California No. M21089

SUMMARY OF EXPERIENCE:

Professional Mechanical Engineer with over 20 years experience in the Power and Petroleum industries. Currently is the Manager of Engineering for Duke / Fluor Daniel's Power Department in the Houston office. Previously worked as Project Manager / Project Engineer on various combined cycle and cogeneration projects and studies. Has four years of experience in Project Controls as an estimator, scheduler and cost engineer on petroleum and waste incineration projects and studies. Spent 12 years as a Process / Mechanical Engineer on various power projects and studies. Experienced in power sales and marketing.

SIGNIFICANT EXPERIENCE:
DUKE / FLUOR DANIEL (1987 - Present)

MANAGER OF ENGINEERING

Duke / Fluor Daniel Office — Sugar Land, Texas

Responsible for Technical direction and supervision of the Power Systems Group in Duke / Fluor Daniel's Houston Office. Directly supervises all Power Discipline Engineers, Document Management and Information Services personnel for all power plant projects, studies and proposals. Interfaces with Clients for proposals and presentations; involved with sales and marketing activities for the Power Group.

PROJECT ENGINEER

Rabigh Steam Power Plant Extension, Stage IV — General Electric International, Rabigh, Saudi Arabia

Project Engineer on a 385 MW combined cycle power plant utilizing 4 - GE Frame 7EA combustion turbines. Responsible for technical and commercial coordination with clientand progress reporting. Project Information Manager responsible for electronic communication, document storage and retrieval systems and database coordination.

PROJECT MANAGER

Entergy / Mobil Cogeneration Screening Study	Entergy and Mobil Oil Corp. Beaumont, Texas

This study compared three technologies for performance and cost using a petroleum coke feed: combined cycle power plant, IGCC and fluidized bed boiler. As the Project Manager, in charge of engineering, estimating, cost control, and client interface; was intimately involved in writing of the final report.

Mindanao IGCC Power Plant	Falcon Seaboard, Houston, Texas

This project created an unsolicited proposal to the Philippine government for the building and operation of an IGCC plant on Mindanao island. As the Project Manager, assembled the final document, performed client and vendor coordination, wrote sections of the report and was the engineering interface on all activities.

GE IGCC Performance/Cost Model Project	General Electric Co. Schenectady, New York

The Integrated Gasification Combined Cycle (IGCC) Model Project created a user friendly, Windows driven software program that models the performance and cost of an IGCC plant. The model uses "user-entered" parameters to define the plant configuration, feedstock type and flowrate and plant cost variables such as plant location. The model outputs plant performance characteristics and cost information.

As the Project Manager, assembled the project team; defined the scope; interfaced with the client; wrote the Windows drivers and finalized the user's manual; and was responsible for contract, budget, schedule and scope compliance.

WEPCO Cogeneration Facility Project	Wisconsin Electric Power Company Wisconsin

The WEPCO project analyzed various aspects of two configurations of gas turbine power plants: a one train GE frame 7FA with reheat in a combined cycle, and a two train GE frame 7EA in a combined cycle. Overall costs and schedule (Engineering and Construction), plant power, availability, operating costs and design options were evaluated and reported.

As the Project Manager, tasks included client liaison, discipline coordination and overseeing of the technical aspects of the project and cost and schedule responsibility. The Manager had the central responsibility of task completion, interface, technical completeness and issuing of the final report.

ICARUS Computer Simulation Project

Project Manager of the Project that analyzed the use of the ICARUS Computer Simulation program as a standard for Fluor Daniel estimating. Prepared the test procedures, developed funding needs,

established acceptance criteria, final report preparation and management presentations.

Texaco - Mission Energy Cogeneration Study — Texaco, LAP
Wilmington, California

Project Manager and Process Engineer for a study performing conceptual cogeneration plant configurations in the Texaco Wilmington Refinery. Produced various PFD's, equipment lists, cost estimates and process plant configurations evaluations.

SALES/MARKETING ASSISTANT

Power Operating Company's Sales and Marketing Assistant in charge of Power Marketing, creating and computerization of Power qualifications, presentations, proposal coordination and completion, information management, technology innovations, sales management, client and project management interface.

LEAD ESTIMATOR

Texaco Refinery Diesel System Upgrade — Texaco Oil Company
Bakersfield, California

The Texaco Bakersfield Refinery made modifications to the diesel gas system, including the addition of new air coolers and vessels and the replacement of existing heat exchangers.

As the Lead Estimator, estimated the cost of the modifications (approximately $4 million), compiled the estimate and a draft schedule, and presented them to Texaco management. The Project was funded based on the results of the estimate.

Molten Metals Technology, Inc. — Various Locations

Lead Estimator for various proposals teaming with MMT using their proprietary waste incineration process.

PROJECT CONTROLS ENGINEER: COST ESTIMATOR, SCHEDULER

Shell Tabangao Refinery — Shell Oil Company
Tabangao, Philippines

The Shell Tabangao Refinery is a 110,000 barrels/day grass roots refinery producing various weights of fuel. Project Controls Engineer assisting in trend estimating and resolution negotiation, and in charge of trend coordination; schedule tracking and updating; manpower and cost estimation; cash flow analysis; change order control..

LEAD PROCESS/MECHANICAL ENGINEER

Pittsfield Cogeneration Facility — Altresco, Inc.
Pittsfield, Massachusetts

Pittsfield Cogeneration Facility is a 160 MW combined cycle plant which supplies process steam to

a GE. facility in Pittsfield, Massachusetts. Three GE Frame 6 Gas Turbine Generators supply heat to 3 pressure level HRSG's to produce high pressure steam for a GE. steam turbine. intermediate pressure steam for NOx control of the GTG's and an integral deaerator: extraction from the steam turbine supplies the process steam. Power generated is sold to a utility.

Lead Process Engineer in charge of the process group. Responsible for generation of all process PFD's and P&ID's. equipment data sheets, heat and material balances and system descriptions. Wrote plant performance test procedures, evaluated Plant performance test.

Artesia Cogeneration Facility — O'Brien Energy Services
California Milk Producers — Philadelphia, Pennsylvania

Artesia Cogeneration Facility is a 37 MWe combined cycle plant producing intermediate pressure steam for process use and high pressure steam for power generation via a steam turbine-generator. Electricity produced is sold to SCE. A gas turbine, HRSG and steam turbine produces the power produced for sale.

Lead Process/Mechanical Engineer responsible for the process flow diagrams and process and instrumentation diagrams (P&ID) for this study. Computer modeling of the heat and mass balance. Coordination with vendors for equipment quotations, including bid review and economical comparison of different vendors. Client interface for plant design and plant requirements.

Mission-Texaco Screening Studies — Texaco, Bakersfield, California

Completed the cycle design and GTG Screening Study for various configurations of Cogeneration Plants for the Texaco Bakersfield refinery. The study included both on-site and off-site design. Interfaces were with the refinery for feedwater, fuel and power.

BECHTEL POWER CORPORATION (1979 - 1987)

NSSS/STG Lead Mechanical Engineer, Palo Verde Nuclear Generating Station (PVNGS), Arizona
NSSS Responsible Engineer, PVNGS
Mechanical Engineer, PVNGS
Mechanical Engineer, Rancho Seco Nuclear Generating Station, Sacramento, California
Field Engineer, Rancho Seco Nuclear Generating Station
Mechanical/Chemical/Process Engineer, Kuosheng Nuclear Project, Taiwan

Lead Mechanical Engineer for the Nuclear Steam Supply System/Turbine-Generator (NSSS/T-G) Group on the Palo Verde Nuclear Generating Station and responsible for over $400 million of contracts. As a Group Leader, supervised the NSSS/T-G group, assigned tasks to group members, interfaced with management for scheduling, budgeting, and manpower loading, and acted as the main client interface for NSSS/T-G related questions. Attended negotiating sessions with vendors as the client's representative and was responsible for resolving over $100 million NSSS/T-G related backcharges and claims. As the NSSS/T-G Group Leader, responsible for the adequacy of design and performance of all NSSS and T-G related systems. Central focus of all vendor, construction, and start-up activities for these systems.

Previously, the Responsible Engineer for the NSSS contract ($250 million) with Combustion Engineering (C-E) on PVNGS. Served as the client's agent interfacing with C-E on engineering and contractual items. As the NSSS Responsible Engineer, involved in all aspects of NSSS systems. As a Mechanical Engineer on the Palo Verde project, prepared responses to Deficiency Evaluation Reports which were transmitted to the Nuclear Regulatory Commission.

Responsible Engineer in charge of the fire protection contract for the Rancho Seco Nuclear Generating Station. Coordinated activities between the field office and vendors and assisted in troubleshooting activities. A member of the team that updated the existing fire hazards analysis, which also included the addition of new structures for the Rancho Seco project.

At the Rancho Seco jobsite, a Mechanical Field Engineer coordinating activities between engineering and construction for various tasks. The liaison between the client and vendors on various modifications. Interfaced with start-up, operations, scheduling, and construction. Also wrote field purchase requests, dispositioned start-up field reports, analyzed vendor bids and assisted in system troubleshooting and system design.

In an earlier assignment, a Mechanical/Chemical Process Engineer on the Kuosheng Nuclear Project in Taiwan. Designed systems, wrote specifications, ordered equipment, and analyzed bids. Created P&ID's, sized and ordered equipment, coordinated vendor and field activities, and was the Responsible Engineer for several contracts including the $200 million GE-supplied NSSS contract. Assisted field start-up activities and system troubleshooting.

TRAINING:

Windows 3.1, cc:Mail, Lotus, Ami Pro

ASSOCIATIONS:

National Society of Professional Engineers

PUBLICATIONS:

"Advanced Computer Simulation and Modeling for Solving Single-Phase Hydraulic Problems", presented at Power-Gen, December, 1989

"Utilization of Air Blowing for Line Cleaning of Power Plants", presented at ASME Cogen-Turbo IV, August 1990

"Computer Modelling of an IGCC Plant - Performance and Cost", presented at Power-Gen '94 Americas, December, 1994

NEW SMYRNA BEACH POWER PROJECT
PROJECT PROFILE

Expected Plant Capacity:

a.	Nominal rating:	500 MW
b.	Annual average (71F°, 78%RH):	496 MW
c.	Summer (84F°, 80%RH):	476 MW
d.	Winter (15F°, 78%RH):	548 MW
e.	ISO Temperature and Humidity (59F°, 60%RH):	514 MW

Project Energy Production: Approximately 4,000,000 MWH/year

Technology Type: Two Advanced Firing Temperature Technology Combustion Turbines, Two Heat Recovery Steam Generators, and One Steam Turbine Generator in Combined Cycle Configuration

Anticipated Construction Schedule:

a.	Project release date:	December 1999
b.	Construction mobilization date:	May 2000
c.	Commercial in-service date	October 2001

Fuel Type

a.	Primary Fuel	Natural Gas
b.	Alternate Fuel	None

Fuel Use: Approximately 85 Million Standard Cubic Feet of Natural Gas/day, annual average (71F, 78%RH), full load

Air Pollution Control Strategy: Low NOx Burners

Cooling Method: Cooling Tower

Total Site Area: 30.5 acres (approximate)

Construction Status: Planned

Certification Status: Need Determination application filed, anticipate filing Site Certification application Fall 1998

Status with Federal Agencies: EWG Status certified by FERC; market-based rates approved by FERC; federal environmental permit applications under preparation

TABLE 1

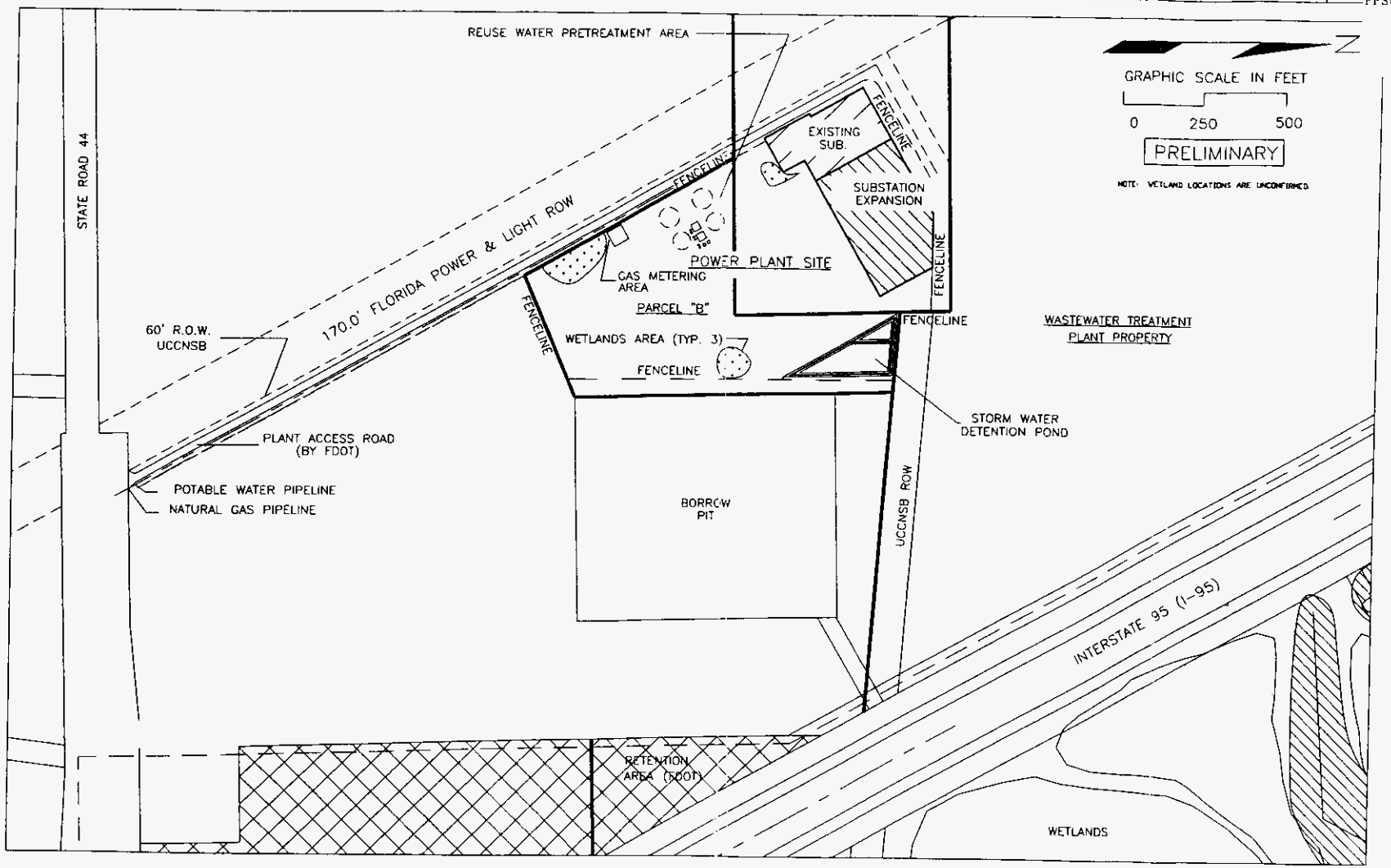
NEW SMYRNA BEACH POWER PROJECT
PROJECT PROFILE
(CONTINUED)

Projected Unit Performance Data:	
Planned Outage Factor (POF):	3 %
Forced Outage Factor (FOF):	1 %
Equivalent Availability Factor (EAF):	96 %
Resulting Capacity Factor(%):	75-92 % (first 10 years)
Average Net Operating Heat Rate (ANHOR):	6,832 Btu/kWh (HHV) (59°F, 60%RH) expected

Projected Unit Financial Data (per Duke Energy):	
Book Life (years):	30 years
Direct Construction Cost (Actual):	$160 Million
AFUDC Amount:	Not applicable
Escalation ($/kW):	Not applicable
Fixed O&M ($/kW per year):	Proprietary
Variable O&M ($/MWH):	Proprietary
K-Factor:	Not applicable
Project Life:	30 years

Expected Plant Air Emissions:	NOx: 12 ppmvd @15% O_2 CO: 12 ppmvd PM: 18 lbs./hour SO_2: 20 lbs./hour Uncombusted Hydrocarbons: 7 ppmvw
Transmission Lines Required:	Approx. 150 feet of 115 kV conductor from step-up transformer to bus at Smyrna Substation
Gas Pipeline Required: (per Duke Energy)	Approx. 42 miles of 16-inch (tentative size) lateral pipeline
Water Requirements:	Approx. 3.8 MGD, annual average (71°F, 78%RH), at full load
Wastewater Discharge:	Zero offsite discharge: wastewater returned to UCNSB treatment plant for reuse

FPSC Docket No. 981042-
UCNSB/Duke New Smyr
Witness: Locasc
Exhibit ____ (ML-



REV.	DATE	REVISION DESCRIPTION	CHK.	APPROVED
A	10/29/98	ISSUED FOR INFORMATION	DB	

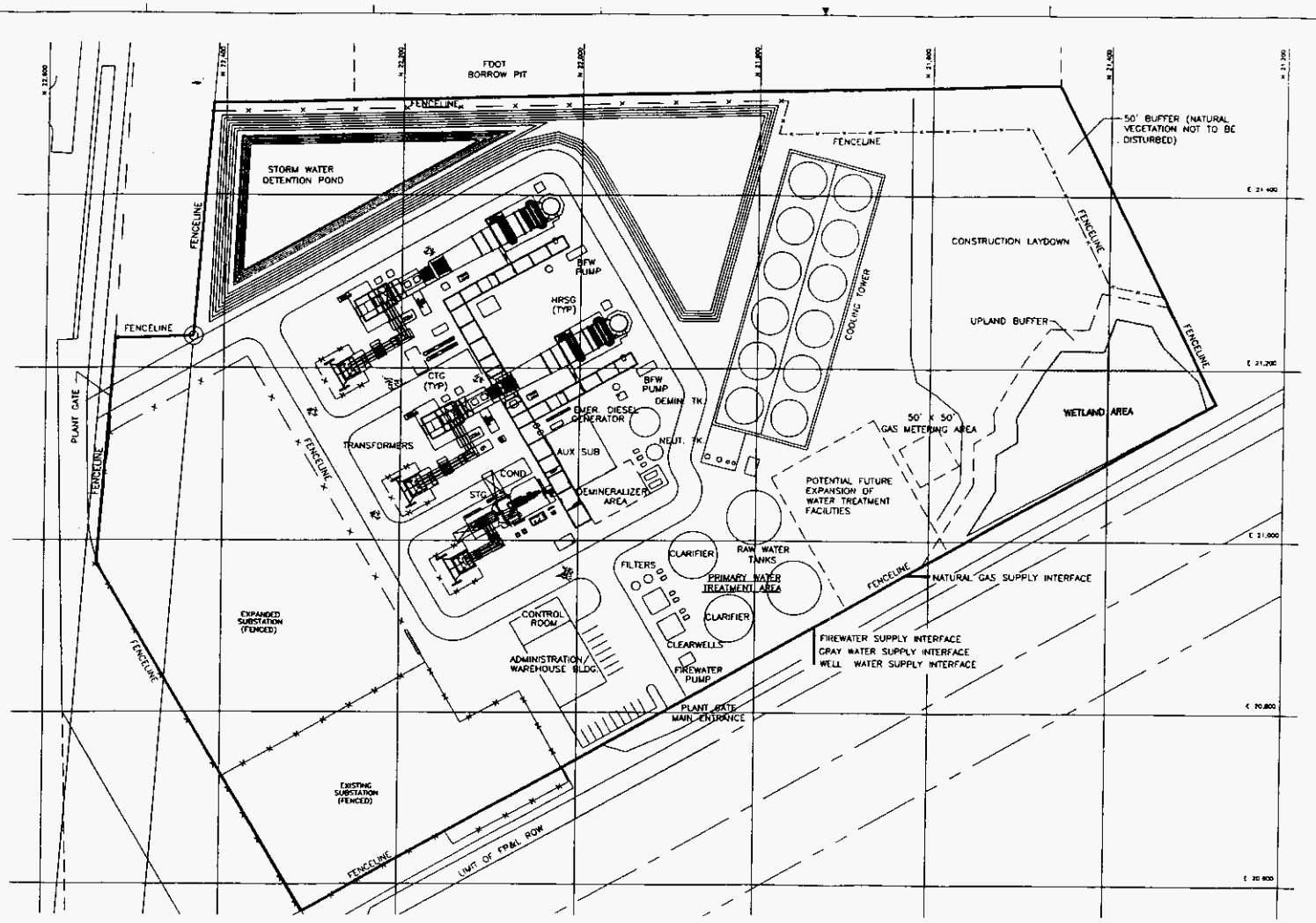
DUKE / FLUOR DANIEL

POWER ENGINEERING • CONSTRUCTION • GENERATING & MAINTENANCE

FIGURE 4
NEW SMYRNA BEACH POWER PROJECT
SITE PLAN

SCALE	DRAWING NUMBER	REV.
NONE	06877401-00-SIT-03	A

CAD DRAWING No. 0051T03A



FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Locascio
Exhibit _____ (ML-4)

NOTES:

1. WAREHOUSE BUILDING INCLUDES A 10' X 10' HAZARDOUS WASTE STORAGE AREA.

REV	DATE	REVISION DESCRIPTION	CHK.	APPROVED
0	9/18/98	ISSUED FOR SCA	DS	DS

DUKE / FLUOR DANIEL
POWER ENGINEERING • CONSTRUCTION • OPERATIONS & MAINTENANCE

PROPOSED PLOT PLAN
DUKE ENERGY POWER SERVICES
NEW SMYRNA BEACH POWER PROJECT

DRAWN BY: G. BROWN
CHECKED BY:
SCS 4/6/98
APPROVED:
APP. DATE:
DRAWING NUMBER: 877401-1-PP-5-00-1
REV: 0
SCALE: 1" = 40'
CAD DRAWING No. 51T01_0.DWG

*DATE*TIME* MANUAL CHANGES MADE - YES ☐ NO ☐ DWG. FILE UPDATED - YES ☐ NO ☐ MODEL UPDATED - YES ☐ NO ☐

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Locascio
Exhibit _____ (ML-6)

Duke Energy Power Services
New Smyrna Beach Power Project
New Smyrna Beach, Florida

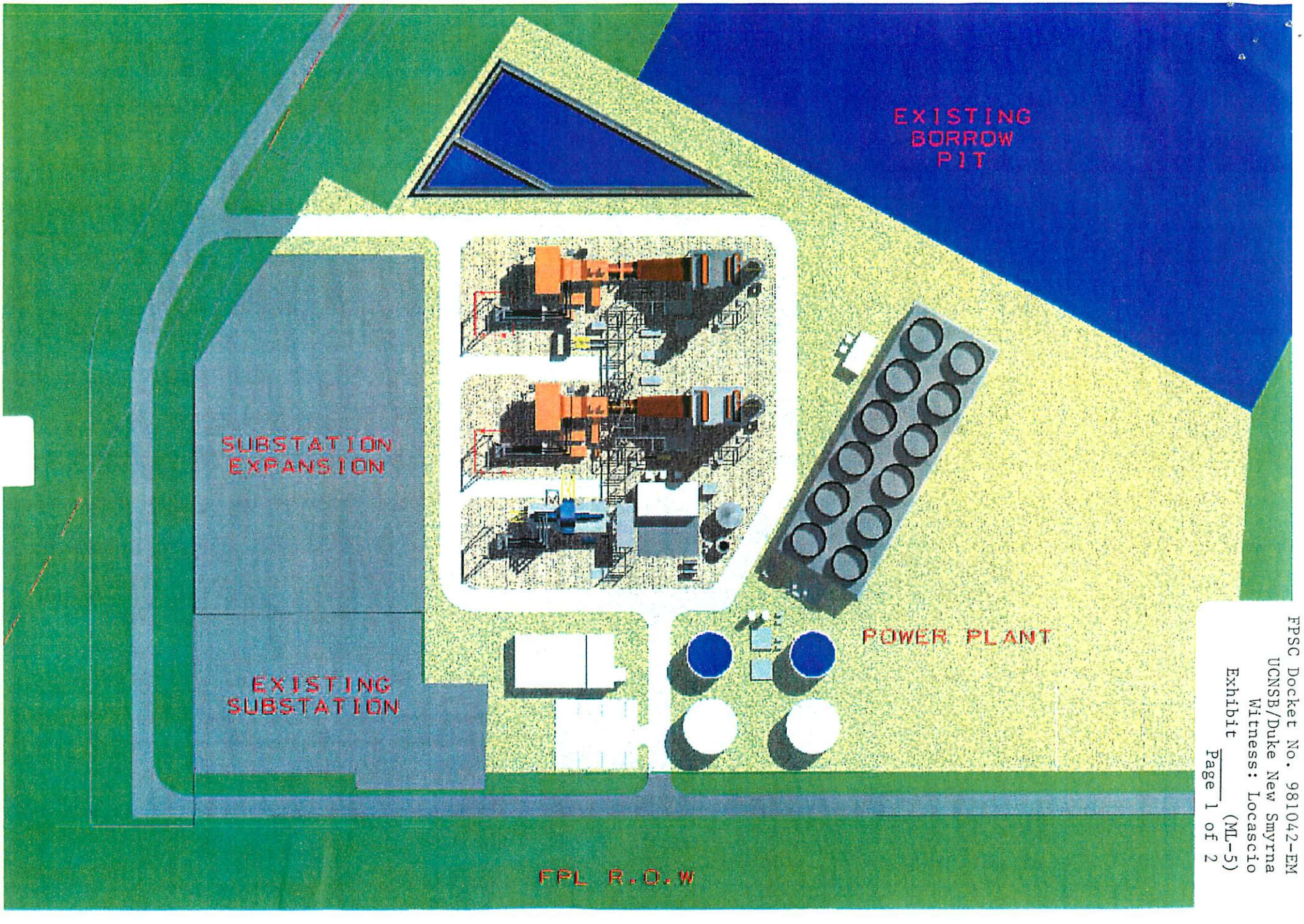
Duke/Fluor Daniel
Contract 06-605102
September 28, 1998

Estimated Plant Performance and Emissions Data
2 x 1 Combined Cycle Plant
Two General Electric Model PG7241(FA) Combustion Turbine Generators
Two Unfired Heat Recovery Steam Generators
One Reheat Condensing Steam Turbine Generator

Combustion turbine load	100%	100%	100%	100%	75%	75%	75%	75%	50%	50%	50%	50%
Ambient temperature (°F)	84	71	59	15	84	71	59	15	84	71	59	15
Relative humidity	80%	78%	60%	78%	80%	78%	60%	78%	80%	78%	60%	78%
Net plant power output (kW)	476,273	496,303	514,328	548,041	384,705	400,592	415,310	438,015	283,468	295,527	309,021	324,276
Net CTG power output (kW)	303,827	318,037	333,072	364,908	229,772	240,897	252,040	273,783	153,365	160,680	167,862	182,095
Net STG power output (kW)	172,446	178,266	181,256	183,133	154,933	159,695	163,270	164,232	130,103	134,847	141,159	142,181
Net plant heat rate, LHV basis (btu/kWh)	6,265	6,217	6,211	6,263	6,532	6,446	6,439	6,417	7,017	6,896	6,907	6,852
Net plant heat rate, HHV basis (btu/kWh)	6,892	6,839	6,832	6,889	7,185	7,091	7,083	7,059	7,719	7,586	7,598	7,537
Net CTG heat rate, LHV basis (btu/kWh)	9,820	9,701	9,591	9,406	10,937	10,719	10,610	10,266	12,970	12,684	12,715	12,203
Net CTG heat rate, HHV basis (btu/kWh)	10,802	10,671	10,550	10,347	12,031	11,791	11,671	11,293	14,267	13,953	13,987	13,423
CTG fuel flow rate (lb/h) - total for two CTGs	142,767	147,634	152,853	164,236	120,247	123,559	127,951	134,495	95,179	97,521	102,129	106,323
CTG heat input, LHV basis (mmbtu/h) - total for two CTGs	2,984	3,085	3,194	3,432	2,513	2,582	2,674	2,811	1,989	2,038	2,134	2,222
CTG exhaust gas flow (lb/h) - total for two CTGs	6,690,340	6,916,800	7,139,660	7,622,280	5,654,260	5,758,760	5,948,460	6,051,540	4,761,600	4,819,320	5,023,200	5,043,300
CTG exhaust gas composition (by volume)												
- Nitrogen + argon	73.64%	74.50%	75.17%	75.93%	73.65%	74.49%	75.16%	75.83%	73.80%	74.65%	75.31%	75.99%
- Oxygen	12.25%	12.45%	12.58%	12.70%	12.27%	12.40%	12.54%	12.45%	12.75%	12.86%	12.98%	12.88%
- Carbon dioxide	3.66%	3.68%	3.70%	3.74%	3.65%	3.70%	3.72%	3.86%	3.44%	3.49%	3.52%	3.66%
- Water	10.45%	9.37%	8.55%	7.63%	10.43%	9.41%	8.58%	7.86%	10.01%	9.00%	8.19%	7.47%
NOx as NO2 (lb/h) - 12 ppmvd @15% O2 - total for two stacks	144	149	154	166	121	125	129	135	95.8	98.2	103	107
CO (lb/h) - 12 ppmvd - total for two stacks	71.5	74.5	77.4	83.1	60.4	62.0	64.4	65.9	51.1	52.1	54.6	55.1
UHC as CH4 (lb/h) - 7 ppmvw - total for two stacks	26.6	27.4	28.2	30.0	22.5	22.8	23.5	23.8	18.9	19.1	19.8	19.8
VOC as CH4 (lb/h) - 1.4 ppmvw - total for two stacks	5.32	5.48	5.64	6.00	4.50	4.56	4.70	4.76	3.78	3.82	3.96	3.97
SOx as SO2 (lb/h) - total for two stacks	18.1	18.7	19.3	20.8	15.2	15.6	16.2	17.0	12.0	12.3	12.9	13.4
Particulates (lb/h) - total for two stacks	18	18	18	18	18	18	18	18	18	18	18	18
Stack velocity (ft/s) - based on a 19 ft. diameter stack	55.5	56.9	58.2	61.8	46.0	46.3	47.5	47.8	38.1	38.1	39.3	39.1
Stack temperature (°F)	193	190	187	185	181	176	173	168	171	166	161	157

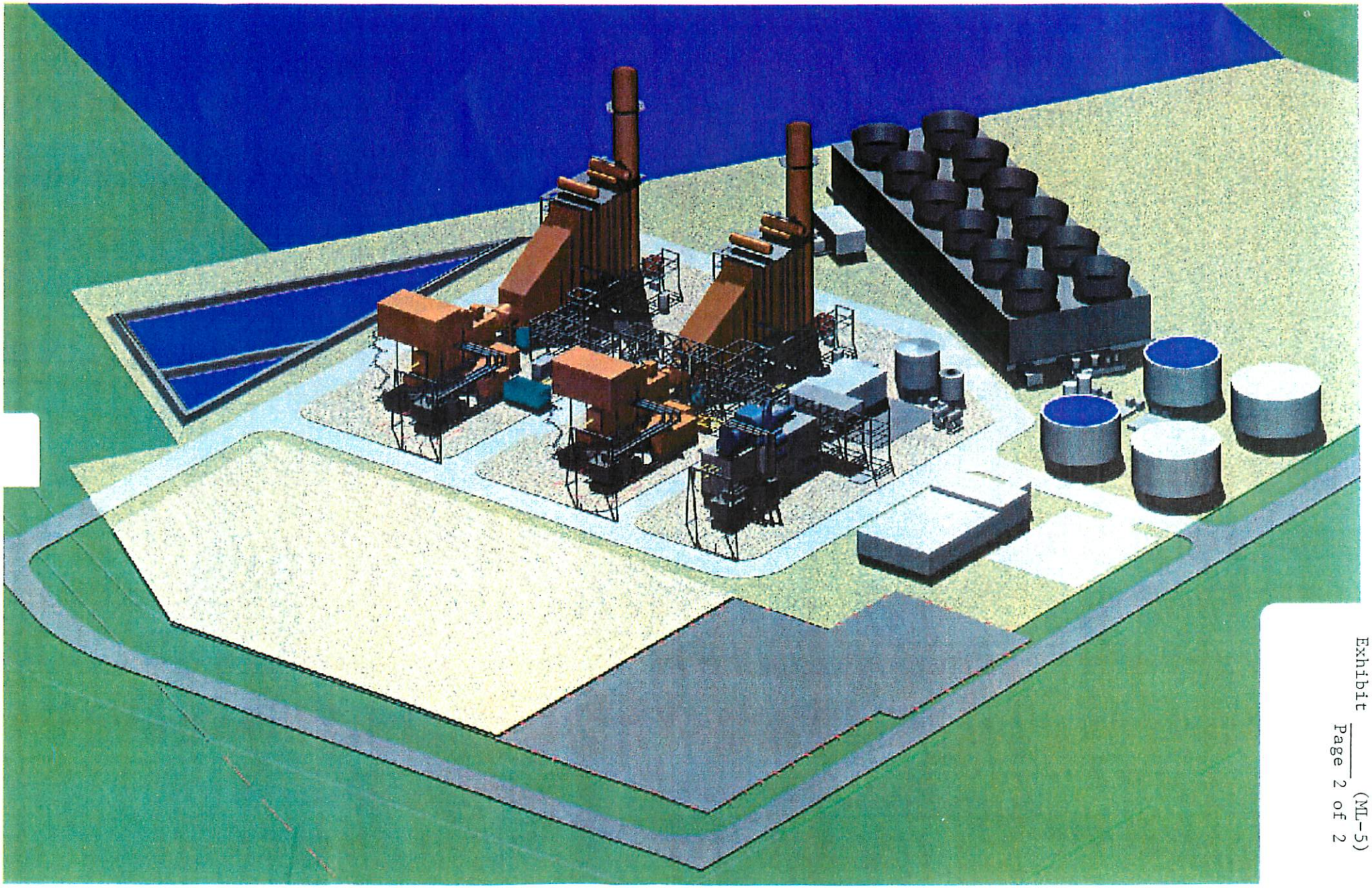
NOTES:
1) SOx emissions are based on firing pipeline quality natural gas with a maximum sulfur content of 2 grains/100 scf.

C:\aaaa\[plntprf5.XLS]Sheet1



NEW SMYRNA BEACH POWER PROJECT
OVERHEAD RENDITION

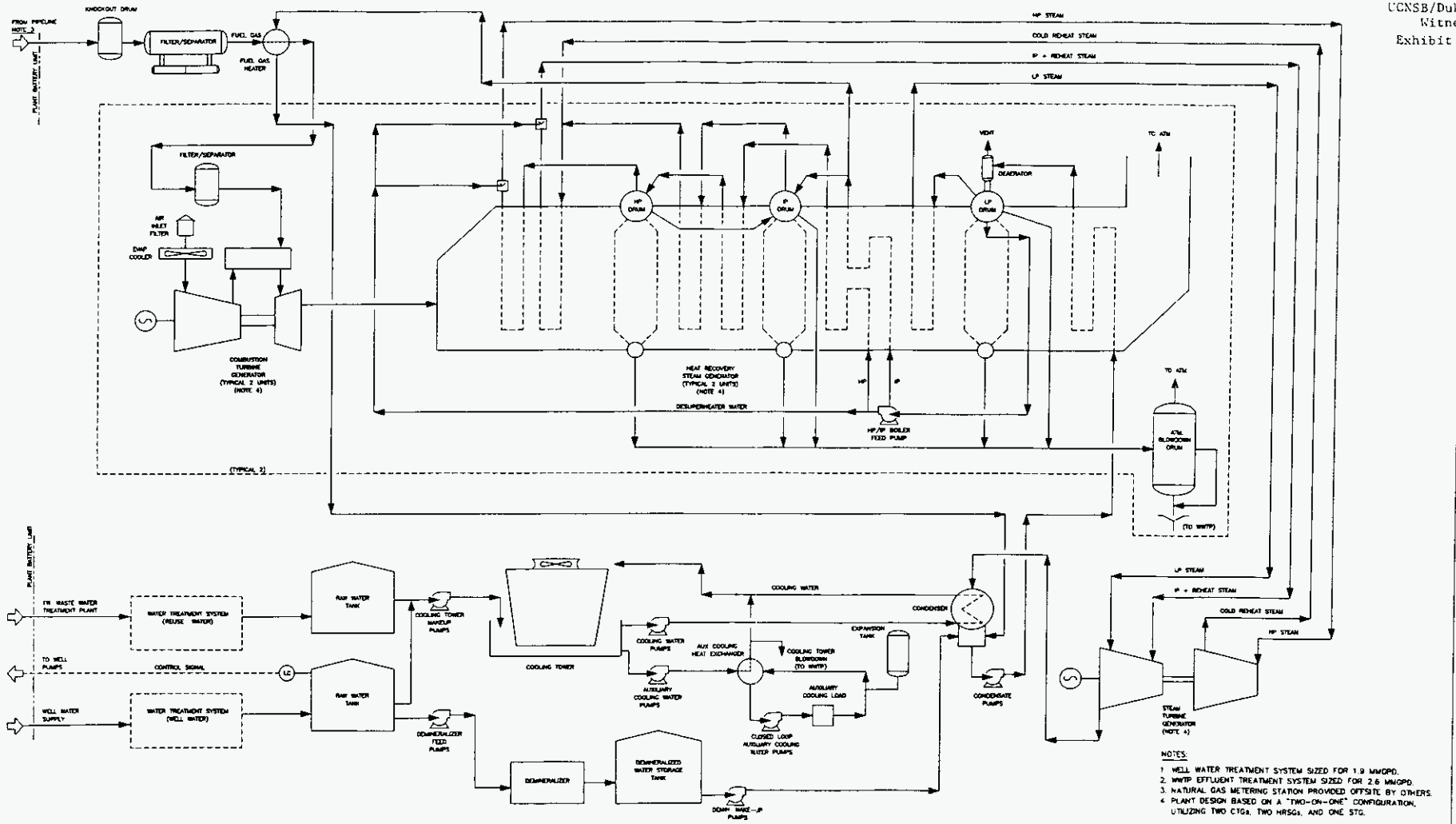
FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Locascio
Exhibit _____ (ML-5)
Page 1 of 2



NEW SMYRNA BEACH POWER PROJECT
PERSPECTIVE RENDITION

Exhibit _____ (ML-5)
Page 2 of 2

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Locascio
Exhibit ____ (ML-7)



NOTES:
1. WELL WATER TREATMENT SYSTEM SIZED FOR 1.9 MMGPD.
2. WWTP EFFLUENT TREATMENT SYSTEM SIZED FOR 2.6 MMGPD.
3. NATURAL GAS METERING STATION PROVIDED OFFSITE BY OTHERS.
4. PLANT DESIGN BASED ON A "TWO-ON-ONE" CONFIGURATION, UTILIZING TWO CTGs, TWO HRSGs, AND ONE STG.

REV.	DATE	REVISION DESCRIPTION	CHK.	APPROVED
0	9/23/98	ISSUED FOR SCA	DR	

DUKE FLUOR DANIEL
POWER ENGINEERING • CONSTRUCTION • OPERATIONS & MAINTENANCE

PROCESS FLOW DIAGRAM
DUKE ENERGY POWER SERVICES
NEW SMYRNA BEACH POWER PROJECT

DRAWING No. 06877401-PFD-001 REV. 0
CAD DRAWING No. PFD001_0

Design Basis
New Smyrna Beach Combined Cycle Project

I. Plant Description

1. General Arrangement

The facility will be located adjacent to the City of New Smyrna Beach Utilities Commission's existing 115 kV ring bus high voltage electrical substation and soon to be constructed six million gallons per day wastewater treatment plant. The proposed site lies approximately one-half mile northwest of the intersection of SR 44 and Interstate 95 in central Volusia County. Refer to the site plan for details.

The site is not subject to flooding. Insurance underwriters' requirements will be used as a basis for flooding and drainage design.

The site fence will enclose the plant boundary area as shown on the plot plan.

The site layout will provide maintenance access to all equipment. Mobile crane access will be provided in the areas not serviced by other cranes and monorails.

Storm water will be sheet runoff to culverts and diverted to an area used by the water treatment plant for storm water retention.

2. Site Description

General Site

The site is adjacent to an existing Utilities Commission high voltage electrical substation. The gas turbine will have an approximate elevation of 30 feet above mean sea level.

General Site Data

Site Elevation (at gas turbine)		30 feet
Ambient Conditions	Dry Bulb / RH	Max. 102°F / 63% Annual Avg. 71°F / 78% Min. 15°F / 78%
	Relative Humidity	Max. 100% Avg. 78% Min. 20%
Prevailing Wind	East to West	
Structural (Wind) Design		
Design Code		per local code requirements
Exposure		Per local code requirements
Basic Wind Speed		Per local code requirements
Airborne Contaminant		New source requirements of FDEP / USEPA

Rainfall		(later)
Snowfall		None
Seismology		Per local code requirements
Backup Power		Available from the utility
Noise Requirements	Equipment	Limit to 90 dBA within 3 feet of all equipment (outside of equipment enclosures)
	Facility	Nearest receptor is ½ mile from plant.

II. Mechanical System Description

1. Plant Capacity

   A nominal 500 MW net power plant will utilize advanced gas turbine / steam turbine combined cycle power plant technology to generate electricity.

2. Steam Cycle

   The plant will utilize a three-pressure level reheat closed loop steam cycle.

3. Major Equipment

   The power plant will include two gas turbine generators (GTGs) with natural gas as the fuel and evaporative coolers for inlet air cooling, two unfired three-pressure level heat recovery steam generators (HRSGs), and a reheat, condensing steam turbine generator (STG). The plant will utilize a multiple cell cooling tower and a steam surface condenser.

4. Plant Operating Modes

   Base load: this plant will normally be operated as a base load plant running an average of 8,500 hours per year, except for major overhaul years; that equates to 97% availability for non-overhaul years, and 88% availability for overhaul years

   Daily Start-up Capability: less than 40 plant starts /annum

   GTG: 60 –100% Load with commensurate steam turbine load; the system will not be designed to allow the GTGs to operate in simple cycle mode (bypassing the HRSG)

5. Gas Turbine Generators (GTG)

   Two (2) advanced firing gas turbines, GE Frame 7FA or equivalent will be provided. The GTGs will be capable of delivering electric power in continuous operation, and will include all associated auxiliary systems and accessory equipment. An evaporative cooler will be supplied for cooling of inlet air. A dry, low NOx combustor for turbine exhaust emission control will be furnished. The emissions under all operating conditions will satisfy the requirements of the site discharge limit. Fuel oil firing is not included.

6. Steam Turbine Generator (STG)

   The STG will be a condensing type, with reheat capability. The unit will include all of the associated auxiliary systems and accessory equipment.

7. Heat Recovery Steam Generators (HRSG)

One HRSG will be provided for each gas turbine unit to recover the waste heat from gas turbine exhaust and generate steam. The HRSG will be of an unfired three-pressure level, natural circulation design with steam reheat and superheater sections, complete with steam desuperheaters. Space will be provided for future installation of SCR catalyst. All associated auxiliary systems and accessory equipment, and a 150 feet high stack will be provided.

8. Fuel Gas System

The plant will utilize natural gas as the fuel, supplied at a sufficient pressure at the plant boundary so that no additional fuel compression will be required. Fuel oil back up will not be used. Fuel gas liquids removal and gas preheating will be utilized as part of the fuel gas system. Gas metering facilities will be provided by others and located just outside the plant battery limits.

9. Steam System

The steam system will consist of HRSG steam drums, superheaters and economizers, steam piping to and from the steam turbine, steam turbine bypass piping, steam piping to gland seal and steam jet air ejector system, steam deaeration, solids and chemistry control. No export steam is produced at this plant.

10. Condensate System

The condensate system will be designed to provide water sufficiently deaerated and with the proper water chemistry to meet HRSG requirements. The system will provide sufficient capacity for operation over the entire ambient range.

11. Feedwater System

Feedwater from the boiler feedwater system is also used as spray water for superheater desuperheaters. A three-element feedwater control system will be provided for each section of the HRSG.

12. Cooling Water System / Steam Condensing

The cooling water system will provide cooling for condensing the steam turbine exhaust and the plant auxiliary equipment. The system will consist of a multiple-cell cooling tower constructed of Douglas Fir and a steam surface condenser with vacuum system. The cooling tower will be complete with pumps, water chemistry control (including biocides), and fire protection. The cooling tower approach is 11°F and the range is 12°F at an ambient of 71°F / 78% R.H. (wet bulb of 66.2°F). The condenser will operate at a nominal 1.68" HgA on a 71°F day.

13. Closed Loop Auxiliary Cooling Water System

The closed loop auxiliary cooling water system provides cooling for auxiliary equipment. The system will utilize demineralized water with corrosion inhibitor.

14. Fire Protection System

A complete fire protection will be provided for the plant. It will include fixed water fire suppression systems, fire hose stations, hydrants, portable fire extinguishers, detection and control systems, etc. It will be designed and installed in accordance with the National Fire

Protection Association (NFPA) standards and recommendations. All fire protection equipment and systems will be UL or FM approved, and will comply with the local fire protection authority's and owner's insurance carrier requirements and recommendations. The primary source of firewater is the city 12" water main. The secondary source will be the raw water system.

15. Raw Water System

Raw water is supplied as make up water lost from cooling tower losses and as feed to the demineralizer. This water will be provided from two sources. The primary source will be treated effluent from the nearby municipal wastewater treatment plant, at a maximum daily flow of 2,000,000 gallons / day. This water will flow through a clarifier, a pressure filter, and an activated carbon filter, then to a raw water storage tank. The secondary source is well water, supplied by the city water utility, which will flow through a clarifier and a pressure filter, then into a separate raw water storage tank. The wells will be owned by the city water utility, which will supply the wells, pumps, piping up to the plant battery limit, and the electrical connects / power. The well pumps will be controlled via the raw water storage tank level control system. The raw water storage tank will be sized to provide four (4) hours of water storage at the maximum flow required.

16. Demineralizer

Demineralized water is supplied as makeup water to the steam cycle lost as boiler blowdown and steam losses. Raw water will be processed by the demineralizer system, which reduces the dissolved solids to the final requirements by using synthetic ion exchange resins. The system will be a cation, anion, and mixed bed vessel type, complete with two 100% capacity trains. The ion exchange resins will be regenerated with a strong acid and a caustic. The effluent from the demineralized system will be directed to the demineralized water storage tank. The demineralized water storage tank will provide demineralized water for condenser hotwell makeup. The storage tank will be sized to provide 7 days of storage at the normal flowrate.

17. Waste Water System

A regeneration waste neutralization system will receive the regeneration wastes from the demineralized waste system and the chemical waste sump. This system will agitate the regeneration wastes and inject acid or caustic to adjust the pH of the wastes into compliance with permit limits.

Process wastewater contaminated with oils will be segregated from other wastewater and treated in the oily waste water system. Oil contaminated wastewater will be collected in the oily waste water sump then pumped to an oil / water separator to remove the oil.

Treated wastewater and waste from the cooling tower will be directed to the nearby municipal wastewater treatment plant. Storm water will be routed via sheet flow to culverts and directed to a nearby retention area.

18. Miscellaneous Systems

- Hose stations will be supplied around the plant, complete with water and service air.
- Instrument air and service air will be supplied with two 100% capacity compressors.
- Potable water will be supplied via the city water system.

- A sanitary lift station will be provided for sewage waste, which will be sent to the nearby municipal wastewater treatment plant.
- Sump systems
- Continuous Emissions Monitoring System (CEMS) monitoring NOx, CO, opacity and diluent gas
- Miscellaneous lifting equipment

III. Electrical System Description

1. Utility Interface

   The electrical interconnection with the utility will be at 115 kV. The electrical interface will be at the existing 115 kV substation. Transmission lines will connect the high side of the generator step-up transformers to circuit breakers located in the substation extension.

2. Substation

   The existing 115 kV substation will be utilized. Modifications to the substation are in the scope of the city utility.

3. Cathodic Protection

   Cathodic protection will be provided, as required by the soil analysis.

4. Intraplant communication

   A system for intraplant communication will be provided.

4. Plant Lighting

   A complete plant lighting system, including emergency lighting will be supplied.

5. Backup Power

   An UPS system (battery backup) will be included. Normal backup power will be from the utility.

IV. Instrument and Control System Description

1. DCS

   A plant Distributed Control System will be supplied to monitor, record and control plant functions. Local control panels (PLC's) will be used for some equipment, such as the water treatment system, GTGs, and STG. Local panels will be connected to the DCS for monitoring and reporting. An historical plant recorder will also be included.

2. Control Philosophy

   Environmental monitoring will be collected in the DCS. Control systems will have feedback / feedforward systems as required, and will be monitored in the control room. Operator intervention will be required on an as needed basis.

3. Freeze Protection / Heat Tracing System

Although freezing temperatures are occasionally encountered at the site, they are not of sufficient duration to warrant winterization of the facility.

V. Civil Structural System Description

1. Site Geotechnical Conditions

   It is anticipated that piling will be required. Details will be available after review of the site geotechnical survey.

2. Structural Design

   Standard power plant structural design, taking into account site seismic zone and wind loads, will be used.

3. Buildings

   A 4,800 square foot warehouse / administration / maintenance building will be built at the plant entrance. A 3,850 square foot control room will be provided to house the DCS and plant operations personnel.

VI. Environmental Concerns

1. NOx and other emissions limit to be permitted.
2. Far field noise limitations on housing ½ mile away.
3. Waste water / effluent conditioning: temperature, biocide, etc.

NEW SMYRNA BEACH POWER PROJECT
GENERATING ALTERNATIVES EVALUATED

I. GENERATION TECHNOLOGIES CONSIDERED

Combustion Turbine (Gas/Oil)	Not cost-effective based on Florida market projections
Combined Cycle - Gas	Selected
Combined Cycle - Oil	Not cost-effective against Combined Cycle - Gas
Pulverized Coal	Not cost-effective against Combined Cycle
Coal Gasification Combined Cycle	Not cost-effective against Combined Cycle
Nuclear	Not cost-effective against Combined Cycle
Gas/Oil Steam	Not cost-effective against Combined Cycle
Waste to Energy	Not cost-effective against Combined Cycle

II. COMBINED CYCLE MANUFACTURERS CONSIDERED

General Electric

Westinghouse

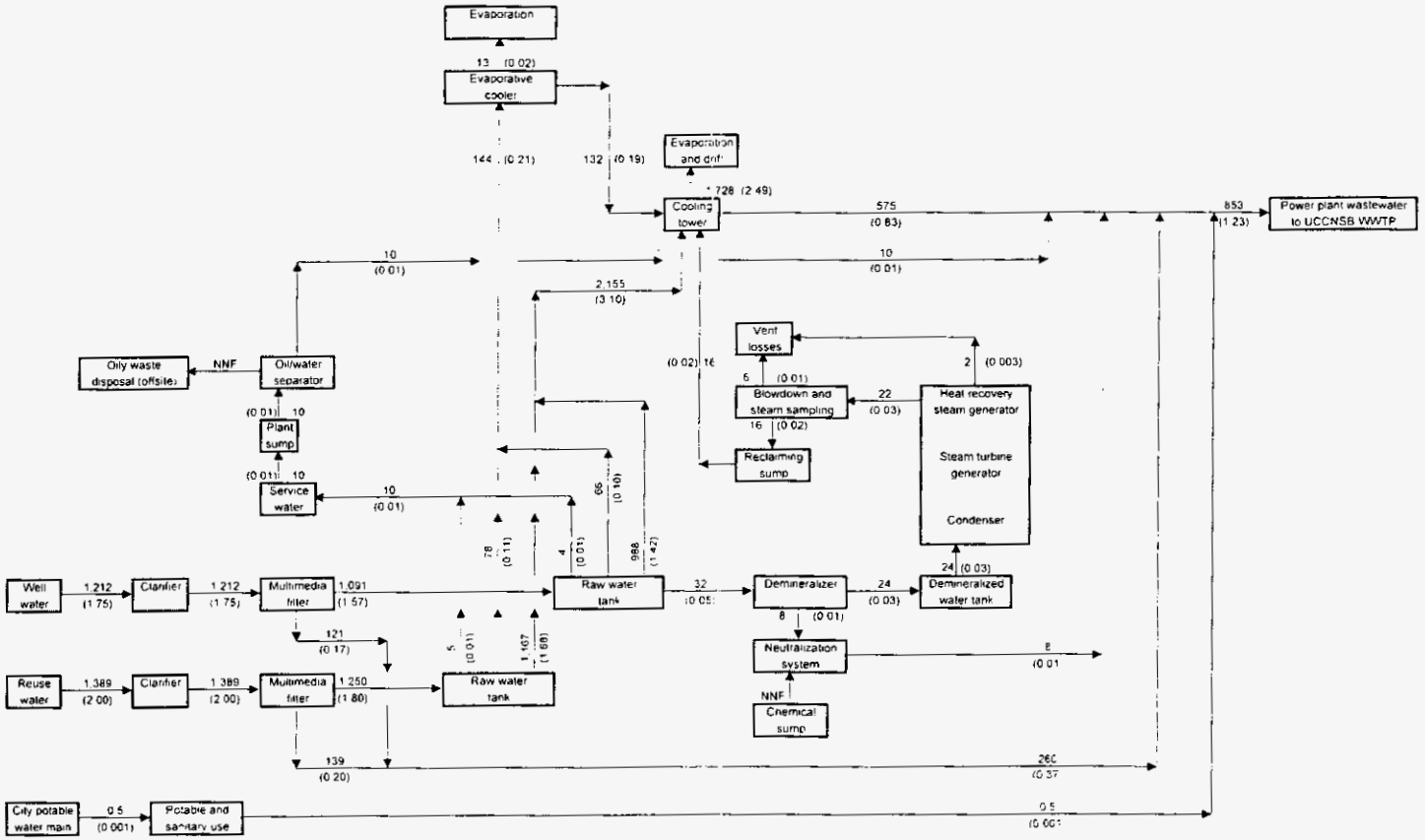
Siemens

ASEA Brown Boveri (ABB)

Duke Energy Power Services
New Smyrna Beach Power Project
New Smyrna Beach, Florida

Duke/Fluor Daniel
Contract 06-605 02
September 24 1998

PRELIMINARY WATER BALANCE - MAXIMUM ANNUAL 24 HOUR CASE



NOTES
1) Flows are in shown in gallons per minute and in (million gallons per day)
2) Cooling tower blowdown is based on four cycles of concentration
3) NNF - normally no flow

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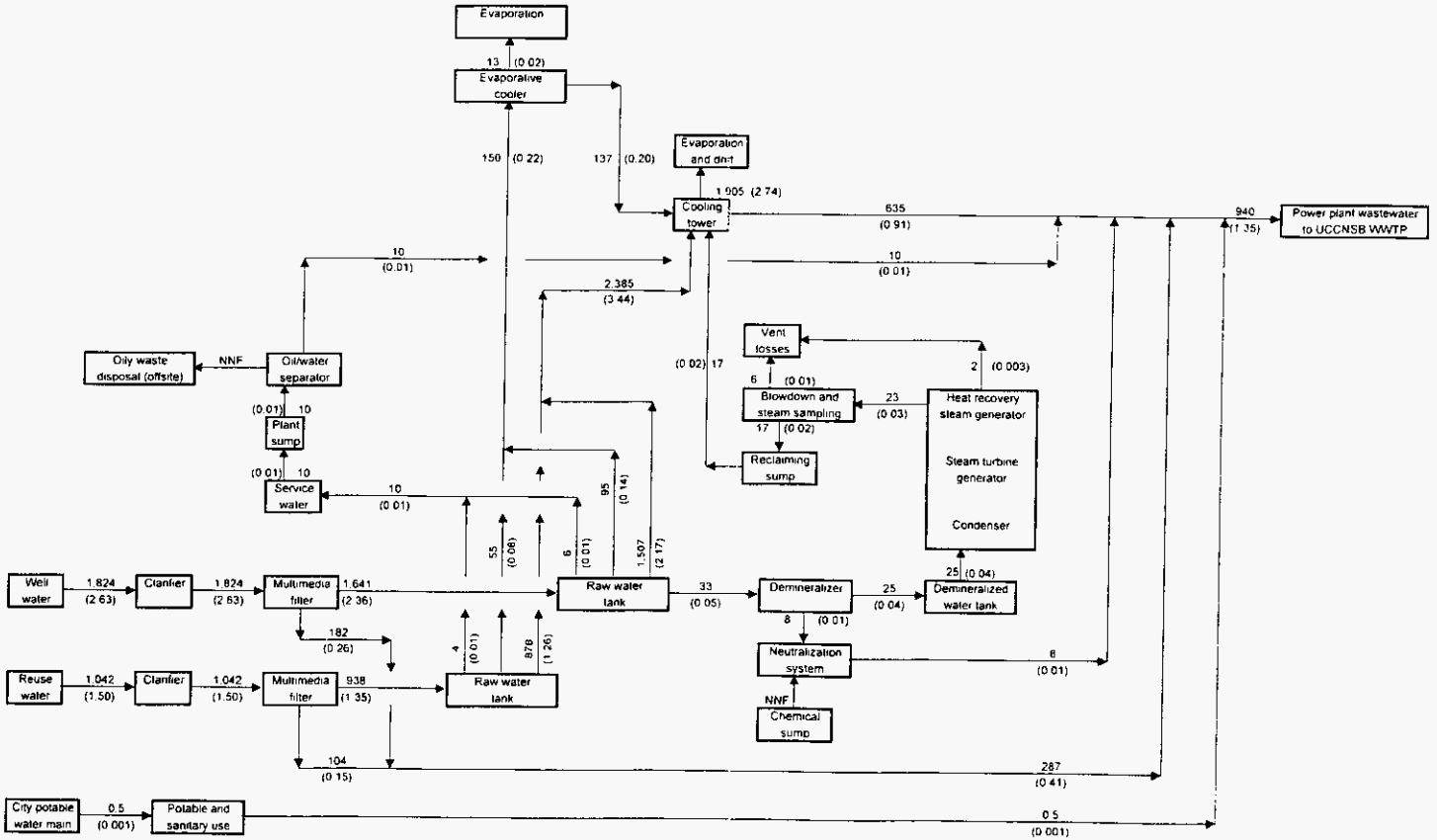
Duke Energy Power Services
New Smyrna Beach Power Project
New Smyrna Beach, Florida

Duke/Fluor Daniel
Contract 06-605102
September 21 1998

PRELIMINARY WATER BALANCE - MAXIMUM MONTHLY 24 HOUR CASE



NOTES:
1) Flows are in shown in gallons per minute and in (million gallons per day)
2) Cooling tower blowdown is based on four cycles of concentration
3) NNF - normally no flow

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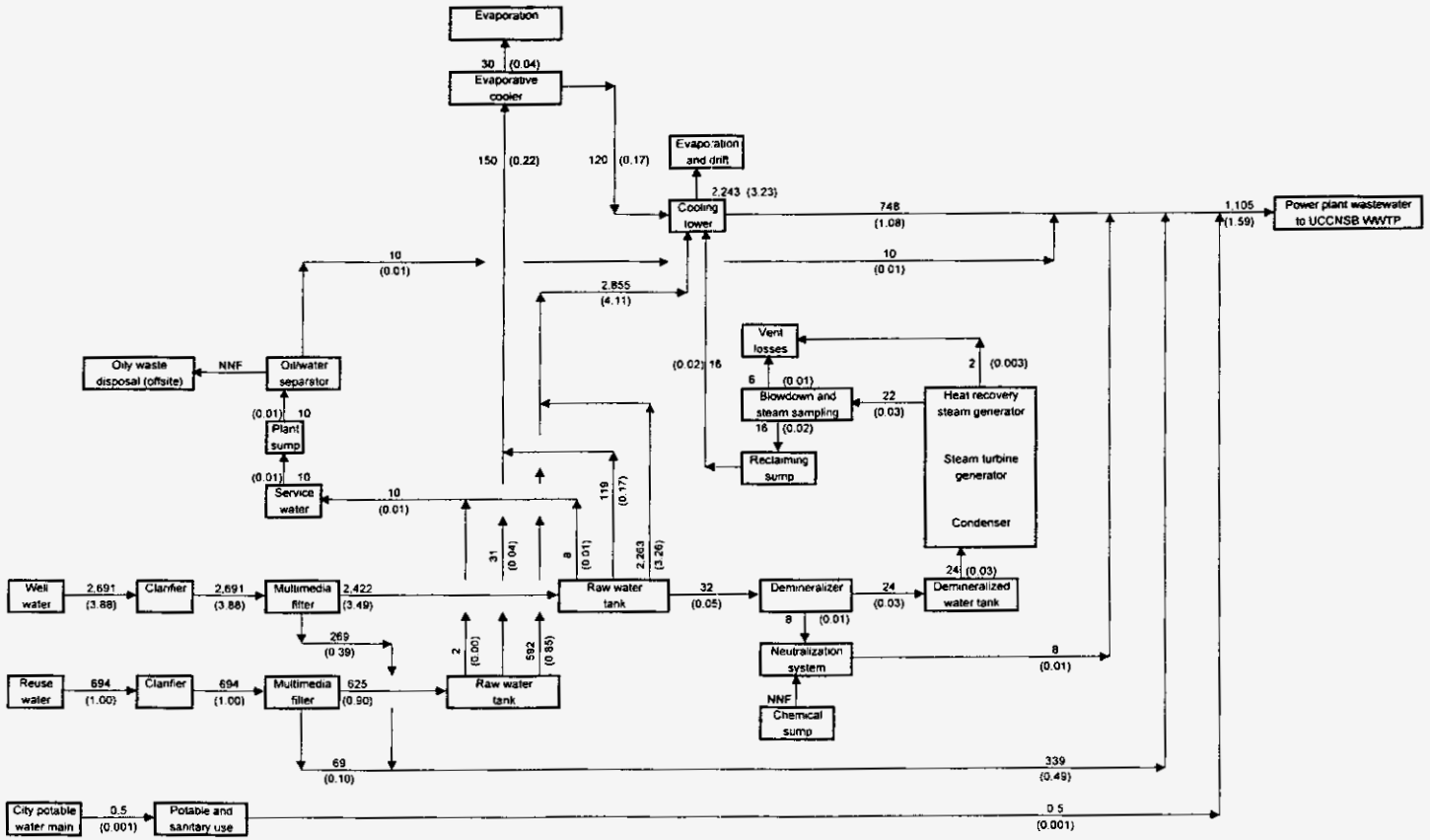
Duke Energy Power Services
New Smyrna Beach Power Project
New Smyrna Beach, Florida

Duke/Fluor Daniel
Contract 06-605102
September 21, 1998

PRELIMINARY WATER BALANCE - MAXIMUM DAILY CASE



NOTES:
1) Flows are in shown in gallons per minute and in (million gallons per day).
2) Cooling tower blowdown is based on four cycles of concentration.
3) NNF - normally no flow.

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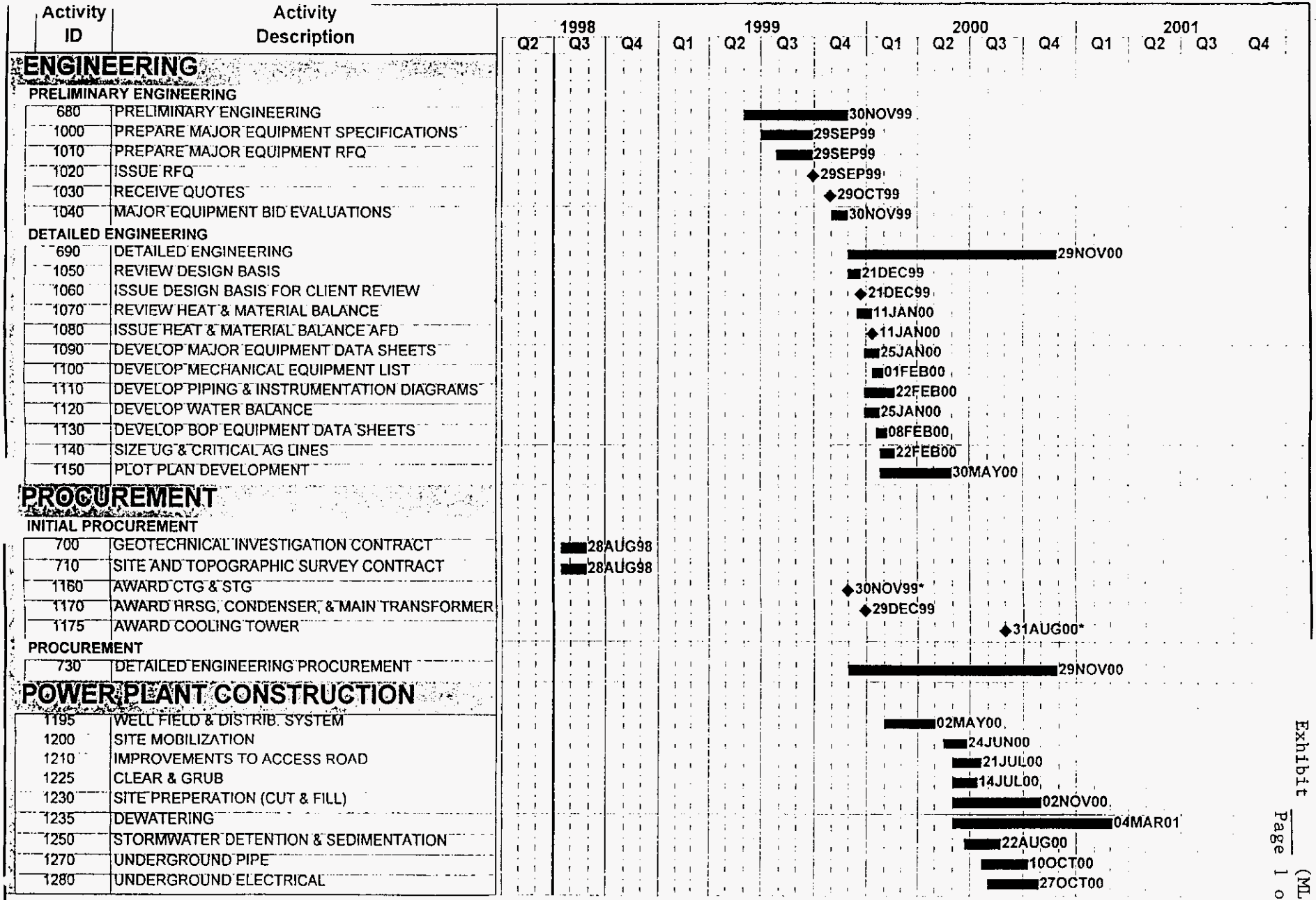


FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Locascio
Exhibit (ML-11)
Page 1 of 2

Activity ID	Activity Description
POWER PLANT CONSTRUCTION	
1300	PILING
1310	ADMIN/WAREHOUSE & CONTROL ROOM
1320	CONCRETE
1330	PIPERACK ERECTION
1335	REUSE WATER SYSTEM TO PLANT
1340	BOP MECHNICAL
1370	CTG 1 DELIVERY
1380	CTG 1 INSTALLATION
1400	CTG 2 DELIVERY
1410	CTG 2 INSTALLATION
1420	HRSG 1 DELIVERY
1430	HRSG 2 DELIVERY
1440	HRSG INSTALLATION (1 & 2)
1442	STG DELIVERY
1444	STG INSTALLATION
1450	COOLING TOWER BASIN
1460	COOLING TOWER ERECTION
1480	ERECT TANKS & CLARIFIERS
1482	SUBSTATION
1484	115 KV XMISSION LN. DBL. CIRCUITING
1486	TRANSFORMER INSTALLATION
1488	BOP ELECTRICAL
1490	CEMS
1492	DCS
1494	PAINTING & INSULATION
1496	GAS SUPPLY PIPELINE & METERING STATION
1500	MECHANICAL COMPLETION
1505	IN-PLANT ROADS
1510	PAVING PLANT ACCESS ROAD FROM SR 44
COMMISSIONING, STARTUP, & PERF. T	
770	COMMISSIONING, STARTUP, PERFORMANCE
COMMERCIAL OPERATION	
780	COMMERCIAL OPERATION

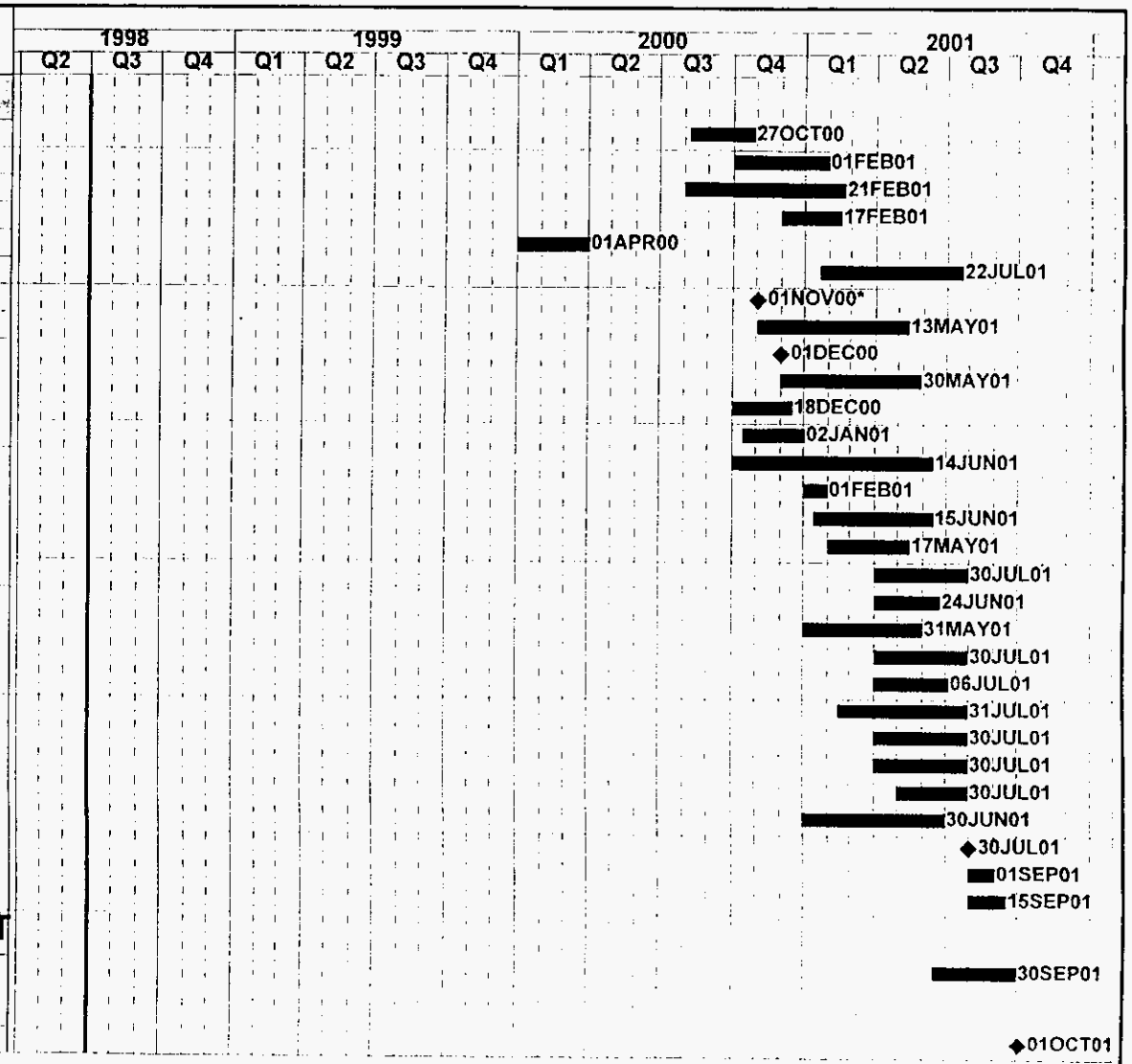


Exhibit ____ (ML-11)
Page 2 of 2

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Armand
Exhibit ____ (MPA-1)

QUALIFICATIONS OF MICHEL P. ARMAND, P.E.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 24-Part1
COMPANY/ WITNESS: Armand
DATE: 12-2-98

MICHEL P. ARMAND

Michel Armand is a professional electrical engineer with over 30 years of experience in utility transmission and distribution planning and engineering. He is particularly proficient in the areas of transmission reliability and network security, having performed numerous load flow, short-circuit and transient stability studies to justify system development plans, determine the need for system reinforcements or to identify operating limits. Over the past decade, Mr. Armand was instrumental in developing a system-wide breaker evaluation program and introducing an innovative methodology for assessing system-wide losses for Florida Power & Light Company. He also performed the first statistical analysis of the performance of the utility's distribution system, leading to a process of continual improvement in system losses and a reduction in outages. In addition, Mr. Armand has testified before the Nuclear Regulatory Commission and various state courts in condemnation hearings.

EDUCATION

M.B.A. - Engineering Management
Baruch College of City University of New York

B.E. - Electrical Engineering
City College of City University of New York

B.A. - Liberal Arts
College St. Martial, Port-Au-Prince, Haiti

PROFESSIONAL HISTORY

Resource Management International, Inc.
Manager, Transmission Planning

Government of Haiti
Energy Consultant, Prime Minister's Office

Florida Power and Light Company
Director, Protection and Control Systems

Consolidated Edison Company of New York
Senior Engineer

REPRESENTATIVE PROJECT EXPERIENCE

Performed an independent assessment of Florida Power & Light Company's energy reduction product offerings and determined their effectiveness in achieving the goals of the utility's demand-side programs. Based on analysis, recommended a marketing approach based on the market potential for a specific program given the four very distinct weather regions of Florida. The analysis also provided valuable insight into the behavior of load during the state's winter and summer seasons. As a result, the utility rescheduled pool pumps, an 800-MW load at the time, to different time slots to avoid the early morning peak in the winter and the late afternoon peak in the summer.

As a project team member, conducted evaluations necessary to justify Florida Power & Light Company's plans to construct two

500-kV lines from the Georgia state line in the north to a point 310 miles south. Wrote testimony in support of the economic and reliability benefits of the lines in proceedings of the Florida Transmission Line Siting Act before the state Public Service Commission. Performed technical studies to define the line parameters, the ancillary equipment, and the termination of various segments of the project. Given the considerable benefits of reducing oil consumption in favor of coal, the project was given accelerated depreciation privileges for ratemaking purposes.

As a utility manager, developed a set of recommendations for preventing a blackout similar to one on May 17, 1985 that put the Greater Miami-Ft. Lauderdale area in the dark for three hours. Recommended a computer program that monitors Florida Power & Light Company's utility system for specific conditions and takes remedial action within a 15-20 second time window. The utility had incurred severe economic penalties up until the time this computer program was deployed and economic dispatch was resumed. The same computer-supervised program was replicated in another part of the utility system, providing additional economic benefit.

As project manager, oversaw the definition, design, development, testing, and implementation of an automated system for evaluating the adequacy of transmission circuit breakers on the Florida Power & Light Company system. Coordinated the work of equipment specialists, computer programmers, and system planners to arrive at a program that would consistently and accurately perform the numerous calculations required for determining system reliability. The program was instrumental in eliminating the serious potential for human errors associated with the manual methods previously used. The process of an annual evaluation provided the lead time needed to order and install system replacements in a coordinated fashion.

As chief energy advisor, was responsible for developing and recommending options for restructuring Haiti's state-owned utility in response to that government's shrinking ability to fund the utility system. Evaluated various options that included: (1) restructuring the utility to operate as an independent commercial enterprise owned by the state; (2) contracting with a foreign entity to manage and operate the utility within a fixed time period; (3) leasing the utility's assets and the franchise for a 25-30 year period with the assets plus additions reverting to the state at contract expiration; and (4) selling the utility outright to private local and/or foreign investors. Each option was evaluated based on economic, financial and political risk considerations and presented to the government of Haiti. Based on the analysis, recommended proceeding with the lease option to be preceded by a five-year management contract to increase the value of the assets and the

lease. The Haitian parliament approved the approach and is developing a new regulatory framework to allow the state and the system operator to achieve their objectives.

As lead investigator, directed an intensive three-month analysis of electric system losses to help Florida Power & Light Company make more informed economic decisions on system reinforcements. Collected extensive data and interviewed dozens of utility personnel. Determined the techniques used to measure system losses varied throughout the company, leading to capital investment decisions that were often based on crude assumptions. As a result, prepared a reference document in which every component of system losses and their various implications were addressed. Using this systematic approach, the utility is able to reduce system losses more cost-effectively.

As project manager, was charged with researching, developing, and implementing a transmission outage database system for Florida Power & Light Company. The purpose was to collect information in such a way that it could be stored, analyzed, categorized, and used by all departments involved in the design, engineering, construction, and operation of the transmission system. The task involved the collection of valid requirements from all concerned parties, the resolution of conflicting demands, and the acquisition of senior management approval of a plan for collecting, analyzing, and categorizing data from the prior period of 1983 to 1987. The data not only proved invaluable to the system operators, transmission maintenance personnel, and transmission design and engineering staff, it had other unexpected results. The information was used to effectively show potential industrial customers the reliability of a particular transmission line, relied on in court proceedings addressing power quality issues, and used in regulatory hearings dealing with the need for new transmission corridors.

As department supervisor, was responsible for testing and assessing the dynamic performance of the planned generation and transmission system for Florida Power & Light Company. Presented testimony on the ability of the system to support the addition of a second nuclear unit at St. Lucie Power Station in hearings before the Atomic Safety and Licensing Appeal Board of the Nuclear Regulatory Commission. Successfully demonstrated the adequacy of the transmission grid, leading to approval of the operating license.

As project manager, conducted an examination of options available to Florida Power & Light Company to determine final disposition of the utility's questionable power generation assets. The assets could be kept in use, put into long-term reserve, shut down, retired, or sold. Taking into account the various interests of the

operating groups, recommendation was made to choose the long-term reserve shutdown as the most attractive option financially, based on considerations of capacity addition and system adequacy and reliability.

PROFESSIONAL MEMBERSHIPS

Institute of Electric and Electronic Engineers

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Armand
Exhibit ____ (MPA-2)

SUMMARY OF TRANSMISSION PROJECT EXPERIENCE,

RESOURCE MANAGEMENT INTERNATIONAL, INC.

Klamath Falls Project - Oregon - RMI conducted an evaluation of the impacts and benefits to the region's 500-kV and 230-kV transmission system associated with the interconnection of a proposed 500 MW cogeneration facility with the system in Southern Oregon. In assessing these effects and benefits, RMI performed pre- and post-project studies modeling both normal and contingency conditions. These studies utilized power flow, post-transient, and transient stability study methodologies and revealed that the project provided voltage support to the system and potentially increased transfer capability.

Proposed Power Project in the ECAR Area - RMI conducted preliminary evaluations of interconnecting proposed generating facilities (ranging from 200 to 800 MW in size) to the transmission system at four sites in the Virginia-West Virginia-Kentucky area and delivering the project output to customers in Virginia, the northeastern United States, or the southeastern United States. The evaluations addressed: (i) pre- and post-project transmission system performance under both normal and contingency conditions for the "as planned" system in the 2004 period; (ii) pre- and post-project transmission system performance with key proposed facilities not in service; and (iii) rates for transmission service over the transmission facilities of major utilities in the area.

Combustion Turbine Siting - Minnesota - RMI performed a preliminary siting study relative to the potential development of a 125-MW combustion turbine project connected to the system of Northern States Power in Minnesota. RMI identified potential sites with proximity to natural gas pipelines and transmission facilities taking into account the location of wetlands and areas which are attainment and non-attainment with respect to SOx and NOx emissions. RMI then used information on potential site locations in powerflow analyses of the NSP system without the combustion turbine project and with the project interconnected at various points on the utility's 115-kV and 345-kV system.

Proposed Power Project - New York - RMI conducted powerflow studies of the system in upper New York to assess the relative merits of the installation of local generation or the development of reinforcements to the transmission system. The results of these studies were subsequently used in developing information regarding reliability and power quality issues facing a municipal electric in the area which is presently served via a radial system with a history of poor reliability.

Proposed Power Project - Hawaii - RMI provided transmission planning services relative to the interconnection of a potential power project with the system of the Hawaii Electric Light Company (HELCO) which serves the island of Hawaii. In doing so, evaluated: (1) the facilities required to properly interconnect the new generating facility to the HELCO transmission system; (2) the system reinforcements, if any, required due to the addition of proposed new generating facilities by HELCO or by the developer; (3) the effects on HELCO's system losses for different resource development plans; and (4) the reasonableness of HELCO's cost estimates associated with the interconnection facilities and system reinforcements for the different plans.

Proposed Merchant Plants- Texas - RMI has conducted assessments regarding the interconnection of merchant plants with the interconnected 345/138-kV system in northeastern Texas and in southern Texas. Those in northeastern Texas were conducted to identify potential interconnection points for 500-1000 MW of new generation facilities while those in southern Texas were conducted to identify potential interconnection points for 200-400 MW of new generation in the Brownsville area. Both studies addressed system impacts associated with such generation and included. included conducting both base case and N-1 outage studies on the pre-and

post-generating project system.

High Desert Power Project - RMI has been involved in the siting and licensing aspects of the High Desert Power Project (located near Victorville, California) since the project's inception. Specific activities have included: (i) performing the initial evaluations of potential contractual transmission paths between the proposed power project and potential municipal customers in southern California and the effects which the proposed project would have on the interconnected transmission system in southern California; (ii) performing more specific technical analyses and developing cost estimates which served as the basis for the "transmission/interconnection" portions of the Application for Certification (AFC); (iii) working with the project proponents in responding to questions raised by CEC staff and an intervener; and (iv) working with the project proponents in review of SCE's activities relative to a project interconnection study.

Merchant Plant Development in Los Angeles Area - RMI provided technical and analytical services to a project developer considering the development of merchant facilities at sites within the Los Angeles area. Activities undertaken by RMI included: (i) reviewing the relationship of the proposed sites to the existing transmission system; (ii) obtaining, reviewing, and updating powerflow base cases and assessing pre-"project" transmission capacity; (iii) developing "site specific" base cases and assessing post-"project" transmission capacity; and (iv) developing information which differentiated the sites.

Expansion of Existing QF Sites - RMI performed a screening level evaluation of the potential for adding natural gas-fired generation at several power project sites in central and northern California owned by an IPP. The projects evaluated are fueled by biomass (wood waste) or coal and range in size from approximately 20 MW to 35 MW and are interconnected with the low voltage transmission systems of Pacific Gas & Electric or Southern California Edison. As part of this evaluation, RMI: (i) assessed if there was sufficient capacity in the existing transmission facilities to deliver both existing and potential new capacity from each site into the main grid; and (ii) identified and developed preliminary cost estimates for the additional transmission facilities that might be required to interconnect each expanded project site with the main grid.

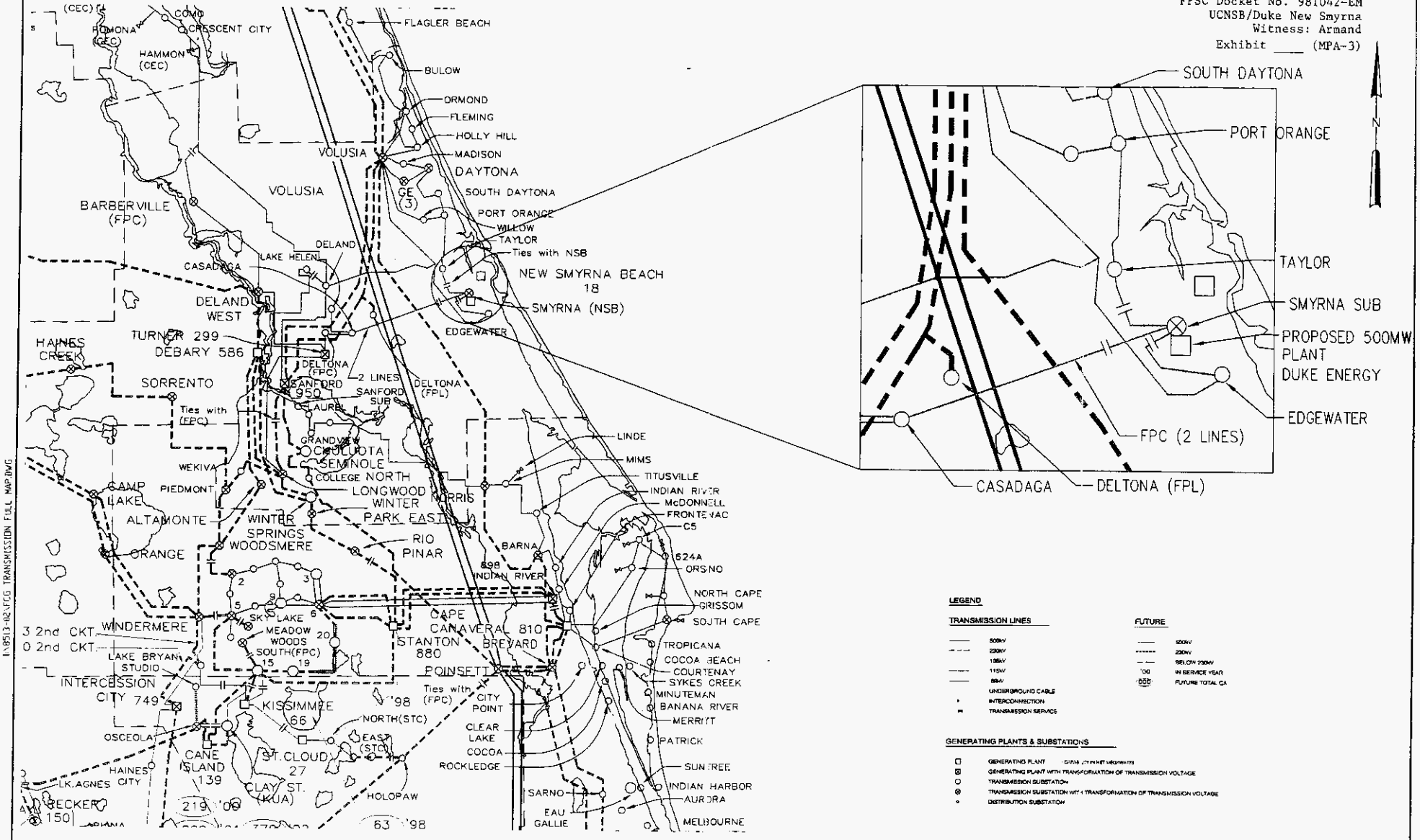
Merchant Plant Development in San Francisco Bay Area - RMI provided technical and analytical services to a project developer considering the development of merchant facilities at sites within the greater San Francisco Bay Area and the potential acquisition of certain generating facilities in the Area. Specific activities undertaken by RMI included: (i) developing information on capacity and energy requirements for various portions of the Area (e.g., the City and County of San Francisco); (ii) identifying and quantifying transmission constraints on identified transmission paths into and within the Area; (iii) assessing the degree to which the addition of generation would mitigate transmission constraints; and (iv) assessing the addition of new generation at both existing and greenfield plant sites on the fringes of the Bay Area.

Characterization of California Electric Supply and Transmission Infrastructure - RMI developed a report for a major project developer which addressed various aspects of the electric power industry including: (i) the Power Exchange (WEPEX) and the Independent System Operator (ISO) organizations and market structures; (ii) the identification of existing in-state generation and other sources of supply and the key attributes of each that would affect its market placement; (iii) current load forecasts and the need for new generation; (iv) the electric transmission system and evolving operating rules for it; and (v) the natural gas bulk transmission system and its future

outlook and the gas supply resources (and their costs) available to the different pipeline systems.

Market Price Projections for California and Southern Nevada/Western Arizona - RMI utilized the General Electric Multi-Area Production Simulation ("MAPS") model to develop projections of market clearing prices in California. Specific activities included: (i) acquiring a MAPS data set for the entire Western Systems Coordinating Council ("WSCC") and updating/expanding the model's transmission, generation, and fuel price assumptions to reflect latest available information; (ii) incorporating specific assumptions about future resources, fuel prices, and markets; (iii) developing data such that the operation of the transmission systems mimicked the postage stamp tariff structures of the Independent System Operator; and (iv) performing numerous simulations under several resource plans and hydroelectric availability conditions to develop market price forecasts and estimates of revenues and total costs for key resources.

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Armand
Exhibit ____ (MPA-3)



LEGEND

TRANSMISSION LINES

- 500kV
- 230kV
- 138kV
- 115kV
- 69kV
- UNDERGROUND CABLE
- INTERCONNECTION
- TRANSMISSION SERVICE

FUTURE

- 500kV
- 230kV
- BELOW 230kV
- '00 IN SERVICE YEAR
- 000 FUTURE TOTAL CA

GENERATING PLANTS & SUBSTATIONS

- GENERATING PLANT
- GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
- TRANSMISSION SUBSTATION
- TRANSMISSION SUBSTATION WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
- DISTRIBUTION SUBSTATION

I:\BS13-02\FIG TRANSMISSION FULL MAP.DWG

DESIGNED LARRY JAMES DRAWN CHECKED PROJ. ENGR.	FRANK ALONSO P.E. 38091 DATE	RMI RESOURCE MANAGEMENT INTERNATIONAL, INC.	SCALE NONE CAD REF FOR TRANSMISSION FULL MAP PROJ. NO. BS13.02	DUKE ENERGY POWER SERVICES	FIGURE 12 NEW SMYRNA BEACH POWER PROJECT TRANSMISSION INTERCONNECTION	DATE: AUGUST 1998 SHEET: ___ OF ___ DRAWING: F-1

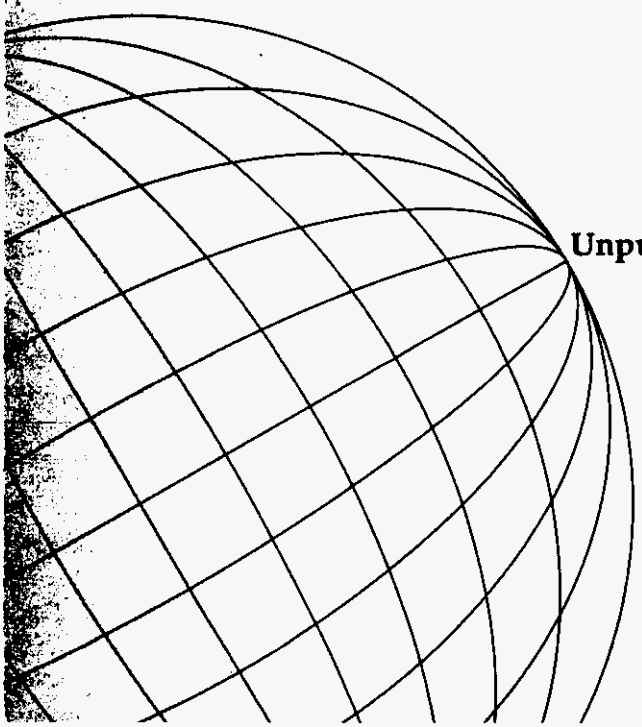
FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Armand
Exhibit ____ (MPA-4)

RESULTS OF POWER FLOW STUDIES 2001

Prepared for

DUKE ENERGY POWER SERVICES, INC.

July 2, 1998



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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 24-Part 2
COMPANY/ WITNESS: Armand
DATE: 12-2-98

RMI
RESOURCE MANAGEMENT INTERNATIONAL, INC.

RMI

RESOURCE MANAGEMENT
INTERNATIONAL, INC.

CONFIDENTIAL

July 2, 1998

Mr. Peter J. Ledig
Managing Director
Duke Energy Power Services, Inc.
5400 Westheimer Court
Houston, TX 77251

Subject: Transmission System Analysis in Support of
Duke Energy New Smyrna Beach Power Company

Dear Peter:

Enclosed are four copies of the subject report prepared in accordance with our agreement with Duke Energy Power Services. The study was re-run to accommodate the change in transmission configuration: a new 115kV circuit from Cassadaga to Lake Helen in place of the second 115kV circuit from Cassadaga to Detlona East.

The starting point for the analysis was supposed to be the powerflow base case, which we obtained from the Florida Municipal Power Agency. The electronic copy we received exhibited serious modeling flaws, and it became obvious that unless we were a member of the Florida Reliability Coordinating Council (FRCC), we would not have the means to thoroughly validate the model. After several frustrating attempts, we decided to obtain the 2001 Florida Electric Power Coordinating Group (FCG) model submitted to FERC in 1996. This model, after extensive testing, revealed itself to be a much better representation of the Florida transmission system. This is the model we used and which we believe to be accurate. This was confirmed, as the study progressed, when we received a copy of the FRCC 1999 Reliability Study and reviewed the 1998 Ten-Year Plan documents of the major utilities in Florida.

Therefore, the powerflow studies discussed in the enclosed report evaluated:

- Pre- and post-project transmission system performance for the year 2001 when the Florida system experiences peak loading conditions and imports 3,600 MW of power from Georgia.
- Pre- and post-project transmission system performance for the year 2001 when the Florida system is at peak load and imports 2,400 MW from Georgia.

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- Pre- and post-project transmission system performance for the year 2001 when the Florida system is loaded to 60% of summer peak load and imports 2,400 MW from Georgia. This load level is considered the average loading of the Florida system.
- Pre- and post-project transmission system performance for the year 2001 when the Florida system is experiencing 40% of summer peak load and imports 1,500 MW from Georgia. This load level is considered the minimum loading which occurs in the early morning hours in the spring.

Based on the studies discussed in the enclosed report, it appears that:

1. The proposed 500 MW project at New Smyrna Beach can reliably deliver its output into the Florida Transmission System.
2. The dispatch of generation at Florida Power Corporation's Debary plant has an impact on the distribution of the plant output at peak load conditions.
3. At average load conditions, 60% of summer peak, the output of the plant more evenly distributes itself on the transmission systems of Florida Power & Light and Florida Power Corporation.

We look forward to discussing the enclosed report with you and your counsel, Scheff Wright, at your convenience. In the interim, please call me at (916) 852-1300 should you have any questions on the enclosed.

Sincerely,

Michel P. Armand

Michel P. Armand
Manager

Enclosures

DUKE ENERGY POWER SERVICES, INC.

PROPOSED 500 MW FLORIDA GENERATING FACILITY
RESULTS OF POWER FLOW STUDIES
2001

Prepared for

DUKE ENERGY POWER
SERVICES, INC.

Prepared by

RMI
RESOURCE MANAGEMENT
INTERNATIONAL, INC.

UNPUBLISHED WORK © JULY 1998

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DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

PROPOSED 500 MW FLORIDA GENERATING FACILITY

RESULTS OF POWER FLOW STUDIES - 2001

EXECUTIVE SUMMARY

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. is proposing to build a 500 MW merchant plant in Florida in a joint venture with the Utilities Commission, City of New Smyrna Beach, Florida. The facility will be sited adjacent to the City's Smyrna Substation in Volusia County, Florida, and is scheduled to begin commercial operation by the summer of 2001. Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. retained Resource Management International, Inc. (RMI) to assist them in evaluating the interconnection of the proposed project with the Florida Transmission network.

In providing this support, RMI performed a series of preliminary power flow studies evaluating:

- Summer 2001 transmission system performance at peak load, importing 3,600 MW from the Southern Company, with and without the project.
- Summer 2001 transmission system performance at peak load, importing 2,400 MW from the Southern Company, with and without the project.
- Summer 2001 transmission system performance at an average 60% of peak load, importing 2,400 MW from the Southern Company, with and without the project.
- Summer 2001 transmission system performance at valley, 40% of summer peak, load condition importing 1,500 MW from the Southern Company, with and without the project.

To determine the ability of the project to deliver its output over the Florida transmission system, it was agreed that the total plant output will be scheduled alternatively to Florida Power and Light Company (FPL), Florida Power Corporation (FPC), Tampa Electric Company (TEC), Jacksonville Electric Authority (JEA), and Seminole Electric Cooperative (SEC). Each of these dispatch scenarios were modeled and tested with the four base cases.

It was also assumed, based on information received from the Utilities Commission, City of New Smyrna Beach, that the transmission configuration around the plant would be reinforced as follows:

1. Addition of a second Smyrna to Cassadaga 115-kV transmission circuit;
2. Addition of a new Cassadaga to Lake Helen 115-kV transmission circuit; and
3. Existing Debary to Altamonte 230-kV transmission circuit re-routed and connected to the Sanford 230-kV bus.

These transmission additions were modeled in all the power flow cases.

In summary, these studies (which are summarized in Table ES-1 and discussed in detail in Sections 1 and 2) show that for the conditions modeled:

1. None of the lines in the vicinity of the proposed Duke project were overloaded in the twenty-four base cases which were developed for these studies, and which model system normal conditions.
2. During the summer 2001 peak load period, loss of the Smyrna-Edgewater section of the Smyrna to Volusia 115-kV circuit No. 2 causes the Smyrna-Taylor section of the Smyrna to Volusia 115-kV circuit No. 1 to overload for all dispatch scenarios, when importing 3,600 MW from Georgia.
3. During the summer 2001 peak load period, when importing 2,400 MW from Georgia, loss of the Smyrna-Edgewater section of the Smyrna to Volusia 115-kV circuit No. 2 overloads the Smyrna-Taylor section of the Smyrna to Volusia 115-kV circuit No. 1. The highest overload occurs when the plant output is scheduled to Seminole. This same Smyrna-Taylor line section is also overloaded for loss of one of the two Cassadaga to Smyrna 115-kV circuits.
4. At loading levels of sixty percent and forty percent modeled in the study, no overload is noticed for all the contingencies simulated and for all dispatch scenarios. This is essentially the result of generation dispatched at FPC's Turner and Debary plants. At lower load levels, there is no unit dispatched at Turner and only 108 MW is dispatched at Debary. At peak load, Debary carries 610 MW and Turner 58 MW, which increases the initial flow on the Smyrna to Volusia two 115-kV circuits and results in one circuit overloading under certain outage conditions.

TABLE ES-1
SUMMARY OF POWERFLOW BASE CASES EVALUATED

Year	Case	Georgia Imports (MW)	Duke Generation (MW)	Output Delivered to:
2001	2001.PI	3,600	- 0 -	N/A
	2001.PIa	3,600	500	Florida Power & Light
	2001.PIb	3,600	500	Florida Power Corporation
	2001.PIc	3,600	500	Tampa Electric Company
	2001.PId	3,600	500	Jacksonville Electric Authority
	2001.PIe	3,600	500	Seminole Electric Cooperative
2001	2001.	2,400	- 0 -	N/A
	2001.a	2,400	500	Florida Power & Light
	2001.b	2,400	500	Florida Power Corporation
	2001.c	2,400	500	Tampa Electric Company
	2001.d	2,400	500	Jacksonville Electric Authority
	2001.e	2,400	500	Seminole Electric Cooperative
2001	2001-60	2,400	- 0 -	N/A
	2001-60a	2,400	500	Florida Power & Light
	2001-60b	2,400	500	Florida Power Corporation
	2001-60c	2,400	500	Tampa Electric Company
	2001-60d	2,400	500	Jacksonville Electric Authority
	2001-60e	2,400	500	Seminole Electric Cooperative
2001	2001-40	1,500	- 0 -	N/A
	2001-40a	1,500	500	Florida Power & Light
	2001-40b	1,500	500	Florida Power Corporation
	2001-40c	1,500	500	Tampa Electric Company
	2001-40d	1,500	500	Jacksonville Electric Authority
	2001-40e	1,500	500	Seminole Electric Cooperative

Therefore, based on the preliminary studies discussed in this report, it appears that:

1. 500 MW can be reliably sited at the Smyrna Substation of the Utilities Commission, City of New Smyrna Beach with the proposed transmission reinforcements.
2. The output of the plant minus the portion reserved for New Smyrna Beach, can be delivered without imposing undue burden on the Florida Transmission system under most dispersed dispatch scenarios.

As discussed in Section 2 (Results of Powerflow Studies), each of the cases summarized in Table ES-1 were used as a starting point in evaluating system performance under both normal and single facility-line or generator-(N-1) outage conditions. Comparison of pre- and post-project power flows over key lines in the proximity of the project shows that at peak most of the plant output, 55.4%, flows over the two Smyrna to Volusia transmission circuits, while the two Smyrna to Cassadaga transmission circuits carry a lower, 33.4%, percentage. The remainder is absorbed by loads in the City of New Smyrna Beach. At lower load levels, when Turner plant is not dispatched and the output of Debary plant is reduced, the projected plant output is more evenly distributed between FPL: (49.0%) and FPC (41.5%).

Documents reviewed and utilized by RMI during these studies included:

- The Florida Reliability Coordinating Council (FRCC) "1997 Ten Year Plan - State of Florida" prepared in early 1997.
- The Florida Public Service Commission "Review of Electric Utility 1996 Ten Year Site Plans"
- FPL's "1998 Ten Year Plant Site Plan"
- FMPA's "1998 Ten Year Site Plan"
- The "Ten Year Site Plans" prepared by the other generating utilities in Florida
- FRCC's "1997 Final Transmission System Constraint Maps"
- FRCC's "1997 Transfer Capability Study: FLA/SOU Interface
- FRCC's "1999 Reliability Study"

The powerflow base cases used in these studies were based on the 2001 summer peak case filed with FERC by the Florida Coordinating Group (FCG) in the spring of 1996. The FCG case was reviewed and modified as necessary to represent both the existing

and planned utility generation anticipated to be on-line in 2001 based on information in the documents referenced above. The original case was also updated to reflect approximately 95 percent of the amount of firm non-utility generation capacity anticipated to be on-line in 2001. The resultant 2001 summer peak case (case 2001) was then used to derive the other cases: 2001-PI, 2001-60, and 2001-40.

Case 2001-PI was obtained by increasing import from George to 3,600 MW and reducing FPL generation in the south end by approximately 1,200 MW. All loads were maintained at peak load.

Case 2001-60 was obtained by scaling loads in Florida and Georgia to represent 60% of peak load level. Generation in Florida was redispatched for each control area. Generation in Georgia was scaled down. Import was maintained at 2,400 MW.

Case 2001-40 was derived by scaling loads in Florida and Georgia to represent 40% of peak load level. Generation in Florida was redispatched for each control area. Generation in Georgia was scaled down. Import from Georgia was reduced to 1,500 MW and interchange schedules were modified.

SECTION 1 POWERFLOW BASE CASE DEVELOPMENT

As noted in the Executive Summary, the powerflow base cases used in these studies were based on the 2001 summer peak case filed with FERC by the Florida Electric Power Coordinating Group (FCG) in the spring of 1996. This powerflow case represented the system in peninsular Florida as consisting of fifteen control areas with a combined load of slightly over 36,000 MW and with approximately 34,400 MW of generation (both utility and non-utility) as being on-line. Imports into Florida from Georgia were approximately 2,400 MW and Florida system losses were approximately 740 MW. The fifteen control areas and the load and generation represented in each, are summarized in Table 1-1.

TABLE 1-1
FLORIDA CONTROL AREA LOADS AND GENERATION IN FCG 2001 PEAK CASE

Control Area	Load (MW)	Generation (MW)
FP&L	17,107	15,350
FPC	7,092	7,918
Ft. Pierce/Vero Beach	255	164
Gainsville	382	393
Homestead	57	15
Jacksonville	2,247	2,549
Key West	114	49
Kissimmee 1/	235	335
Lake Worth	83	57
New Smyrna Beach	83	20
FMPP 2/	1,183	1,932
Seminole	2,430	1,682
City of Starke	16	6
Tallahassee	497	471
Tampa Electric	3,298	3,494

1/ includes all of the generation at Cane Island.

2/ Includes FMPA, Orlando, Lakeland, and St. Cloud.

As shown in Table 1-1, the FCG 1996 base case for 2001 assumed that Fort Pierce and Vero Beach would operate as a mini-pool and that Kissimmee would operate its own

control area. RMI is aware that Kissimmee has become a member of the FMPP and of the current FMPA IDO pool changes taking place, which separate Fort Pierce's and Vero Beach's operations. Knowing that these IDO arrangements are still being sutdied and are likely to result in further changes, RMI assumed that Fort Pierce and Vero Beach would continue to operate as a mini-pool, and that Kissimmee would operate its own control area in the studies performed for Duke Energy Services. The same control areas were identically replicated in the latest FRCC transmission study: 1999 Reliability Study.

RMI is also aware of the fact that loads on the system in Florida tend to be higher in the winter than in the summer. However, because the peak winter load periods tend to be of relatively short duration compared to those during the summer, it is believed that studies of summer conditions are more appropriate in the preliminary types of studies conducted for Duke Energy Services.

The FCG case was carefully reviewed and the data on generation resources was compared to information contained in the FRCC's 1997 Ten Year Plan - State of Florida (Plan), and the other documents referenced in the Executive Summary. Data on the transmission system was also carefully reviewed and appropriate adjustments made. Specifically:

1. The maximum capacity available (the "Pmax") for each utility generating unit in-service as of January 1, 1997, was set equal to the "summer net capability."
2. Utility generating units were added based on information in the Plan such that the data base represented generation anticipated to be available as of the summer of 2001. One of the units added was a 120 MW FMPA combustion turbine at Cane island denoted in the Plan as being in service in June 2001.
3. A list of non-utility generators modeled in the FCG case was developed and compared to the information relative to the firm capacity from such resources presented in the Plan. Efforts were made to replicate, as closely as possible, the information in the Plan. The final result was a data set that modeled a total of 2,395 MW of firm non-utility generation in peninsular Florida (the Plan shows that total of non-utility generation in peninsular Florida would be 2,416 MW as of January 1, 1997, and 2,531 MW as of January 1, 1999).
4. The transmission system around the Smyrna 115 kV Substation, belonging to the Utilities Commission, City of New Smyrna Beach, was found to be substantially different than the actual system configuration. A new 230/115-kV substation belonging to Florida Power and Light was modeled at a site named Sugarmill north of the Smyrna Substation. Extensive transmission

reconfiguration was also modeled. Upon research, it was concluded that such substation, although represented in the case, was not reported in any public document by FP&L for the period extending to the year 2007. Therefore, the transmission system around Smyrna substation was restored to present day configuration.

The result of these efforts was a new base case (Case 2001) with the load and resource characteristics summarized in Table 1-2. This new case was modified to reflect the proposed 500MW plant connected at the Smyrna Substation and the additional transmission as proposed by the Utilities Commission, City of Smyrna Beach. Specifically:

1. The addition of a second 115-kV transmission circuit between Smyrna Substation and the Cassadaga Substation of Florida Power Corporation.
2. The addition of a new 115-kV transmission circuit between the Cassadaga and Lake Helen Substations of Florida Power Corporation.
3. The rerouting of the existing 230-kV transmission circuit between Debary generating station and Altamonte Substation of Florida Power Corporation into the Sanford generating station 230-kV switchyard of Florida Power and Light. The result is a new Debary-Sanford 230-kV circuit and a new Sanford-Altamonte 230-kV circuit.

The 2001. base case, modified with the proposed plant and the added transmission reinforcement, was then used to develop the peak import case, representing a 3,600 MW of import from Georgia. This was accomplished by increasing generation in Georgia by slightly over 1,200 MW, and decreasing FP&L generation at Turkey Point by approximately 770 MW and at Port Everglades by approximately 410 MW. The FP&L swing generator (at Cape Canaveral) adjusted to provide the slight amounts of additional capacity required. The resultant case was denoted Case 2001-PI (peak import).

TABLE 1-2: CASE 2001 - FLORIDA PENINSULAR LOADS AND RESOURCES

	Control Area			Interchange				Generation			On Line	Spinning		Total	Ready 1/	
	Load	Losses	Total	Net	GA Firm	Scherer	Other	Required	QF/IPP	Utility	Capacity	MW	% 2/	Capacity	MW	% 2/
FP&L 3/	17,107	344	17,451	(2,054)	(913)	(633)	(508)	15,397	907	14,490	15,055	565	3.30	15,534	479	2.80
FPC	7,092	190	7,282	763	(405)	0	1,168	8,045	1,152	6,893	7,217	324	4.57	7,591	374	5.27
Ft. Pierce/Vero Bch	255	2	257	(94)	0	0	(94)	163	0	163	164	1	0.39	279	115	45.10
Gainesville	382	4	386	8	0	0	8	394	0	394	413	19	4.97	512	99	25.92
Homestead	57	0	57	(42)	0	0	(42)	15	0	15	27	12	21.05	52	25	43.86
Jacksonville	2,247	38	2,285	266	(220)	(200)	686	2,551	0	2,551	2,665	114	5.07	2,720	55	2.45
Key West	114	2	116	(67)	0	0	(67)	49	0	49	54	5	4.39	88	34	29.82
Kissimmee	235	4	239	75	0	0	75	314	0	314	325	11	4.68	325	0	0.00
Lake Worth	83	0	83	(26)	0	0	(26)	57	0	57	78	21	25.30	78	0	0.00
New Smyrna Bch	83	0	83	(64)	0	0	(64)	19	0	19	20	1	1.20	20	0	0.00
FMPP 4/	2,194	27	2,221	(152)	0	0	(152)	2,069	0	2,069	2,346	277	12.63	2,775	429	19.55
Seminole	2,430	34	2,464	(972)	0	0	(972)	1,492	296	1,196	1,250	54	2.22	1,250	0	0.00
Stark	16	0	16	(10)	0	0	(10)	6	0	6	7	1	6.25	7	0	0.00
Tallahassee	497	13	510	(35)	0	0	(35)	475	0	475	510	35	7.04	694	184	37.02
Tampa EC	3,305	51	3,356	33	0	0	33	3,389	41	3,348	3,530	182	5.51	3,530	0	0.00
Total	36,097	709	36,806	(2,371)	(1,538)	(833)	0	34,435	2,396	32,039	33,661	1,622	4.49	35,455	1,794	4.97

Total Reserves (MW)	3,416
Total Reserves (% of load)	9.46

1/ "Ready (reserves)" consists of capacity that is not in operation but which would be avialable to serve load upon startup.

2/ As percent of load

3/ Does not include 14 MW of diesels at Turkey Point

4/ Does not include 5 MW of diesels at Larsen

The 2001. base case, representing peak load level and 2,400 MW of import from Georgia, was modified to represent loading conditions of 60% of peak. This load level is considered average loading for the Florida system, and represents a considerable portion of the load duration curve for Florida. Therefore, this load level has always been the benchmark of all transmission assessment studies by powerflow or by transient stability conducted by the Florida Electric Power Coordinating Group, the predecessor of the FRCC. To achieve such reduction, the load in each control area was scaled down to sixty percent. The total generation required for each area was calculated by adding load plus generation plus interchange and then re-dispatching each area by the removal of appropriate generating units to achieve total required generation. The only exception was Area 10, New Smyrna Beach, where the total generation was removed. The resultant case was denoted 2001-60.

The 2001. base case, representing peak load level and 2,400 MW of import from Georgia, was modified to represent loading conditions of 40% of peak and a 1,500 MW of import from Georgia. This minimum load level, usually called valley load, is experienced in the spring time and is considered in most FRCC analysis of the Florida transmission system. The concern of valley load is high voltage on the transmission system necessitating removal of most shunt capacitors, activation of available shunt reactors and ultimately in the extreme, removal of high-voltage transmission circuits. The great majority of shunt capacitors were removed due to high voltage, but no transmission line was removed and the new case denoted 2001-40.

The dispatch for FPL, modeled after the FRCC 1999 Reliability Study of January 29, 1997, shows one St. Lucie Nuclear out on refueling, both Manatee units at full output (presumably on Orimulsion) and the combined cycle units at Martin Plant shut down. With only the nuclear units at Turkey Point, the Lauderdale combined cycle at full output, the only way to model sale of 500 MW to FPL in case 2001-40a. was to reduce one Manatee unit output by 500 MW. Similarly, the dispatch for FPC modeled after the same FRCC 1999 Reliability Study requires the reduction of output for the two Crystal River fossil units on line as modeled in case 2001-40b.

SECTION 2 RESULTS OF POWERFLOW STUDIES

As discussed in Section 1, twenty-four powerflow base cases (Summarized in Table 2-1) were developed in order to evaluate the effects of the proposed 500 MW plant on the performance of the Florida system. Each of the cases summarized in Table 2-1 were used as a starting point in evaluating system performance under normal conditions by comparing pre- and post-project powerflows over key lines in the proximity of the plant and over certain lines monitored in past FCG transmission assessment studies.

In addition, a number of single line or generator outages (N-1) were simulated on all of the base cases to assess performance under other than normal conditions. RMI also checked flows over twelve of the thirteen constrained transmission paths discussed in the FRCC 1997 Final Transmission System Constraint Maps. Table 2-2 is a list of the single outages simulated on each of the twenty-four base cases. Table 2-3 is tabulation of the FRCC constrained paths and the transmission circuits affected. Constrained paths #15 and #16 are the Stanton-Rio Pinar 230-kV line. Because the studies performed represent summer season peak load conditions and, therefore, power transfers from Georgia to Florida, Constraint #13 (which deals with flows from Florida to Georgia) was not checked. Appendix V is a summary of total constrained path flows in graph form, representing the pre- and post-project performance for the 24 bases cases.

The contingencies listed in Table 2-2 represent a broad array of outages throughout the Florida system designed to test any negative impact this new plant may have. Those outages are similar to those selected for FRCC transmission assessment studies. Some were not expected to be impacted by the new plant. Others could potentially be influenced by whether the output was scheduled to the different receiving parties. In all cases, the most pessimistic conditions were modeled.

The circuits monitored as shown in Table 2-4 represent transmission lines that showed a tendency to experience loading problems in an earlier 1989 FCG study of the "1999 Long-Range Bulk Transmission Study." Those overloaded lines were localized phenomenons which seem to have since been corrected as we will see later in the discussion.

TABLE 2-1
SUMMARY OF POWERFLOW BASE CASES EVALUATED

Year	Case	Georgia Imports (MW)	Duke Generation (MW)	Output Delivered to:
2001	2001.PI	3,600	- 0 -	N/A
	2001.PIa	3,600	500	Florida Power & Light
	2001.PIb	3,600	500	Florida Power Corporation
	2001.PIc	3,600	500	Tampa Electric Company
	2001.PId	3,600	500	Jacksonville Electric Authority
	2001.PIe	3,600	500	Seminole Electric Cooperative
2001	2001.	2,400	- 0 -	N/A
	2001.a	2,400	500	Florida Power & Light
	2001.b	2,400	500	Florida Power Corporation
	2001.c	2,400	500	Tampa Electric Company
	2001.d	2,400	500	Jacksonville Electric Authority
	2001.e	2,400	500	Seminole Electric Cooperative
2001	2001-60	2,400	- 0 -	N/A
	2001-60a	2,400	500	Florida Power & Light
	2001-60b	2,400	500	Florida Power Corporation
	2001-60c	2,400	500	Tampa Electric Company
	2001-60d	2,400	500	Jacksonville Electric Authority
	2001-60e	2,400	500	Seminole Electric Cooperative
2001	2001-40	1,500	- 0 -	N/A
	2001-40a	1,500	500	Florida Power & Light
	2001-40b	1,500	500	Florida Power Corporation
	2001-40c	1,500	500	Tampa Electric Company
	2001-40d	1,500	500	Jacksonville Electric Authority
	2001-40e	1,500	500	Seminole Electric Cooperative

TABLE 2-2
INDEX TO OUTAGE CONTINGENCIES

Outage #	Bus 1	kV	Bus 2	kV	CKT
1	NSB-SMYR	115	CASSADAG	115	1
2	NSB-SMYR	115	EDGEWATR	115	1
3	NSB-SMYR	115	TAYLOR	115	1
4	NSB-SMYR	115	NSB-ARP	115	1
5	NSB-SMYR	115	NSB-FELD	115	1
6	CAMP LK	230	CENT FLA	230	1
7	SUWANNEE	230	SUWANNEE	115	1
8	SHELD	230	SHELD-NW	69	1
9	SHELD	230	SHELD-SE	69	1
10	OHIO	138	TMPBAY T	138	1
11	AZALEA	115	BENNETT	115	1
12	PERSHING	115	MICHIGAN	115	1
13	DUVAL	500	POINSETT	500	1
14	SILVR SP	230	SILVSPN	230	1
15	DUVAL	500	HATCH	500	1
16	ARCHER	230	HAILE	230	1
17	FT WHT N	230	SUWANNEE	230	1
18	OHIO-N	230	ELEVEN W	230	1
19	WOODSMER	230	PINEHILL	230	1
20	SO WOOD	230	SO WOOD	115	1
21	IND RIV	230	STANTON	230	1
22	CURRY FD	230	STANTON	230	1
23	BRKRIDGE	500	CRYST RV	500	1
24	KATHLEEN	500	CENT FLA	500	1
25	SUWANNEE	230	STERLING	230	1
26	KATH-DUM	500	KATHLEEN	230	1
27	NLONGWD	230	WTR SPGS	230	1
28	SKY LAKE	230	SO WOOD	230	1
29	WINDERME	230	SO WOOD	230	1
30	SO GIB	230	B BEND	230	1
31	SANFORD4	24	390 MW Gen		1
32	TP.4	22	693 MW Gen		1
33	STLUCIE1	22	839 MW Gen		1
34	MANATEE1	22	819 MW Gen		1
35	CR RV G3	22	812 MW Gen		1

TABLE 2-3
LIST OF CONSTRAINED PATHS IN FLORIDA

Const. Number	Constrained Path Name	Transmission Lines Involved
5	Lake Tarpon - Sheldon	Three Lake Tarpon-Sheldon: 230-kV lines.
6	Central-South East	Poinsett-Martin & Poinsett-Midway: 500-kV Lines Malabar-Midway & Malabar-Emerson: 230-kV Lines Malabar-West: 138-kV Line
7	Central-South	Ruskin-Manatee: 230-kV Line Big Bend-Manatee: 230-kV Line Big Bend-Ruskin: 230-kV Line
8	Northwest-Central	2 Silver Spring North-Silver Springs: 230-kv Line
9	Brookridge-South	Brookridge-Lake Tarpon: 500-kV Line Brookridge-Brooksville West: 230-kV Line Brookridge-Hudson: 230-kV Line
10	Northeast-Central	Duval-Poinsett & Rice-Poinsett: 500-kV Lines Putnam-Volusia & Burnel-Volusia: 230-kV Lines
11	Sylvan-North Longwood	Sylvan-North Longwood: 230-kV Line
12	Georgia-Florida	Hatch-Duval & Thalman-Duval: 500-kV Line Pine Grove-Sunannee & Kingsland-Yulee: 230-kV Line South Bainbridge-Tallahassee (sub 20): 230-kV Line Callaway-Port St. Joe: 230-kV Line Pine Grove-Jasper, Tarver-Jasper: 115-kV Line Scholtz-Woodruff: 115-kV Line Twin Lake-Suwannee Pl: 115-kV Line
13	Florida-Georgia	Same as 12 (flows reversed)
14	Crystal River-South	Crystal River-Brookridge: 500-kV Line CR Plant-Brookridge: 230-kV Line CR Plant-Cryst RE: 230-kV Line
15	Cape Canaveral-Indian River	Cape Canaveral-Indian River: 230-kV Line
16	Indian River-Cape Canaveral	Indian River-Cape Canaveral: 230-kV Line
17	Stanton-Central Florida	Stanton-Rio Pinar: 230-kV Line

TABLE 2-4
MONITORED BRANCHES

Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area
2001-Pl-1	SN PLANT	230	SYLVAN	230	1	1
2001-Pl-1	SYLVAN	230	N LONGWD	230	1	1
2001-Pl-1	IND RIV	230	STANTON	230	1	11
2001-Pl-1	SILVR SP	230	SILV SPN	230	1	2
2001-Pl-1	SILVR SP	230	SILV SPN	230	2	2
2001-Pl-1	RIO PINR	230	CURRY FD	230	1	2
2001-Pl-1	JUNEAU-W	138	GANNON	138	1	16
2001-Pl-1	NSB-SMYR	115	CASSADAG	115	1	2
2001-Pl-1	NSB-SMYR	115	EDGEWATR	115	1	1
2001-Pl-1	NSB-SMYR	115	TAYLOR	115	1	1
2001-Pl-1	NSB-SMYR	115	NSB-ARP	115	1	10
2001-Pl-1	NSB-SMYR	115	NSB-FELD	115	1	10
2001-Pl-1	SN PLANT	115	TURNER	115	1	1
2001-Pl-1	PASADENA	115	40ST-DUM	115	1	2
2001-Pl-1	MICHIGAN	115	KALEY	115	1	11
2001-Pl-1	MICHIGAN	115	GRANT	115	1	11
2001-Pl-1	PERSHING	115	GRANT	115	1	11
2001-Pl-1	AMERICAN	115	KALEY	115	1	11
2001-Pl-1	JASPER	115	WGHTCHPL	115	1	2
2001-Pl-1	AZALEA	115	BENNETT	115	1	11
2001-Pl-1	FLORALTP	69	INVERNTP	69	1	2
2001-Pl-1	ALACH TP	69	HIGH SPG	69	1	2
2001-Pl-1	PASADENA	230	PASADENA	115	1	2
2001-Pl-1	SUWANNEE	230	SUWANNEE	115	1	2
2001-Pl-1	SUWANNEE	230	SUWANNEE	115	2	2
2001-Pl-1	E CLRWTR	230	E CLRWTR	115	1	2
2001-Pl-1	IND RIV	230	IND RIV	115	1	11
2001-Pl-1	LARGO	230	LARGO A	69	1	2
2001-Pl-1	SHELD	230	SHELD-NW	69	1	16
2001-Pl-1	CLMT EST	230	CLMT EST	69	1	2
2001-Pl-1	WINDERME	230	WINDERME	69	1	2
2001-Pl-1	RIVER-S	230	RIVER-S	69	1	16
2001-Pl-1	ELEVEN W	230	ELEVEN-E	69	1	16
2001-Pl-1	JUNEAU-E	138	JUNEAU-E	69	1	16
2001-Pl-1	JASPER	115	JASPER	69	1	2

2000 - PI CASES

The result of these cases, representing summer peak loading in Florida and peak import of 3600 MW from Georgia, are summarized in Appendix I, which presents information about the lines monitored, the specific outage, and the five dispatch scenarios: the plant output respectively delivered to FPL, FPC, TEC, JEA, and SEC.

The analysis reveals that for the simulated outage of one Smyrna to Cassadaga 115-kV circuit, the Smyrna to Taylor Section of the Smyrna to Volusia No. 1, 115-kV circuit, loads to 100% of its rating when the output of the plant is delivered to Seminole.

Similarly, for the simulated outage of the Smyrna to Edgewater section of the Smyrna to Volusia No. 2 115-kV circuit, the Smyrna to Taylor Section of the Smyrna to Volusia No. 1 115-kV circuit is loaded above 100% for all dispatch scenarios. The configuration between Volusia Substation and Smyrna Substation is described in Figure 2-1, which presents the various line sections, their impedance values, and their MVA ratings. The loading of the substations supplied by each circuit is shown in Table 2-5. From our analysis of the result of this simulation, it appears that the overload on the Smyrna to Taylor section can be remedied by upgrading the section rating to 254 MVA if desired. However, the probability of failure of the line section between Smyrna and Edgewater must be carefully evaluated before such action is contemplated.

Redispatching was not considered a viable option since most units in Florida were on line at peak load. The redispatch to allow the import from Georgia to reach 3,600 MW was achieved by decreasing FPL generation at Turkey Point by approximately 770 MW, and at Port Everglades by approximately 440 MW. All generating stations around the proposed 500 MW project, Putnam, Debary, Sanford, Cape Canaveral, Stanton, and Indian River were at or near maximum dispatch level. Only FPC Turner plant, next to Debary, seems to have available capacity. However, dispatching more generation at Turner Plant would only increase the loading of the Smyrna to Volusia 115-kV circuits. It appears that, if the concern is the loss of the Smyrna to Edgewater section of the Smyrna to Volusia 115-kV circuit No. 2 at time of system peak, the output of the plant may have to be curtailed from peak value. This is not expected to be a common occurrence.

The strength of the network north of the plant causes a greater portion of its output to flow over the circuits between Smyrna and Volusia Substations, and a smaller portion to be delivered over the Smyrna to Cassadaga 115-kV circuits. The distribution of flows over the various lines emanating from Smyrna Substation for the various dispatch scenarios are shown in Appendix I-A.

2001. CASES

The result of these cases representing summer peak loading in Florida and an import of 2,400 MW from Georgia are summarized in Appendix II, which presents information about the lines monitored, the specific outage, and the five dispatch scenarios: the plant output respectively delivered to FPL, FPC, TEC, JEA, and SEC.

The analysis reveals that for the simulated outage of one Smyrna to Cassadaga 115-kV circuit, the Smyrna to Taylor section of the Smyrna to Volusia No. 1 115-kV circuit, exceeded its rating when the plant output is delivered to TECO, JEA, or SEC.

For the simulated outage of the Smyrna to Edgewater section of the Smyrna to Volusia No. 2 115-kV circuit, the Smyrna to Taylor section of the Smyrna to Volusia No. 1, 115-kV circuit is loaded above 100% of its rating for all dispatch scenarios. That same line section operates at its maximum rating when the plant output is delivered to Seminole under other simulated outages.

Appendix II-A shows the distribution of flows over the various lines emanating from Smyrna Substation for the various dispatch scenarios.

2001-60 CASES

The result of these cases representing 60% of summer peak loading condition in Florida, and an import of 2,400 MW from Georgia are summarized in Appendix III, which present information about the lines monitored, the specific outage and the five dispatch scenarios: the plant ouput respectively delivered to FPL, FPC, TEC, JEA, and SEC.

Review of the distribution of line flows around the plant, Appendix III-A, reveals a more even distribution of plant output between the lines going to FPL and FPC. The Smyrna to Volusia circuits carry approximately 49% of plant output, while the Smyrna to Cassadaga circuits carry about 41% of plant output. The decreased loading of the Smyrna to Volusia circuit No. 1 makes it less prone to overload under simulated outages. The difference resides in the dispatch of generation around the proposed plant.

At peak load, cases 2001. and 2001-PI, all the generators in Central East Florida were on line at Sanford, Cape Canaveral, Debary, Turner, Indian River, and Stanton. Most units were at their peak rating. The result was a tendency of the proposed plant output to flow toward Volusia and the FPL 230-kV system. At 60% load level, with

less generation on line in the Central East Area, more of the plant output is going over the Smyrna to Cassadaga circuits and less over the Smyrna to Volusia circuits.

The analysis reveals that for all the scenarios and all contingencies, no monitored line reached its maximum rating. Since 60% load level is representative of average loading of the Florida system, it appears the proposed plant can be dispatched most of the time.

2001-40 CASES

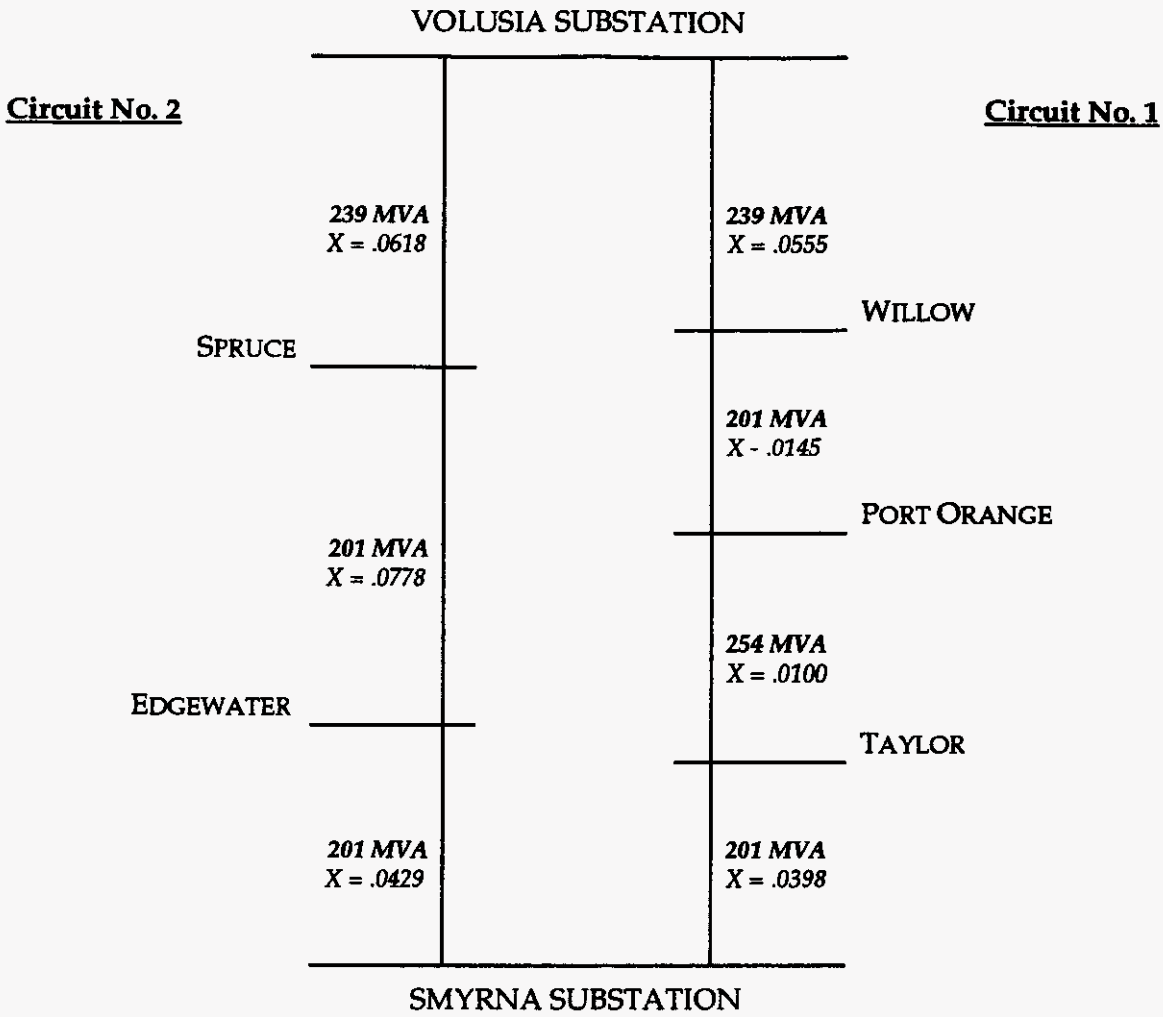
The result of these cases representing valley load conditions in Florida, 40% of summer peak load, and import of 1,500 MW shows that no simulated contingency causes any monitored line to exceed its rating. While the total plant output was dispatched in the five scenarios; realistically, less than maximum output would be needed. The Eastern interconnection is notorious for overgenerating in this season due to minimum loading requirements on the big coal units north of the Florida border. Scheduling 1,500 MW from Georgia may aggravate the project dispatch priority. Therefore, there is no expected transmission limitation at 40% load level to the full dispatch of the plant output. The results are summarized in Appendix IV.

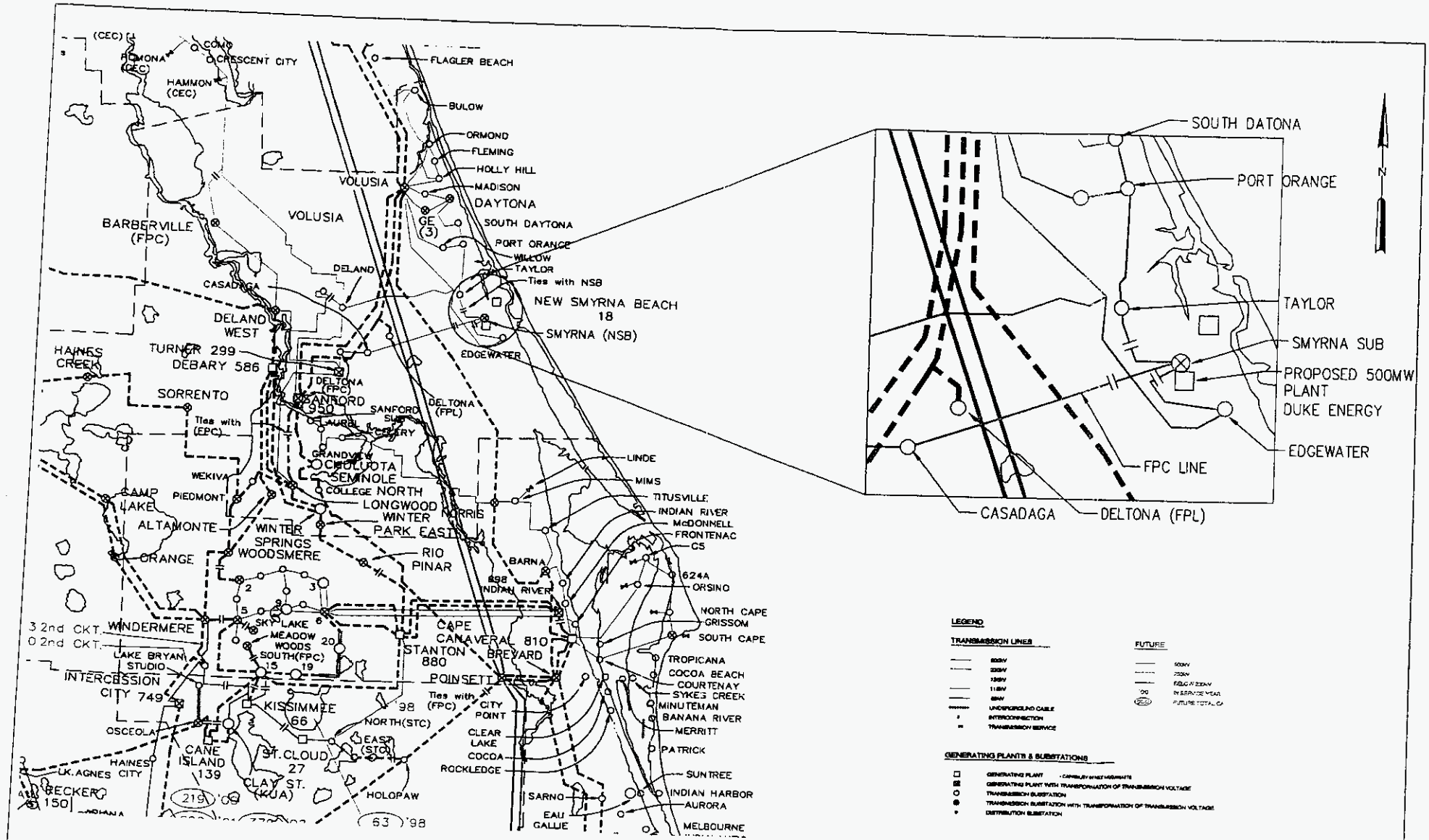
Appendix IV-A shows the distribution of flows over the various lines coming out of the proposed plant. The distribution of flows is more evenly divided between FPL (48.5%) and FPC (45.8%). This is due to the reduced level of generation around the proposed plant. The reduced loading of the Smyrna to Volusia No. 1 circuit makes it less susceptible to overload under specific outages as was the case in the peak load and peak import cases.

TABLE 2-5
SUBSTATION LOADS BY CIRCUIT

	Substation	P Load	Q Load
Circuit No. 1			
	Willow	46.70	16.40
	Port Orange	83.00	29.30
	Taylor	38.50	10.90
	Total	168.20	56.60
Circuit No. 2			
	Edgewater	45.50	15.70
	Spruce	24.10	8.10
	Total	69.60	23.80

FIGURE 2-1


VOLUSIA SUBSTATION
Circuit No. 2
Circuit No. 1
239 MVA
X = .0618
239 MVA
X = .0555
WILLOW
SPRUCE
201 MVA
X - .0145
PORT ORANGE
201 MVA
X = .0778
254 MVA
X = .0100
EDGEWATER
TAYLOR
201 MVA
X = .0429
201 MVA
X = .0398
SMYRNA SUBSTATION



DRAWN: LARRY JAMES	FRANK ALONZO P.E.	RMI Resource Management International, Inc.	SCALE: NONE	DUKE ENERGY POWER SERVICES	TRANSMISSION INTERCONNECTION 500 MW PLANT AT NEW SMYRNA BEACH
CHECKED:			CAD REF:		DATE: MARCH 1998
FINAL CHK:			FINAL NO:		SHEET: — OF —
					DRAWING: E-1

APPENDIX I

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-1	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-1	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-1	IND RIV	230	STANTON	230	1	11						
2001-PI-1	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-1	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-1	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-1	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-1	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-1	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-1	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-1	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-1	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-1	SN PLANT	115	TURNER	115	1	1						
2001-PI-1	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-1	MICHIGAN	115	KALEY	115	1	11						
2001-PI-1	MICHIGAN	115	GRANT	115	1	11						
2001-PI-1	PERSHING	115	GRANT	115	1	11						
2001-PI-1	AMERICA	115	KALEY	115	1	11						
2001-PI-1	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-1	AZALEA	115	BENNETT	115	1	11						
2001-PI-1	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-1	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-1	PASADENA	230	PASADENA	115	1	2						
2001-PI-1	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-1	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-1	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-1	IND RIV	230	IND RIV	115	1	11						
2001-PI-1	LARGO	230	LARGO A	69	1	2						
2001-PI-1	SHELD	230	SHELD-NW	69	1	16						
2001-PI-1	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-1	WINDERME	230	WINDERME	69	1	2						
2001-PI-1	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-1	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-1	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-1	JASPER	115	JASPER	69	1	2						
2001-PI-2	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-2	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-2	IND RIV	230	STANTON	230	1	11						
2001-PI-2	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-2	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-2	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-2	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-2	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-2	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-2	NSB-SMYR	115	TAYLOR	115	1	1		103.7	103.8	105.8	105.8	110.5
2001-PI-2	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-2	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-2	SN PLANT	115	TURNER	115	1	1						
2001-PI-2	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-2	MICHIGAN	115	KALEY	115	1	11						
2001-PI-2	MICHIGAN	115	GRANT	115	1	11						
2001-PI-2	PERSHING	115	GRANT	115	1	11						
2001-PI-2	AMERICA	115	KALEY	115	1	11						
2001-PI-2	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-2	AZALEA	115	BENNETT	115	1	11						
2001-PI-2	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-2	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-2	PASADENA	230	PASADENA	115	1	2						
2001-PI-2	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-2	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-2	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-2	IND RIV	230	IND RIV	115	1	11						
2001-PI-2	LARGO	230	LARGO A	69	1	2						
2001-PI-2	SHELD	230	SHELD-NW	69	1	16						
2001-PI-2	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-2	WINDERME	230	WINDERME	69	1	2						
2001-PI-2	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-2	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-2	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-2	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-3	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-3	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-3	IND RIV	230	STANTON	230	1	11						
2001-PI-3	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-3	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-3	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-3	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-3	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-3	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-3	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-3	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-3	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-3	SN PLANT	115	TURNER	115	1	1						
2001-PI-3	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-3	MICHIGAN	115	KALEY	115	1	11						
2001-PI-3	MICHIGAN	115	GRANT	115	1	11						
2001-PI-3	PERSHING	115	GRANT	115	1	11						
2001-PI-3	AMERICA	115	KALEY	115	1	11						
2001-PI-3	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-3	AZALEA	115	BENNETT	115	1	11						
2001-PI-3	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-3	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-3	PASADENA	230	PASADENA	115	1	2						
2001-PI-3	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-3	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-3	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-3	IND RIV	230	IND RIV	115	1	11						
2001-PI-3	LARGO	230	LARGO A	69	1	2						
2001-PI-3	SHELD	230	SHELD-NW	69	1	16						
2001-PI-3	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-3	WINDERME	230	WINDERME	69	1	2						
2001-PI-3	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-3	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-3	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-3	JASPER	115	JASPER	69	1	2						
2001-PI-4	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-4	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-4	IND RIV	230	STANTON	230	1	11						
2001-PI-4	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-4	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-4	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-4	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-4	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-4	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-4	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-4	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-4	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-4	SN PLANT	115	TURNER	115	1	1						
2001-PI-4	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-4	MICHIGAN	115	KALEY	115	1	11						
2001-PI-4	MICHIGAN	115	GRANT	115	1	11						
2001-PI-4	PERSHING	115	GRANT	115	1	11						
2001-PI-4	AMERICA	115	KALEY	115	1	11						
2001-PI-4	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-4	AZALEA	115	BENNETT	115	1	11						
2001-PI-4	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-4	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-4	PASADENA	230	PASADENA	115	1	2						
2001-PI-4	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-4	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-4	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-4	IND RIV	230	IND RIV	115	1	11						
2001-PI-4	LARGO	230	LARGO A	69	1	2						
2001-PI-4	SHELD	230	SHELD-NW	69	1	16						
2001-PI-4	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-4	WINDERME	230	WINDERME	69	1	2						
2001-PI-4	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-4	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-4	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-4	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-5	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-5	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-5	IND RIV	230	STANTON	230	1	11						
2001-PI-5	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-5	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-5	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-5	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-5	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-5	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-5	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-5	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-5	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-5	SN PLANT	115	TURNER	115	1	1						
2001-PI-5	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-5	MICHIGAN	115	KALEY	115	1	11						
2001-PI-5	MICHIGAN	115	GRANT	115	1	11						
2001-PI-5	PERSHING	115	GRANT	115	1	11						
2001-PI-5	AMERICA	115	KALEY	115	1	11						
2001-PI-5	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-5	AZALEA	115	BENNETT	115	1	11						
2001-PI-5	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-5	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-5	PASADENA	230	PASADENA	115	1	2						
2001-PI-5	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-5	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-5	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-5	IND RIV	230	IND RIV	115	1	11						
2001-PI-5	LARGO	230	LARGO A	69	1	2						
2001-PI-5	SHELD	230	SHELD-NW	69	1	16						
2001-PI-5	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-5	WINDERME	230	WINDERME	69	1	2						
2001-PI-5	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-5	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-5	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-5	JASPER	115	JASPER	69	1	2						
2001-PI-6	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-6	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-6	IND RIV	230	STANTON	230	1	11						
2001-PI-6	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-6	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-6	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-6	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-6	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-6	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-6	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-6	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-6	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-6	SN PLANT	115	TURNER	115	1	1						
2001-PI-6	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-6	MICHIGAN	115	KALEY	115	1	11						
2001-PI-6	MICHIGAN	115	GRANT	115	1	11						
2001-PI-6	PERSHING	115	GRANT	115	1	11						
2001-PI-6	AMERICA	115	KALEY	115	1	11						
2001-PI-6	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-6	AZALEA	115	BENNETT	115	1	11						
2001-PI-6	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-6	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-6	PASADENA	230	PASADENA	115	1	2						
2001-PI-6	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-6	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-6	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-6	IND RIV	230	IND RIV	115	1	11						
2001-PI-6	LARGO	230	LARGO A	69	1	2						
2001-PI-6	SHELD	230	SHELD-NW	69	1	16						
2001-PI-6	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-6	WINDERME	230	WINDERME	69	1	2						
2001-PI-6	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-6	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-6	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-6	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-7	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-7	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-7	IND RIV	230	STANTON	230	1	11						
2001-PI-7	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-7	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-7	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-7	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-7	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-7	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-7	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-7	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-7	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-7	SN PLANT	115	TURNER	115	1	1						
2001-PI-7	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-7	MICHIGAN	115	KALEY	115	1	11						
2001-PI-7	MICHIGAN	115	GRANT	115	1	11						
2001-PI-7	PERSHING	115	GRANT	115	1	11						
2001-PI-7	AMERICA	115	KALEY	115	1	11						
2001-PI-7	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-7	AZALEA	115	BENNETT	115	1	11						
2001-PI-7	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-7	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-7	PASADENA	230	PASADENA	115	1	2						
2001-PI-7	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-7	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-7	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-7	IND RIV	230	IND RIV	115	1	11						
2001-PI-7	LARGO	230	LARGO A	69	1	2						
2001-PI-7	SHELD	230	SHELD-NW	69	1	16						
2001-PI-7	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-7	WINDERME	230	WINDERME	69	1	2						
2001-PI-7	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-7	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-7	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-7	JASPER	115	JASPER	69	1	2						
2001-PI-8	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-8	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-8	IND RIV	230	STANTON	230	1	11						
2001-PI-8	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-8	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-8	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-8	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-8	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-8	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-8	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-8	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-8	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-8	SN PLANT	115	TURNER	115	1	1						
2001-PI-8	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-8	MICHIGAN	115	KALEY	115	1	11						
2001-PI-8	MICHIGAN	115	GRANT	115	1	11						
2001-PI-8	PERSHING	115	GRANT	115	1	11						
2001-PI-8	AMERICA	115	KALEY	115	1	11						
2001-PI-8	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-8	AZALEA	115	BENNETT	115	1	11						
2001-PI-8	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-8	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-8	PASADENA	230	PASADENA	115	1	2						
2001-PI-8	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-8	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-8	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-8	IND RIV	230	IND RIV	115	1	11						
2001-PI-8	LARGO	230	LARGO A	69	1	2						
2001-PI-8	SHELD	230	SHELD-NW	69	1	16						
2001-PI-8	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-8	WINDERME	230	WINDERME	69	1	2						
2001-PI-8	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-8	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-8	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-8	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-9	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-9	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-9	IND RIV	230	STANTON	230	1	11						
2001-PI-9	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-9	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-9	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-9	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-9	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-9	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-9	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-9	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-9	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-9	SN PLANT	115	TURNER	115	1	1						
2001-PI-9	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-9	MICHIGAN	115	KALEY	115	1	11						
2001-PI-9	MICHIGAN	115	GRANT	115	1	11						
2001-PI-9	PERSHING	115	GRANT	115	1	11						
2001-PI-9	AMERICA	115	KALEY	115	1	11						
2001-PI-9	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-9	AZALEA	115	BENNETT	115	1	11						
2001-PI-9	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-9	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-9	PASADENA	230	PASADENA	115	1	2						
2001-PI-9	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-9	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-9	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-9	IND RIV	230	IND RIV	115	1	11						
2001-PI-9	LARGO	230	LARGO A	69	1	2						
2001-PI-9	SHELD	230	SHELD-NW	69	1	16						
2001-PI-9	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-9	WINDERME	230	WINDERME	69	1	2						
2001-PI-9	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-9	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-9	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-9	JASPER	115	JASPER	69	1	2						
2001-PI-10	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-10	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-10	IND RIV	230	STANTON	230	1	11						
2001-PI-10	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-10	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-10	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-10	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-10	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-10	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-10	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-10	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-10	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-10	SN PLANT	115	TURNER	115	1	1						
2001-PI-10	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-10	MICHIGAN	115	KALEY	115	1	11						
2001-PI-10	MICHIGAN	115	GRANT	115	1	11						
2001-PI-10	PERSHING	115	GRANT	115	1	11						
2001-PI-10	AMERICA	115	KALEY	115	1	11						
2001-PI-10	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-10	AZALEA	115	BENNETT	115	1	11						
2001-PI-10	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-10	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-10	PASADENA	230	PASADENA	115	1	2						
2001-PI-10	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-10	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-10	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-10	IND RIV	230	IND RIV	115	1	11						
2001-PI-10	LARGO	230	LARGO A	69	1	2						
2001-PI-10	SHELD	230	SHELD-NW	69	1	16						
2001-PI-10	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-10	WINDERME	230	WINDERME	69	1	2						
2001-PI-10	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-10	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-10	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-10	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-11	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-11	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-11	IND RIV	230	STANTON	230	1	11						
2001-PI-11	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-11	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-11	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-11	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-11	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-11	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-11	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-11	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-11	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-11	SN PLANT	115	TURNER	115	1	1						
2001-PI-11	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-11	MICHIGAN	115	KALEY	115	1	11						
2001-PI-11	MICHIGAN	115	GRANT	115	1	11						
2001-PI-11	PERSHING	115	GRANT	115	1	11						
2001-PI-11	AMERICA	115	KALEY	115	1	11						
2001-PI-11	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-11	AZALEA	115	BENNETT	115	1	11						
2001-PI-11	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-11	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-11	PASADENA	230	PASADENA	115	1	2						
2001-PI-11	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-11	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-11	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-11	IND RIV	230	IND RIV	115	1	11						
2001-PI-11	LARGO	230	LARGO A	69	1	2						
2001-PI-11	SHELD	230	SHELD-NW	69	1	16						
2001-PI-11	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-11	WINDERME	230	WINDERME	69	1	2						
2001-PI-11	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-11	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-11	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-11	JASPER	115	JASPER	69	1	2						
2001-PI-12	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-12	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-12	IND RIV	230	STANTON	230	1	11						
2001-PI-12	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-12	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-12	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-12	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-12	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-12	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-12	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-12	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-12	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-12	SN PLANT	115	TURNER	115	1	1						
2001-PI-12	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-12	MICHIGAN	115	KALEY	115	1	11						
2001-PI-12	MICHIGAN	115	GRANT	115	1	11						
2001-PI-12	PERSHING	115	GRANT	115	1	11						
2001-PI-12	AMERICA	115	KALEY	115	1	11						
2001-PI-12	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-12	AZALEA	115	BENNETT	115	1	11						
2001-PI-12	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-12	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-12	PASADENA	230	PASADENA	115	1	2						
2001-PI-12	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-12	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-12	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-12	IND RIV	230	IND RIV	115	1	11						
2001-PI-12	LARGO	230	LARGO A	69	1	2						
2001-PI-12	SHELD	230	SHELD-NW	69	1	16						
2001-PI-12	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-12	WINDERME	230	WINDERME	69	1	2						
2001-PI-12	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-12	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-12	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-12	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-13	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-13	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-13	IND RIV	230	STANTON	230	1	11						
2001-PI-13	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-13	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-13	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-13	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-13	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-13	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-13	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-13	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-13	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-13	SN PLANT	115	TURNER	115	1	1						
2001-PI-13	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-13	MICHIGAN	115	KALEY	115	1	11						
2001-PI-13	MICHIGAN	115	GRANT	115	1	11						
2001-PI-13	PERSHING	115	GRANT	115	1	11						
2001-PI-13	AMERICA	115	KALEY	115	1	11						
2001-PI-13	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-13	AZALEA	115	BENNETT	115	1	11						
2001-PI-13	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-13	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-13	PASADENA	230	PASADENA	115	1	2						
2001-PI-13	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-13	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-13	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-13	IND RIV	230	IND RIV	115	1	11						
2001-PI-13	LARGO	230	LARGO A	69	1	2						
2001-PI-13	SHELD	230	SHELD-NW	69	1	16						
2001-PI-13	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-13	WINDERME	230	WINDERME	69	1	2						
2001-PI-13	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-13	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-13	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-13	JASPER	115	JASPER	69	1	2						
2001-PI-14	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-14	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-14	IND RIV	230	STANTON	230	1	11						
2001-PI-14	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-14	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-14	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-14	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-14	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-14	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-14	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-14	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-14	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-14	SN PLANT	115	TURNER	115	1	1						
2001-PI-14	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-14	MICHIGAN	115	KALEY	115	1	11						
2001-PI-14	MICHIGAN	115	GRANT	115	1	11						
2001-PI-14	PERSHING	115	GRANT	115	1	11						
2001-PI-14	AMERICA	115	KALEY	115	1	11						
2001-PI-14	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-14	AZALEA	115	BENNETT	115	1	11						
2001-PI-14	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-14	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-14	PASADENA	230	PASADENA	115	1	2						
2001-PI-14	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-14	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-14	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-14	IND RIV	230	IND RIV	115	1	11						
2001-PI-14	LARGO	230	LARGO A	69	1	2						
2001-PI-14	SHELD	230	SHELD-NW	69	1	16						
2001-PI-14	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-14	WINDERME	230	WINDERME	69	1	2						
2001-PI-14	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-14	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-14	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-14	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-15	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-15	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-15	IND RIV	230	STANTON	230	1	11						
2001-PI-15	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-15	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-15	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-15	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-15	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-15	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-15	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-15	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-15	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-15	SN PLANT	115	TURNER	115	1	1						
2001-PI-15	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-15	MICHIGAN	115	KALEY	115	1	11						
2001-PI-15	MICHIGAN	115	GRANT	115	1	11						
2001-PI-15	PERSHING	115	GRANT	115	1	11						
2001-PI-15	AMERICA	115	KALEY	115	1	11						
2001-PI-15	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-15	AZALEA	115	BENNETT	115	1	11						
2001-PI-15	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-15	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-15	PASADENA	230	PASADENA	115	1	2						
2001-PI-15	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-15	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-15	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-15	IND RIV	230	IND RIV	115	1	11						
2001-PI-15	LARGO	230	LARGO A	69	1	2						
2001-PI-15	SHELD	230	SHELD-NW	69	1	16						
2001-PI-15	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-15	WINDERME	230	WINDERME	69	1	2						
2001-PI-15	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-15	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-15	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-15	JASPER	115	JASPER	69	1	2						
2001-PI-16	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-16	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-16	IND RIV	230	STANTON	230	1	11						
2001-PI-16	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-16	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-16	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-16	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-16	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-16	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-16	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-16	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-16	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-16	SN PLANT	115	TURNER	115	1	1						
2001-PI-16	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-16	MICHIGAN	115	KALEY	115	1	11						
2001-PI-16	MICHIGAN	115	GRANT	115	1	11						
2001-PI-16	PERSHING	115	GRANT	115	1	11						
2001-PI-16	AMERICA	115	KALEY	115	1	11						
2001-PI-16	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-16	AZALEA	115	BENNETT	115	1	11						
2001-PI-16	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-16	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-16	PASADENA	230	PASADENA	115	1	2						
2001-PI-16	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-16	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-16	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-16	IND RIV	230	IND RIV	115	1	11						
2001-PI-16	LARGO	230	LARGO A	69	1	2						
2001-PI-16	SHELD	230	SHELD-NW	69	1	16						
2001-PI-16	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-16	WINDERME	230	WINDERME	69	1	2						
2001-PI-16	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-16	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-16	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-16	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-17	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-17	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-17	IND RIV	230	STANTON	230	1	11						
2001-PI-17	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-17	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-17	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-17	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-17	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-17	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-17	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-17	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-17	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-17	SN PLANT	115	TURNER	115	1	1						
2001-PI-17	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-17	MICHIGAN	115	KALEY	115	1	11						
2001-PI-17	MICHIGAN	115	GRANT	115	1	11						
2001-PI-17	PERSHING	115	GRANT	115	1	11						
2001-PI-17	AMERICA	115	KALEY	115	1	11						
2001-PI-17	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-17	AZALEA	115	BENNETT	115	1	11						
2001-PI-17	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-17	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-17	PASADENA	230	PASADENA	115	1	2						
2001-PI-17	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-17	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-17	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-17	IND RIV	230	IND RIV	115	1	11						
2001-PI-17	LARGO	230	LARGO A	69	1	2						
2001-PI-17	SHELD	230	SHELD-NW	69	1	16						
2001-PI-17	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-17	WINDERME	230	WINDERME	69	1	2						
2001-PI-17	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-17	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-17	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-17	JASPER	115	JASPER	69	1	2						
2001-PI-18	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-18	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-18	IND RIV	230	STANTON	230	1	11						
2001-PI-18	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-18	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-18	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-18	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-18	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-18	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-18	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-18	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-18	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-18	SN PLANT	115	TURNER	115	1	1						
2001-PI-18	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-18	MICHIGAN	115	KALEY	115	1	11						
2001-PI-18	MICHIGAN	115	GRANT	115	1	11						
2001-PI-18	PERSHING	115	GRANT	115	1	11						
2001-PI-18	AMERICA	115	KALEY	115	1	11						
2001-PI-18	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-18	AZALEA	115	BENNETT	115	1	11						
2001-PI-18	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-18	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-18	PASADENA	230	PASADENA	115	1	2						
2001-PI-18	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-18	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-18	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-18	IND RIV	230	IND RIV	115	1	11						
2001-PI-18	LARGO	230	LARGO A	69	1	2						
2001-PI-18	SHELD	230	SHELD-NW	69	1	16						
2001-PI-18	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-18	WINDERME	230	WINDERME	69	1	2						
2001-PI-18	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-18	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-18	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-18	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-19	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-19	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-19	IND RIV	230	STANTON	230	1	11						
2001-PI-19	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-19	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-19	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-19	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-19	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-19	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-19	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-19	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-19	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-19	SN PLANT	115	TURNER	115	1	1						
2001-PI-19	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-19	MICHIGAN	115	KALEY	115	1	11						
2001-PI-19	MICHIGAN	115	GRANT	115	1	11						
2001-PI-19	PERSHING	115	GRANT	115	1	11						
2001-PI-19	AMERICA	115	KALEY	115	1	11						
2001-PI-19	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-19	AZALEA	115	BENNETT	115	1	11						
2001-PI-19	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-19	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-19	PASADENA	230	PASADENA	115	1	2						
2001-PI-19	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-19	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-19	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-19	IND RIV	230	IND RIV	115	1	11						
2001-PI-19	LARGO	230	LARGO A	69	1	2						
2001-PI-19	SHELD	230	SHELD-NW	69	1	16						
2001-PI-19	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-19	WINDERME	230	WINDERME	69	1	2						
2001-PI-19	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-19	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-19	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-19	JASPER	115	JASPER	69	1	2						
2001-PI-20	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-20	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-20	IND RIV	230	STANTON	230	1	11						
2001-PI-20	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-20	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-20	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-20	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-20	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-20	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-20	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-20	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-20	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-20	SN PLANT	115	TURNER	115	1	1						
2001-PI-20	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-20	MICHIGAN	115	KALEY	115	1	11						
2001-PI-20	MICHIGAN	115	GRANT	115	1	11						
2001-PI-20	PERSHING	115	GRANT	115	1	11						
2001-PI-20	AMERICA	115	KALEY	115	1	11						
2001-PI-20	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-20	AZALEA	115	BENNETT	115	1	11						
2001-PI-20	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-20	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-20	PASADENA	230	PASADENA	115	1	2						
2001-PI-20	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-20	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-20	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-20	IND RIV	230	IND RIV	115	1	11						
2001-PI-20	LARGO	230	LARGO A	69	1	2						
2001-PI-20	SHELD	230	SHELD-NW	69	1	16						
2001-PI-20	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-20	WINDERME	230	WINDERME	69	1	2						
2001-PI-20	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-20	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-20	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-20	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-21	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-21	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-21	IND RIV	230	STANTON	230	1	11						
2001-PI-21	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-21	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-21	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-21	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-21	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-21	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-21	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-21	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-21	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-21	SN PLANT	115	TURNER	115	1	1						
2001-PI-21	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-21	MICHIGAN	115	KALEY	115	1	11						
2001-PI-21	MICHIGAN	115	GRANT	115	1	11						
2001-PI-21	PERSHING	115	GRANT	115	1	11						
2001-PI-21	AMERICA	115	KALEY	115	1	11						
2001-PI-21	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-21	AZALEA	115	BENNETT	115	1	11						
2001-PI-21	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-21	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-21	PASADENA	230	PASADENA	115	1	2						
2001-PI-21	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-21	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-21	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-21	IND RIV	230	IND RIV	115	1	11						
2001-PI-21	LARGO	230	LARGO A	69	1	2						
2001-PI-21	SHELD	230	SHELD-NW	69	1	16						
2001-PI-21	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-21	WINDERME	230	WINDERME	69	1	2						
2001-PI-21	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-21	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-21	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-21	JASPER	115	JASPER	69	1	2						
2001-PI-22	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-22	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-22	IND RIV	230	STANTON	230	1	11						
2001-PI-22	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-22	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-22	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-22	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-22	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-22	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-22	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-22	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-22	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-22	SN PLANT	115	TURNER	115	1	1						
2001-PI-22	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-22	MICHIGAN	115	KALEY	115	1	11						
2001-PI-22	MICHIGAN	115	GRANT	115	1	11						
2001-PI-22	PERSHING	115	GRANT	115	1	11						
2001-PI-22	AMERICA	115	KALEY	115	1	11						
2001-PI-22	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-22	AZALEA	115	BENNETT	115	1	11						
2001-PI-22	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-22	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-22	PASADENA	230	PASADENA	115	1	2						
2001-PI-22	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-22	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-22	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-22	IND RIV	230	IND RIV	115	1	11						
2001-PI-22	LARGO	230	LARGO A	69	1	2						
2001-PI-22	SHELD	230	SHELD-NW	69	1	16						
2001-PI-22	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-22	WINDERME	230	WINDERME	69	1	2						
2001-PI-22	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-22	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-22	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-22	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-23	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-23	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-23	IND RIV	230	STANTON	230	1	11						
2001-PI-23	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-23	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-23	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-23	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-23	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-23	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-23	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-23	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-23	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-23	SN PLANT	115	TURNER	115	1	1						
2001-PI-23	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-23	MICHIGAN	115	KALEY	115	1	11						
2001-PI-23	MICHIGAN	115	GRANT	115	1	11						
2001-PI-23	PERSHING	115	GRANT	115	1	11						
2001-PI-23	AMERICA	115	KALEY	115	1	11						
2001-PI-23	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-23	AZALEA	115	BENNETT	115	1	11						
2001-PI-23	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-23	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-23	PASADENA	230	PASADENA	115	1	2						
2001-PI-23	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-23	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-23	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-23	IND RIV	230	IND RIV	115	1	11						
2001-PI-23	LARGO	230	LARGO A	69	1	2						
2001-PI-23	SHELD	230	SHELD-NW	69	1	16						
2001-PI-23	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-23	WINDERME	230	WINDERME	69	1	2						
2001-PI-23	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-23	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-23	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-23	JASPER	115	JASPER	69	1	2						
2001-PI-24	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-24	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-24	IND RIV	230	STANTON	230	1	11						
2001-PI-24	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-24	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-24	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-24	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-24	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-24	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-24	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-24	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-24	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-24	SN PLANT	115	TURNER	115	1	1						
2001-PI-24	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-24	MICHIGAN	115	KALEY	115	1	11						
2001-PI-24	MICHIGAN	115	GRANT	115	1	11						
2001-PI-24	PERSHING	115	GRANT	115	1	11						
2001-PI-24	AMERICA	115	KALEY	115	1	11						
2001-PI-24	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-24	AZALEA	115	BENNETT	115	1	11						
2001-PI-24	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-24	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-24	PASADENA	230	PASADENA	115	1	2						
2001-PI-24	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-24	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-24	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-24	IND RIV	230	IND RIV	115	1	11						
2001-PI-24	LARGO	230	LARGO A	69	1	2						
2001-PI-24	SHELD	230	SHELD-NW	69	1	16						
2001-PI-24	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-24	WINDERME	230	WINDERME	69	1	2						
2001-PI-24	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-24	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-24	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-24	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-25	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-25	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-25	IND RIV	230	STANTON	230	1	11						
2001-PI-25	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-25	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-25	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-25	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-25	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-25	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-25	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-25	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-25	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-25	SN PLANT	115	TURNER	115	1	1						
2001-PI-25	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-25	MICHIGAN	115	KALEY	115	1	11						
2001-PI-25	MICHIGAN	115	GRANT	115	1	11						
2001-PI-25	PERSHING	115	GRANT	115	1	11						
2001-PI-25	AMERICA	115	KALEY	115	1	11						
2001-PI-25	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-25	AZALEA	115	BENNETT	115	1	11						
2001-PI-25	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-25	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-25	PASADENA	230	PASADENA	115	1	2						
2001-PI-25	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-25	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-25	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-25	IND RIV	230	IND RIV	115	1	11						
2001-PI-25	LARGO	230	LARGO A	69	1	2						
2001-PI-25	SHELD	230	SHELD-NW	69	1	16						
2001-PI-25	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-25	WINDERME	230	WINDERME	69	1	2						
2001-PI-25	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-25	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-25	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-25	JASPER	115	JASPER	69	1	2						
2001-PI-26	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-26	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-26	IND RIV	230	STANTON	230	1	11						
2001-PI-26	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-26	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-26	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-26	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-26	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-26	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-26	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-26	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-26	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-26	SN PLANT	115	TURNER	115	1	1						
2001-PI-26	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-26	MICHIGAN	115	KALEY	115	1	11						
2001-PI-26	MICHIGAN	115	GRANT	115	1	11						
2001-PI-26	PERSHING	115	GRANT	115	1	11						
2001-PI-26	AMERICA	115	KALEY	115	1	11						
2001-PI-26	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-26	AZALEA	115	BENNETT	115	1	11						
2001-PI-26	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-26	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-26	PASADENA	230	PASADENA	115	1	2						
2001-PI-26	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-26	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-26	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-26	IND RIV	230	IND RIV	115	1	11						
2001-PI-26	LARGO	230	LARGO A	69	1	2						
2001-PI-26	SHELD	230	SHELD-NW	69	1	16						
2001-PI-26	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-26	WINDERME	230	WINDERME	69	1	2						
2001-PI-26	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-26	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-26	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-26	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-27	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-27	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-27	IND RIV	230	STANTON	230	1	11						
2001-PI-27	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-27	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-27	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-27	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-27	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-27	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-27	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-27	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-27	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-27	SN PLANT	115	TURNER	115	1	1						
2001-PI-27	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-27	MICHIGAN	115	KALEY	115	1	11						
2001-PI-27	MICHIGAN	115	GRANT	115	1	11						
2001-PI-27	PERSHING	115	GRANT	115	1	11						
2001-PI-27	AMERICA	115	KALEY	115	1	11						
2001-PI-27	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-27	AZALEA	115	BENNETT	115	1	11						
2001-PI-27	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-27	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-27	PASADENA	230	PASADENA	115	1	2						
2001-PI-27	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-27	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-27	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-27	IND RIV	230	IND RIV	115	1	11						
2001-PI-27	LARGO	230	LARGO A	69	1	2						
2001-PI-27	SHELD	230	SHELD-NW	69	1	16						
2001-PI-27	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-27	WINDERME	230	WINDERME	69	1	2						
2001-PI-27	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-27	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-27	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-27	JASPER	115	JASPER	69	1	2						
2001-PI-28	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-28	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-28	IND RIV	230	STANTON	230	1	11						
2001-PI-28	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-28	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-28	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-28	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-28	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-28	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-28	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-28	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-28	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-28	SN PLANT	115	TURNER	115	1	1						
2001-PI-28	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-28	MICHIGAN	115	KALEY	115	1	11						
2001-PI-28	MICHIGAN	115	GRANT	115	1	11						
2001-PI-28	PERSHING	115	GRANT	115	1	11						
2001-PI-28	AMERICA	115	KALEY	115	1	11						
2001-PI-28	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-28	AZALEA	115	BENNETT	115	1	11						
2001-PI-28	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-28	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-28	PASADENA	230	PASADENA	115	1	2						
2001-PI-28	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-28	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-28	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-28	IND RIV	230	IND RIV	115	1	11						
2001-PI-28	LARGO	230	LARGO A	69	1	2						
2001-PI-28	SHELD	230	SHELD-NW	69	1	16						
2001-PI-28	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-28	WINDERME	230	WINDERME	69	1	2						
2001-PI-28	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-28	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-28	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-28	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-29	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-29	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-29	IND RIV	230	STANTON	230	1	11						
2001-PI-29	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-29	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-29	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-29	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-29	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-29	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-29	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-29	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-29	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-29	SN PLANT	115	TURNER	115	1	1						
2001-PI-29	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-29	MICHIGAN	115	KALEY	115	1	11						
2001-PI-29	MICHIGAN	115	GRANT	115	1	11						
2001-PI-29	PERSHING	115	GRANT	115	1	11						
2001-PI-29	AMERICA	115	KALEY	115	1	11						
2001-PI-29	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-29	AZALEA	115	BENNETT	115	1	11						
2001-PI-29	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-29	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-29	PASADENA	230	PASADENA	115	1	2						
2001-PI-29	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-29	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-29	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-29	IND RIV	230	IND RIV	115	1	11						
2001-PI-29	LARGO	230	LARGO A	69	1	2						
2001-PI-29	SHELD	230	SHELD-NW	69	1	16						
2001-PI-29	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-29	WINDERME	230	WINDERME	69	1	2						
2001-PI-29	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-29	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-29	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-29	JASPER	115	JASPER	69	1	2						
2001-PI-30	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-30	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-30	IND RIV	230	STANTON	230	1	11						
2001-PI-30	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-30	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-30	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-30	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-30	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-30	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-30	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-30	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-30	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-30	SN PLANT	115	TURNER	115	1	1						
2001-PI-30	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-30	MICHIGAN	115	KALEY	115	1	11						
2001-PI-30	MICHIGAN	115	GRANT	115	1	11						
2001-PI-30	PERSHING	115	GRANT	115	1	11						
2001-PI-30	AMERICA	115	KALEY	115	1	11						
2001-PI-30	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-30	AZALEA	115	BENNETT	115	1	11						
2001-PI-30	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-30	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-30	PASADENA	230	PASADENA	115	1	2						
2001-PI-30	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-30	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-30	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-30	IND RIV	230	IND RIV	115	1	11						
2001-PI-30	LARGO	230	LARGO A	69	1	2						
2001-PI-30	SHELD	230	SHELD-NW	69	1	16						
2001-PI-30	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-30	WINDERME	230	WINDERME	69	1	2						
2001-PI-30	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-30	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-30	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-30	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-31	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-31	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-31	IND RIV	230	STANTON	230	1	11						
2001-PI-31	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-31	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-31	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-31	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-31	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-31	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-31	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-31	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-31	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-31	SN PLANT	115	TURNER	115	1	1						
2001-PI-31	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-31	MICHIGAN	115	KALEY	115	1	11						
2001-PI-31	MICHIGAN	115	GRANT	115	1	11						
2001-PI-31	PERSHING	115	GRANT	115	1	11						
2001-PI-31	AMERICA	115	KALEY	115	1	11						
2001-PI-31	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-31	AZALEA	115	BENNETT	115	1	11						
2001-PI-31	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-31	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-31	PASADENA	230	PASADENA	115	1	2						
2001-PI-31	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-31	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-31	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-31	IND RIV	230	IND RIV	115	1	11						
2001-PI-31	LARGO	230	LARGO A	69	1	2						
2001-PI-31	SHELD	230	SHELD-NW	69	1	16						
2001-PI-31	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-31	WINDERME	230	WINDERME	69	1	2						
2001-PI-31	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-31	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-31	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-31	JASPER	115	JASPER	69	1	2						
2001-PI-32	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-32	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-32	IND RIV	230	STANTON	230	1	11						
2001-PI-32	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-32	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-32	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-32	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-32	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-32	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-32	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-32	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-32	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-32	SN PLANT	115	TURNER	115	1	1						
2001-PI-32	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-32	MICHIGAN	115	KALEY	115	1	11						
2001-PI-32	MICHIGAN	115	GRANT	115	1	11						
2001-PI-32	PERSHING	115	GRANT	115	1	11						
2001-PI-32	AMERICA	115	KALEY	115	1	11						
2001-PI-32	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-32	AZALEA	115	BENNETT	115	1	11						
2001-PI-32	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-32	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-32	PASADENA	230	PASADENA	115	1	2						
2001-PI-32	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-32	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-32	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-32	IND RIV	230	IND RIV	115	1	11						
2001-PI-32	LARGO	230	LARGO A	69	1	2						
2001-PI-32	SHELD	230	SHELD-NW	69	1	16						
2001-PI-32	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-32	WINDERME	230	WINDERME	69	1	2						
2001-PI-32	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-32	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-32	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-32	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-33	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-33	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-33	IND RIV	230	STANTON	230	1	11						
2001-PI-33	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-33	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-33	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-33	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-33	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-33	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-33	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-33	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-33	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-33	SN PLANT	115	TURNER	115	1	1						
2001-PI-33	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-33	MICHIGAN	115	KALEY	115	1	11						
2001-PI-33	MICHIGAN	115	GRANT	115	1	11						
2001-PI-33	PERSHING	115	GRANT	115	1	11						
2001-PI-33	AMERICA	115	KALEY	115	1	11						
2001-PI-33	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-33	AZALEA	115	BENNETT	115	1	11						
2001-PI-33	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-33	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-33	PASADENA	230	PASADENA	115	1	2						
2001-PI-33	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-33	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-33	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-33	IND RIV	230	IND RIV	115	1	11						
2001-PI-33	LARGO	230	LARGO A	69	1	2						
2001-PI-33	SHELD	230	SHELD-NW	69	1	16						
2001-PI-33	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-33	WINDERME	230	WINDERME	69	1	2						
2001-PI-33	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-33	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-33	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-33	JASPER	115	JASPER	69	1	2						
2001-PI-34	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-34	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-34	IND RIV	230	STANTON	230	1	11						
2001-PI-34	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-34	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-34	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-34	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-34	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-34	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-34	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-34	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-34	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-34	SN PLANT	115	TURNER	115	1	1						
2001-PI-34	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-34	MICHIGAN	115	KALEY	115	1	11						
2001-PI-34	MICHIGAN	115	GRANT	115	1	11						
2001-PI-34	PERSHING	115	GRANT	115	1	11						
2001-PI-34	AMERICA	115	KALEY	115	1	11						
2001-PI-34	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-34	AZALEA	115	BENNETT	115	1	11						
2001-PI-34	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-34	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-34	PASADENA	230	PASADENA	115	1	2						
2001-PI-34	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-34	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-34	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-34	IND RIV	230	IND RIV	115	1	11						
2001-PI-34	LARGO	230	LARGO A	69	1	2						
2001-PI-34	SHELD	230	SHELD-NW	69	1	16						
2001-PI-34	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-34	WINDERME	230	WINDERME	69	1	2						
2001-PI-34	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-34	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-34	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-34	JASPER	115	JASPER	69	1	2						

Table II

Comparison of Line & Transformer Flows
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100% Load Base Case

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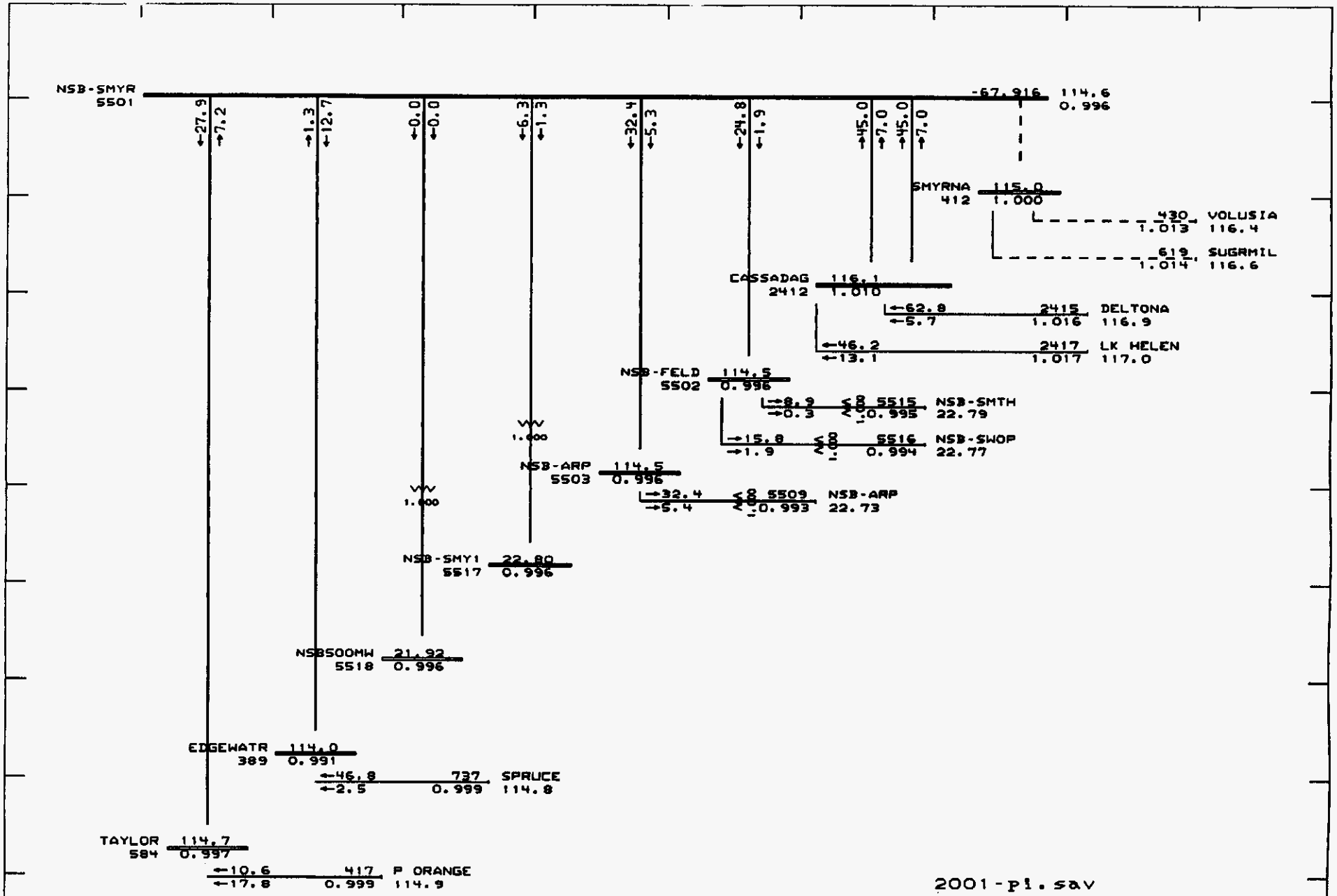
Monitored Branches							Case 2001-PI Base No NSB Gen	Case 2001-PIA Sell to FPL	Case 2001-PIB Sell to FPC	Case 2001-PIC Sell to TEC	Case 2001-PID Sell to JEA	Case 2001-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-PI-35	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-35	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-35	IND RIV	230	STANTON	230	1	11						
2001-PI-35	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-35	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-35	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-35	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-35	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-35	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-35	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-35	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-35	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-35	SN PLANT	115	TURNER	115	1	1						
2001-PI-35	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-35	MICHIGAN	115	KALEY	115	1	11						
2001-PI-35	MICHIGAN	115	GRANT	115	1	11						
2001-PI-35	PERSHING	115	GRANT	115	1	11						
2001-PI-35	AMERICA	115	KALEY	115	1	11						
2001-PI-35	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-35	AZALEA	115	BENNETT	115	1	11						
2001-PI-35	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-35	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-35	PASADENA	230	PASADENA	115	1	2						
2001-PI-35	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-35	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-35	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-35	IND RIV	230	IND RIV	115	1	11						
2001-PI-35	LARGO	230	LARGO A	69	1	2						
2001-PI-35	SHELD	230	SHELD-NW	69	1	16						
2001-PI-35	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-35	WINDERME	230	WINDERME	69	1	2						
2001-PI-35	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-35	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-35	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-35	JASPER	115	JASPER	69	1	2						
2001-PI-36	SN PLANT	230	SYLVAN	230	1	1						
2001-PI-36	SYLVAN	230	N LONGWD	230	1	1						
2001-PI-36	IND RIV	230	STANTON	230	1	11						
2001-PI-36	SILVR SP	230	SILV SPN	230	1	2						
2001-PI-36	SILVR SP	230	SILV SPN	230	2	2						
2001-PI-36	RIO PINR	230	CURRY FD	230	1	2						
2001-PI-36	JUNEAU-W	138	GANNON	138	1	16						
2001-PI-36	NSB-SMYR	115	CASSADAG	115	1	2						
2001-PI-36	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-PI-36	NSB-SMYR	115	TAYLOR	115	1	1						
2001-PI-36	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-PI-36	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-PI-36	SN PLANT	115	TURNER	115	1	1						
2001-PI-36	PASADENA	115	40ST-DUM	115	1	2						
2001-PI-36	MICHIGAN	115	KALEY	115	1	11						
2001-PI-36	MICHIGAN	115	GRANT	115	1	11						
2001-PI-36	PERSHING	115	GRANT	115	1	11						
2001-PI-36	AMERICA	115	KALEY	115	1	11						
2001-PI-36	JASPER	115	WGHTCHPL	115	1	2						
2001-PI-36	AZALEA	115	BENNETT	115	1	11						
2001-PI-36	FLORALTP	69	INVERNTP	69	1	2						
2001-PI-36	ALACH TP	69	HIGH SPG	69	1	2						
2001-PI-36	PASADENA	230	PASADENA	115	1	2						
2001-PI-36	SUWANNEE	230	SUWANNEE	115	1	2						
2001-PI-36	SUWANNEE	230	SUWANNEE	115	2	2						
2001-PI-36	E CLRWTR	230	E CLRWTR	115	1	2						
2001-PI-36	IND RIV	230	IND RIV	115	1	11						
2001-PI-36	LARGO	230	LARGO A	69	1	2						
2001-PI-36	SHELD	230	SHELD-NW	69	1	16						
2001-PI-36	CLMT EST	230	CLMT EST	69	1	2						
2001-PI-36	WINDERME	230	WINDERME	69	1	2						
2001-PI-36	RIVER-S	230	RIVER-S	69	1	16						
2001-PI-36	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-PI-36	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-PI-36	JASPER	115	JASPER	69	1	2						

APPENDIX I-A



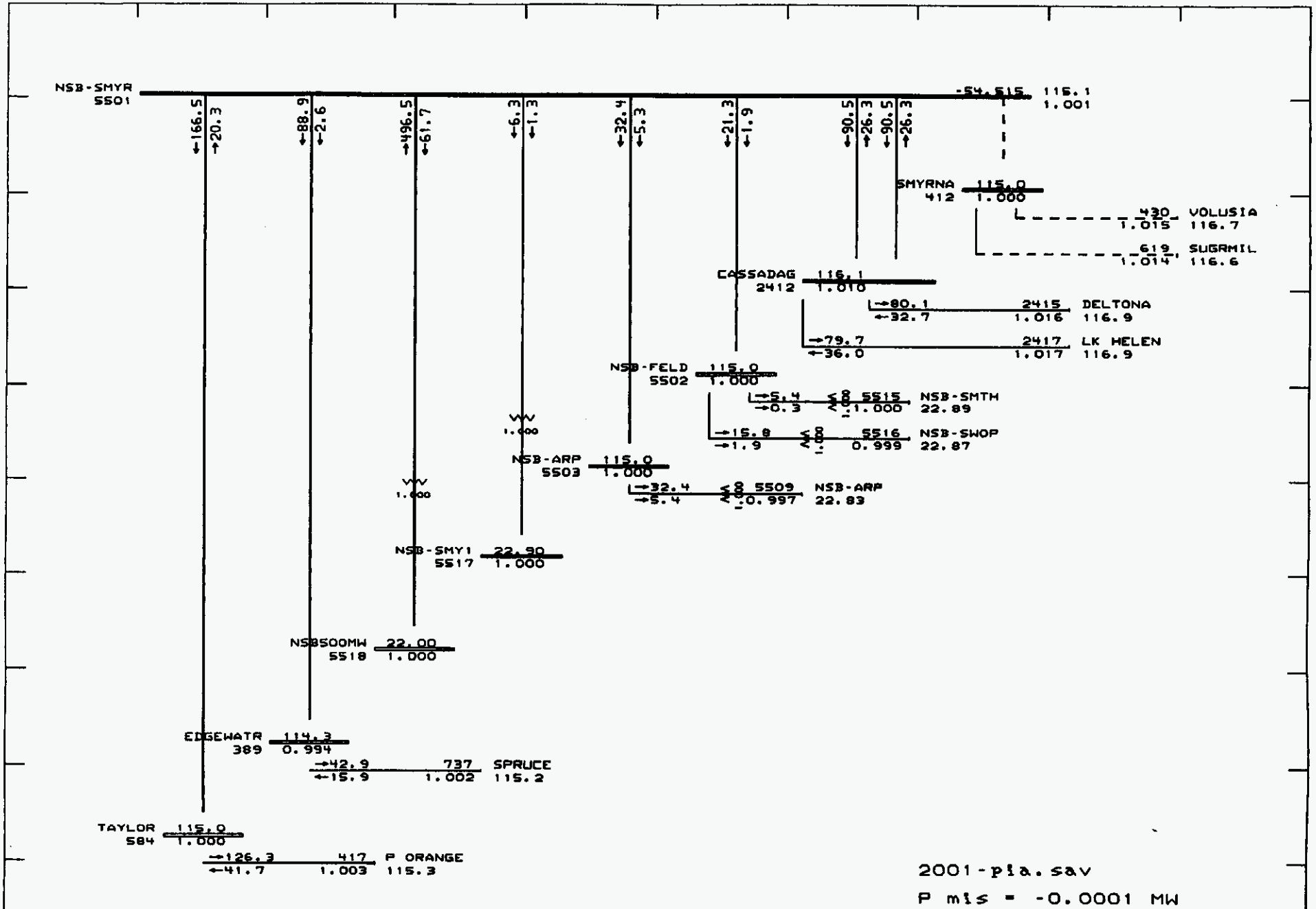
General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:15:30 1998

RMI RESOURCE MANAGEMENT INTERNATIONAL INC.

CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES

2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.

2001-p1.sav



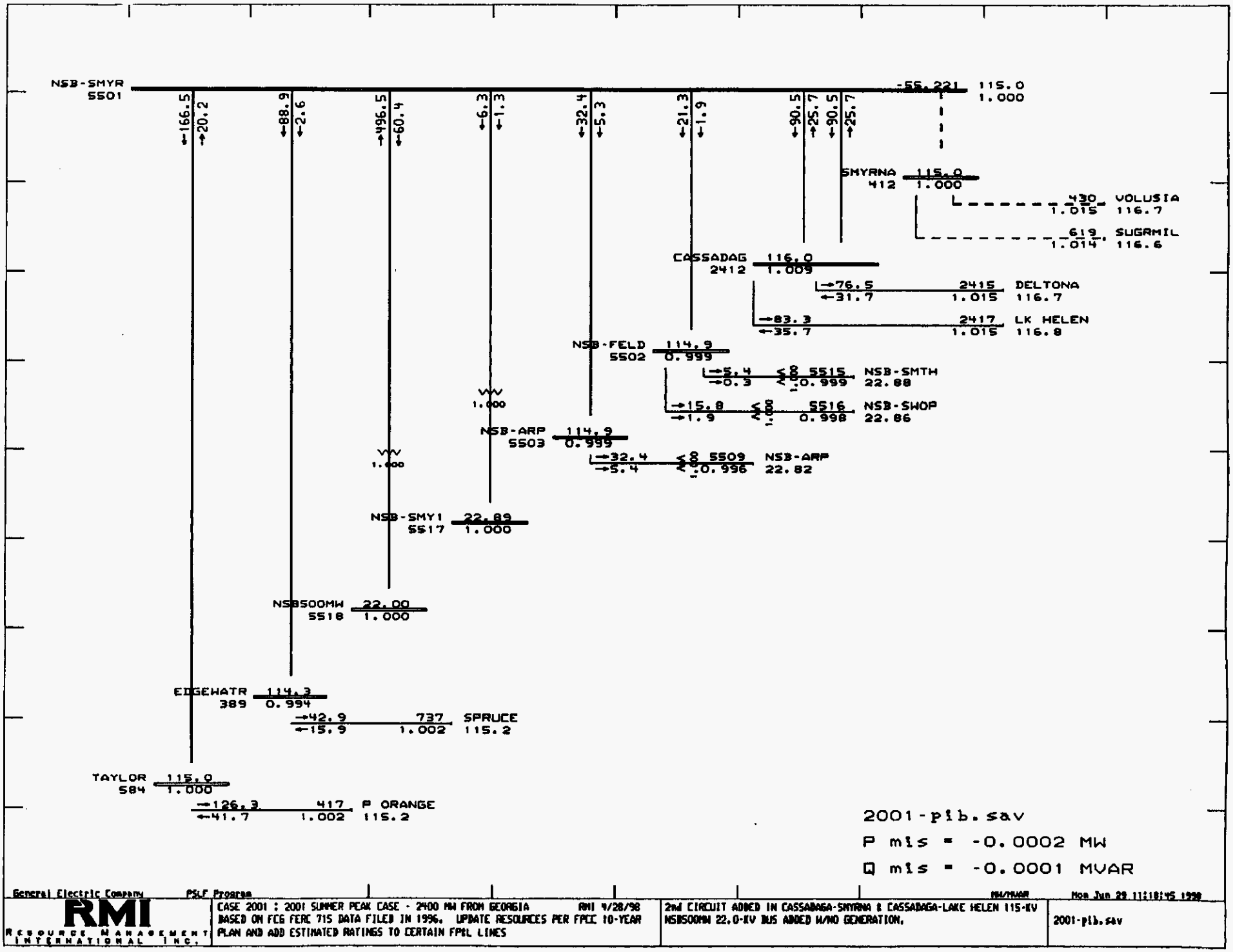
General Electric Company PSLF Program MW/MVAR Mon Jan 29 11:18:14 1990

RMI Resource Management International, Inc.

CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES

2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSBSOOMW 22.0-KV BUS ADDED W/NO GENERATION.

2001-pia.sav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1.000
SMYRNA 115.0
412 1.000
430 VOLUSIA
1.015 116.7
619 SUGRMIL
1.014 116.6
CASSADAG 116.0
2412 1.009
76.5 2415 DELTONA
31.7 1.015 116.7
83.3 2417 LK HELEN
35.7 1.015 116.8
NSB-FELD 114.9
5502 0.999
5.4 5515 NSB-SMTH
0.3 0.999 22.88
15.8 5516 NSB-SHOP
1.9 0.998 22.86
NSB-ARP 114.9
5503 0.999
32.4 5509 NSB-ARP
5.4 0.996 22.82
NSB-SMY1 22.89
5517 1.000
NSB500MW 22.00
5518 1.000
EDGEWATR 114.3
389 0.994
42.9 737 SPRUCE
15.9 1.002 115.2
TAYLOR 115.9
584 1.000
126.3 417 P ORANGE
41.7 1.002 115.2
166.5
20.2
88.9
2.6
496.5
60.4
6.3
1.3
32.4
5.3
21.3
1.9
90.5
25.7
90.5
25.7
1.000
1.000
2001-pib.sav
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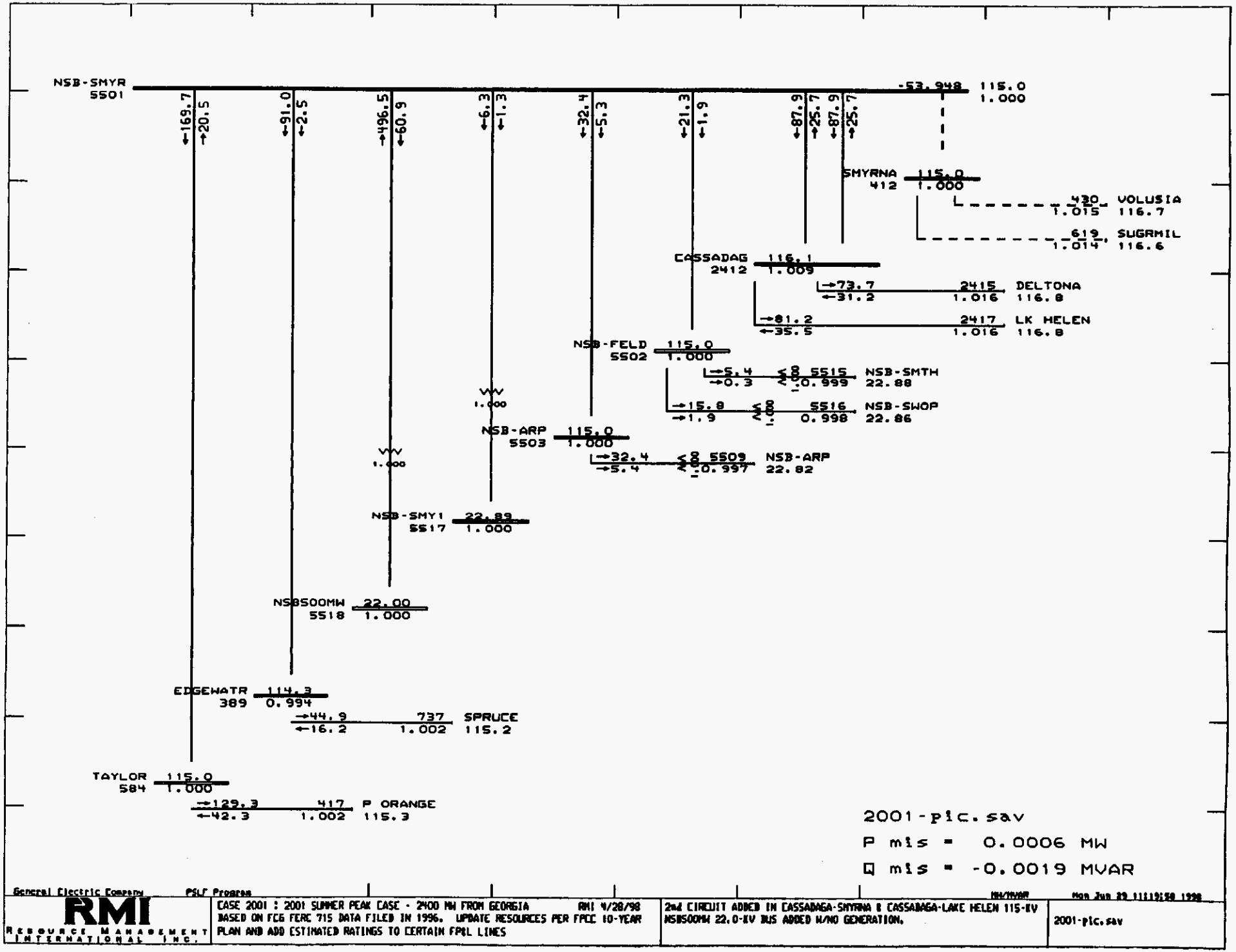
Q mis = -0.0001 MVAR
General Electric Company PSLF Program
MW/MVAR
Mon Jun 29 11:18:45 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPSC 10-YEAR
PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FPSL LINES
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001-pib.sav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←6.3
←1.3
←32.4
←5.3
←21.3
←1.9
←87.9
→25.7
←87.9
→25.7
SMYRNA 115.0
412 1.000
430 VOLUSIA
1.015 116.7
619 SUGRMIL
1.014 116.6
CASSADAG 116.1
2412 1.009
→73.7 2415 DELTONA
←31.2 1.016 116.8
→81.2 2417 LK HELEN
←35.5 1.016 116.8
NSB-FELD 115.0
5502 1.000
→5.4 ≤θ 5515 NSB-SMTH
→0.3 1.000 22.88
→15.8 ≤θ 5516 NSB-SWOP
→1.9 0.998 22.86
1.000
NSB-ARP 115.0
5503 1.000
→32.4 ≤θ 5509 NSB-ARP
→5.4 0.997 22.82
1.000
NSB-SMY1 22.89
5517 1.000
NSBSOOMW 22.00
5518 1.000
EDGEWATR 114.3
389 0.994
→44.9 737 SPRUCE
←16.2 1.002 115.2
TAYLOR 115.0
584 1.000
→129.3 417 P ORANGE
←42.3 1.002 115.3
2001-pic.sav
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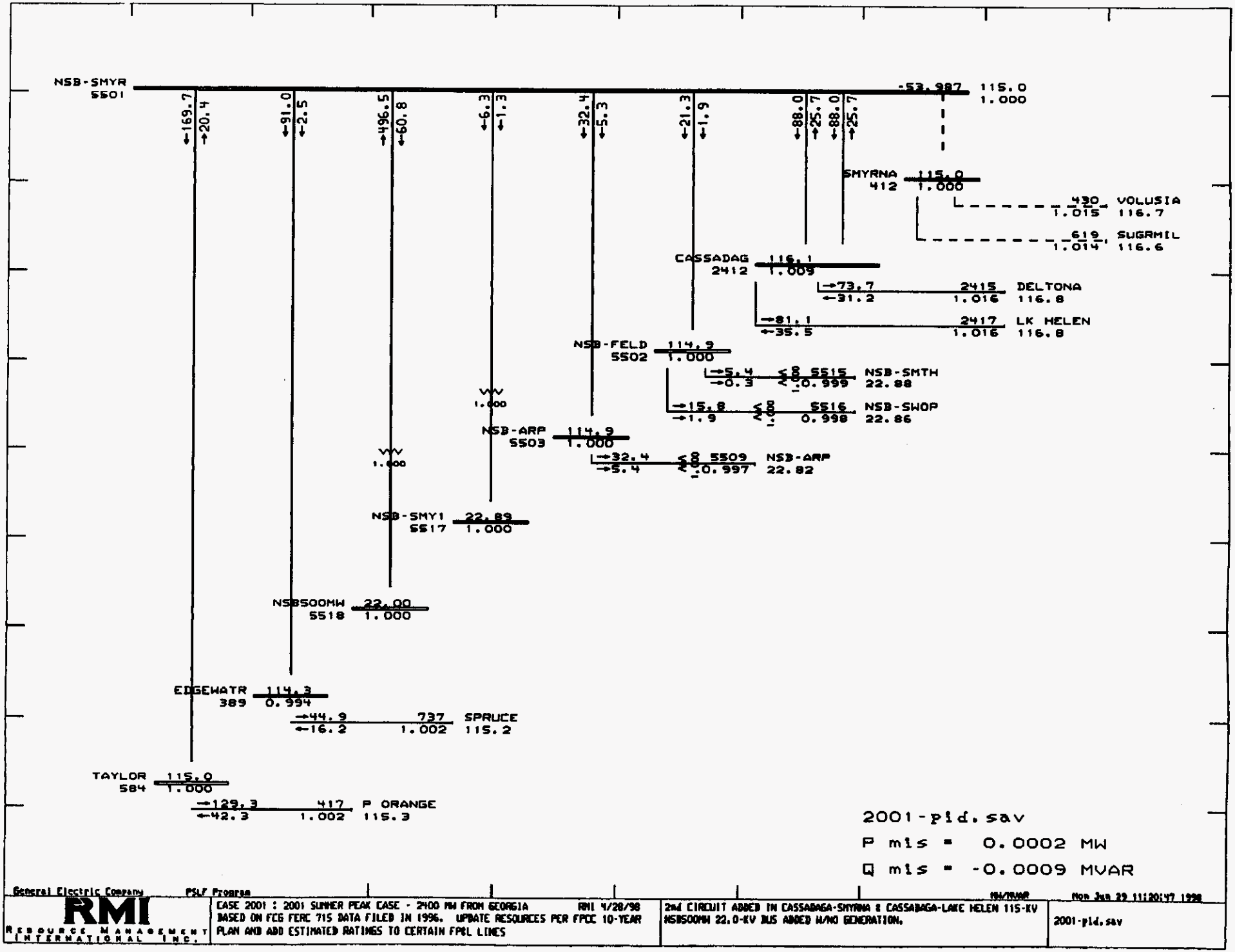
General Electric Company PSLF Program
MW/MVAR
Mon Jun 29 11:19:50 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPCC 10-YEAR
PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSBSOOMW 22.0-KV BUS ADDED W/NO GENERATION.
2001-pic.sav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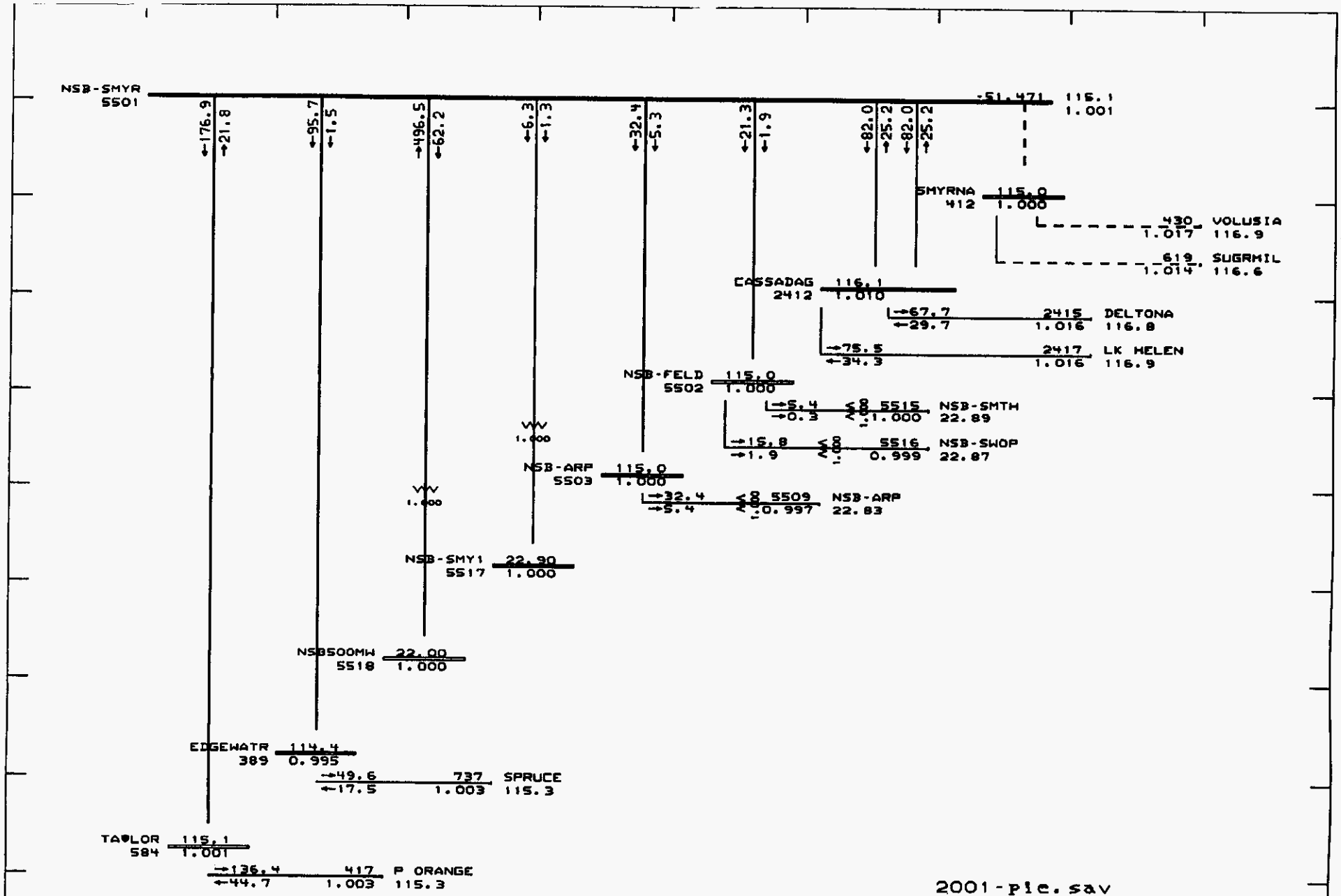
1.000
←169.7
→20.4
←91.0
←2.5
→96.5
←60.8
←6.3
←1.3
←32.4
←5.3
←21.3
←1.9
←88.0
→25.7
←88.0
→25.7
SMYRNA 115.0
412 1.000
430 VOLUSIA
1.015 116.7
619 SUGRMIL
1.014 116.6
CASSADAG 116.1
2412 1.009
→73.7 2415 DELTONA
←31.2 1.016 116.8
→81.1 2417 LK HELEN
←35.5 1.016 116.8
NSB-FELD 114.9
5502 1.000
→5.4 <8 5515 NSB-SMTH
→0.3 :0.999 22.88
→15.8 <8 5516 NSB-SWDP
→1.9 :0.998 22.86
1.000
NSB-ARP 114.9
5503 1.000
→32.4 <8 5509 NSB-ARP
→5.4 :0.997 22.82
1.000
NSB-SMY1 22.89
5517 1.000
NSBSOOMW 22.00
5518 1.000
EDGEWATR 114.3
389 0.994
→44.9 737 SPRUCE
←16.2 1.002 115.2
TAYLOR 115.0
584 1.000
→129.3 417 P ORANGE
←42.3 1.002 115.3
2001-pid.sav
P mis = 0.0002 MW
Q mis = -0.0009 MVAR
General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:20:47 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES
2nd CIRCUIT ADDED IN CASSABAGA-SMYRNA & CASSABAGA-LAKE HELEN 115-KV
NSBSOOMW 22.0-KV BUS ADDED W/NO GENERATION.
2001-pid.sav



General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:21:11 1998

RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.

CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FPRL LINES

2nd CIRCUIT ADDED IN CASSABAGA-SMYRNA & CASSABAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.

2001-pie.sav

APPENDIX II

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-1	SN PLANT	230	SYLVAN	230	1	1						
2001-1	SYLVAN	230	N LONGWD	230	1	1						
2001-1	IND RIV	230	STANTON	230	1	11						
2001-1	SILVR SP	230	SILV SPN	230	1	2						
2001-1	SILVR SP	230	SILV SPN	230	2	2						
2001-1	RIO PINR	230	CURRY FD	230	1	2						
2001-1	JUNEAU-W	138	GANNON	138	1	16						
2001-1	NSB-SMYR	115	CASSADAG	115	1	2						
2001-1	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-1	NSB-SMYR	115	TAYLOR	115	1	1					100.8	
2001-1	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-1	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-1	SN PLANT	115	TURNER	115	1	1						
2001-1	PASADENA	115	40ST-DUM	115	1	2						
2001-1	MICHIGAN	115	KALEY	115	1	11						
2001-1	MICHIGAN	115	GRANT	115	1	11						
2001-1	PERSHING	115	GRANT	115	1	11						
2001-1	AMERICA	115	KALEY	115	1	11						
2001-1	JASPER	115	WGHTCHPL	115	1	2						
2001-1	AZALEA	115	BENNETT	115	1	11						
2001-1	FLORALTP	69	INVERNTP	69	1	2						
2001-1	ALACH TP	69	HIGH SPG	69	1	2						
2001-1	PASADENA	230	PASADENA	115	1	2						
2001-1	SUWANNEE	230	SUWANNEE	115	1	2						
2001-1	SUWANNEE	230	SUWANNEE	115	2	2						
2001-1	E CLRWTR	230	E CLRWTR	115	1	2						
2001-1	IND RIV	230	IND RIV	115	1	11						
2001-1	LARGO	230	LARGO A	69	1	2						
2001-1	SHELD	230	SHELD-NW	69	1	16						
2001-1	CLMT EST	230	CLMT EST	69	1	2						
2001-1	WINDERME	230	WINDERME	69	1	2						
2001-1	RIVER-S	230	RIVER-S	69	1	16						
2001-1	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-1	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-1	JASPER	115	JASPER	69	1	2						
2001-2	SN PLANT	230	SYLVAN	230	1	1						
2001-2	SYLVAN	230	N LONGWD	230	1	1						
2001-2	IND RIV	230	STANTON	230	1	11						
2001-2	SILVR SP	230	SILV SPN	230	1	2						
2001-2	SILVR SP	230	SILV SPN	230	2	2						
2001-2	RIO PINR	230	CURRY FD	230	1	2						
2001-2	JUNEAU-W	138	GANNON	138	1	16						
2001-2	NSB-SMYR	115	CASSADAG	115	1	2						
2001-2	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-2	NSB-SMYR	115	TAYLOR	115	1	1		108.1	108.1	110.1	114.6	111.9
2001-2	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-2	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-2	SN PLANT	115	TURNER	115	1	1						
2001-2	PASADENA	115	40ST-DUM	115	1	2						
2001-2	MICHIGAN	115	KALEY	115	1	11						
2001-2	MICHIGAN	115	GRANT	115	1	11						
2001-2	PERSHING	115	GRANT	115	1	11						
2001-2	AMERICA	115	KALEY	115	1	11						
2001-2	JASPER	115	WGHTCHPL	115	1	2						
2001-2	AZALEA	115	BENNETT	115	1	11						
2001-2	FLORALTP	69	INVERNTP	69	1	2						
2001-2	ALACH TP	69	HIGH SPG	69	1	2						
2001-2	PASADENA	230	PASADENA	115	1	2						
2001-2	SUWANNEE	230	SUWANNEE	115	1	2						
2001-2	SUWANNEE	230	SUWANNEE	115	2	2						
2001-2	E CLRWTR	230	E CLRWTR	115	1	2						
2001-2	IND RIV	230	IND RIV	115	1	11						
2001-2	LARGO	230	LARGO A	69	1	2						
2001-2	SHELD	230	SHELD-NW	69	1	16						
2001-2	CLMT EST	230	CLMT EST	69	1	2						
2001-2	WINDERME	230	WINDERME	69	1	2						
2001-2	RIVER-S	230	RIVER-S	69	1	16						
2001-2	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-2	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-2	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-3	SN PLANT	230	SYLVAN	230	1	1						
2001-3	SYLVAN	230	N LONGWD	230	1	1						
2001-3	IND RIV	230	STANTON	230	1	11						
2001-3	SILVR SP	230	SILV SPN	230	1	2						
2001-3	SILVR SP	230	SILV SPN	230	2	2						
2001-3	RIO PINR	230	CURRY FD	230	1	2						
2001-3	JUNEAU-W	138	GANNON	138	1	16						
2001-3	NSB-SMYR	115	CASSADAG	115	1	2						
2001-3	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-3	NSB-SMYR	115	TAYLOR	115	1	1						
2001-3	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-3	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-3	SN PLANT	115	TURNER	115	1	1						
2001-3	PASADENA	115	40ST-DUM	115	1	2						
2001-3	MICHIGAN	115	KALEY	115	1	11						
2001-3	MICHIGAN	115	GRANT	115	1	11						
2001-3	PERSHING	115	GRANT	115	1	11						
2001-3	AMERICA	115	KALEY	115	1	11						
2001-3	JASPER	115	WGHTCHPL	115	1	2						
2001-3	AZALEA	115	BENNETT	115	1	11						
2001-3	FLORALTP	69	INVERNTP	69	1	2						
2001-3	ALACH TP	69	HIGH SPG	69	1	2						
2001-3	PASADENA	230	PASADENA	115	1	2						
2001-3	SUWANNEE	230	SUWANNEE	115	1	2						
2001-3	SUWANNEE	230	SUWANNEE	115	2	2						
2001-3	E CLRWTR	230	E CLRWTR	115	1	2						
2001-3	IND RIV	230	IND RIV	115	1	11						
2001-3	LARGO	230	LARGO A	69	1	2						
2001-3	SHELD	230	SHELD-NW	69	1	16						
2001-3	CLMT EST	230	CLMT EST	69	1	2						
2001-3	WINDERME	230	WINDERME	69	1	2						
2001-3	RIVER-S	230	RIVER-S	69	1	16						
2001-3	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-3	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-3	JASPER	115	JASPER	69	1	2						
2001-4	SN PLANT	230	SYLVAN	230	1	1						
2001-4	SYLVAN	230	N LONGWD	230	1	1						
2001-4	IND RIV	230	STANTON	230	1	11						
2001-4	SILVR SP	230	SILV SPN	230	1	2						
2001-4	SILVR SP	230	SILV SPN	230	2	2						
2001-4	RIO PINR	230	CURRY FD	230	1	2						
2001-4	JUNEAU-W	138	GANNON	138	1	16						
2001-4	NSB-SMYR	115	CASSADAG	115	1	2						
2001-4	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-4	NSB-SMYR	115	TAYLOR	115	1	1						
2001-4	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-4	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-4	SN PLANT	115	TURNER	115	1	1						
2001-4	PASADENA	115	40ST-DUM	115	1	2						
2001-4	MICHIGAN	115	KALEY	115	1	11						
2001-4	MICHIGAN	115	GRANT	115	1	11						
2001-4	PERSHING	115	GRANT	115	1	11						
2001-4	AMERICA	115	KALEY	115	1	11						
2001-4	JASPER	115	WGHTCHPL	115	1	2						
2001-4	AZALEA	115	BENNETT	115	1	11						
2001-4	FLORALTP	69	INVERNTP	69	1	2						
2001-4	ALACH TP	69	HIGH SPG	69	1	2						
2001-4	PASADENA	230	PASADENA	115	1	2						
2001-4	SUWANNEE	230	SUWANNEE	115	1	2						
2001-4	SUWANNEE	230	SUWANNEE	115	2	2						
2001-4	E CLRWTR	230	E CLRWTR	115	1	2						
2001-4	IND RIV	230	IND RIV	115	1	11						
2001-4	LARGO	230	LARGO A	69	1	2						
2001-4	SHELD	230	SHELD-NW	69	1	16						
2001-4	CLMT EST	230	CLMT EST	69	1	2						
2001-4	WINDERME	230	WINDERME	69	1	2						
2001-4	RIVER-S	230	RIVER-S	69	1	16						
2001-4	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-4	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-4	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-5	SN PLANT	230	SYLVAN	230	1	1						
2001-5	SYLVAN	230	N LONGWD	230	1	1						
2001-5	IND RIV	230	STANTON	230	1	11						
2001-5	SILVR SP	230	SILV SPN	230	1	2						
2001-5	SILVR SP	230	SILV SPN	230	2	2						
2001-5	RIO PINR	230	CURRY FD	230	1	2						
2001-5	JUNEAU-W	138	GANNON	138	1	16						
2001-5	NSB-SMYR	115	CASSADAG	115	1	2						
2001-5	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-5	NSB-SMYR	115	TAYLOR	115	1	1						
2001-5	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-5	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-5	SN PLANT	115	TURNER	115	1	1						
2001-5	PASADENA	115	40ST-DUM	115	1	2						
2001-5	MICHIGAN	115	KALEY	115	1	11						
2001-5	MICHIGAN	115	GRANT	115	1	11						
2001-5	PERSHING	115	GRANT	115	1	11						
2001-5	AMERICA	115	KALEY	115	1	11						
2001-5	JASPER	115	WGHTCHPL	115	1	2						
2001-5	AZALEA	115	BENNETT	115	1	11						
2001-5	FLORALTP	69	INVERNTP	69	1	2						
2001-5	ALACH TP	69	HIGH SPG	69	1	2						
2001-5	PASADENA	230	PASADENA	115	1	2						
2001-5	SUWANNEE	230	SUWANNEE	115	1	2						
2001-5	SUWANNEE	230	SUWANNEE	115	2	2						
2001-5	E CLRWTR	230	E CLRWTR	115	1	2						
2001-5	IND RIV	230	IND RIV	115	1	11						
2001-5	LARGO	230	LARGO A	69	1	2						
2001-5	SHELD	230	SHELD-NW	69	1	16						
2001-5	CLMT EST	230	CLMT EST	69	1	2						
2001-5	WINDERME	230	WINDERME	69	1	2						
2001-5	RIVER-S	230	RIVER-S	69	1	16						
2001-5	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-5	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-5	JASPER	115	JASPER	69	1	2						
2001-6	SN PLANT	230	SYLVAN	230	1	1						
2001-6	SYLVAN	230	N LONGWD	230	1	1						
2001-6	IND RIV	230	STANTON	230	1	11						
2001-6	SILVR SP	230	SILV SPN	230	1	2						
2001-6	SILVR SP	230	SILV SPN	230	2	2						
2001-6	RIO PINR	230	CURRY FD	230	1	2						
2001-6	JUNEAU-W	138	GANNON	138	1	16						
2001-6	NSB-SMYR	115	CASSADAG	115	1	2						
2001-6	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-6	NSB-SMYR	115	TAYLOR	115	1	1						
2001-6	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-6	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-6	SN PLANT	115	TURNER	115	1	1						
2001-6	PASADENA	115	40ST-DUM	115	1	2						
2001-6	MICHIGAN	115	KALEY	115	1	11						
2001-6	MICHIGAN	115	GRANT	115	1	11						
2001-6	PERSHING	115	GRANT	115	1	11						
2001-6	AMERICA	115	KALEY	115	1	11						
2001-6	JASPER	115	WGHTCHPL	115	1	2						
2001-6	AZALEA	115	BENNETT	115	1	11						
2001-6	FLORALTP	69	INVERNTP	69	1	2						
2001-6	ALACH TP	69	HIGH SPG	69	1	2						
2001-6	PASADENA	230	PASADENA	115	1	2						
2001-6	SUWANNEE	230	SUWANNEE	115	1	2						
2001-6	SUWANNEE	230	SUWANNEE	115	2	2						
2001-6	E CLRWTR	230	E CLRWTR	115	1	2						
2001-6	IND RIV	230	IND RIV	115	1	11						
2001-6	LARGO	230	LARGO A	69	1	2						
2001-6	SHELD	230	SHELD-NW	69	1	16						
2001-6	CLMT EST	230	CLMT EST	69	1	2						
2001-6	WINDERME	230	WINDERME	69	1	2						
2001-6	RIVER-S	230	RIVER-S	69	1	16						
2001-6	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-6	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-6	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
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100% Load Base Case

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-7	SN PLANT	230	SYLVAN	230	1	1						
2001-7	SYLVAN	230	N LONGWD	230	1	1						
2001-7	IND RIV	230	STANTON	230	1	11						
2001-7	SILVR SP	230	SILV SPN	230	1	2						
2001-7	SILVR SP	230	SILV SPN	230	2	2						
2001-7	RIO PINR	230	CURRY FD	230	1	2						
2001-7	JUNEAU-W	138	GANNON	138	1	16						
2001-7	NSB-SMYR	115	CASSADAG	115	1	2						
2001-7	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-7	NSB-SMYR	115	TAYLOR	115	1	1						
2001-7	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-7	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-7	SN PLANT	115	TURNER	115	1	1						
2001-7	PASADENA	115	40ST-DUM	115	1	2						
2001-7	MICHIGAN	115	KALEY	115	1	11						
2001-7	MICHIGAN	115	GRANT	115	1	11						
2001-7	PERSHING	115	GRANT	115	1	11						
2001-7	AMERICA	115	KALEY	115	1	11						
2001-7	JASPER	115	WGHTCHPL	115	1	2						
2001-7	AZALEA	115	BENNETT	115	1	11						
2001-7	FLORALTP	69	INVERNTP	69	1	2						
2001-7	ALACH TP	69	HIGH SPG	69	1	2						
2001-7	PASADENA	230	PASADENA	115	1	2						
2001-7	SUWANNEE	230	SUWANNEE	115	1	2						
2001-7	SUWANNEE	230	SUWANNEE	115	2	2						
2001-7	E CLRWTR	230	E CLRWTR	115	1	2						
2001-7	IND RIV	230	IND RIV	115	1	11						
2001-7	LARGO	230	LARGO A	69	1	2						
2001-7	SHELD	230	SHELD-NW	69	1	16						
2001-7	CLMT EST	230	CLMT EST	69	1	2						
2001-7	WINDERME	230	WINDERME	69	1	2						
2001-7	RIVER-S	230	RIVER-S	69	1	16						
2001-7	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-7	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-7	JASPER	115	JASPER	69	1	2						
2001-8	SN PLANT	230	SYLVAN	230	1	1						
2001-8	SYLVAN	230	N LONGWD	230	1	1						
2001-8	IND RIV	230	STANTON	230	1	11						
2001-8	SILVR SP	230	SILV SPN	230	1	2						
2001-8	SILVR SP	230	SILV SPN	230	2	2						
2001-8	RIO PINR	230	CURRY FD	230	1	2						
2001-8	JUNEAU-W	138	GANNON	138	1	16						
2001-8	NSB-SMYR	115	CASSADAG	115	1	2						
2001-8	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-8	NSB-SMYR	115	TAYLOR	115	1	1						
2001-8	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-8	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-8	SN PLANT	115	TURNER	115	1	1						
2001-8	PASADENA	115	40ST-DUM	115	1	2						
2001-8	MICHIGAN	115	KALEY	115	1	11						
2001-8	MICHIGAN	115	GRANT	115	1	11						
2001-8	PERSHING	115	GRANT	115	1	11						
2001-8	AMERICA	115	KALEY	115	1	11						
2001-8	JASPER	115	WGHTCHPL	115	1	2						
2001-8	AZALEA	115	BENNETT	115	1	11						
2001-8	FLORALTP	69	INVERNTP	69	1	2						
2001-8	ALACH TP	69	HIGH SPG	69	1	2						
2001-8	PASADENA	230	PASADENA	115	1	2						
2001-8	SUWANNEE	230	SUWANNEE	115	1	2						
2001-8	SUWANNEE	230	SUWANNEE	115	2	2						
2001-8	E CLRWTR	230	E CLRWTR	115	1	2						
2001-8	IND RIV	230	IND RIV	115	1	11						
2001-8	LARGO	230	LARGO A	69	1	2						
2001-8	SHELD	230	SHELD-NW	69	1	16						
2001-8	CLMT EST	230	CLMT EST	69	1	2						
2001-8	WINDERME	230	WINDERME	69	1	2						
2001-8	RIVER-S	230	RIVER-S	69	1	16						
2001-8	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-8	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-8	JASPER	115	JASPER	69	1	2						

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100% Load Base Case

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-9	SN PLANT	230	SYLVAN	230	1	1						
2001-9	SYLVAN	230	N LONGWD	230	1	1						
2001-9	IND RIV	230	STANTON	230	1	11						
2001-9	SILVR SP	230	SILV SPN	230	1	2						
2001-9	SILVR SP	230	SILV SPN	230	2	2						
2001-9	RIO PINR	230	CURRY FD	230	1	2						
2001-9	JUNEAU-W	138	GANNON	138	1	16						
2001-9	NSB-SMYR	115	CASSADAG	115	1	2						
2001-9	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-9	NSB-SMYR	115	TAYLOR	115	1	1						
2001-9	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-9	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-9	SN PLANT	115	TURNER	115	1	1						
2001-9	PASADENA	115	40ST-DUM	115	1	2						
2001-9	MICHIGAN	115	KALEY	115	1	11						
2001-9	MICHIGAN	115	GRANT	115	1	11						
2001-9	PERSHING	115	GRANT	115	1	11						
2001-9	AMERICA	115	KALEY	115	1	11						
2001-9	JASPER	115	WGHTCHPL	115	1	2						
2001-9	AZALEA	115	BENNETT	115	1	11						
2001-9	FLORALTP	69	INVERNTP	69	1	2						
2001-9	ALACH TP	69	HIGH SPG	69	1	2						
2001-9	PASADENA	230	PASADENA	115	1	2						
2001-9	SUWANNEE	230	SUWANNEE	115	1	2						
2001-9	SUWANNEE	230	SUWANNEE	115	2	2						
2001-9	E CLRWTR	230	E CLRWTR	115	1	2						
2001-9	IND RIV	230	IND RIV	115	1	11						
2001-9	LARGO	230	LARGO A	69	1	2						
2001-9	SHELD	230	SHELD-NW	69	1	16						
2001-9	CLMT EST	230	CLMT EST	69	1	2						
2001-9	WINDERME	230	WINDERME	69	1	2						
2001-9	RIVER-S	230	RIVER-S	69	1	16						
2001-9	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-9	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-9	JASPER	115	JASPER	69	1	2						
2001-10	SN PLANT	230	SYLVAN	230	1	1						
2001-10	SYLVAN	230	N LONGWD	230	1	1						
2001-10	IND RIV	230	STANTON	230	1	11						
2001-10	SILVR SP	230	SILV SPN	230	1	2						
2001-10	SILVR SP	230	SILV SPN	230	2	2						
2001-10	RIO PINR	230	CURRY FD	230	1	2						
2001-10	JUNEAU-W	138	GANNON	138	1	16						
2001-10	NSB-SMYR	115	CASSADAG	115	1	2						
2001-10	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-10	NSB-SMYR	115	TAYLOR	115	1	1						
2001-10	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-10	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-10	SN PLANT	115	TURNER	115	1	1						
2001-10	PASADENA	115	40ST-DUM	115	1	2						
2001-10	MICHIGAN	115	KALEY	115	1	11						
2001-10	MICHIGAN	115	GRANT	115	1	11						
2001-10	PERSHING	115	GRANT	115	1	11						
2001-10	AMERICA	115	KALEY	115	1	11						
2001-10	JASPER	115	WGHTCHPL	115	1	2						
2001-10	AZALEA	115	BENNETT	115	1	11						
2001-10	FLORALTP	69	INVERNTP	69	1	2						
2001-10	ALACH TP	69	HIGH SPG	69	1	2						
2001-10	PASADENA	230	PASADENA	115	1	2						
2001-10	SUWANNEE	230	SUWANNEE	115	1	2						
2001-10	SUWANNEE	230	SUWANNEE	115	2	2						
2001-10	E CLRWTR	230	E CLRWTR	115	1	2						
2001-10	IND RIV	230	IND RIV	115	1	11						
2001-10	LARGO	230	LARGO A	69	1	2						
2001-10	SHELD	230	SHELD-NW	69	1	16						
2001-10	CLMT EST	230	CLMT EST	69	1	2						
2001-10	WINDERME	230	WINDERME	69	1	2						
2001-10	RIVER-S	230	RIVER-S	69	1	16						
2001-10	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-10	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-10	JASPER	115	JASPER	69	1	2						

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-11	SN PLANT	230	SYLVAN	230	1	1						
2001-11	SYLVAN	230	N LONGWD	230	1	1						
2001-11	IND RIV	230	STANTON	230	1	11						
2001-11	SILVR SP	230	SILV SPN	230	1	2						
2001-11	SILVR SP	230	SILV SPN	230	2	2						
2001-11	RIO PINR	230	CURRY FD	230	1	2						
2001-11	JUNEAU-W	138	GANNON	138	1	16						
2001-11	NSB-SMYR	115	CASSADAG	115	1	2						
2001-11	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-11	NSB-SMYR	115	TAYLOR	115	1	1						
2001-11	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-11	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-11	SN PLANT	115	TURNER	115	1	1						
2001-11	PASADENA	115	40ST-DUM	115	1	2						
2001-11	MICHIGAN	115	KALEY	115	1	11						
2001-11	MICHIGAN	115	GRANT	115	1	11						
2001-11	PERSHING	115	GRANT	115	1	11						
2001-11	AMERICA	115	KALEY	115	1	11						
2001-11	JASPER	115	WGHTCHPL	115	1	2						
2001-11	AZALEA	115	BENNETT	115	1	11						
2001-11	FLORALTP	69	INVERNTP	69	1	2						
2001-11	ALACH TP	69	HIGH SPG	69	1	2						
2001-11	PASADENA	230	PASADENA	115	1	2						
2001-11	SUWANNEE	230	SUWANNEE	115	1	2						
2001-11	SUWANNEE	230	SUWANNEE	115	2	2						
2001-11	E CLRWTR	230	E CLRWTR	115	1	2						
2001-11	IND RIV	230	IND RIV	115	1	11						
2001-11	LARGO	230	LARGO A	69	1	2						
2001-11	SHELD	230	SHELD-NW	69	1	16						
2001-11	CLMT EST	230	CLMT EST	69	1	2						
2001-11	WINDERME	230	WINDERME	69	1	2						
2001-11	RIVER-S	230	RIVER-S	69	1	16						
2001-11	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-11	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-11	JASPER	115	JASPER	69	1	2						
2001-12	SN PLANT	230	SYLVAN	230	1	1						
2001-12	SYLVAN	230	N LONGWD	230	1	1						
2001-12	IND RIV	230	STANTON	230	1	11						
2001-12	SILVR SP	230	SILV SPN	230	1	2						
2001-12	SILVR SP	230	SILV SPN	230	2	2						
2001-12	RIO PINR	230	CURRY FD	230	1	2						
2001-12	JUNEAU-W	138	GANNON	138	1	16						
2001-12	NSB-SMYR	115	CASSADAG	115	1	2						
2001-12	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-12	NSB-SMYR	115	TAYLOR	115	1	1						
2001-12	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-12	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-12	SN PLANT	115	TURNER	115	1	1						
2001-12	PASADENA	115	40ST-DUM	115	1	2						
2001-12	MICHIGAN	115	KALEY	115	1	11						
2001-12	MICHIGAN	115	GRANT	115	1	11						
2001-12	PERSHING	115	GRANT	115	1	11						
2001-12	AMERICA	115	KALEY	115	1	11						
2001-12	JASPER	115	WGHTCHPL	115	1	2						
2001-12	AZALEA	115	BENNETT	115	1	11						
2001-12	FLORALTP	69	INVERNTP	69	1	2						
2001-12	ALACH TP	69	HIGH SPG	69	1	2						
2001-12	PASADENA	230	PASADENA	115	1	2						
2001-12	SUWANNEE	230	SUWANNEE	115	1	2						
2001-12	SUWANNEE	230	SUWANNEE	115	2	2						
2001-12	E CLRWTR	230	E CLRWTR	115	1	2						
2001-12	IND RIV	230	IND RIV	115	1	11						
2001-12	LARGO	230	LARGO A	69	1	2						
2001-12	SHELD	230	SHELD-NW	69	1	16						
2001-12	CLMT EST	230	CLMT EST	69	1	2						
2001-12	WINDERME	230	WINDERME	69	1	2						
2001-12	RIVER-S	230	RIVER-S	69	1	16						
2001-12	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-12	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-12	JASPER	115	JASPER	69	1	2						

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100% Load Base Case

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-13	SN PLANT	230	SYLVAN	230	1	1						
2001-13	SYLVAN	230	N LONGWD	230	1	1						
2001-13	IND RIV	230	STANTON	230	1	11						
2001-13	SILVR SP	230	SILV SPN	230	1	2						
2001-13	SILVR SP	230	SILV SPN	230	2	2						
2001-13	RIO PINR	230	CURRY FD	230	1	2						
2001-13	JUNEAU-W	138	GANNON	138	1	16						
2001-13	NSB-SMYR	115	CASSADAG	115	1	2						
2001-13	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-13	NSB-SMYR	115	TAYLOR	115	1	1						
2001-13	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-13	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-13	SN PLANT	115	TURNER	115	1	1						
2001-13	PASADENA	115	40ST-DUM	115	1	2						
2001-13	MICHIGAN	115	KALEY	115	1	11						
2001-13	MICHIGAN	115	GRANT	115	1	11						
2001-13	PERSHING	115	GRANT	115	1	11						
2001-13	AMERICA	115	KALEY	115	1	11						
2001-13	JASPER	115	WGHTCHPL	115	1	2						
2001-13	AZALEA	115	BENNETT	115	1	11						
2001-13	FLORALTP	69	INVERNTP	69	1	2						
2001-13	ALACH TP	69	HIGH SPG	69	1	2						
2001-13	PASADENA	230	PASADENA	115	1	2						
2001-13	SUWANNEE	230	SUWANNEE	115	1	2						
2001-13	SUWANNEE	230	SUWANNEE	115	2	2						
2001-13	E CLRWTR	230	E CLRWTR	115	1	2						
2001-13	IND RIV	230	IND RIV	115	1	11						
2001-13	LARGO	230	LARGO A	69	1	2						
2001-13	SHELD	230	SHELD-NW	69	1	16						
2001-13	CLMT EST	230	CLMT EST	69	1	2						
2001-13	WINDERME	230	WINDERME	69	1	2						
2001-13	RIVER-S	230	RIVER-S	69	1	16						
2001-13	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-13	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-13	JASPER	115	JASPER	69	1	2						
2001-14	SN PLANT	230	SYLVAN	230	1	1						
2001-14	SYLVAN	230	N LONGWD	230	1	1						
2001-14	IND RIV	230	STANTON	230	1	11						
2001-14	SILVR SP	230	SILV SPN	230	1	2						
2001-14	SILVR SP	230	SILV SPN	230	2	2						
2001-14	RIO PINR	230	CURRY FD	230	1	2						
2001-14	JUNEAU-W	138	GANNON	138	1	16						
2001-14	NSB-SMYR	115	CASSADAG	115	1	2						
2001-14	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-14	NSB-SMYR	115	TAYLOR	115	1	1						
2001-14	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-14	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-14	SN PLANT	115	TURNER	115	1	1						
2001-14	PASADENA	115	40ST-DUM	115	1	2						
2001-14	MICHIGAN	115	KALEY	115	1	11						
2001-14	MICHIGAN	115	GRANT	115	1	11						
2001-14	PERSHING	115	GRANT	115	1	11						
2001-14	AMERICA	115	KALEY	115	1	11						
2001-14	JASPER	115	WGHTCHPL	115	1	2						
2001-14	AZALEA	115	BENNETT	115	1	11						
2001-14	FLORALTP	69	INVERNTP	69	1	2						
2001-14	ALACH TP	69	HIGH SPG	69	1	2						
2001-14	PASADENA	230	PASADENA	115	1	2						
2001-14	SUWANNEE	230	SUWANNEE	115	1	2						
2001-14	SUWANNEE	230	SUWANNEE	115	2	2						
2001-14	E CLRWTR	230	E CLRWTR	115	1	2						
2001-14	IND RIV	230	IND RIV	115	1	11						
2001-14	LARGO	230	LARGO A	69	1	2						
2001-14	SHELD	230	SHELD-NW	69	1	16						
2001-14	CLMT EST	230	CLMT EST	69	1	2						
2001-14	WINDERME	230	WINDERME	69	1	2						
2001-14	RIVER-S	230	RIVER-S	69	1	16						
2001-14	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-14	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-14	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-15	SN PLANT	230	SYLVAN	230	1	1						
2001-15	SYLVAN	230	N LONGWD	230	1	1						
2001-15	IND RIV	230	STANTON	230	1	11						
2001-15	SILVR SP	230	SILV SPN	230	1	2						
2001-15	SILVR SP	230	SILV SPN	230	2	2						
2001-15	RIO PINR	230	CURRY FD	230	1	2						
2001-15	JUNEAU-W	138	GANNON	138	1	16						
2001-15	NSB-SMYR	115	CASSADAG	115	1	2						
2001-15	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-15	NSB-SMYR	115	TAYLOR	115	1	1						
2001-15	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-15	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-15	SN PLANT	115	TURNER	115	1	1						
2001-15	PASADENA	115	40ST-DUM	115	1	2						
2001-15	MICHIGAN	115	KALEY	115	1	11						
2001-15	MICHIGAN	115	GRANT	115	1	11						
2001-15	PERSHING	115	GRANT	115	1	11						
2001-15	AMERICA	115	KALEY	115	1	11						
2001-15	JASPER	115	WGHTCHPL	115	1	2						
2001-15	AZALEA	115	BENNETT	115	1	11						
2001-15	FLORALTP	69	INVERNTP	69	1	2						
2001-15	ALACH TP	69	HIGH SPG	69	1	2						
2001-15	PASADENA	230	PASADENA	115	1	2						
2001-15	SUWANNEE	230	SUWANNEE	115	1	2						
2001-15	SUWANNEE	230	SUWANNEE	115	2	2						
2001-15	E CLRWTR	230	E CLRWTR	115	1	2						
2001-15	IND RIV	230	IND RIV	115	1	11						
2001-15	LARGO	230	LARGO A	69	1	2						
2001-15	SHELD	230	SHELD-NW	69	1	16						
2001-15	CLMT EST	230	CLMT EST	69	1	2						
2001-15	WINDERME	230	WINDERME	69	1	2						
2001-15	RIVER-S	230	RIVER-S	69	1	16						
2001-15	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-15	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-15	JASPER	115	JASPER	69	1	2						
2001-16	SN PLANT	230	SYLVAN	230	1	1						
2001-16	SYLVAN	230	N LONGWD	230	1	1						
2001-16	IND RIV	230	STANTON	230	1	11						
2001-16	SILVR SP	230	SILV SPN	230	1	2						
2001-16	SILVR SP	230	SILV SPN	230	2	2						
2001-16	RIO PINR	230	CURRY FD	230	1	2						
2001-16	JUNEAU-W	138	GANNON	138	1	16						
2001-16	NSB-SMYR	115	CASSADAG	115	1	2						
2001-16	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-16	NSB-SMYR	115	TAYLOR	115	1	1						
2001-16	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-16	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-16	SN PLANT	115	TURNER	115	1	1						
2001-16	PASADENA	115	40ST-DUM	115	1	2						
2001-16	MICHIGAN	115	KALEY	115	1	11						
2001-16	MICHIGAN	115	GRANT	115	1	11						
2001-16	PERSHING	115	GRANT	115	1	11						
2001-16	AMERICA	115	KALEY	115	1	11						
2001-16	JASPER	115	WGHTCHPL	115	1	2						
2001-16	AZALEA	115	BENNETT	115	1	11						
2001-16	FLORALTP	69	INVERNTP	69	1	2						
2001-16	ALACH TP	69	HIGH SPG	69	1	2						
2001-16	PASADENA	230	PASADENA	115	1	2						
2001-16	SUWANNEE	230	SUWANNEE	115	1	2						
2001-16	SUWANNEE	230	SUWANNEE	115	2	2						
2001-16	E CLRWTR	230	E CLRWTR	115	1	2						
2001-16	IND RIV	230	IND RIV	115	1	11						
2001-16	LARGO	230	LARGO A	69	1	2						
2001-16	SHELD	230	SHELD-NW	69	1	16						
2001-16	CLMT EST	230	CLMT EST	69	1	2						
2001-16	WINDERME	230	WINDERME	69	1	2						
2001-16	RIVER-S	230	RIVER-S	69	1	16						
2001-16	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-16	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-16	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
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100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-17	SN PLANT	230	SYLVAN	230	1	1						
2001-17	SYLVAN	230	N LONGWD	230	1	1						
2001-17	IND RIV	230	STANTON	230	1	11						
2001-17	SILVR SP	230	SILV SPN	230	1	2						
2001-17	SILVR SP	230	SILV SPN	230	2	2						
2001-17	RIO PINR	230	CURRY FD	230	1	2						
2001-17	JUNEAU-W	138	GANNON	138	1	16						
2001-17	NSB-SMYR	115	CASSADAG	115	1	2						
2001-17	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-17	NSB-SMYR	115	TAYLOR	115	1	1						
2001-17	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-17	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-17	SN PLANT	115	TURNER	115	1	1						
2001-17	PASADENA	115	40ST-DUM	115	1	2						
2001-17	MICHIGAN	115	KALEY	115	1	11						
2001-17	MICHIGAN	115	GRANT	115	1	11						
2001-17	PERSHING	115	GRANT	115	1	11						
2001-17	AMERICA	115	KALEY	115	1	11						
2001-17	JASPER	115	WGHTCHPL	115	1	2						
2001-17	AZALEA	115	BENNETT	115	1	11						
2001-17	FLORALTP	69	INVERNTP	69	1	2						
2001-17	ALACH TP	69	HIGH SPG	69	1	2						
2001-17	PASADENA	230	PASADENA	115	1	2						
2001-17	SUWANNEE	230	SUWANNEE	115	1	2						
2001-17	SUWANNEE	230	SUWANNEE	115	2	2						
2001-17	E CLRWTR	230	E CLRWTR	115	1	2						
2001-17	IND RIV	230	IND RIV	115	1	11						
2001-17	LARGO	230	LARGO A	69	1	2						
2001-17	SHELD	230	SHELD-NW	69	1	16						
2001-17	CLMT EST	230	CLMT EST	69	1	2						
2001-17	WINDERME	230	WINDERME	69	1	2						
2001-17	RIVER-S	230	RIVER-S	69	1	16						
2001-17	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-17	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-17	JASPER	115	JASPER	69	1	2						
2001-18	SN PLANT	230	SYLVAN	230	1	1						
2001-18	SYLVAN	230	N LONGWD	230	1	1						
2001-18	IND RIV	230	STANTON	230	1	11						
2001-18	SILVR SP	230	SILV SPN	230	1	2						
2001-18	SILVR SP	230	SILV SPN	230	2	2						
2001-18	RIO PINR	230	CURRY FD	230	1	2						
2001-18	JUNEAU-W	138	GANNON	138	1	16						
2001-18	NSB-SMYR	115	CASSADAG	115	1	2						
2001-18	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-18	NSB-SMYR	115	TAYLOR	115	1	1						
2001-18	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-18	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-18	SN PLANT	115	TURNER	115	1	1						
2001-18	PASADENA	115	40ST-DUM	115	1	2						
2001-18	MICHIGAN	115	KALEY	115	1	11						
2001-18	MICHIGAN	115	GRANT	115	1	11						
2001-18	PERSHING	115	GRANT	115	1	11						
2001-18	AMERICA	115	KALEY	115	1	11						
2001-18	JASPER	115	WGHTCHPL	115	1	2						
2001-18	AZALEA	115	BENNETT	115	1	11						
2001-18	FLORALTP	69	INVERNTP	69	1	2						
2001-18	ALACH TP	69	HIGH SPG	69	1	2						
2001-18	PASADENA	230	PASADENA	115	1	2						
2001-18	SUWANNEE	230	SUWANNEE	115	1	2						
2001-18	SUWANNEE	230	SUWANNEE	115	2	2						
2001-18	E CLRWTR	230	E CLRWTR	115	1	2						
2001-18	IND RIV	230	IND RIV	115	1	11						
2001-18	LARGO	230	LARGO A	69	1	2						
2001-18	SHELD	230	SHELD-NW	69	1	16						
2001-18	CLMT EST	230	CLMT EST	69	1	2						
2001-18	WINDERME	230	WINDERME	69	1	2						
2001-18	RIVER-S	230	RIVER-S	69	1	16						
2001-18	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-18	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-18	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
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100% Load Base Case

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-19	SN PLANT	230	SYLVAN	230	1	1						
2001-19	SYLVAN	230	N LONGWD	230	1	1						
2001-19	IND RIV	230	STANTON	230	1	11						
2001-19	SILVR SP	230	SILV SPN	230	1	2						
2001-19	SILVR SP	230	SILV SPN	230	2	2						
2001-19	RIO PINR	230	CURRY FD	230	1	2						
2001-19	JUNEAU-W	138	GANNON	138	1	16						
2001-19	NSB-SMYR	115	CASSADAG	115	1	2						
2001-19	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-19	NSB-SMYR	115	TAYLOR	115	1	1						
2001-19	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-19	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-19	SN PLANT	115	TURNER	115	1	1						
2001-19	PASADENA	115	40ST-DUM	115	1	2						
2001-19	MICHIGAN	115	KALEY	115	1	11						
2001-19	MICHIGAN	115	GRANT	115	1	11						
2001-19	PERSHING	115	GRANT	115	1	11						
2001-19	AMERICA	115	KALEY	115	1	11						
2001-19	JASPER	115	WGHTCHPL	115	1	2						
2001-19	AZALEA	115	BENNETT	115	1	11						
2001-19	FLORALTP	69	INVERNTP	69	1	2						
2001-19	ALACH TP	69	HIGH SPG	69	1	2						
2001-19	PASADENA	230	PASADENA	115	1	2						
2001-19	SUWANNEE	230	SUWANNEE	115	1	2						
2001-19	SUWANNEE	230	SUWANNEE	115	2	2						
2001-19	E CLRWTR	230	E CLRWTR	115	1	2						
2001-19	IND RIV	230	IND RIV	115	1	11						
2001-19	LARGO	230	LARGO A	69	1	2						
2001-19	SHELD	230	SHELD-NW	69	1	16						
2001-19	CLMT EST	230	CLMT EST	69	1	2						
2001-19	WINDERME	230	WINDERME	69	1	2						
2001-19	RIVER-S	230	RIVER-S	69	1	16						
2001-19	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-19	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-19	JASPER	115	JASPER	69	1	2						
2001-20	SN PLANT	230	SYLVAN	230	1	1						
2001-20	SYLVAN	230	N LONGWD	230	1	1						
2001-20	IND RIV	230	STANTON	230	1	11						
2001-20	SILVR SP	230	SILV SPN	230	1	2						
2001-20	SILVR SP	230	SILV SPN	230	2	2						
2001-20	RIO PINR	230	CURRY FD	230	1	2						
2001-20	JUNEAU-W	138	GANNON	138	1	16						
2001-20	NSB-SMYR	115	CASSADAG	115	1	2						
2001-20	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-20	NSB-SMYR	115	TAYLOR	115	1	1						
2001-20	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-20	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-20	SN PLANT	115	TURNER	115	1	1						
2001-20	PASADENA	115	40ST-DUM	115	1	2						
2001-20	MICHIGAN	115	KALEY	115	1	11						
2001-20	MICHIGAN	115	GRANT	115	1	11						
2001-20	PERSHING	115	GRANT	115	1	11						
2001-20	AMERICA	115	KALEY	115	1	11						
2001-20	JASPER	115	WGHTCHPL	115	1	2						
2001-20	AZALEA	115	BENNETT	115	1	11						
2001-20	FLORALTP	69	INVERNTP	69	1	2						
2001-20	ALACH TP	69	HIGH SPG	69	1	2						
2001-20	PASADENA	230	PASADENA	115	1	2						
2001-20	SUWANNEE	230	SUWANNEE	115	1	2						
2001-20	SUWANNEE	230	SUWANNEE	115	2	2						
2001-20	E CLRWTR	230	E CLRWTR	115	1	2						
2001-20	IND RIV	230	IND RIV	115	1	11						
2001-20	LARGO	230	LARGO A	69	1	2						
2001-20	SHELD	230	SHELD-NW	69	1	16						
2001-20	CLMT EST	230	CLMT EST	69	1	2						
2001-20	WINDERME	230	WINDERME	69	1	2						
2001-20	RIVER-S	230	RIVER-S	69	1	16						
2001-20	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-20	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-20	JASPER	115	JASPER	69	1	2						

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100% Load Base Case

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-21	SN PLANT	230	SYLVAN	230	1	1						
2001-21	SYLVAN	230	N LONGWD	230	1	1						
2001-21	IND RIV	230	STANTON	230	1	11						
2001-21	SILVR SP	230	SILV SPN	230	1	2						
2001-21	SILVR SP	230	SILV SPN	230	2	2						
2001-21	RIO PINR	230	CURRY FD	230	1	2						
2001-21	JUNEAU-W	138	GANNON	138	1	16						
2001-21	NSB-SMYR	115	CASSADAG	115	1	2						
2001-21	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-21	NSB-SMYR	115	TAYLOR	115	1	1						
2001-21	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-21	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-21	SN PLANT	115	TURNER	115	1	1						
2001-21	PASADENA	115	40ST-DUM	115	1	2						
2001-21	MICHIGAN	115	KALEY	115	1	11						
2001-21	MICHIGAN	115	GRANT	115	1	11						
2001-21	PERSHING	115	GRANT	115	1	11						
2001-21	AMERICA	115	KALEY	115	1	11						
2001-21	JASPER	115	WGHTCHPL	115	1	2						
2001-21	AZALEA	115	BENNETT	115	1	11						
2001-21	FLORALTP	69	INVERNTP	69	1	2						
2001-21	ALACH TP	69	HIGH SPG	69	1	2						
2001-21	PASADENA	230	PASADENA	115	1	2						
2001-21	SUWANNEE	230	SUWANNEE	115	1	2						
2001-21	SUWANNEE	230	SUWANNEE	115	2	2						
2001-21	E CLRWTR	230	E CLRWTR	115	1	2						
2001-21	IND RIV	230	IND RIV	115	1	11						
2001-21	LARGO	230	LARGO A	69	1	2						
2001-21	SHELD	230	SHELD-NW	69	1	16						
2001-21	CLMT EST	230	CLMT EST	69	1	2						
2001-21	WINDERME	230	WINDERME	69	1	2						
2001-21	RIVER-S	230	RIVER-S	69	1	16						
2001-21	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-21	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-21	JASPER	115	JASPER	69	1	2						
2001-22	SN PLANT	230	SYLVAN	230	1	1						
2001-22	SYLVAN	230	N LONGWD	230	1	1						
2001-22	IND RIV	230	STANTON	230	1	11						
2001-22	SILVR SP	230	SILV SPN	230	1	2						
2001-22	SILVR SP	230	SILV SPN	230	2	2						
2001-22	RIO PINR	230	CURRY FD	230	1	2						
2001-22	JUNEAU-W	138	GANNON	138	1	16						
2001-22	NSB-SMYR	115	CASSADAG	115	1	2						
2001-22	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-22	NSB-SMYR	115	TAYLOR	115	1	1						
2001-22	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-22	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-22	SN PLANT	115	TURNER	115	1	1						
2001-22	PASADENA	115	40ST-DUM	115	1	2						
2001-22	MICHIGAN	115	KALEY	115	1	11						
2001-22	MICHIGAN	115	GRANT	115	1	11						
2001-22	PERSHING	115	GRANT	115	1	11						
2001-22	AMERICA	115	KALEY	115	1	11						
2001-22	JASPER	115	WGHTCHPL	115	1	2						
2001-22	AZALEA	115	BENNETT	115	1	11						
2001-22	FLORALTP	69	INVERNTP	69	1	2						
2001-22	ALACH TP	69	HIGH SPG	69	1	2						
2001-22	PASADENA	230	PASADENA	115	1	2						
2001-22	SUWANNEE	230	SUWANNEE	115	1	2						
2001-22	SUWANNEE	230	SUWANNEE	115	2	2						
2001-22	E CLRWTR	230	E CLRWTR	115	1	2						
2001-22	IND RIV	230	IND RIV	115	1	11						
2001-22	LARGO	230	LARGO A	69	1	2						
2001-22	SHELD	230	SHELD-NW	69	1	16						
2001-22	CLMT EST	230	CLMT EST	69	1	2						
2001-22	WINDERME	230	WINDERME	69	1	2						
2001-22	RIVER-S	230	RIVER-S	69	1	16						
2001-22	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-22	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-22	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
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100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-23	SN PLANT	230	SYLVAN	230	1	1						
2001-23	SYLVAN	230	N LONGWD	230	1	1						
2001-23	IND RIV	230	STANTON	230	1	11						
2001-23	SILVR SP	230	SILV SPN	230	1	2						
2001-23	SILVR SP	230	SILV SPN	230	2	2						
2001-23	RIO PINR	230	CURRY FD	230	1	2						
2001-23	JUNEAU-W	138	GANNON	138	1	16						
2001-23	NSB-SMYR	115	CASSADAG	115	1	2						
2001-23	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-23	NSB-SMYR	115	TAYLOR	115	1	1						
2001-23	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-23	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-23	SN PLANT	115	TURNER	115	1	1						
2001-23	PASADENA	115	40ST-DUM	115	1	2						
2001-23	MICHIGAN	115	KALEY	115	1	11						
2001-23	MICHIGAN	115	GRANT	115	1	11						
2001-23	PERSHING	115	GRANT	115	1	11						
2001-23	AMERICA	115	KALEY	115	1	11						
2001-23	JASPER	115	WGHTCHPL	115	1	2						
2001-23	AZALEA	115	BENNETT	115	1	11						
2001-23	FLORALTP	69	INVERNTP	69	1	2						
2001-23	ALACH TP	69	HIGH SPG	69	1	2						
2001-23	PASADENA	230	PASADENA	115	1	2						
2001-23	SUWANNEE	230	SUWANNEE	115	1	2						
2001-23	SUWANNEE	230	SUWANNEE	115	2	2						
2001-23	E CLRWTR	230	E CLRWTR	115	1	2						
2001-23	IND RIV	230	IND RIV	115	1	11						
2001-23	LARGO	230	LARGO A	69	1	2						
2001-23	SHELD	230	SHELD-NW	69	1	16						
2001-23	CLMT EST	230	CLMT EST	69	1	2						
2001-23	WINDERME	230	WINDERME	69	1	2						
2001-23	RIVER-S	230	RIVER-S	69	1	16						
2001-23	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-23	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-23	JASPER	115	JASPER	69	1	2						
2001-24	SN PLANT	230	SYLVAN	230	1	1						
2001-24	SYLVAN	230	N LONGWD	230	1	1						
2001-24	IND RIV	230	STANTON	230	1	11						
2001-24	SILVR SP	230	SILV SPN	230	1	2						
2001-24	SILVR SP	230	SILV SPN	230	2	2						
2001-24	RIO PINR	230	CURRY FD	230	1	2						
2001-24	JUNEAU-W	138	GANNON	138	1	16						
2001-24	NSB-SMYR	115	CASSADAG	115	1	2						
2001-24	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-24	NSB-SMYR	115	TAYLOR	115	1	1						
2001-24	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-24	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-24	SN PLANT	115	TURNER	115	1	1						
2001-24	PASADENA	115	40ST-DUM	115	1	2						
2001-24	MICHIGAN	115	KALEY	115	1	11						
2001-24	MICHIGAN	115	GRANT	115	1	11						
2001-24	PERSHING	115	GRANT	115	1	11						
2001-24	AMERICA	115	KALEY	115	1	11						
2001-24	JASPER	115	WGHTCHPL	115	1	2						
2001-24	AZALEA	115	BENNETT	115	1	11						
2001-24	FLORALTP	69	INVERNTP	69	1	2						
2001-24	ALACH TP	69	HIGH SPG	69	1	2						
2001-24	PASADENA	230	PASADENA	115	1	2						
2001-24	SUWANNEE	230	SUWANNEE	115	1	2						
2001-24	SUWANNEE	230	SUWANNEE	115	2	2						
2001-24	E CLRWTR	230	E CLRWTR	115	1	2						
2001-24	IND RIV	230	IND RIV	115	1	11						
2001-24	LARGO	230	LARGO A	69	1	2						
2001-24	SHELD	230	SHELD-NW	69	1	16						
2001-24	CLMT EST	230	CLMT EST	69	1	2						
2001-24	WINDERME	230	WINDERME	69	1	2						
2001-24	RIVER-S	230	RIVER-S	69	1	16						
2001-24	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-24	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-24	JASPER	115	JASPER	69	1	2						

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-25	SN PLANT	230	SYLVAN	230	1	1						
2001-25	SYLVAN	230	N LONGWD	230	1	1						
2001-25	IND RIV	230	STANTON	230	1	11						
2001-25	SILVR SP	230	SILV SPN	230	1	2						
2001-25	SILVR SP	230	SILV SPN	230	2	2						
2001-25	RIO PINR	230	CURRY FD	230	1	2						
2001-25	JUNEAU-W	138	GANNON	138	1	16						
2001-25	NSB-SMYR	115	CASSADAG	115	1	2						
2001-25	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-25	NSB-SMYR	115	TAYLOR	115	1	1						
2001-25	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-25	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-25	SN PLANT	115	TURNER	115	1	1						
2001-25	PASADENA	115	40ST-DUM	115	1	2						
2001-25	MICHIGAN	115	KALEY	115	1	11						
2001-25	MICHIGAN	115	GRANT	115	1	11						
2001-25	PERSHING	115	GRANT	115	1	11						
2001-25	AMERICA	115	KALEY	115	1	11						
2001-25	JASPER	115	WGHTCHPL	115	1	2						
2001-25	AZALEA	115	BENNETT	115	1	11						
2001-25	FLORALTP	69	INVERNTP	69	1	2						
2001-25	ALACH TP	69	HIGH SPG	69	1	2						
2001-25	PASADENA	230	PASADENA	115	1	2						
2001-25	SUWANNEE	230	SUWANNEE	115	1	2						
2001-25	SUWANNEE	230	SUWANNEE	115	2	2						
2001-25	E CLRWTR	230	E CLRWTR	115	1	2						
2001-25	IND RIV	230	IND RIV	115	1	11						
2001-25	LARGO	230	LARGO A	69	1	2						
2001-25	SHELD	230	SHELD-NW	69	1	16						
2001-25	CLMT EST	230	CLMT EST	69	1	2						
2001-25	WINDERME	230	WINDERME	69	1	2						
2001-25	RIVER-S	230	RIVER-S	69	1	16						
2001-25	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-25	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-25	JASPER	115	JASPER	69	1	2						
2001-26	SN PLANT	230	SYLVAN	230	1	1						
2001-26	SYLVAN	230	N LONGWD	230	1	1						
2001-26	IND RIV	230	STANTON	230	1	11						
2001-26	SILVR SP	230	SILV SPN	230	1	2						
2001-26	SILVR SP	230	SILV SPN	230	2	2						
2001-26	RIO PINR	230	CURRY FD	230	1	2						
2001-26	JUNEAU-W	138	GANNON	138	1	16						
2001-26	NSB-SMYR	115	CASSADAG	115	1	2						
2001-26	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-26	NSB-SMYR	115	TAYLOR	115	1	1						
2001-26	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-26	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-26	SN PLANT	115	TURNER	115	1	1						
2001-26	PASADENA	115	40ST-DUM	115	1	2						
2001-26	MICHIGAN	115	KALEY	115	1	11						
2001-26	MICHIGAN	115	GRANT	115	1	11						
2001-26	PERSHING	115	GRANT	115	1	11						
2001-26	AMERICA	115	KALEY	115	1	11						
2001-26	JASPER	115	WGHTCHPL	115	1	2						
2001-26	AZALEA	115	BENNETT	115	1	11						
2001-26	FLORALTP	69	INVERNTP	69	1	2						
2001-26	ALACH TP	69	HIGH SPG	69	1	2						
2001-26	PASADENA	230	PASADENA	115	1	2						
2001-26	SUWANNEE	230	SUWANNEE	115	1	2						
2001-26	SUWANNEE	230	SUWANNEE	115	2	2						
2001-26	E CLRWTR	230	E CLRWTR	115	1	2						
2001-26	IND RIV	230	IND RIV	115	1	11						
2001-26	LARGO	230	LARGO A	69	1	2						
2001-26	SHELD	230	SHELD-NW	69	1	16						
2001-26	CLMT EST	230	CLMT EST	69	1	2						
2001-26	WINDERME	230	WINDERME	69	1	2						
2001-26	RIVER-S	230	RIVER-S	69	1	16						
2001-26	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-26	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-26	JASPER	115	JASPER	69	1	2						

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-27	SN PLANT	230	SYLVAN	230	1	1						
2001-27	SYLVAN	230	N LONGWD	230	1	1						
2001-27	IND RIV	230	STANTON	230	1	11						
2001-27	SILVR SP	230	SILV SPN	230	1	2						
2001-27	SILVR SP	230	SILV SPN	230	2	2						
2001-27	RIO PINR	230	CURRY FD	230	1	2						
2001-27	JUNEAU-W	138	GANNON	138	1	16						
2001-27	NSB-SMYR	115	CASSADAG	115	1	2						
2001-27	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-27	NSB-SMYR	115	TAYLOR	115	1	1						
2001-27	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-27	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-27	SN PLANT	115	TURNER	115	1	1						
2001-27	PASADENA	115	40ST-DUM	115	1	2						
2001-27	MICHIGAN	115	KALEY	115	1	11						
2001-27	MICHIGAN	115	GRANT	115	1	11						
2001-27	PERSHING	115	GRANT	115	1	11						
2001-27	AMERICA	115	KALEY	115	1	11						
2001-27	JASPER	115	WGHTCHPL	115	1	2						
2001-27	AZALEA	115	BENNETT	115	1	11						
2001-27	FLORALTP	69	INVERNTP	69	1	2						
2001-27	ALACH TP	69	HIGH SPG	69	1	2						
2001-27	PASADENA	230	PASADENA	115	1	2						
2001-27	SUWANNEE	230	SUWANNEE	115	1	2						
2001-27	SUWANNEE	230	SUWANNEE	115	2	2						
2001-27	E CLRWTR	230	E CLRWTR	115	1	2						
2001-27	IND RIV	230	IND RIV	115	1	11						
2001-27	LARGO	230	LARGO A	69	1	2						
2001-27	SHELD	230	SHELD-NW	69	1	16						
2001-27	CLMT EST	230	CLMT EST	69	1	2						
2001-27	WINDERME	230	WINDERME	69	1	2						
2001-27	RIVER-S	230	RIVER-S	69	1	16						
2001-27	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-27	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-27	JASPER	115	JASPER	69	1	2						
2001-28	SN PLANT	230	SYLVAN	230	1	1						
2001-28	SYLVAN	230	N LONGWD	230	1	1						
2001-28	IND RIV	230	STANTON	230	1	11						
2001-28	SILVR SP	230	SILV SPN	230	1	2						
2001-28	SILVR SP	230	SILV SPN	230	2	2						
2001-28	RIO PINR	230	CURRY FD	230	1	2						
2001-28	JUNEAU-W	138	GANNON	138	1	16						
2001-28	NSB-SMYR	115	CASSADAG	115	1	2						
2001-28	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-28	NSB-SMYR	115	TAYLOR	115	1	1						
2001-28	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-28	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-28	SN PLANT	115	TURNER	115	1	1						
2001-28	PASADENA	115	40ST-DUM	115	1	2						
2001-28	MICHIGAN	115	KALEY	115	1	11						
2001-28	MICHIGAN	115	GRANT	115	1	11						
2001-28	PERSHING	115	GRANT	115	1	11						
2001-28	AMERICA	115	KALEY	115	1	11						
2001-28	JASPER	115	WGHTCHPL	115	1	2						
2001-28	AZALEA	115	BENNETT	115	1	11						
2001-28	FLORALTP	69	INVERNTP	69	1	2						
2001-28	ALACH TP	69	HIGH SPG	69	1	2						
2001-28	PASADENA	230	PASADENA	115	1	2						
2001-28	SUWANNEE	230	SUWANNEE	115	1	2						
2001-28	SUWANNEE	230	SUWANNEE	115	2	2						
2001-28	E CLRWTR	230	E CLRWTR	115	1	2						
2001-28	IND RIV	230	IND RIV	115	1	11						
2001-28	LARGO	230	LARGO A	69	1	2						
2001-28	SHELD	230	SHELD-NW	69	1	16						
2001-28	CLMT EST	230	CLMT EST	69	1	2						
2001-28	WINDERME	230	WINDERME	69	1	2						
2001-28	RIVER-S	230	RIVER-S	69	1	16						
2001-28	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-28	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-28	JASPER	115	JASPER	69	1	2						

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-29	SN PLANT	230	SYLVAN	230	1	1						
2001-29	SYLVAN	230	N LONGWD	230	1	1						
2001-29	IND RIV	230	STANTON	230	1	11						
2001-29	SILVR SP	230	SILV SPN	230	1	2						
2001-29	SILVR SP	230	SILV SPN	230	2	2						
2001-29	RIO PINR	230	CURRY FD	230	1	2						
2001-29	JUNEAU-W	138	GANNON	138	1	16						
2001-29	NSB-SMYR	115	CASSADAG	115	1	2						
2001-29	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-29	NSB-SMYR	115	TAYLOR	115	1	1						
2001-29	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-29	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-29	SN PLANT	115	TURNER	115	1	1						
2001-29	PASADENA	115	40ST-DUM	115	1	2						
2001-29	MICHIGAN	115	KALEY	115	1	11						
2001-29	MICHIGAN	115	GRANT	115	1	11						
2001-29	PERSHING	115	GRANT	115	1	11						
2001-29	AMERICA	115	KALEY	115	1	11						
2001-29	JASPER	115	WGHTCHPL	115	1	2						
2001-29	AZALEA	115	BENNETT	115	1	11						
2001-29	FLORALTP	69	INVERNTP	69	1	2						
2001-29	ALACH TP	69	HIGH SPG	69	1	2						
2001-29	PASADENA	230	PASADENA	115	1	2						
2001-29	SUWANNEE	230	SUWANNEE	115	1	2						
2001-29	SUWANNEE	230	SUWANNEE	115	2	2						
2001-29	E CLRWTR	230	E CLRWTR	115	1	2						
2001-29	IND RIV	230	IND RIV	115	1	11						
2001-29	LARGO	230	LARGO A	69	1	2						
2001-29	SHELD	230	SHELD-NW	69	1	16						
2001-29	CLMT EST	230	CLMT EST	69	1	2						
2001-29	WINDERME	230	WINDERME	69	1	2						
2001-29	RIVER-S	230	RIVER-S	69	1	16						
2001-29	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-29	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-29	JASPER	115	JASPER	69	1	2						
2001-30	SN PLANT	230	SYLVAN	230	1	1						
2001-30	SYLVAN	230	N LONGWD	230	1	1						
2001-30	IND RIV	230	STANTON	230	1	11						
2001-30	SILVR SP	230	SILV SPN	230	1	2						
2001-30	SILVR SP	230	SILV SPN	230	2	2						
2001-30	RIO PINR	230	CURRY FD	230	1	2						
2001-30	JUNEAU-W	138	GANNON	138	1	16						
2001-30	NSB-SMYR	115	CASSADAG	115	1	2						
2001-30	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-30	NSB-SMYR	115	TAYLOR	115	1	1						
2001-30	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-30	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-30	SN PLANT	115	TURNER	115	1	1						
2001-30	PASADENA	115	40ST-DUM	115	1	2						
2001-30	MICHIGAN	115	KALEY	115	1	11						
2001-30	MICHIGAN	115	GRANT	115	1	11						
2001-30	PERSHING	115	GRANT	115	1	11						
2001-30	AMERICA	115	KALEY	115	1	11						
2001-30	JASPER	115	WGHTCHPL	115	1	2						
2001-30	AZALEA	115	BENNETT	115	1	11						
2001-30	FLORALTP	69	INVERNTP	69	1	2						
2001-30	ALACH TP	69	HIGH SPG	69	1	2						
2001-30	PASADENA	230	PASADENA	115	1	2						
2001-30	SUWANNEE	230	SUWANNEE	115	1	2						
2001-30	SUWANNEE	230	SUWANNEE	115	2	2						
2001-30	E CLRWTR	230	E CLRWTR	115	1	2						
2001-30	IND RIV	230	IND RIV	115	1	11						
2001-30	LARGO	230	LARGO A	69	1	2						
2001-30	SHELD	230	SHELD-NW	69	1	16						
2001-30	CLMT EST	230	CLMT EST	69	1	2						
2001-30	WINDERME	230	WINDERME	69	1	2						
2001-30	RIVER-S	230	RIVER-S	69	1	16						
2001-30	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-30	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-30	JASPER	115	JASPER	69	1	2						

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Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-31	SN PLANT	230	SYLVAN	230	1	1						
2001-31	SYLVAN	230	N LONGWD	230	1	1						
2001-31	IND RIV	230	STANTON	230	1	11						
2001-31	SILVR SP	230	SILV SPN	230	1	2						
2001-31	SILVR SP	230	SILV SPN	230	2	2						
2001-31	RIO PINR	230	CURRY FD	230	1	2						
2001-31	JUNEAU-W	138	GANNON	138	1	16						
2001-31	NSB-SMYR	115	CASSADAG	115	1	2						
2001-31	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-31	NSB-SMYR	115	TAYLOR	115	1	1						
2001-31	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-31	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-31	SN PLANT	115	TURNER	115	1	1						
2001-31	PASADENA	115	40ST-DUM	115	1	2						
2001-31	MICHIGAN	115	KALEY	115	1	11						
2001-31	MICHIGAN	115	GRANT	115	1	11						
2001-31	PERSHING	115	GRANT	115	1	11						
2001-31	AMERICA	115	KALEY	115	1	11						
2001-31	JASPER	115	WGHTCHPL	115	1	2						
2001-31	AZALEA	115	BENNETT	115	1	11						
2001-31	FLORALTP	69	INVERNTP	69	1	2						
2001-31	ALACH TP	69	HIGH SPG	69	1	2						
2001-31	PASADENA	230	PASADENA	115	1	2						
2001-31	SUWANNEE	230	SUWANNEE	115	1	2						
2001-31	SUWANNEE	230	SUWANNEE	115	2	2						
2001-31	E CLRWTR	230	E CLRWTR	115	1	2						
2001-31	IND RIV	230	IND RIV	115	1	11						
2001-31	LARGO	230	LARGO A	69	1	2						
2001-31	SHELD	230	SHELD-NW	69	1	16						
2001-31	CLMT EST	230	CLMT EST	69	1	2						
2001-31	WINDERME	230	WINDERME	69	1	2						
2001-31	RIVER-S	230	RIVER-S	69	1	16						
2001-31	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-31	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-31	JASPER	115	JASPER	69	1	2						
2001-32	SN PLANT	230	SYLVAN	230	1	1						
2001-32	SYLVAN	230	N LONGWD	230	1	1						
2001-32	IND RIV	230	STANTON	230	1	11						
2001-32	SILVR SP	230	SILV SPN	230	1	2						
2001-32	SILVR SP	230	SILV SPN	230	2	2						
2001-32	RIO PINR	230	CURRY FD	230	1	2						
2001-32	JUNEAU-W	138	GANNON	138	1	16						
2001-32	NSB-SMYR	115	CASSADAG	115	1	2						
2001-32	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-32	NSB-SMYR	115	TAYLOR	115	1	1						
2001-32	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-32	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-32	SN PLANT	115	TURNER	115	1	1						
2001-32	PASADENA	115	40ST-DUM	115	1	2						
2001-32	MICHIGAN	115	KALEY	115	1	11						
2001-32	MICHIGAN	115	GRANT	115	1	11						
2001-32	PERSHING	115	GRANT	115	1	11						
2001-32	AMERICA	115	KALEY	115	1	11						
2001-32	JASPER	115	WGHTCHPL	115	1	2						
2001-32	AZALEA	115	BENNETT	115	1	11						
2001-32	FLORALTP	69	INVERNTP	69	1	2						
2001-32	ALACH TP	69	HIGH SPG	69	1	2						
2001-32	PASADENA	230	PASADENA	115	1	2						
2001-32	SUWANNEE	230	SUWANNEE	115	1	2						
2001-32	SUWANNEE	230	SUWANNEE	115	2	2						
2001-32	E CLRWTR	230	E CLRWTR	115	1	2						
2001-32	IND RIV	230	IND RIV	115	1	11						
2001-32	LARGO	230	LARGO A	69	1	2						
2001-32	SHELD	230	SHELD-NW	69	1	16						
2001-32	CLMT EST	230	CLMT EST	69	1	2						
2001-32	WINDERME	230	WINDERME	69	1	2						
2001-32	RIVER-S	230	RIVER-S	69	1	16						
2001-32	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-32	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-32	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-33	SN PLANT	230	SYLVAN	230	1	1						
2001-33	SYLVAN	230	N LONGWD	230	1	1						
2001-33	IND RIV	230	STANTON	230	1	11						
2001-33	SILVR SP	230	SILV SPN	230	1	2						
2001-33	SILVR SP	230	SILV SPN	230	2	2						
2001-33	RIO PINR	230	CURRY FD	230	1	2						
2001-33	JUNEAU-W	138	GANNON	138	1	16						
2001-33	NSB-SMYR	115	CASSADAG	115	1	2						
2001-33	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-33	NSB-SMYR	115	TAYLOR	115	1	1						
2001-33	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-33	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-33	SN PLANT	115	TURNER	115	1	1						
2001-33	PASADENA	115	40ST-DUM	115	1	2						
2001-33	MICHIGAN	115	KALEY	115	1	11						
2001-33	MICHIGAN	115	GRANT	115	1	11						
2001-33	PERSHING	115	GRANT	115	1	11						
2001-33	AMERICA	115	KALEY	115	1	11						
2001-33	JASPER	115	WGHTCHPL	115	1	2						
2001-33	AZALEA	115	BENNETT	115	1	11						
2001-33	FLORALTP	69	INVERNTP	69	1	2						
2001-33	ALACH TP	69	HIGH SPG	69	1	2						
2001-33	PASADENA	230	PASADENA	115	1	2						
2001-33	SUWANNEE	230	SUWANNEE	115	1	2						
2001-33	SUWANNEE	230	SUWANNEE	115	2	2						
2001-33	E CLRWTR	230	E CLRWTR	115	1	2						
2001-33	IND RIV	230	IND RIV	115	1	11						
2001-33	LARGO	230	LARGO A	69	1	2						
2001-33	SHELD	230	SHELD-NW	69	1	16						
2001-33	CLMT EST	230	CLMT EST	69	1	2						
2001-33	WINDERME	230	WINDERME	69	1	2						
2001-33	RIVER-S	230	RIVER-S	69	1	16						
2001-33	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-33	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-33	JASPER	115	JASPER	69	1	2						
2001-34	SN PLANT	230	SYLVAN	230	1	1						
2001-34	SYLVAN	230	N LONGWD	230	1	1						
2001-34	IND RIV	230	STANTON	230	1	11						
2001-34	SILVR SP	230	SILV SPN	230	1	2						
2001-34	SILVR SP	230	SILV SPN	230	2	2						
2001-34	RIO PINR	230	CURRY FD	230	1	2						
2001-34	JUNEAU-W	138	GANNON	138	1	16						
2001-34	NSB-SMYR	115	CASSADAG	115	1	2						
2001-34	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-34	NSB-SMYR	115	TAYLOR	115	1	1						
2001-34	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-34	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-34	SN PLANT	115	TURNER	115	1	1						
2001-34	PASADENA	115	40ST-DUM	115	1	2						
2001-34	MICHIGAN	115	KALEY	115	1	11						
2001-34	MICHIGAN	115	GRANT	115	1	11						
2001-34	PERSHING	115	GRANT	115	1	11						
2001-34	AMERICA	115	KALEY	115	1	11						
2001-34	JASPER	115	WGHTCHPL	115	1	2						
2001-34	AZALEA	115	BENNETT	115	1	11						
2001-34	FLORALTP	69	INVERNTP	69	1	2						
2001-34	ALACH TP	69	HIGH SPG	69	1	2						
2001-34	PASADENA	230	PASADENA	115	1	2						
2001-34	SUWANNEE	230	SUWANNEE	115	1	2						
2001-34	SUWANNEE	230	SUWANNEE	115	2	2						
2001-34	E CLRWTR	230	E CLRWTR	115	1	2						
2001-34	IND RIV	230	IND RIV	115	1	11						
2001-34	LARGO	230	LARGO A	69	1	2						
2001-34	SHELD	230	SHELD-NW	69	1	16						
2001-34	CLMT EST	230	CLMT EST	69	1	2						
2001-34	WINDERME	230	WINDERME	69	1	2						
2001-34	RIVER-S	230	RIVER-S	69	1	16						
2001-34	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-34	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-34	JASPER	115	JASPER	69	1	2						

Table I

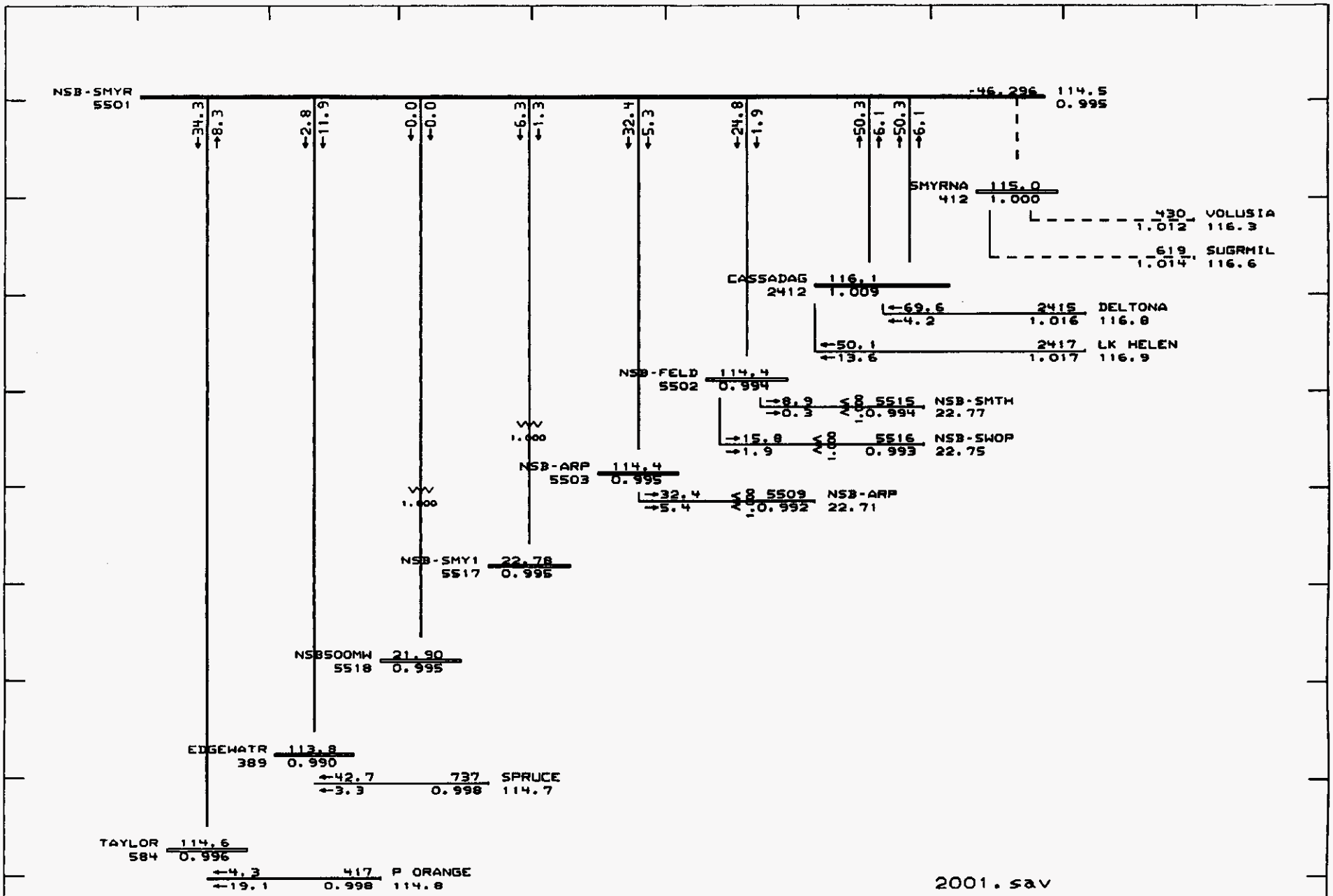
Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001 Base No NSB Gen	Case 2001A Sell to FPL	Case 2001B Sell to FPC	Case 2001C Sell to TEC	Case 2001D Sell to JEA	Case 2001E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-35	SN PLANT	230	SYLVAN	230	1	1						
2001-35	SYLVAN	230	N LONGWD	230	1	1						
2001-35	IND RIV	230	STANTON	230	1	11						
2001-35	SILVR SP	230	SILV SPN	230	1	2						
2001-35	SILVR SP	230	SILV SPN	230	2	2						
2001-35	RIO PINR	230	CURRY FD	230	1	2						
2001-35	JUNEAU-W	138	GANNON	138	1	16						
2001-35	NSB-SMYR	115	CASSADAG	115	1	2						
2001-35	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-35	NSB-SMYR	115	TAYLOR	115	1	1						
2001-35	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-35	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-35	SN PLANT	115	TURNER	115	1	1						
2001-35	PASADENA	115	40ST-DUM	115	1	2						
2001-35	MICHIGAN	115	KALEY	115	1	11						
2001-35	MICHIGAN	115	GRANT	115	1	11						
2001-35	PERSHING	115	GRANT	115	1	11						
2001-35	AMERICA	115	KALEY	115	1	11						
2001-35	JASPER	115	WGHTCHPL	115	1	2						
2001-35	AZALEA	115	BENNETT	115	1	11						
2001-35	FLORALTP	69	INVERNTP	69	1	2						
2001-35	ALACH TP	69	HIGH SPG	69	1	2						
2001-35	PASADENA	230	PASADENA	115	1	2						
2001-35	SUWANNEE	230	SUWANNEE	115	1	2						
2001-35	SUWANNEE	230	SUWANNEE	115	2	2						
2001-35	E CLRWTR	230	E CLRWTR	115	1	2						
2001-35	IND RIV	230	IND RIV	115	1	11						
2001-35	LARGO	230	LARGO A	69	1	2						
2001-35	SHELD	230	SHELD-NW	69	1	16						
2001-35	CLMT EST	230	CLMT EST	69	1	2						
2001-35	WINDERME	230	WINDERME	69	1	2						
2001-35	RIVER-S	230	RIVER-S	69	1	16						
2001-35	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-35	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-35	JASPER	115	JASPER	69	1	2						
2001-36	SN PLANT	230	SYLVAN	230	1	1						
2001-36	SYLVAN	230	N LONGWD	230	1	1						
2001-36	IND RIV	230	STANTON	230	1	11						
2001-36	SILVR SP	230	SILV SPN	230	1	2						
2001-36	SILVR SP	230	SILV SPN	230	2	2						
2001-36	RIO PINR	230	CURRY FD	230	1	2						
2001-36	JUNEAU-W	138	GANNON	138	1	16						
2001-36	NSB-SMYR	115	CASSADAG	115	1	2						
2001-36	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-36	NSB-SMYR	115	TAYLOR	115	1	1						
2001-36	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-36	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-36	SN PLANT	115	TURNER	115	1	1						
2001-36	PASADENA	115	40ST-DUM	115	1	2						
2001-36	MICHIGAN	115	KALEY	115	1	11						
2001-36	MICHIGAN	115	GRANT	115	1	11						
2001-36	PERSHING	115	GRANT	115	1	11						
2001-36	AMERICA	115	KALEY	115	1	11						
2001-36	JASPER	115	WGHTCHPL	115	1	2						
2001-36	AZALEA	115	BENNETT	115	1	11						
2001-36	FLORALTP	69	INVERNTP	69	1	2						
2001-36	ALACH TP	69	HIGH SPG	69	1	2						
2001-36	PASADENA	230	PASADENA	115	1	2						
2001-36	SUWANNEE	230	SUWANNEE	115	1	2						
2001-36	SUWANNEE	230	SUWANNEE	115	2	2						
2001-36	E CLRWTR	230	E CLRWTR	115	1	2						
2001-36	IND RIV	230	IND RIV	115	1	11						
2001-36	LARGO	230	LARGO A	69	1	2						
2001-36	SHELD	230	SHELD-NW	69	1	16						
2001-36	CLMT EST	230	CLMT EST	69	1	2						
2001-36	WINDERME	230	WINDERME	69	1	2						
2001-36	RIVER-S	230	RIVER-S	69	1	16						
2001-36	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-36	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-36	JASPER	115	JASPER	69	1	2						

APPENDIX II-A



General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:30:07 1998

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CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES

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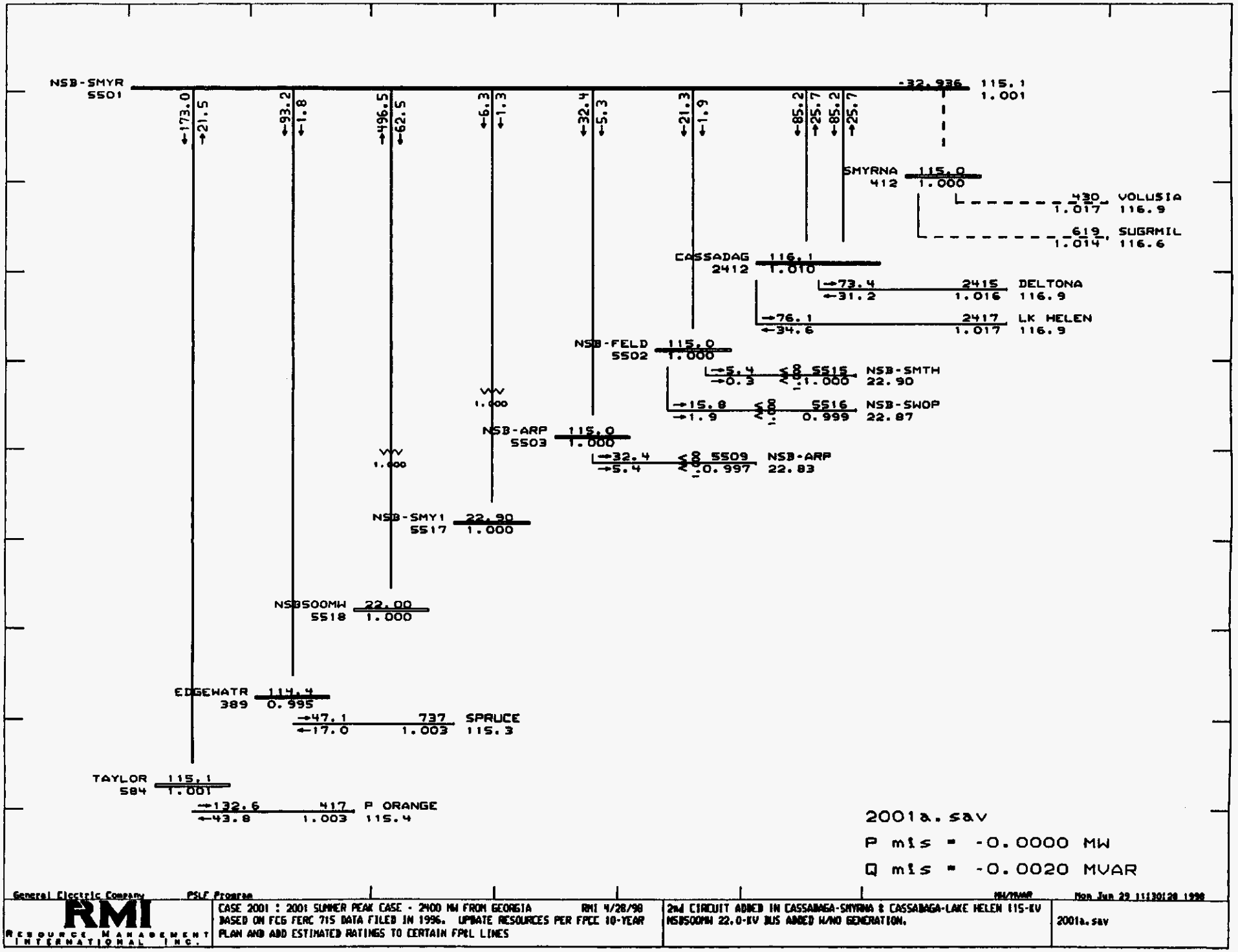

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General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:30:28 1998

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CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES

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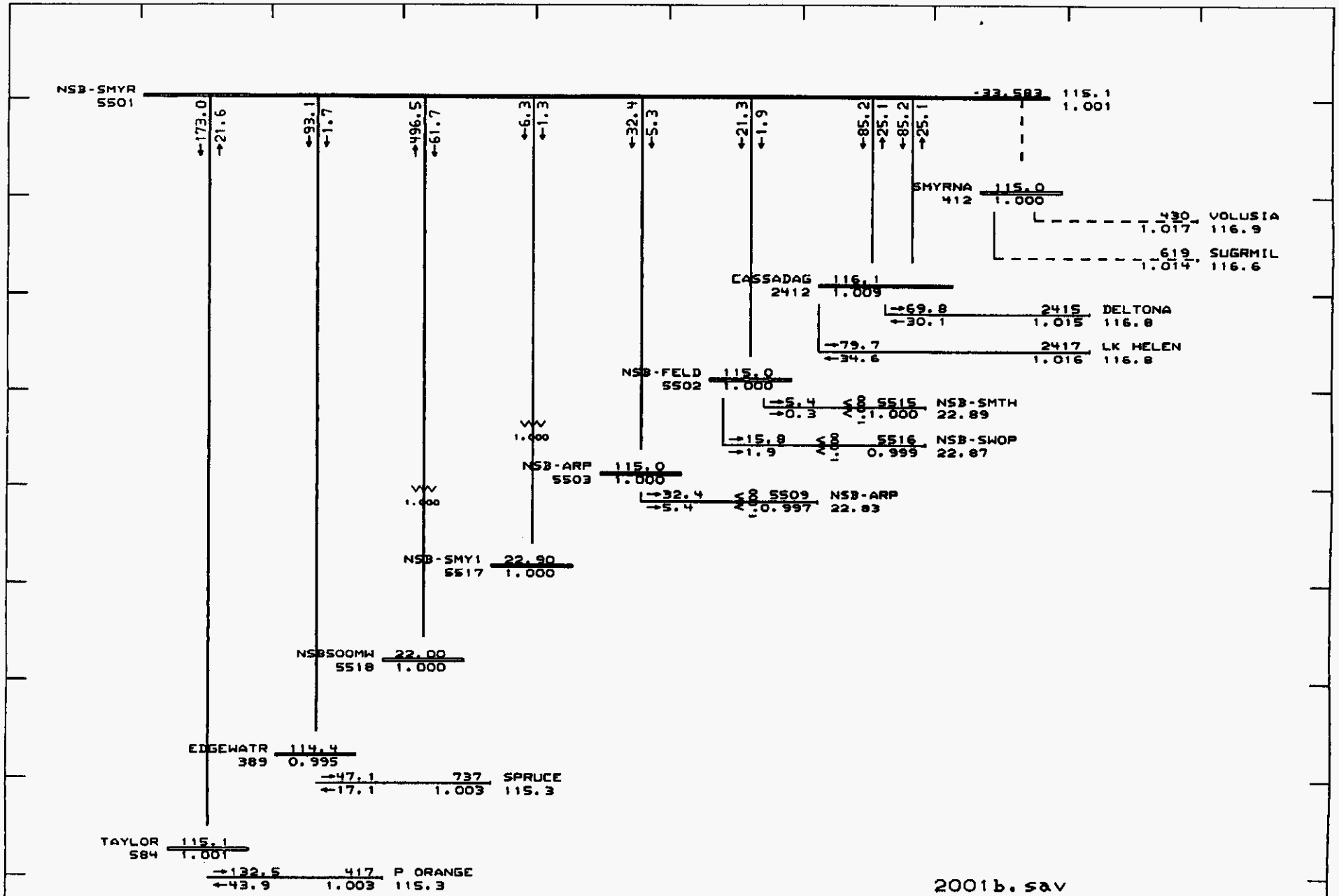

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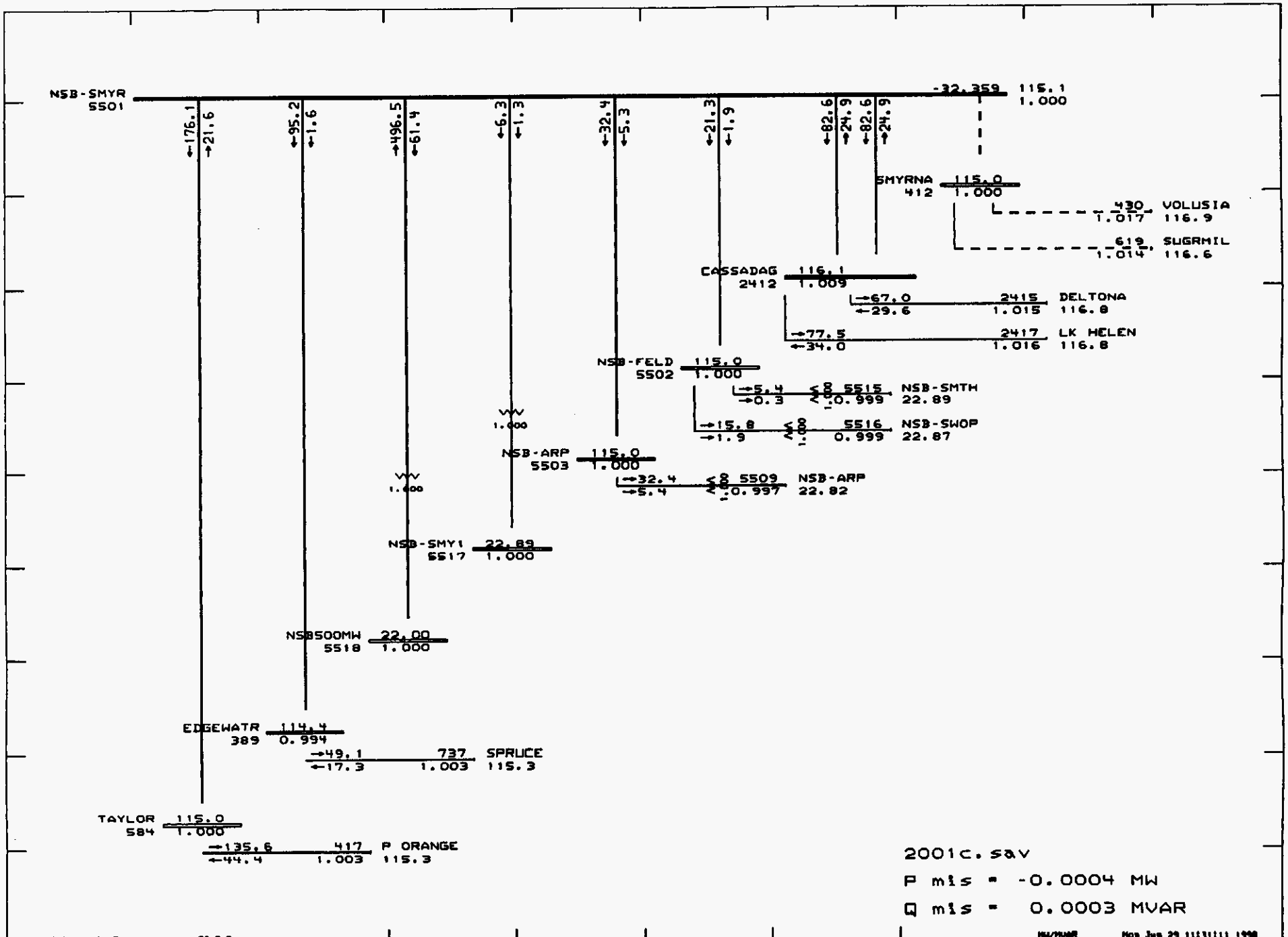
General Electric Company PSLF Progress MW/MVAR Mon Jun 29 11:20:19 1998

RMI Resource Management International, Inc.

CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES

2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.

2001b.sav



General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:31:11 1998

RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.

CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FPRL LINES

2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.

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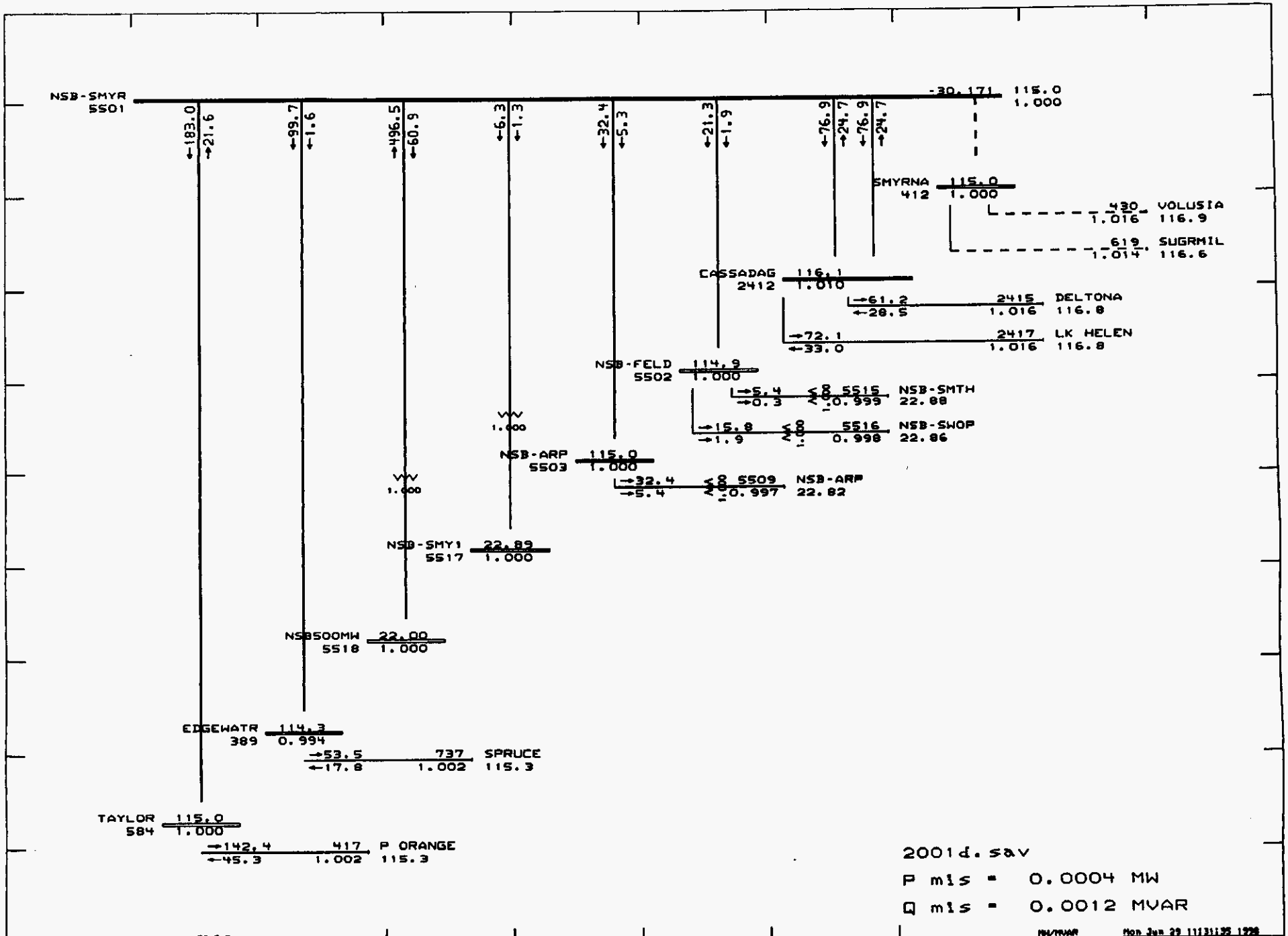
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←76.9
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CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA RMI 4/28/98
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPSC 10-YEAR
PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES
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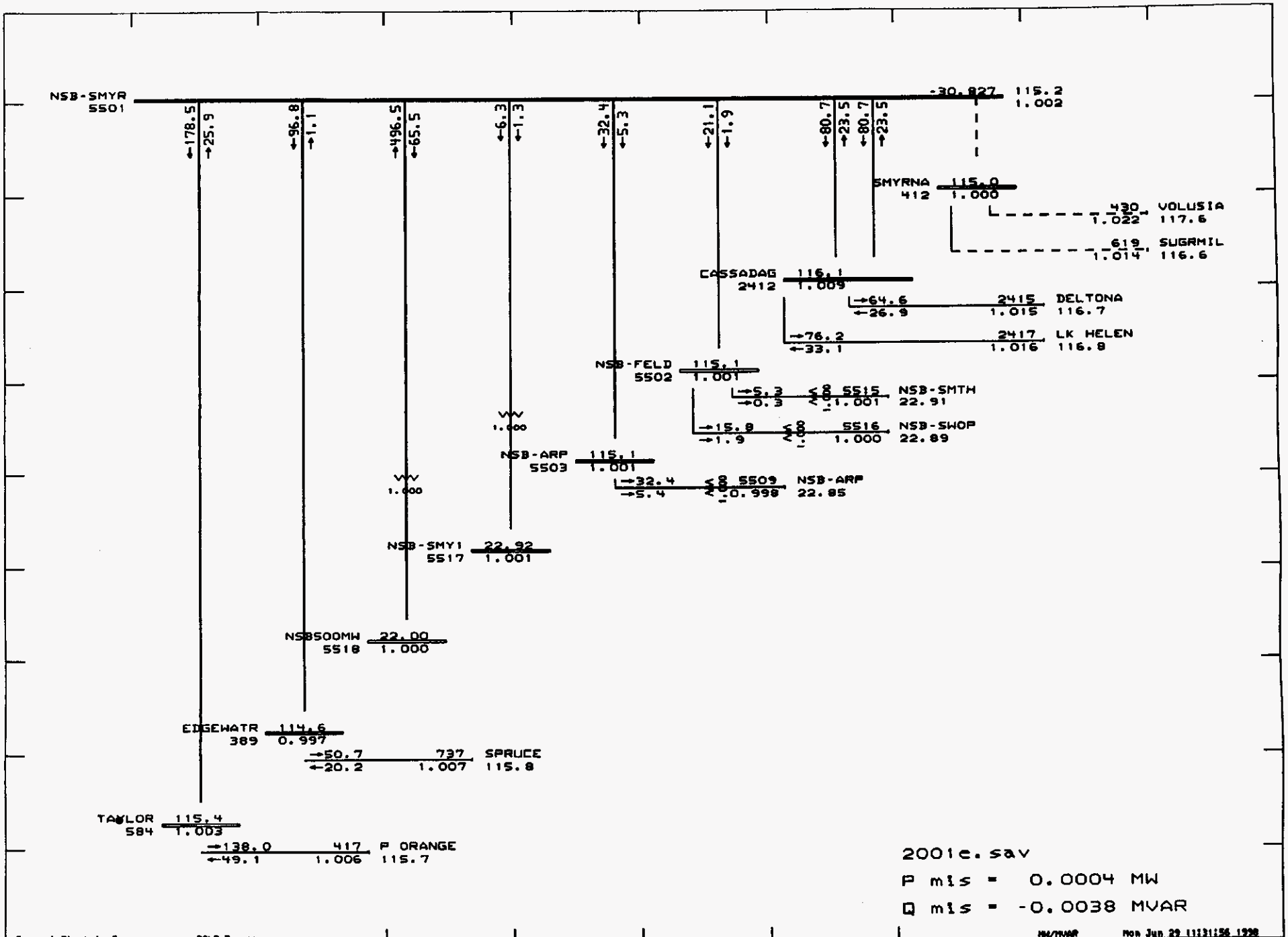
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Q mis = -0.0038 MVAR
MW/MVAR
Mon Jun 29 11:31:56 1998
General Electric Company
PSLF Program
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER PEAK CASE - 2400 MW FROM GEORGIA
BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FPCC 10-YEAR PLAN AND ADD ESTIMATED RATINGS TO CERTAIN FP&L LINES
RMI 4/28/98
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001c.sav

APPENDIX III

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-1	SN PLANT	230	SYLVAN	230	1	1						
2001-60-1	SYLVAN	230	N LONGWD	230	1	1						
2001-60-1	IND RIV	230	STANTON	230	1	11						
2001-60-1	SILVR SP	230	SILV SPN	230	1	2						
2001-60-1	SILVR SP	230	SILV SPN	230	2	2						
2001-60-1	RIO PINR	230	CURRY FD	230	1	2						
2001-60-1	JUNEAU-W	138	GANNON	138	1	16						
2001-60-1	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-1	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-1	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-1	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-1	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-1	SN PLANT	115	TURNER	115	1	1						
2001-60-1	PASADENA	115	40ST-DUM	115	1	2						
2001-60-1	MICHIGAN	115	KALEY	115	1	11						
2001-60-1	MICHIGAN	115	GRANT	115	1	11						
2001-60-1	PERSHING	115	GRANT	115	1	11						
2001-60-1	AMERICA	115	KALEY	115	1	11						
2001-60-1	JASPER	115	WGHTCHPL	115	1	2						
2001-60-1	AZALEA	115	BENNETT	115	1	11						
2001-60-1	FLORALTP	69	INVERNTP	69	1	2						
2001-60-1	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-1	PASADENA	230	PASADENA	115	1	2						
2001-60-1	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-1	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-1	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-1	IND RIV	230	IND RIV	115	1	11						
2001-60-1	LARGO	230	LARGO A	69	1	2						
2001-60-1	SHELD	230	SHELD-NW	69	1	16						
2001-60-1	CLMT EST	230	CLMT EST	69	1	2						
2001-60-1	WINDERME	230	WINDERME	69	1	2						
2001-60-1	RIVER-S	230	RIVER-S	69	1	16						
2001-60-1	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-1	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-1	JASPER	115	JASPER	69	1	2						
2001-60-2	SN PLANT	230	SYLVAN	230	1	1						
2001-60-2	SYLVAN	230	N LONGWD	230	1	1						
2001-60-2	IND RIV	230	STANTON	230	1	11						
2001-60-2	SILVR SP	230	SILV SPN	230	1	2						
2001-60-2	SILVR SP	230	SILV SPN	230	2	2						
2001-60-2	RIO PINR	230	CURRY FD	230	1	2						
2001-60-2	JUNEAU-W	138	GANNON	138	1	16						
2001-60-2	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-2	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-2	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-2	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-2	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-2	SN PLANT	115	TURNER	115	1	1						
2001-60-2	PASADENA	115	40ST-DUM	115	1	2						
2001-60-2	MICHIGAN	115	KALEY	115	1	11						
2001-60-2	MICHIGAN	115	GRANT	115	1	11						
2001-60-2	PERSHING	115	GRANT	115	1	11						
2001-60-2	AMERICA	115	KALEY	115	1	11						
2001-60-2	JASPER	115	WGHTCHPL	115	1	2						
2001-60-2	AZALEA	115	BENNETT	115	1	11						
2001-60-2	FLORALTP	69	INVERNTP	69	1	2						
2001-60-2	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-2	PASADENA	230	PASADENA	115	1	2						
2001-60-2	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-2	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-2	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-2	IND RIV	230	IND RIV	115	1	11						
2001-60-2	LARGO	230	LARGO A	69	1	2						
2001-60-2	SHELD	230	SHELD-NW	69	1	16						
2001-60-2	CLMT EST	230	CLMT EST	69	1	2						
2001-60-2	WINDERME	230	WINDERME	69	1	2						
2001-60-2	RIVER-S	230	RIVER-S	69	1	16						
2001-60-2	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-2	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-2	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-3	SN PLANT	230	SYLVAN	230	1	1						
2001-60-3	SYLVAN	230	N LONGWD	230	1	1						
2001-60-3	IND RIV	230	STANTON	230	1	11						
2001-60-3	SILVR SP	230	SILV SPN	230	1	2						
2001-60-3	SILVR SP	230	SILV SPN	230	2	2						
2001-60-3	RIO PINR	230	CURRY FD	230	1	2						
2001-60-3	JUNEAU-W	138	GANNON	138	1	16						
2001-60-3	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-3	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-3	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-3	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-3	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-3	SN PLANT	115	TURNER	115	1	1						
2001-60-3	PASADENA	115	40ST-DUM	115	1	2						
2001-60-3	MICHIGAN	115	KALEY	115	1	11						
2001-60-3	MICHIGAN	115	GRANT	115	1	11						
2001-60-3	PERSHING	115	GRANT	115	1	11						
2001-60-3	AMERICA	115	KALEY	115	1	11						
2001-60-3	JASPER	115	WGHTCHPL	115	1	2						
2001-60-3	AZALEA	115	BENNETT	115	1	11						
2001-60-3	FLORALTP	69	INVERNTP	69	1	2						
2001-60-3	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-3	PASADENA	230	PASADENA	115	1	2						
2001-60-3	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-3	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-3	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-3	IND RIV	230	IND RIV	115	1	11						
2001-60-3	LARGO	230	LARGO A	69	1	2						
2001-60-3	SHELD	230	SHELD-NW	69	1	16						
2001-60-3	CLMT EST	230	CLMT EST	69	1	2						
2001-60-3	WINDERME	230	WINDERME	69	1	2						
2001-60-3	RIVER-S	230	RIVER-S	69	1	16						
2001-60-3	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-3	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-3	JASPER	115	JASPER	69	1	2						
2001-60-4	SN PLANT	230	SYLVAN	230	1	1						
2001-60-4	SYLVAN	230	N LONGWD	230	1	1						
2001-60-4	IND RIV	230	STANTON	230	1	11						
2001-60-4	SILVR SP	230	SILV SPN	230	1	2						
2001-60-4	SILVR SP	230	SILV SPN	230	2	2						
2001-60-4	RIO PINR	230	CURRY FD	230	1	2						
2001-60-4	JUNEAU-W	138	GANNON	138	1	16						
2001-60-4	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-4	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-4	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-4	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-4	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-4	SN PLANT	115	TURNER	115	1	1						
2001-60-4	PASADENA	115	40ST-DUM	115	1	2						
2001-60-4	MICHIGAN	115	KALEY	115	1	11						
2001-60-4	MICHIGAN	115	GRANT	115	1	11						
2001-60-4	PERSHING	115	GRANT	115	1	11						
2001-60-4	AMERICA	115	KALEY	115	1	11						
2001-60-4	JASPER	115	WGHTCHPL	115	1	2						
2001-60-4	AZALEA	115	BENNETT	115	1	11						
2001-60-4	FLORALTP	69	INVERNTP	69	1	2						
2001-60-4	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-4	PASADENA	230	PASADENA	115	1	2						
2001-60-4	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-4	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-4	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-4	IND RIV	230	IND RIV	115	1	11						
2001-60-4	LARGO	230	LARGO A	69	1	2						
2001-60-4	SHELD	230	SHELD-NW	69	1	16						
2001-60-4	CLMT EST	230	CLMT EST	69	1	2						
2001-60-4	WINDERME	230	WINDERME	69	1	2						
2001-60-4	RIVER-S	230	RIVER-S	69	1	16						
2001-60-4	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-4	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-4	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-5	SN PLANT	230	SYLVAN	230	1	1						
2001-60-5	SYLVAN	230	N LONGWD	230	1	1						
2001-60-5	IND RIV	230	STANTON	230	1	11						
2001-60-5	SILVR SP	230	SILV SPN	230	1	2						
2001-60-5	SILVR SP	230	SILV SPN	230	2	2						
2001-60-5	RIO PINR	230	CURRY FD	230	1	2						
2001-60-5	JUNEAU-W	138	GANNON	138	1	16						
2001-60-5	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-5	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-5	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-5	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-5	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-5	SN PLANT	115	TURNER	115	1	1						
2001-60-5	PASADENA	115	40ST-DUM	115	1	2						
2001-60-5	MICHIGAN	115	KALEY	115	1	11						
2001-60-5	MICHIGAN	115	GRANT	115	1	11						
2001-60-5	PERSHING	115	GRANT	115	1	11						
2001-60-5	AMERICA	115	KALEY	115	1	11						
2001-60-5	JASPER	115	WGHTCHPL	115	1	2						
2001-60-5	AZALEA	115	BENNETT	115	1	11						
2001-60-5	FLORALTP	69	INVERNTP	69	1	2						
2001-60-5	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-5	PASADENA	230	PASADENA	115	1	2						
2001-60-5	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-5	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-5	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-5	IND RIV	230	IND RIV	115	1	11						
2001-60-5	LARGO	230	LARGO A	69	1	2						
2001-60-5	SHELD	230	SHELD-NW	69	1	16						
2001-60-5	CLMT EST	230	CLMT EST	69	1	2						
2001-60-5	WINDERME	230	WINDERME	69	1	2						
2001-60-5	RIVER-S	230	RIVER-S	69	1	16						
2001-60-5	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-5	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-5	JASPER	115	JASPER	69	1	2						
2001-60-6	SN PLANT	230	SYLVAN	230	1	1						
2001-60-6	SYLVAN	230	N LONGWD	230	1	1						
2001-60-6	IND RIV	230	STANTON	230	1	11						
2001-60-6	SILVR SP	230	SILV SPN	230	1	2						
2001-60-6	SILVR SP	230	SILV SPN	230	2	2						
2001-60-6	RIO PINR	230	CURRY FD	230	1	2						
2001-60-6	JUNEAU-W	138	GANNON	138	1	16						
2001-60-6	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-6	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-6	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-6	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-6	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-6	SN PLANT	115	TURNER	115	1	1						
2001-60-6	PASADENA	115	40ST-DUM	115	1	2						
2001-60-6	MICHIGAN	115	KALEY	115	1	11						
2001-60-6	MICHIGAN	115	GRANT	115	1	11						
2001-60-6	PERSHING	115	GRANT	115	1	11						
2001-60-6	AMERICA	115	KALEY	115	1	11						
2001-60-6	JASPER	115	WGHTCHPL	115	1	2						
2001-60-6	AZALEA	115	BENNETT	115	1	11						
2001-60-6	FLORALTP	69	INVERNTP	69	1	2						
2001-60-6	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-6	PASADENA	230	PASADENA	115	1	2						
2001-60-6	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-6	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-6	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-6	IND RIV	230	IND RIV	115	1	11						
2001-60-6	LARGO	230	LARGO A	69	1	2						
2001-60-6	SHELD	230	SHELD-NW	69	1	16						
2001-60-6	CLMT EST	230	CLMT EST	69	1	2						
2001-60-6	WINDERME	230	WINDERME	69	1	2						
2001-60-6	RIVER-S	230	RIVER-S	69	1	16						
2001-60-6	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-6	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-6	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-7	SN PLANT	230	SYLVAN	230	1	1						
2001-60-7	SYLVAN	230	N LONGWD	230	1	1						
2001-60-7	IND RIV	230	STANTON	230	1	11						
2001-60-7	SILVR SP	230	SILV SPN	230	1	2						
2001-60-7	SILVR SP	230	SILV SPN	230	2	2						
2001-60-7	RIO PINR	230	CURRY FD	230	1	2						
2001-60-7	JUNEAU-W	138	GANNON	138	1	16						
2001-60-7	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-7	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-7	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-7	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-7	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-7	SN PLANT	115	TURNER	115	1	1						
2001-60-7	PASADENA	115	40ST-DUM	115	1	2						
2001-60-7	MICHIGAN	115	KALEY	115	1	11						
2001-60-7	MICHIGAN	115	GRANT	115	1	11						
2001-60-7	PERSHING	115	GRANT	115	1	11						
2001-60-7	AMERICA	115	KALEY	115	1	11						
2001-60-7	JASPER	115	WGHTCHPL	115	1	2						
2001-60-7	AZALEA	115	BENNETT	115	1	11						
2001-60-7	FLORALTP	69	INVERNTP	69	1	2						
2001-60-7	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-7	PASADENA	230	PASADENA	115	1	2						
2001-60-7	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-7	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-7	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-7	IND RIV	230	IND RIV	115	1	11						
2001-60-7	LARGO	230	LARGO A	69	1	2						
2001-60-7	SHELD	230	SHELD-NW	69	1	16						
2001-60-7	CLMT EST	230	CLMT EST	69	1	2						
2001-60-7	WINDERME	230	WINDERME	69	1	2						
2001-60-7	RIVER-S	230	RIVER-S	69	1	16						
2001-60-7	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-7	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-7	JASPER	115	JASPER	69	1	2						
2001-60-8	SN PLANT	230	SYLVAN	230	1	1						
2001-60-8	SYLVAN	230	N LONGWD	230	1	1						
2001-60-8	IND RIV	230	STANTON	230	1	11						
2001-60-8	SILVR SP	230	SILV SPN	230	1	2						
2001-60-8	SILVR SP	230	SILV SPN	230	2	2						
2001-60-8	RIO PINR	230	CURRY FD	230	1	2						
2001-60-8	JUNEAU-W	138	GANNON	138	1	16						
2001-60-8	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-8	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-8	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-8	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-8	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-8	SN PLANT	115	TURNER	115	1	1						
2001-60-8	PASADENA	115	40ST-DUM	115	1	2						
2001-60-8	MICHIGAN	115	KALEY	115	1	11						
2001-60-8	MICHIGAN	115	GRANT	115	1	11						
2001-60-8	PERSHING	115	GRANT	115	1	11						
2001-60-8	AMERICA	115	KALEY	115	1	11						
2001-60-8	JASPER	115	WGHTCHPL	115	1	2						
2001-60-8	AZALEA	115	BENNETT	115	1	11						
2001-60-8	FLORALTP	69	INVERNTP	69	1	2						
2001-60-8	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-8	PASADENA	230	PASADENA	115	1	2						
2001-60-8	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-8	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-8	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-8	IND RIV	230	IND RIV	115	1	11						
2001-60-8	LARGO	230	LARGO A	69	1	2						
2001-60-8	SHELD	230	SHELD-NW	69	1	16						
2001-60-8	CLMT EST	230	CLMT EST	69	1	2						
2001-60-8	WINDERME	230	WINDERME	69	1	2						
2001-60-8	RIVER-S	230	RIVER-S	69	1	16						
2001-60-8	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-8	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-8	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-9	SN PLANT	230	SYLVAN	230	1	1						
2001-60-9	SYLVAN	230	N LONGWD	230	1	1						
2001-60-9	IND RIV	230	STANTON	230	1	11						
2001-60-9	SILVR SP	230	SILV SPN	230	1	2						
2001-60-9	SILVR SP	230	SILV SPN	230	2	2						
2001-60-9	RIO PINR	230	CURRY FD	230	1	2						
2001-60-9	JUNEAU-W	138	GANNON	138	1	16						
2001-60-9	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-9	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-9	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-9	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-9	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-9	SN PLANT	115	TURNER	115	1	1						
2001-60-9	PASADENA	115	40ST-DUM	115	1	2						
2001-60-9	MICHIGAN	115	KALEY	115	1	11						
2001-60-9	MICHIGAN	115	GRANT	115	1	11						
2001-60-9	PERSHING	115	GRANT	115	1	11						
2001-60-9	AMERICA	115	KALEY	115	1	11						
2001-60-9	JASPER	115	WGHTCHPL	115	1	2						
2001-60-9	AZALEA	115	BENNETT	115	1	11						
2001-60-9	FLORALTP	69	INVERNTP	69	1	2						
2001-60-9	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-9	PASADENA	230	PASADENA	115	1	2						
2001-60-9	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-9	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-9	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-9	IND RIV	230	IND RIV	115	1	11						
2001-60-9	LARGO	230	LARGO A	69	1	2						
2001-60-9	SHELD	230	SHELD-NW	69	1	16						
2001-60-9	CLMT EST	230	CLMT EST	69	1	2						
2001-60-9	WINDERME	230	WINDERME	69	1	2						
2001-60-9	RIVER-S	230	RIVER-S	69	1	16						
2001-60-9	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-9	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-9	JASPER	115	JASPER	69	1	2						
2001-60-10	SN PLANT	230	SYLVAN	230	1	1						
2001-60-10	SYLVAN	230	N LONGWD	230	1	1						
2001-60-10	IND RIV	230	STANTON	230	1	11						
2001-60-10	SILVR SP	230	SILV SPN	230	1	2						
2001-60-10	SILVR SP	230	SILV SPN	230	2	2						
2001-60-10	RIO PINR	230	CURRY FD	230	1	2						
2001-60-10	JUNEAU-W	138	GANNON	138	1	16						
2001-60-10	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-10	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-10	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-10	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-10	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-10	SN PLANT	115	TURNER	115	1	1						
2001-60-10	PASADENA	115	40ST-DUM	115	1	2						
2001-60-10	MICHIGAN	115	KALEY	115	1	11						
2001-60-10	MICHIGAN	115	GRANT	115	1	11						
2001-60-10	PERSHING	115	GRANT	115	1	11						
2001-60-10	AMERICA	115	KALEY	115	1	11						
2001-60-10	JASPER	115	WGHTCHPL	115	1	2						
2001-60-10	AZALEA	115	BENNETT	115	1	11						
2001-60-10	FLORALTP	69	INVERNTP	69	1	2						
2001-60-10	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-10	PASADENA	230	PASADENA	115	1	2						
2001-60-10	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-10	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-10	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-10	IND RIV	230	IND RIV	115	1	11						
2001-60-10	LARGO	230	LARGO A	69	1	2						
2001-60-10	SHELD	230	SHELD-NW	69	1	16						
2001-60-10	CLMT EST	230	CLMT EST	69	1	2						
2001-60-10	WINDERME	230	WINDERME	69	1	2						
2001-60-10	RIVER-S	230	RIVER-S	69	1	16						
2001-60-10	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-10	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-10	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-11	SN PLANT	230	SYLVAN	230	1	1						
2001-60-11	SYLVAN	230	N LONGWD	230	1	1						
2001-60-11	IND RIV	230	STANTON	230	1	11						
2001-60-11	SILVR SP	230	SILV SPN	230	1	2						
2001-60-11	SILVR SP	230	SILV SPN	230	2	2						
2001-60-11	RIO PINR	230	CURRY FD	230	1	2						
2001-60-11	JUNEAU-W	138	GANNON	138	1	16						
2001-60-11	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-11	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-11	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-11	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-11	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-11	SN PLANT	115	TURNER	115	1	1						
2001-60-11	PASADENA	115	40ST-DUM	115	1	2						
2001-60-11	MICHIGAN	115	KALEY	115	1	11						
2001-60-11	MICHIGAN	115	GRANT	115	1	11						
2001-60-11	PERSHING	115	GRANT	115	1	11						
2001-60-11	AMERICA	115	KALEY	115	1	11						
2001-60-11	JASPER	115	WGHTCHPL	115	1	2						
2001-60-11	AZALEA	115	BENNETT	115	1	11						
2001-60-11	FLORALTP	69	INVERNTP	69	1	2						
2001-60-11	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-11	PASADENA	230	PASADENA	115	1	2						
2001-60-11	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-11	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-11	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-11	IND RIV	230	IND RIV	115	1	11						
2001-60-11	LARGO	230	LARGO A	69	1	2						
2001-60-11	SHELD	230	SHELD-NW	69	1	16						
2001-60-11	CLMT EST	230	CLMT EST	69	1	2						
2001-60-11	WINDERME	230	WINDERME	69	1	2						
2001-60-11	RIVER-S	230	RIVER-S	69	1	16						
2001-60-11	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-11	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-11	JASPER	115	JASPER	69	1	2						
2001-60-12	SN PLANT	230	SYLVAN	230	1	1						
2001-60-12	SYLVAN	230	N LONGWD	230	1	1						
2001-60-12	IND RIV	230	STANTON	230	1	11						
2001-60-12	SILVR SP	230	SILV SPN	230	1	2						
2001-60-12	SILVR SP	230	SILV SPN	230	2	2						
2001-60-12	RIO PINR	230	CURRY FD	230	1	2						
2001-60-12	JUNEAU-W	138	GANNON	138	1	16						
2001-60-12	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-12	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-12	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-12	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-12	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-12	SN PLANT	115	TURNER	115	1	1						
2001-60-12	PASADENA	115	40ST-DUM	115	1	2						
2001-60-12	MICHIGAN	115	KALEY	115	1	11						
2001-60-12	MICHIGAN	115	GRANT	115	1	11						
2001-60-12	PERSHING	115	GRANT	115	1	11						
2001-60-12	AMERICA	115	KALEY	115	1	11						
2001-60-12	JASPER	115	WGHTCHPL	115	1	2						
2001-60-12	AZALEA	115	BENNETT	115	1	11						
2001-60-12	FLORALTP	69	INVERNTP	69	1	2						
2001-60-12	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-12	PASADENA	230	PASADENA	115	1	2						
2001-60-12	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-12	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-12	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-12	IND RIV	230	IND RIV	115	1	11						
2001-60-12	LARGO	230	LARGO A	69	1	2						
2001-60-12	SHELD	230	SHELD-NW	69	1	16						
2001-60-12	CLMT EST	230	CLMT EST	69	1	2						
2001-60-12	WINDERME	230	WINDERME	69	1	2						
2001-60-12	RIVER-S	230	RIVER-S	69	1	16						
2001-60-12	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-12	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-12	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60E Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-13	SN PLANT	230	SYLVAN	230	1	1						
2001-60-13	SYLVAN	230	N LONGWD	230	1	1						
2001-60-13	IND RIV	230	STANTON	230	1	11						
2001-60-13	SILVR SP	230	SILV SPN	230	1	2						
2001-60-13	SILVR SP	230	SILV SPN	230	2	2						
2001-60-13	RIO PINR	230	CURRY FD	230	1	2						
2001-60-13	JUNEAU-W	138	GANNON	138	1	16						
2001-60-13	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-13	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-13	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-13	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-13	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-13	SN PLANT	115	TURNER	115	1	1						
2001-60-13	PASADENA	115	40ST-DUM	115	1	2						
2001-60-13	MICHIGAN	115	KALEY	115	1	11						
2001-60-13	MICHIGAN	115	GRANT	115	1	11						
2001-60-13	PERSHING	115	GRANT	115	1	11						
2001-60-13	AMERICA	115	KALEY	115	1	11						
2001-60-13	JASPER	115	WGHTCHPL	115	1	2						
2001-60-13	AZALEA	115	BENNETT	115	1	11						
2001-60-13	FLORALTP	69	INVERNTP	69	1	2						
2001-60-13	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-13	PASADENA	230	PASADENA	115	1	2						
2001-60-13	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-13	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-13	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-13	IND RIV	230	IND RIV	115	1	11						
2001-60-13	LARGO	230	LARGO A	69	1	2						
2001-60-13	SHELD	230	SHELD-NW	69	1	16						
2001-60-13	CLMT EST	230	CLMT EST	69	1	2						
2001-60-13	WINDERME	230	WINDERME	69	1	2						
2001-60-13	RIVER-S	230	RIVER-S	69	1	16						
2001-60-13	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-13	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-13	JASPER	115	JASPER	69	1	2						
2001-60-14	SN PLANT	230	SYLVAN	230	1	1						
2001-60-14	SYLVAN	230	N LONGWD	230	1	1						
2001-60-14	IND RIV	230	STANTON	230	1	11						
2001-60-14	SILVR SP	230	SILV SPN	230	1	2						
2001-60-14	SILVR SP	230	SILV SPN	230	2	2						
2001-60-14	RIO PINR	230	CURRY FD	230	1	2						
2001-60-14	JUNEAU-W	138	GANNON	138	1	16						
2001-60-14	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-14	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-14	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-14	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-14	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-14	SN PLANT	115	TURNER	115	1	1						
2001-60-14	PASADENA	115	40ST-DUM	115	1	2						
2001-60-14	MICHIGAN	115	KALEY	115	1	11						
2001-60-14	MICHIGAN	115	GRANT	115	1	11						
2001-60-14	PERSHING	115	GRANT	115	1	11						
2001-60-14	AMERICA	115	KALEY	115	1	11						
2001-60-14	JASPER	115	WGHTCHPL	115	1	2						
2001-60-14	AZALEA	115	BENNETT	115	1	11						
2001-60-14	FLORALTP	69	INVERNTP	69	1	2						
2001-60-14	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-14	PASADENA	230	PASADENA	115	1	2						
2001-60-14	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-14	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-14	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-14	IND RIV	230	IND RIV	115	1	11						
2001-60-14	LARGO	230	LARGO A	69	1	2						
2001-60-14	SHELD	230	SHELD-NW	69	1	16						
2001-60-14	CLMT EST	230	CLMT EST	69	1	2						
2001-60-14	WINDERME	230	WINDERME	69	1	2						
2001-60-14	RIVER-S	230	RIVER-S	69	1	16						
2001-60-14	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-14	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-14	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-15	SN PLANT	230	SYLVAN	230	1	1						
2001-60-15	SYLVAN	230	N LONGWD	230	1	1						
2001-60-15	IND RIV	230	STANTON	230	1	11						
2001-60-15	SILVR SP	230	SILV SPN	230	1	2						
2001-60-15	SILVR SP	230	SILV SPN	230	2	2						
2001-60-15	RIO PINR	230	CURRY FD	230	1	2						
2001-60-15	JUNEAU-W	138	GANNON	138	1	16						
2001-60-15	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-15	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-15	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-15	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-15	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-15	SN PLANT	115	TURNER	115	1	1						
2001-60-15	PASADENA	115	40ST-DUM	115	1	2						
2001-60-15	MICHIGAN	115	KALEY	115	1	11						
2001-60-15	MICHIGAN	115	GRANT	115	1	11						
2001-60-15	PERSHING	115	GRANT	115	1	11						
2001-60-15	AMERICA	115	KALEY	115	1	11						
2001-60-15	JASPER	115	WGHTCHPL	115	1	2						
2001-60-15	AZALEA	115	BENNETT	115	1	11						
2001-60-15	FLORALTP	69	INVERNTP	69	1	2						
2001-60-15	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-15	PASADENA	230	PASADENA	115	1	2						
2001-60-15	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-15	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-15	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-15	IND RIV	230	IND RIV	115	1	11						
2001-60-15	LARGO	230	LARGO A	69	1	2						
2001-60-15	SHELD	230	SHELD-NW	69	1	16						
2001-60-15	CLMT EST	230	CLMT EST	69	1	2						
2001-60-15	WINDERME	230	WINDERME	69	1	2						
2001-60-15	RIVER-S	230	RIVER-S	69	1	16						
2001-60-15	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-15	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-15	JASPER	115	JASPER	69	1	2						
2001-60-16	SN PLANT	230	SYLVAN	230	1	1						
2001-60-16	SYLVAN	230	N LONGWD	230	1	1						
2001-60-16	IND RIV	230	STANTON	230	1	11						
2001-60-16	SILVR SP	230	SILV SPN	230	1	2						
2001-60-16	SILVR SP	230	SILV SPN	230	2	2						
2001-60-16	RIO PINR	230	CURRY FD	230	1	2						
2001-60-16	JUNEAU-W	138	GANNON	138	1	16						
2001-60-16	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-16	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-16	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-16	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-16	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-16	SN PLANT	115	TURNER	115	1	1						
2001-60-16	PASADENA	115	40ST-DUM	115	1	2						
2001-60-16	MICHIGAN	115	KALEY	115	1	11						
2001-60-16	MICHIGAN	115	GRANT	115	1	11						
2001-60-16	PERSHING	115	GRANT	115	1	11						
2001-60-16	AMERICA	115	KALEY	115	1	11						
2001-60-16	JASPER	115	WGHTCHPL	115	1	2						
2001-60-16	AZALEA	115	BENNETT	115	1	11						
2001-60-16	FLORALTP	69	INVERNTP	69	1	2						
2001-60-16	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-16	PASADENA	230	PASADENA	115	1	2						
2001-60-16	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-16	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-16	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-16	IND RIV	230	IND RIV	115	1	11						
2001-60-16	LARGO	230	LARGO A	69	1	2						
2001-60-16	SHELD	230	SHELD-NW	69	1	16						
2001-60-16	CLMT EST	230	CLMT EST	69	1	2						
2001-60-16	WINDERME	230	WINDERME	69	1	2						
2001-60-16	RIVER-S	230	RIVER-S	69	1	16						
2001-60-16	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-16	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-16	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60E Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-17	SN PLANT	230	SYLVAN	230	1	1						
2001-60-17	SYLVAN	230	N LONGWD	230	1	1						
2001-60-17	IND RIV	230	STANTON	230	1	11						
2001-60-17	SILVR SP	230	SILV SPN	230	1	2						
2001-60-17	SILVR SP	230	SILV SPN	230	2	2						
2001-60-17	RIO PINR	230	CURRY FD	230	1	2						
2001-60-17	JUNEAU-W	138	GANNON	138	1	16						
2001-60-17	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-17	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-17	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-17	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-17	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-17	SN PLANT	115	TURNER	115	1	1						
2001-60-17	PASADENA	115	40ST-DUM	115	1	2						
2001-60-17	MICHIGAN	115	KALEY	115	1	11						
2001-60-17	MICHIGAN	115	GRANT	115	1	11						
2001-60-17	PERSHING	115	GRANT	115	1	11						
2001-60-17	AMERICA	115	KALEY	115	1	11						
2001-60-17	JASPER	115	WGHTCHPL	115	1	2						
2001-60-17	AZALEA	115	BENNETT	115	1	11						
2001-60-17	FLORALTP	69	INVERNTP	69	1	2						
2001-60-17	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-17	PASADENA	230	PASADENA	115	1	2						
2001-60-17	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-17	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-17	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-17	IND RIV	230	IND RIV	115	1	11						
2001-60-17	LARGO	230	LARGO A	69	1	2						
2001-60-17	SHELD	230	SHELD-NW	69	1	16						
2001-60-17	CLMT EST	230	CLMT EST	69	1	2						
2001-60-17	WINDERME	230	WINDERME	69	1	2						
2001-60-17	RIVER-S	230	RIVER-S	69	1	16						
2001-60-17	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-17	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-17	JASPER	115	JASPER	69	1	2						
2001-60-18	SN PLANT	230	SYLVAN	230	1	1						
2001-60-18	SYLVAN	230	N LONGWD	230	1	1						
2001-60-18	IND RIV	230	STANTON	230	1	11						
2001-60-18	SILVR SP	230	SILV SPN	230	1	2						
2001-60-18	SILVR SP	230	SILV SPN	230	2	2						
2001-60-18	RIO PINR	230	CURRY FD	230	1	2						
2001-60-18	JUNEAU-W	138	GANNON	138	1	16						
2001-60-18	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-18	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-18	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-18	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-18	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-18	SN PLANT	115	TURNER	115	1	1						
2001-60-18	PASADENA	115	40ST-DUM	115	1	2						
2001-60-18	MICHIGAN	115	KALEY	115	1	11						
2001-60-18	MICHIGAN	115	GRANT	115	1	11						
2001-60-18	PERSHING	115	GRANT	115	1	11						
2001-60-18	AMERICA	115	KALEY	115	1	11						
2001-60-18	JASPER	115	WGHTCHPL	115	1	2						
2001-60-18	AZALEA	115	BENNETT	115	1	11						
2001-60-18	FLORALTP	69	INVERNTP	69	1	2						
2001-60-18	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-18	PASADENA	230	PASADENA	115	1	2						
2001-60-18	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-18	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-18	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-18	IND RIV	230	IND RIV	115	1	11						
2001-60-18	LARGO	230	LARGO A	69	1	2						
2001-60-18	SHELD	230	SHELD-NW	69	1	16						
2001-60-18	CLMT EST	230	CLMT EST	69	1	2						
2001-60-18	WINDERME	230	WINDERME	69	1	2						
2001-60-18	RIVER-S	230	RIVER-S	69	1	16						
2001-60-18	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-18	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-18	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-19	SN PLANT	230	SYLVAN	230	1	1						
2001-60-19	SYLVAN	230	N LONGWD	230	1	1						
2001-60-19	IND RIV	230	STANTON	230	1	11						
2001-60-19	SILVR SP	230	SILV SPN	230	1	2						
2001-60-19	SILVR SP	230	SILV SPN	230	2	2						
2001-60-19	RIO PINR	230	CURRY FD	230	1	2						
2001-60-19	JUNEAU-W	138	GANNON	138	1	16						
2001-60-19	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-19	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-19	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-19	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-19	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-19	SN PLANT	115	TURNER	115	1	1						
2001-60-19	PASADENA	115	40ST-DUM	115	1	2						
2001-60-19	MICHIGAN	115	KALEY	115	1	11						
2001-60-19	MICHIGAN	115	GRANT	115	1	11						
2001-60-19	PERSHING	115	GRANT	115	1	11						
2001-60-19	AMERICA	115	KALEY	115	1	11						
2001-60-19	JASPER	115	WGHTCHPL	115	1	2						
2001-60-19	AZALEA	115	BENNETT	115	1	11						
2001-60-19	FLORALTP	69	INVERNTP	69	1	2						
2001-60-19	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-19	PASADENA	230	PASADENA	115	1	2						
2001-60-19	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-19	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-19	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-19	IND RIV	230	IND RIV	115	1	11						
2001-60-19	LARGO	230	LARGO A	69	1	2						
2001-60-19	SHELD	230	SHELD-NW	69	1	16						
2001-60-19	CLMT EST	230	CLMT EST	69	1	2						
2001-60-19	WINDERME	230	WINDERME	69	1	2						
2001-60-19	RIVER-S	230	RIVER-S	69	1	16						
2001-60-19	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-19	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-19	JASPER	115	JASPER	69	1	2						
2001-60-20	SN PLANT	230	SYLVAN	230	1	1						
2001-60-20	SYLVAN	230	N LONGWD	230	1	1						
2001-60-20	IND RIV	230	STANTON	230	1	11						
2001-60-20	SILVR SP	230	SILV SPN	230	1	2						
2001-60-20	SILVR SP	230	SILV SPN	230	2	2						
2001-60-20	RIO PINR	230	CURRY FD	230	1	2						
2001-60-20	JUNEAU-W	138	GANNON	138	1	16						
2001-60-20	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-20	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-20	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-20	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-20	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-20	SN PLANT	115	TURNER	115	1	1						
2001-60-20	PASADENA	115	40ST-DUM	115	1	2						
2001-60-20	MICHIGAN	115	KALEY	115	1	11						
2001-60-20	MICHIGAN	115	GRANT	115	1	11						
2001-60-20	PERSHING	115	GRANT	115	1	11						
2001-60-20	AMERICA	115	KALEY	115	1	11						
2001-60-20	JASPER	115	WGHTCHPL	115	1	2						
2001-60-20	AZALEA	115	BENNETT	115	1	11						
2001-60-20	FLORALTP	69	INVERNTP	69	1	2						
2001-60-20	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-20	PASADENA	230	PASADENA	115	1	2						
2001-60-20	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-20	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-20	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-20	IND RIV	230	IND RIV	115	1	11						
2001-60-20	LARGO	230	LARGO A	69	1	2						
2001-60-20	SHELD	230	SHELD-NW	69	1	16						
2001-60-20	CLMT EST	230	CLMT EST	69	1	2						
2001-60-20	WINDERME	230	WINDERME	69	1	2						
2001-60-20	RIVER-S	230	RIVER-S	69	1	16						
2001-60-20	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-20	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-20	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-21	SN PLANT	230	SYLVAN	230	1	1						
2001-60-21	SYLVAN	230	N LONGWD	230	1	1						
2001-60-21	IND RIV	230	STANTON	230	1	11						
2001-60-21	SILVR SP	230	SILV SPN	230	1	2						
2001-60-21	SILVR SP	230	SILV SPN	230	2	2						
2001-60-21	RIO PINR	230	CURRY FD	230	1	2						
2001-60-21	JUNEAU-W	138	GANNON	138	1	16						
2001-60-21	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-21	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-21	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-21	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-21	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-21	SN PLANT	115	TURNER	115	1	1						
2001-60-21	PASADENA	115	40ST-DUM	115	1	2						
2001-60-21	MICHIGAN	115	KALEY	115	1	11						
2001-60-21	MICHIGAN	115	GRANT	115	1	11						
2001-60-21	PERSHING	115	GRANT	115	1	11						
2001-60-21	AMERICA	115	KALEY	115	1	11						
2001-60-21	JASPER	115	WGHTCHPL	115	1	2						
2001-60-21	AZALEA	115	BENNETT	115	1	11						
2001-60-21	FLORALTP	69	INVERNTP	69	1	2						
2001-60-21	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-21	PASADENA	230	PASADENA	115	1	2						
2001-60-21	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-21	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-21	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-21	IND RIV	230	IND RIV	115	1	11						
2001-60-21	LARGO	230	LARGO A	69	1	2						
2001-60-21	SHELD	230	SHELD-NW	69	1	16						
2001-60-21	CLMT EST	230	CLMT EST	69	1	2						
2001-60-21	WINDERME	230	WINDERME	69	1	2						
2001-60-21	RIVER-S	230	RIVER-S	69	1	16						
2001-60-21	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-21	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-21	JASPER	115	JASPER	69	1	2						
2001-60-22	SN PLANT	230	SYLVAN	230	1	1						
2001-60-22	SYLVAN	230	N LONGWD	230	1	1						
2001-60-22	IND RIV	230	STANTON	230	1	11						
2001-60-22	SILVR SP	230	SILV SPN	230	1	2						
2001-60-22	SILVR SP	230	SILV SPN	230	2	2						
2001-60-22	RIO PINR	230	CURRY FD	230	1	2						
2001-60-22	JUNEAU-W	138	GANNON	138	1	16						
2001-60-22	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-22	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-22	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-22	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-22	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-22	SN PLANT	115	TURNER	115	1	1						
2001-60-22	PASADENA	115	40ST-DUM	115	1	2						
2001-60-22	MICHIGAN	115	KALEY	115	1	11						
2001-60-22	MICHIGAN	115	GRANT	115	1	11						
2001-60-22	PERSHING	115	GRANT	115	1	11						
2001-60-22	AMERICA	115	KALEY	115	1	11						
2001-60-22	JASPER	115	WGHTCHPL	115	1	2						
2001-60-22	AZALEA	115	BENNETT	115	1	11						
2001-60-22	FLORALTP	69	INVERNTP	69	1	2						
2001-60-22	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-22	PASADENA	230	PASADENA	115	1	2						
2001-60-22	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-22	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-22	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-22	IND RIV	230	IND RIV	115	1	11						
2001-60-22	LARGO	230	LARGO A	69	1	2						
2001-60-22	SHELD	230	SHELD-NW	69	1	16						
2001-60-22	CLMT EST	230	CLMT EST	69	1	2						
2001-60-22	WINDERME	230	WINDERME	69	1	2						
2001-60-22	RIVER-S	230	RIVER-S	69	1	16						
2001-60-22	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-22	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-22	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-23	SN PLANT	230	SYLVAN	230	1	1						
2001-60-23	SYLVAN	230	N LONGWD	230	1	1						
2001-60-23	IND RIV	230	STANTON	230	1	11						
2001-60-23	SILVR SP	230	SILV SPN	230	1	2						
2001-60-23	SILVR SP	230	SILV SPN	230	2	2						
2001-60-23	RIO PINR	230	CURRY FD	230	1	2						
2001-60-23	JUNEAU-W	138	GANNON	138	1	16						
2001-60-23	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-23	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-23	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-23	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-23	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-23	SN PLANT	115	TURNER	115	1	1						
2001-60-23	PASADENA	115	40ST-DUM	115	1	2						
2001-60-23	MICHIGAN	115	KALEY	115	1	11						
2001-60-23	MICHIGAN	115	GRANT	115	1	11						
2001-60-23	PERSHING	115	GRANT	115	1	11						
2001-60-23	AMERICA	115	KALEY	115	1	11						
2001-60-23	JASPER	115	WGHTCHPL	115	1	2						
2001-60-23	AZALEA	115	BENNETT	115	1	11						
2001-60-23	FLORALTP	69	INVERNTP	69	1	2						
2001-60-23	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-23	PASADENA	230	PASADENA	115	1	2						
2001-60-23	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-23	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-23	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-23	IND RIV	230	IND RIV	115	1	11						
2001-60-23	LARGO	230	LARGO A	69	1	2						
2001-60-23	SHELD	230	SHELD-NW	69	1	16						
2001-60-23	CLMT EST	230	CLMT EST	69	1	2						
2001-60-23	WINDERME	230	WINDERME	69	1	2						
2001-60-23	RIVER-S	230	RIVER-S	69	1	16						
2001-60-23	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-23	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-23	JASPER	115	JASPER	69	1	2						
2001-60-24	SN PLANT	230	SYLVAN	230	1	1						
2001-60-24	SYLVAN	230	N LONGWD	230	1	1						
2001-60-24	IND RIV	230	STANTON	230	1	11						
2001-60-24	SILVR SP	230	SILV SPN	230	1	2						
2001-60-24	SILVR SP	230	SILV SPN	230	2	2						
2001-60-24	RIO PINR	230	CURRY FD	230	1	2						
2001-60-24	JUNEAU-W	138	GANNON	138	1	16						
2001-60-24	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-24	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-24	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-24	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-24	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-24	SN PLANT	115	TURNER	115	1	1						
2001-60-24	PASADENA	115	40ST-DUM	115	1	2						
2001-60-24	MICHIGAN	115	KALEY	115	1	11						
2001-60-24	MICHIGAN	115	GRANT	115	1	11						
2001-60-24	PERSHING	115	GRANT	115	1	11						
2001-60-24	AMERICA	115	KALEY	115	1	11						
2001-60-24	JASPER	115	WGHTCHPL	115	1	2						
2001-60-24	AZALEA	115	BENNETT	115	1	11						
2001-60-24	FLORALTP	69	INVERNTP	69	1	2						
2001-60-24	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-24	PASADENA	230	PASADENA	115	1	2						
2001-60-24	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-24	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-24	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-24	IND RIV	230	IND RIV	115	1	11						
2001-60-24	LARGO	230	LARGO A	69	1	2						
2001-60-24	SHELD	230	SHELD-NW	69	1	16						
2001-60-24	CLMT EST	230	CLMT EST	69	1	2						
2001-60-24	WINDERME	230	WINDERME	69	1	2						
2001-60-24	RIVER-S	230	RIVER-S	69	1	16						
2001-60-24	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-24	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-24	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-25	SN PLANT	230	SYLVAN	230	1	1						
2001-60-25	SYLVAN	230	N LONGWD	230	1	1						
2001-60-25	IND RIV	230	STANTON	230	1	11						
2001-60-25	SILVR SP	230	SILV SPN	230	1	2						
2001-60-25	SILVR SP	230	SILV SPN	230	2	2						
2001-60-25	RIO PINR	230	CURRY FD	230	1	2						
2001-60-25	JUNEAU-W	138	GANNON	138	1	16						
2001-60-25	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-25	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-25	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-25	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-25	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-25	SN PLANT	115	TURNER	115	1	1						
2001-60-25	PASADENA	115	40ST-DUM	115	1	2						
2001-60-25	MICHIGAN	115	KALEY	115	1	11						
2001-60-25	MICHIGAN	115	GRANT	115	1	11						
2001-60-25	PERSHING	115	GRANT	115	1	11						
2001-60-25	AMERICA	115	KALEY	115	1	11						
2001-60-25	JASPER	115	WGHTCHPL	115	1	2						
2001-60-25	AZALEA	115	BENNETT	115	1	11						
2001-60-25	FLORALTP	69	INVERNTP	69	1	2						
2001-60-25	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-25	PASADENA	230	PASADENA	115	1	2						
2001-60-25	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-25	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-25	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-25	IND RIV	230	IND RIV	115	1	11						
2001-60-25	LARGO	230	LARGO A	69	1	2						
2001-60-25	SHELD	230	SHELD-NW	69	1	16						
2001-60-25	CLMT EST	230	CLMT EST	69	1	2						
2001-60-25	WINDERME	230	WINDERME	69	1	2						
2001-60-25	RIVER-S	230	RIVER-S	69	1	16						
2001-60-25	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-25	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-25	JASPER	115	JASPER	69	1	2						
2001-60-26	SN PLANT	230	SYLVAN	230	1	1						
2001-60-26	SYLVAN	230	N LONGWD	230	1	1						
2001-60-26	IND RIV	230	STANTON	230	1	11						
2001-60-26	SILVR SP	230	SILV SPN	230	1	2						
2001-60-26	SILVR SP	230	SILV SPN	230	2	2						
2001-60-26	RIO PINR	230	CURRY FD	230	1	2						
2001-60-26	JUNEAU-W	138	GANNON	138	1	16						
2001-60-26	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-26	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-26	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-26	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-26	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-26	SN PLANT	115	TURNER	115	1	1						
2001-60-26	PASADENA	115	40ST-DUM	115	1	2						
2001-60-26	MICHIGAN	115	KALEY	115	1	11						
2001-60-26	MICHIGAN	115	GRANT	115	1	11						
2001-60-26	PERSHING	115	GRANT	115	1	11						
2001-60-26	AMERICA	115	KALEY	115	1	11						
2001-60-26	JASPER	115	WGHTCHPL	115	1	2						
2001-60-26	AZALEA	115	BENNETT	115	1	11						
2001-60-26	FLORALTP	69	INVERNTP	69	1	2						
2001-60-26	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-26	PASADENA	230	PASADENA	115	1	2						
2001-60-26	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-26	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-26	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-26	IND RIV	230	IND RIV	115	1	11						
2001-60-26	LARGO	230	LARGO A	69	1	2						
2001-60-26	SHELD	230	SHELD-NW	69	1	16						
2001-60-26	CLMT EST	230	CLMT EST	69	1	2						
2001-60-26	WINDERME	230	WINDERME	69	1	2						
2001-60-26	RIVER-S	230	RIVER-S	69	1	16						
2001-60-26	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-26	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-26	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-27	SN PLANT	230	SYLVAN	230	1	1						
2001-60-27	SYLVAN	230	N LONGWD	230	1	1						
2001-60-27	IND RIV	230	STANTON	230	1	11						
2001-60-27	SILVR SP	230	SILV SPN	230	1	2						
2001-60-27	SILVR SP	230	SILV SPN	230	2	2						
2001-60-27	RIO PINR	230	CURRY FD	230	1	2						
2001-60-27	JUNEAU-W	138	GANNON	138	1	16						
2001-60-27	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-27	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-27	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-27	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-27	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-27	SN PLANT	115	TURNER	115	1	1						
2001-60-27	PASADENA	115	40ST-DUM	115	1	2						
2001-60-27	MICHIGAN	115	KALEY	115	1	11						
2001-60-27	MICHIGAN	115	GRANT	115	1	11						
2001-60-27	PERSHING	115	GRANT	115	1	11						
2001-60-27	AMERICA	115	KALEY	115	1	11						
2001-60-27	JASPER	115	WGHTCHPL	115	1	2						
2001-60-27	AZALEA	115	BENNETT	115	1	11						
2001-60-27	FLORALTP	69	INVERNTP	69	1	2						
2001-60-27	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-27	PASADENA	230	PASADENA	115	1	2						
2001-60-27	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-27	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-27	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-27	IND RIV	230	IND RIV	115	1	11						
2001-60-27	LARGO	230	LARGO A	69	1	2						
2001-60-27	SHELD	230	SHELD-NW	69	1	16						
2001-60-27	CLMT EST	230	CLMT EST	69	1	2						
2001-60-27	WINDERME	230	WINDERME	69	1	2						
2001-60-27	RIVER-S	230	RIVER-S	69	1	16						
2001-60-27	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-27	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-27	JASPER	115	JASPER	69	1	2						
2001-60-28	SN PLANT	230	SYLVAN	230	1	1						
2001-60-28	SYLVAN	230	N LONGWD	230	1	1						
2001-60-28	IND RIV	230	STANTON	230	1	11						
2001-60-28	SILVR SP	230	SILV SPN	230	1	2						
2001-60-28	SILVR SP	230	SILV SPN	230	2	2						
2001-60-28	RIO PINR	230	CURRY FD	230	1	2						
2001-60-28	JUNEAU-W	138	GANNON	138	1	16						
2001-60-28	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-28	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-28	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-28	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-28	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-28	SN PLANT	115	TURNER	115	1	1						
2001-60-28	PASADENA	115	40ST-DUM	115	1	2						
2001-60-28	MICHIGAN	115	KALEY	115	1	11						
2001-60-28	MICHIGAN	115	GRANT	115	1	11						
2001-60-28	PERSHING	115	GRANT	115	1	11						
2001-60-28	AMERICA	115	KALEY	115	1	11						
2001-60-28	JASPER	115	WGHTCHPL	115	1	2						
2001-60-28	AZALEA	115	BENNETT	115	1	11						
2001-60-28	FLORALTP	69	INVERNTP	69	1	2						
2001-60-28	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-28	PASADENA	230	PASADENA	115	1	2						
2001-60-28	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-28	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-28	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-28	IND RIV	230	IND RIV	115	1	11						
2001-60-28	LARGO	230	LARGO A	69	1	2						
2001-60-28	SHELD	230	SHELD-NW	69	1	16						
2001-60-28	CLMT EST	230	CLMT EST	69	1	2						
2001-60-28	WINDERME	230	WINDERME	69	1	2						
2001-60-28	RIVER-S	230	RIVER-S	69	1	16						
2001-60-28	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-28	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-28	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-29	SN PLANT	230	SYLVAN	230	1	1						
2001-60-29	SYLVAN	230	N LONGWD	230	1	1						
2001-60-29	IND RIV	230	STANTON	230	1	11						
2001-60-29	SILVR SP	230	SILV SPN	230	1	2						
2001-60-29	SILVR SP	230	SILV SPN	230	2	2						
2001-60-29	RIO PINR	230	CURRY FD	230	1	2						
2001-60-29	JUNEAU-W	138	GANNON	138	1	16						
2001-60-29	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-29	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-29	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-29	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-29	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-29	SN PLANT	115	TURNER	115	1	1						
2001-60-29	PASADENA	115	40ST-DUM	115	1	2						
2001-60-29	MICHIGAN	115	KALEY	115	1	11						
2001-60-29	MICHIGAN	115	GRANT	115	1	11						
2001-60-29	PERSHING	115	GRANT	115	1	11						
2001-60-29	AMERICA	115	KALEY	115	1	11						
2001-60-29	JASPER	115	WGHTCHPL	115	1	2						
2001-60-29	AZALEA	115	BENNETT	115	1	11						
2001-60-29	FLORALTP	69	INVERNTP	69	1	2						
2001-60-29	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-29	PASADENA	230	PASADENA	115	1	2						
2001-60-29	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-29	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-29	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-29	IND RIV	230	IND RIV	115	1	11						
2001-60-29	LARGO	230	LARGO A	69	1	2						
2001-60-29	SHELD	230	SHELD-NW	69	1	16						
2001-60-29	CLMT EST	230	CLMT EST	69	1	2						
2001-60-29	WINDERME	230	WINDERME	69	1	2						
2001-60-29	RIVER-S	230	RIVER-S	69	1	16						
2001-60-29	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-29	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-29	JASPER	115	JASPER	69	1	2						
2001-60-30	SN PLANT	230	SYLVAN	230	1	1						
2001-60-30	SYLVAN	230	N LONGWD	230	1	1						
2001-60-30	IND RIV	230	STANTON	230	1	11						
2001-60-30	SILVR SP	230	SILV SPN	230	1	2						
2001-60-30	SILVR SP	230	SILV SPN	230	2	2						
2001-60-30	RIO PINR	230	CURRY FD	230	1	2						
2001-60-30	JUNEAU-W	138	GANNON	138	1	16						
2001-60-30	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-30	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-30	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-30	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-30	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-30	SN PLANT	115	TURNER	115	1	1						
2001-60-30	PASADENA	115	40ST-DUM	115	1	2						
2001-60-30	MICHIGAN	115	KALEY	115	1	11						
2001-60-30	MICHIGAN	115	GRANT	115	1	11						
2001-60-30	PERSHING	115	GRANT	115	1	11						
2001-60-30	AMERICA	115	KALEY	115	1	11						
2001-60-30	JASPER	115	WGHTCHPL	115	1	2						
2001-60-30	AZALEA	115	BENNETT	115	1	11						
2001-60-30	FLORALTP	69	INVERNTP	69	1	2						
2001-60-30	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-30	PASADENA	230	PASADENA	115	1	2						
2001-60-30	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-30	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-30	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-30	IND RIV	230	IND RIV	115	1	11						
2001-60-30	LARGO	230	LARGO A	69	1	2						
2001-60-30	SHELD	230	SHELD-NW	69	1	16						
2001-60-30	CLMT EST	230	CLMT EST	69	1	2						
2001-60-30	WINDERME	230	WINDERME	69	1	2						
2001-60-30	RIVER-S	230	RIVER-S	69	1	16						
2001-60-30	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-30	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-30	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-31	SN PLANT	230	SYLVAN	230	1	1						
2001-60-31	SYLVAN	230	N LONGWD	230	1	1						
2001-60-31	IND RIV	230	STANTON	230	1	11						
2001-60-31	SILVR SP	230	SILV SPN	230	1	2						
2001-60-31	SILVR SP	230	SILV SPN	230	2	2						
2001-60-31	RIO PINR	230	CURRY FD	230	1	2						
2001-60-31	JUNEAU-W	138	GANNON	138	1	16						
2001-60-31	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-31	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-31	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-31	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-31	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-31	SN PLANT	115	TURNER	115	1	1						
2001-60-31	PASADENA	115	40ST-DUM	115	1	2						
2001-60-31	MICHIGAN	115	KALEY	115	1	11						
2001-60-31	MICHIGAN	115	GRANT	115	1	11						
2001-60-31	PERSHING	115	GRANT	115	1	11						
2001-60-31	AMERICA	115	KALEY	115	1	11						
2001-60-31	JASPER	115	WGHTCHPL	115	1	2						
2001-60-31	AZALEA	115	BENNETT	115	1	11						
2001-60-31	FLORALTP	69	INVERNTP	69	1	2						
2001-60-31	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-31	PASADENA	230	PASADENA	115	1	2						
2001-60-31	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-31	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-31	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-31	IND RIV	230	IND RIV	115	1	11						
2001-60-31	LARGO	230	LARGO A	69	1	2						
2001-60-31	SHELD	230	SHELD-NW	69	1	16						
2001-60-31	CLMT EST	230	CLMT EST	69	1	2						
2001-60-31	WINDERME	230	WINDERME	69	1	2						
2001-60-31	RIVER-S	230	RIVER-S	69	1	16						
2001-60-31	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-31	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-31	JASPER	115	JASPER	69	1	2						
2001-60-32	SN PLANT	230	SYLVAN	230	1	1						
2001-60-32	SYLVAN	230	N LONGWD	230	1	1						
2001-60-32	IND RIV	230	STANTON	230	1	11						
2001-60-32	SILVR SP	230	SILV SPN	230	1	2						
2001-60-32	SILVR SP	230	SILV SPN	230	2	2						
2001-60-32	RIO PINR	230	CURRY FD	230	1	2						
2001-60-32	JUNEAU-W	138	GANNON	138	1	16						
2001-60-32	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-32	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-32	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-32	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-32	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-32	SN PLANT	115	TURNER	115	1	1						
2001-60-32	PASADENA	115	40ST-DUM	115	1	2						
2001-60-32	MICHIGAN	115	KALEY	115	1	11						
2001-60-32	MICHIGAN	115	GRANT	115	1	11						
2001-60-32	PERSHING	115	GRANT	115	1	11						
2001-60-32	AMERICA	115	KALEY	115	1	11						
2001-60-32	JASPER	115	WGHTCHPL	115	1	2						
2001-60-32	AZALEA	115	BENNETT	115	1	11						
2001-60-32	FLORALTP	69	INVERNTP	69	1	2						
2001-60-32	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-32	PASADENA	230	PASADENA	115	1	2						
2001-60-32	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-32	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-32	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-32	IND RIV	230	IND RIV	115	1	11						
2001-60-32	LARGO	230	LARGO A	69	1	2						
2001-60-32	SHELD	230	SHELD-NW	69	1	16						
2001-60-32	CLMT EST	230	CLMT EST	69	1	2						
2001-60-32	WINDERME	230	WINDERME	69	1	2						
2001-60-32	RIVER-S	230	RIVER-S	69	1	16						
2001-60-32	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-32	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-32	JASPER	115	JASPER	69	1	2						

Table VII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60B Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-33	SN PLANT	230	SYLVAN	230	1	1						
2001-60-33	SYLVAN	230	N LONGWD	230	1	1						
2001-60-33	IND RIV	230	STANTON	230	1	11						
2001-60-33	SILVR SP	230	SILV SPN	230	1	2						
2001-60-33	SILVR SP	230	SILV SPN	230	2	2						
2001-60-33	RIO PINR	230	CURRY FD	230	1	2						
2001-60-33	JUNEAU-W	138	GANNON	138	1	16						
2001-60-33	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-33	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-33	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-33	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-33	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-33	SN PLANT	115	TURNER	115	1	1						
2001-60-33	PASADENA	115	40ST-DUM	115	1	2						
2001-60-33	MICHIGAN	115	KALEY	115	1	11						
2001-60-33	MICHIGAN	115	GRANT	115	1	11						
2001-60-33	PERSHING	115	GRANT	115	1	11						
2001-60-33	AMERICA	115	KALEY	115	1	11						
2001-60-33	JASPER	115	WGHTCHPL	115	1	2						
2001-60-33	AZALEA	115	BENNETT	115	1	11						
2001-60-33	FLORALTP	69	INVERNTP	69	1	2						
2001-60-33	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-33	PASADENA	230	PASADENA	115	1	2						
2001-60-33	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-33	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-33	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-33	IND RIV	230	IND RIV	115	1	11						
2001-60-33	LARGO	230	LARGO A	69	1	2						
2001-60-33	SHELD	230	SHELD-NW	69	1	16						
2001-60-33	CLMT EST	230	CLMT EST	69	1	2						
2001-60-33	WINDERME	230	WINDERME	69	1	2						
2001-60-33	RIVER-S	230	RIVER-S	69	1	16						
2001-60-33	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-33	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-33	JASPER	115	JASPER	69	1	2						
2001-60-34	SN PLANT	230	SYLVAN	230	1	1						
2001-60-34	SYLVAN	230	N LONGWD	230	1	1						
2001-60-34	IND RIV	230	STANTON	230	1	11						
2001-60-34	SILVR SP	230	SILV SPN	230	1	2						
2001-60-34	SILVR SP	230	SILV SPN	230	2	2						
2001-60-34	RIO PINR	230	CURRY FD	230	1	2						
2001-60-34	JUNEAU-W	138	GANNON	138	1	16						
2001-60-34	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-34	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-34	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-34	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-34	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-34	SN PLANT	115	TURNER	115	1	1						
2001-60-34	PASADENA	115	40ST-DUM	115	1	2						
2001-60-34	MICHIGAN	115	KALEY	115	1	11						
2001-60-34	MICHIGAN	115	GRANT	115	1	11						
2001-60-34	PERSHING	115	GRANT	115	1	11						
2001-60-34	AMERICA	115	KALEY	115	1	11						
2001-60-34	JASPER	115	WGHTCHPL	115	1	2						
2001-60-34	AZALEA	115	BENNETT	115	1	11						
2001-60-34	FLORALTP	69	INVERNTP	69	1	2						
2001-60-34	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-34	PASADENA	230	PASADENA	115	1	2						
2001-60-34	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-34	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-34	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-34	IND RIV	230	IND RIV	115	1	11						
2001-60-34	LARGO	230	LARGO A	69	1	2						
2001-60-34	SHELD	230	SHELD-NW	69	1	16						
2001-60-34	CLMT EST	230	CLMT EST	69	1	2						
2001-60-34	WINDERME	230	WINDERME	69	1	2						
2001-60-34	RIVER-S	230	RIVER-S	69	1	16						
2001-60-34	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-34	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-34	JASPER	115	JASPER	69	1	2						

Table VII

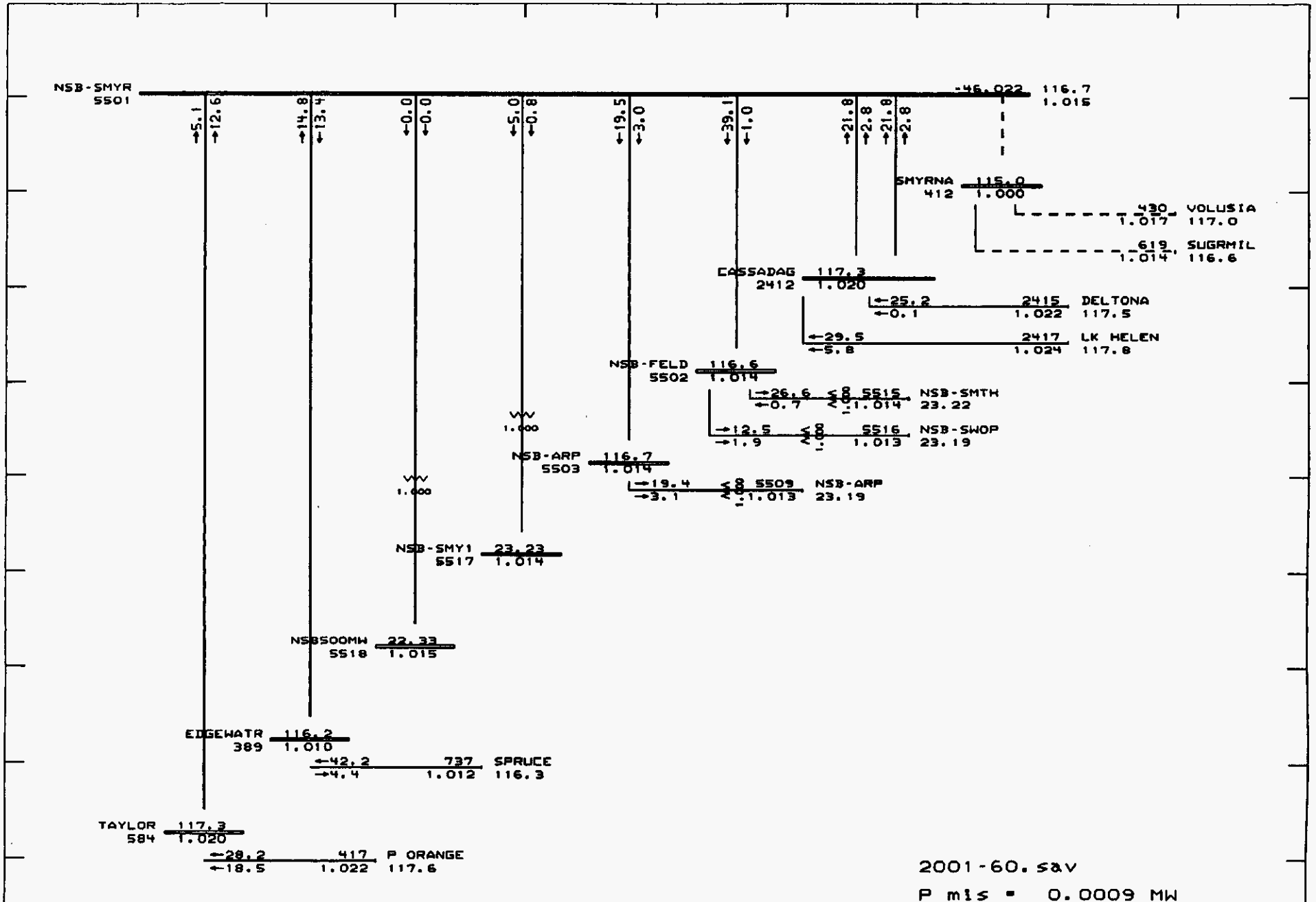
Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-60 Base No NSB Gen	Case 2001-60A Sell to FPL	Case 2001-60E Sell to FPC	Case 2001-60C Sell to TEC	Case 2001-60D Sell to JEA	Case 2001-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-60-35	SN PLANT	230	SYLVAN	230	1	1						
2001-60-35	SYLVAN	230	N LONGWD	230	1	1						
2001-60-35	IND RIV	230	STANTON	230	1	11						
2001-60-35	SILVR SP	230	SILV SPN	230	1	2						
2001-60-35	SILVR SP	230	SILV SPN	230	2	2						
2001-60-35	RIO PINR	230	CURRY FD	230	1	2						
2001-60-35	JUNEAU-W	138	GANNON	138	1	16						
2001-60-35	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-35	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-35	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-35	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-35	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-35	SN PLANT	115	TURNER	115	1	1						
2001-60-35	PASADENA	115	40ST-DUM	115	1	2						
2001-60-35	MICHIGAN	115	KALEY	115	1	11						
2001-60-35	MICHIGAN	115	GRANT	115	1	11						
2001-60-35	PERSHING	115	GRANT	115	1	11						
2001-60-35	AMERICA	115	KALEY	115	1	11						
2001-60-35	JASPER	115	WGHTCHPL	115	1	2						
2001-60-35	AZALEA	115	BENNETT	115	1	11						
2001-60-35	FLORALTP	69	INVERNTP	69	1	2						
2001-60-35	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-35	PASADENA	230	PASADENA	115	1	2						
2001-60-35	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-35	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-35	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-35	IND RIV	230	IND RIV	115	1	11						
2001-60-35	LARGO	230	LARGO A	69	1	2						
2001-60-35	SHELD	230	SHELD-NW	69	1	16						
2001-60-35	CLMT EST	230	CLMT EST	69	1	2						
2001-60-35	WINDERME	230	WINDERME	69	1	2						
2001-60-35	RIVER-S	230	RIVER-S	69	1	16						
2001-60-35	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-35	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-35	JASPER	115	JASPER	69	1	2						
2001-60-36	SN PLANT	230	SYLVAN	230	1	1						
2001-60-36	SYLVAN	230	N LONGWD	230	1	1						
2001-60-36	IND RIV	230	STANTON	230	1	11						
2001-60-36	SILVR SP	230	SILV SPN	230	1	2						
2001-60-36	SILVR SP	230	SILV SPN	230	2	2						
2001-60-36	RIO PINR	230	CURRY FD	230	1	2						
2001-60-36	JUNEAU-W	138	GANNON	138	1	16						
2001-60-36	NSB-SMYR	115	CASSADAG	115	1	2						
2001-60-36	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-60-36	NSB-SMYR	115	TAYLOR	115	1	1						
2001-60-36	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-60-36	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-60-36	SN PLANT	115	TURNER	115	1	1						
2001-60-36	PASADENA	115	40ST-DUM	115	1	2						
2001-60-36	MICHIGAN	115	KALEY	115	1	11						
2001-60-36	MICHIGAN	115	GRANT	115	1	11						
2001-60-36	PERSHING	115	GRANT	115	1	11						
2001-60-36	AMERICA	115	KALEY	115	1	11						
2001-60-36	JASPER	115	WGHTCHPL	115	1	2						
2001-60-36	AZALEA	115	BENNETT	115	1	11						
2001-60-36	FLORALTP	69	INVERNTP	69	1	2						
2001-60-36	ALACH TP	69	HIGH SPG	69	1	2						
2001-60-36	PASADENA	230	PASADENA	115	1	2						
2001-60-36	SUWANNEE	230	SUWANNEE	115	1	2						
2001-60-36	SUWANNEE	230	SUWANNEE	115	2	2						
2001-60-36	E CLRWTR	230	E CLRWTR	115	1	2						
2001-60-36	IND RIV	230	IND RIV	115	1	11						
2001-60-36	LARGO	230	LARGO A	69	1	2						
2001-60-36	SHELD	230	SHELD-NW	69	1	16						
2001-60-36	CLMT EST	230	CLMT EST	69	1	2						
2001-60-36	WINDERME	230	WINDERME	69	1	2						
2001-60-36	RIVER-S	230	RIVER-S	69	1	16						
2001-60-36	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-60-36	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-60-36	JASPER	115	JASPER	69	1	2						

APPENDIX III-A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SMYRNA 412 115.0 1.000
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619 SUGRMIL 1.014 116.6
CASSADAG 2412 117.3 1.020
25.2 0.1 2415 1.022 DELTONA 117.5
29.5 5.8 2417 1.024 LK HELEN 117.8
NSB-FELD 5502 116.6 1.014
26.6 0.7 5515 1.014 NSB-SMTH 23.22
12.5 1.9 5516 1.013 NSB-SWOP 23.19
NSB-ARP 5503 116.7 1.014
19.4 3.1 5509 1.013 NSB-ARP 23.19
NSB-SMY1 5517 23.23 1.014
NSB500MW 5518 22.33 1.015
EDGEWATR 389 116.2 1.010
42.2 4.4 737 1.012 SPRUCE 116.3
TAYLOR 584 117.3 1.020
29.2 18.5 417 1.022 P ORANGE 117.6
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1.000
2001-60.sav
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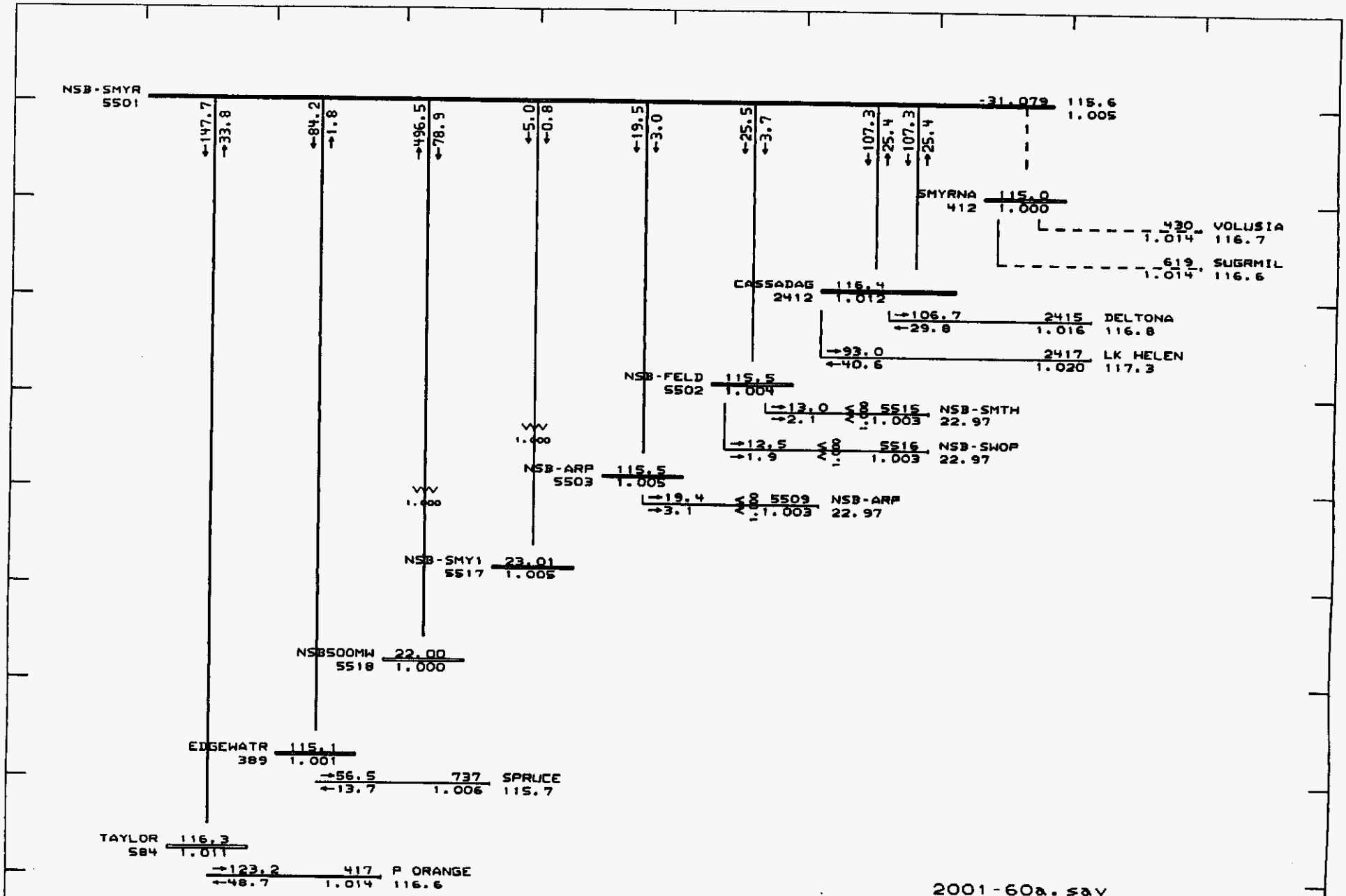
Q mis = 0.0006 MVAR
General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:26:55 1998
RMI RESOURCE MANAGEMENT INTERNATIONAL, INC.
CASE 2001 : 2001 SUMMER 60% PEAK CASE - 2400 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN. RMI 4/28/9
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001-60.sav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SMYRNA 412 115.0 1.000
430 1.014 VOLUSIA 116.7
619 1.014 SUGRMIL 116.6
CASSADAG 2412 116.4 1.012
2415 1.016 DELTONA 116.8
2417 1.020 LK HELEN 117.3
NSB-FELD 5502 115.5 1.004
5515 1.003 NSB-SMTH 22.97
5516 1.003 NSB-SWOP 22.97
NSB-ARP 5503 115.5 1.005
5509 1.003 NSB-ARP 22.97
NSB-SMY1 5517 23.01 1.005
NSB500MW 5518 22.00 1.000
EDGEWATR 389 115.1 1.001
737 1.006 SPRUCE 115.7
TAYLOR 584 116.3 1.011
417 1.014 P ORANGE 116.6
2001-60a.sav
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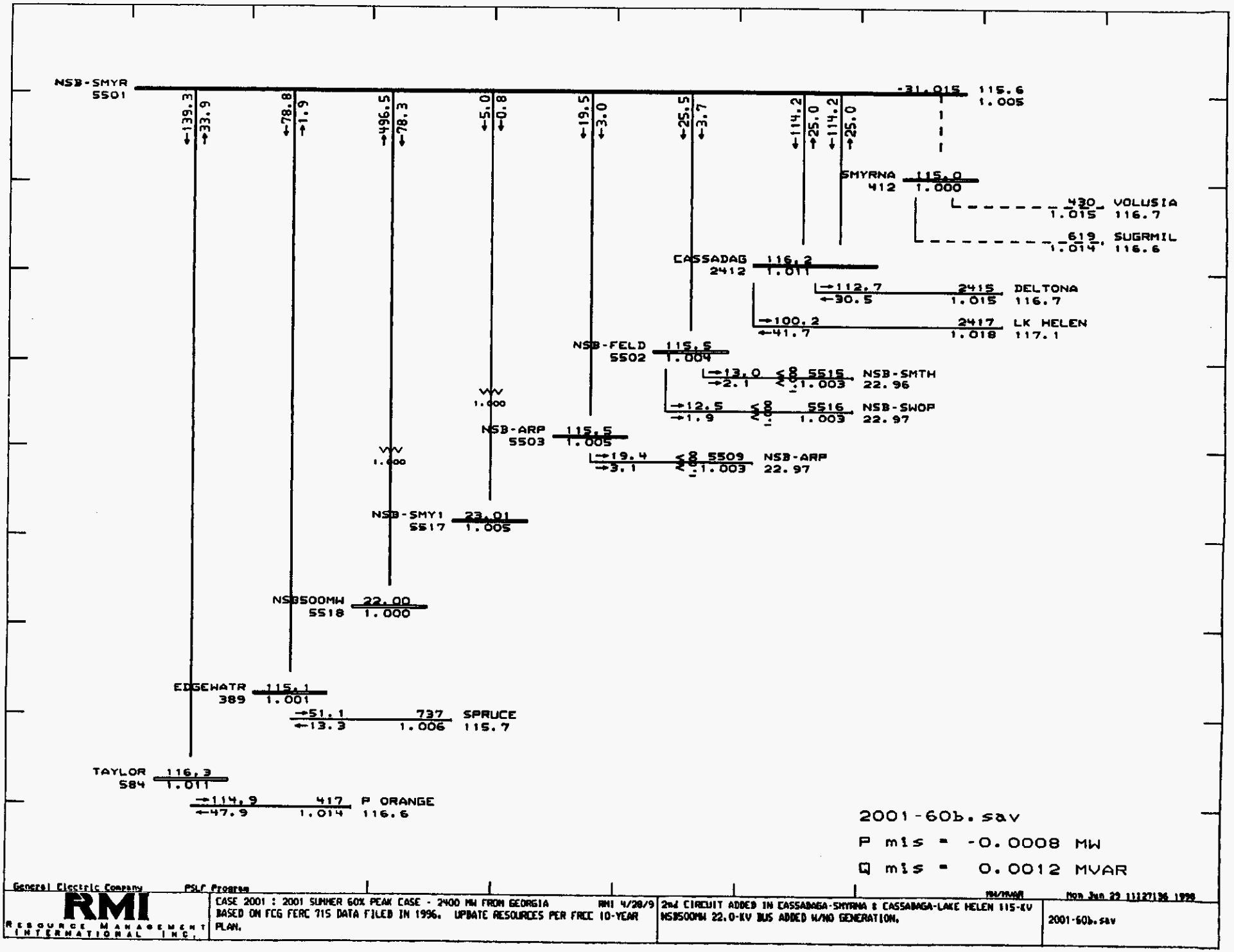
Q mis = 0.0027 MVAR
General Electric Company PSLF Program
RMI Resource Management International, Inc.
CASE 2001 : 2001 SUMMER 60% PEAK CASE - 2400 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN.
RMI 4/28/9
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
MW/MVAR
Mon Jun 29 11:27:15 1998
2001-60a.sav



2001-60b.sav

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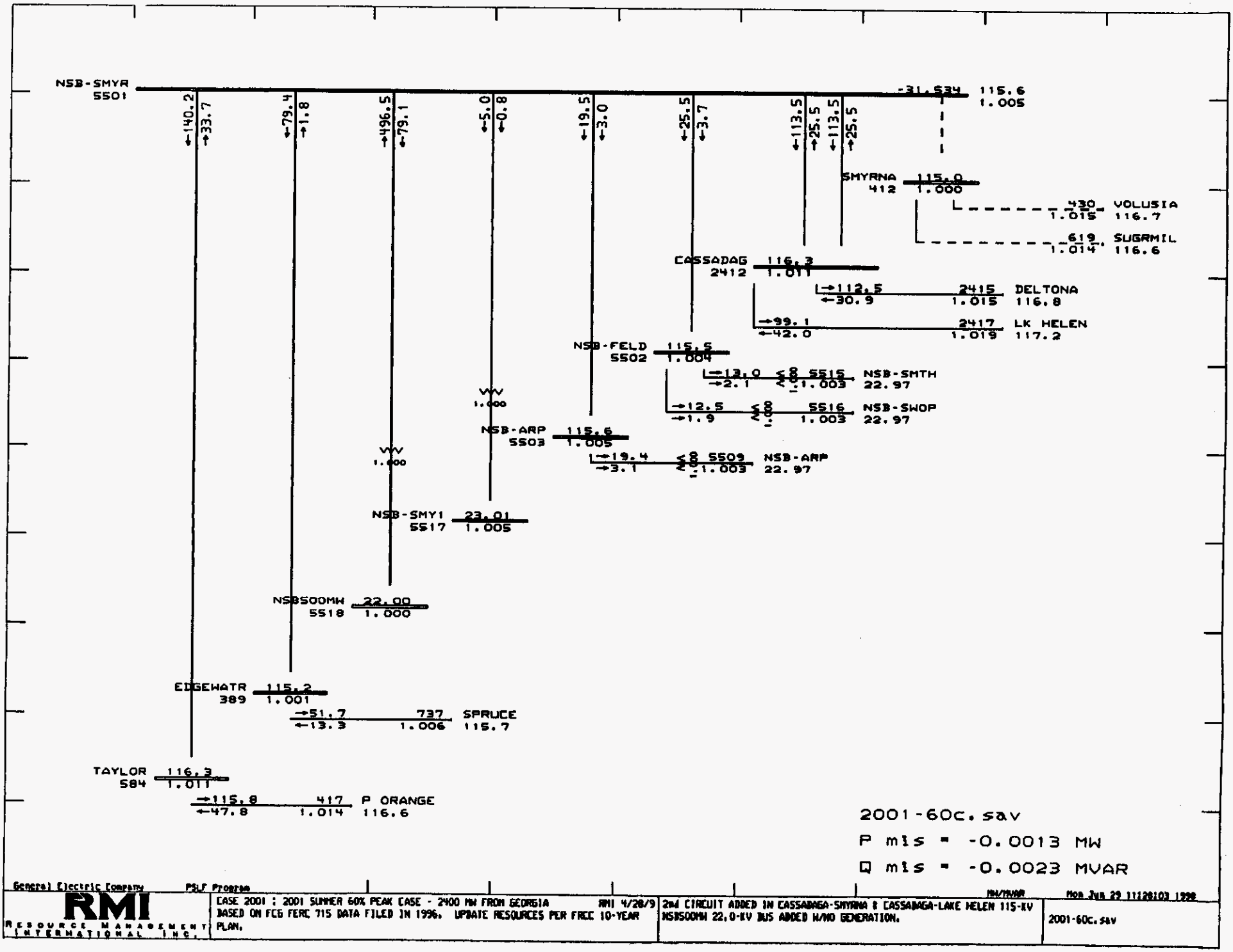
General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:27:36 1998

RMI RESOURCE MANAGEMENT INTERNATIONAL, INC.

CASE 2001 : 2001 SUMMER 60% PEAK CASE - 2400 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN. RMI 4/28/9

2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.

2001-60b.sav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←5.0
←0.8
←19.5
→3.0
←25.5
→3.7
←113.5
→25.5
←113.5
→25.5
SMYRNA
412
115.0
1.000
430
1.015
VOLUSIA
116.7
619
1.014
SUGRMIL
116.6
CASSADAG
2412
116.3
1.011
→112.5
←30.9
2415
1.015
DELTONA
116.8
→99.1
←42.0
2417
1.019
LK HELEN
117.2
NSB-FELD
5502
115.5
1.004
→13.0
→2.1
5515
1.003
NSB-SMTH
22.97
→12.5
→1.9
5516
1.003
NSB-SWOP
22.97
1.000
NSB-ARP
5503
115.6
1.005
→19.4
→3.1
5509
1.003
NSB-ARP
22.97
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NSB-SMY1
5517
23.01
1.005
NSB500MW
5518
22.00
1.000
EDGEWATR
389
115.2
1.001
→51.7
←13.3
737
1.006
SPRUCE
115.7
TAYLOR
584
116.3
1.011
→115.8
←47.8
417
1.014
P ORANGE
116.6
2001-60c.sav
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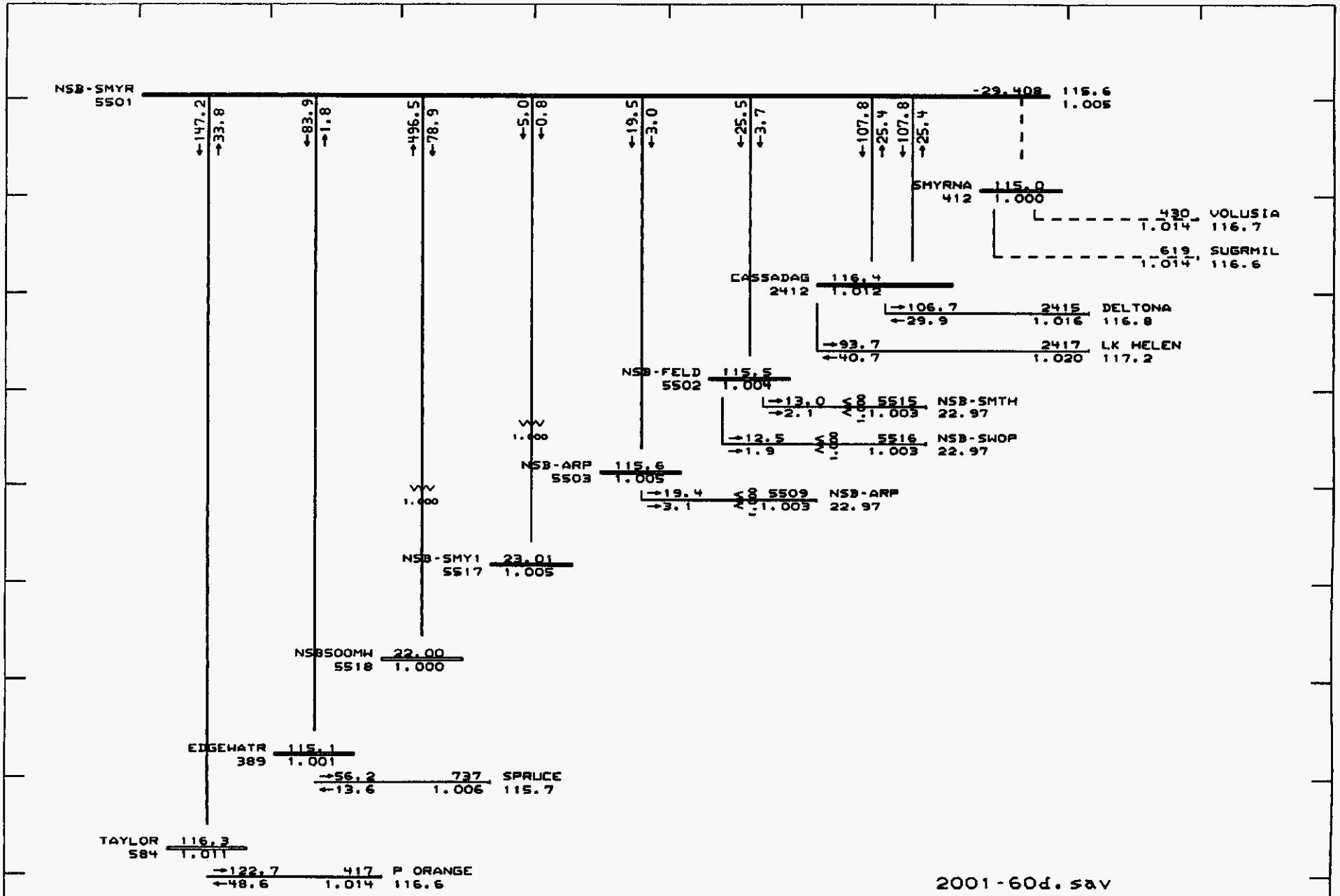
Q mis = -0.0023 MVAR
General Electric Company
PSLF Program
MW/MVAR
Mon Jun 29 11:28:03 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER 60% PEAK CASE - 2400 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN.
RMI 4/28/9
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001-60c.sav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→33.8
←83.9
→1.8
←496.5
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←5.0
→0.8
←19.5
→3.0
←25.5
→3.7
←107.8
→25.4
←107.8
→25.4
SMYRNA 115.0
412 1.000
430 VOLUSIA
1.014 116.7
619 SUGRMIL
1.014 116.6
CASSADAG 116.4
2412 1.012
→106.7 2415 DELTONA
←29.9 1.016 116.8
→93.7 2417 LK HELEN
←40.7 1.020 117.2
NSB-FELD 115.5
5502 1.004
→13.0 ≤θ 5515 NSB-SMTH
→2.1 ≥θ 1.003 22.97
→12.5 ≤θ 5516 NSB-SWOP
→1.9 ≥θ 1.003 22.97
1.000
NSB-ARP 115.6
5503 1.005
→19.4 ≤θ 5509 NSB-ARP
→3.1 ≥θ 1.003 22.97
1.000
NSB-SMY1 23.01
5517 1.005
NSB500MW 22.00
5518 1.000
EDGEWATR 115.1
389 1.001
→56.2 737 SPRUCE
←13.6 1.006 115.7
TAYLOR 116.3
584 1.011
→122.7 417 P ORANGE
←48.6 1.014 116.6
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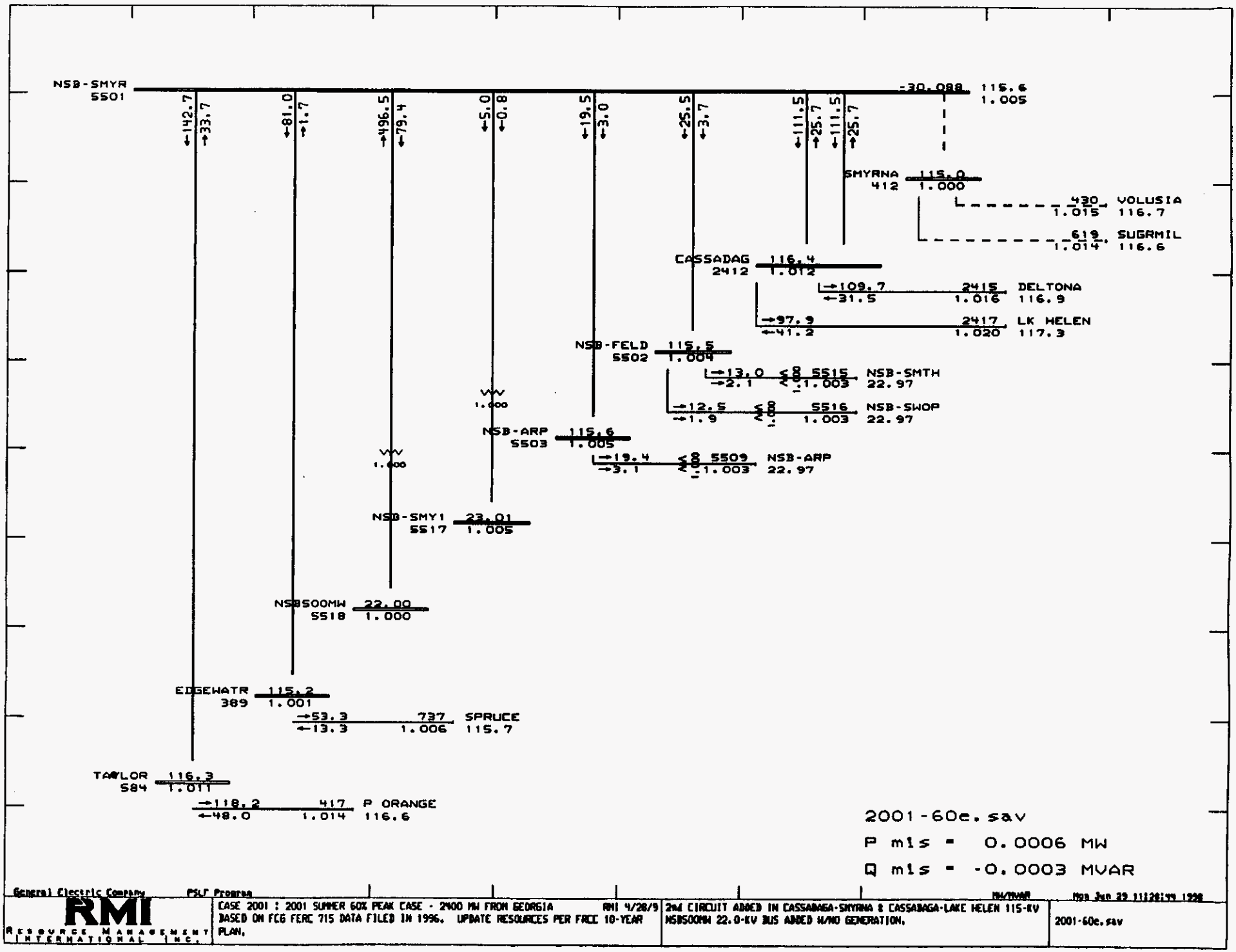
Q mis = 0.0013 MVAR
General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:28:22 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER 60% PEAK CASE - 2400 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN.
RMI 4/28/9
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001-60d.sav



General Electric Company PSLF Program

RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.

CASE 2001 : 2001 SUMMER 60% PEAK CASE - 2400 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN. RMI 4/28/9

2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.

2001-60e.sav

APPENDIX IV

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-1	SN PLANT	230	SYLVAN	230	1	1						
2001-40-1	SYLVAN	230	N LONGWD	230	1	1						
2001-40-1	IND RIV	230	STANTON	230	1	11						
2001-40-1	SILVR SP	230	SILV SPN	230	1	2						
2001-40-1	SILVR SP	230	SILV SPN	230	2	2						
2001-40-1	RIO PINR	230	CURRY FD	230	1	2						
2001-40-1	JUNEAU-W	138	GANNON	138	1	16						
2001-40-1	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-1	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-1	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-1	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-1	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-1	SN PLANT	115	TURNER	115	1	1						
2001-40-1	PASADENA	115	40ST-DUM	115	1	2						
2001-40-1	MICHIGAN	115	KALEY	115	1	11						
2001-40-1	MICHIGAN	115	GRANT	115	1	11						
2001-40-1	PERSHING	115	GRANT	115	1	11						
2001-40-1	AMERICA	115	KALEY	115	1	11						
2001-40-1	JASPER	115	WGHTCHPL	115	1	2						
2001-40-1	AZALEA	115	BENNETT	115	1	11						
2001-40-1	FLORALTP	69	INVERNTP	69	1	2						
2001-40-1	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-1	PASADENA	230	PASADENA	115	1	2						
2001-40-1	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-1	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-1	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-1	IND RIV	230	IND RIV	115	1	11						
2001-40-1	LARGO	230	LARGO A	69	1	2						
2001-40-1	SHELD	230	SHELD-NW	69	1	16						
2001-40-1	CLMT EST	230	CLMT EST	69	1	2						
2001-40-1	WINDERME	230	WINDERME	69	1	2						
2001-40-1	RIVER-S	230	RIVER-S	69	1	16						
2001-40-1	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-1	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-1	JASPER	115	JASPER	69	1	2						
2001-40-2	SN PLANT	230	SYLVAN	230	1	1						
2001-40-2	SYLVAN	230	N LONGWD	230	1	1						
2001-40-2	IND RIV	230	STANTON	230	1	11						
2001-40-2	SILVR SP	230	SILV SPN	230	1	2						
2001-40-2	SILVR SP	230	SILV SPN	230	2	2						
2001-40-2	RIO PINR	230	CURRY FD	230	1	2						
2001-40-2	JUNEAU-W	138	GANNON	138	1	16						
2001-40-2	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-2	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-2	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-2	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-2	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-2	SN PLANT	115	TURNER	115	1	1						
2001-40-2	PASADENA	115	40ST-DUM	115	1	2						
2001-40-2	MICHIGAN	115	KALEY	115	1	11						
2001-40-2	MICHIGAN	115	GRANT	115	1	11						
2001-40-2	PERSHING	115	GRANT	115	1	11						
2001-40-2	AMERICA	115	KALEY	115	1	11						
2001-40-2	JASPER	115	WGHTCHPL	115	1	2						
2001-40-2	AZALEA	115	BENNETT	115	1	11						
2001-40-2	FLORALTP	69	INVERNTP	69	1	2						
2001-40-2	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-2	PASADENA	230	PASADENA	115	1	2						
2001-40-2	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-2	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-2	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-2	IND RIV	230	IND RIV	115	1	11						
2001-40-2	LARGO	230	LARGO A	69	1	2						
2001-40-2	SHELD	230	SHELD-NW	69	1	16						
2001-40-2	CLMT EST	230	CLMT EST	69	1	2						
2001-40-2	WINDERME	230	WINDERME	69	1	2						
2001-40-2	RIVER-S	230	RIVER-S	69	1	16						
2001-40-2	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-2	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-2	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-3	SN PLANT	230	SYLVAN	230	1	1						
2001-40-3	SYLVAN	230	N LONGWD	230	1	1						
2001-40-3	IND RIV	230	STANTON	230	1	11						
2001-40-3	SILVR SP	230	SILV SPN	230	1	2						
2001-40-3	SILVR SP	230	SILV SPN	230	2	2						
2001-40-3	RIO PINR	230	CURRY FD	230	1	2						
2001-40-3	JUNEAU-W	138	GANNON	138	1	16						
2001-40-3	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-3	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-3	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-3	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-3	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-3	SN PLANT	115	TURNER	115	1	1						
2001-40-3	PASADENA	115	40ST-DUM	115	1	2						
2001-40-3	MICHIGAN	115	KALEY	115	1	11						
2001-40-3	MICHIGAN	115	GRANT	115	1	11						
2001-40-3	PERSHING	115	GRANT	115	1	11						
2001-40-3	AMERICA	115	KALEY	115	1	11						
2001-40-3	JASPER	115	WGHTCHPL	115	1	2						
2001-40-3	AZALEA	115	BENNETT	115	1	11						
2001-40-3	FLORALTP	69	INVERNTP	69	1	2						
2001-40-3	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-3	PASADENA	230	PASADENA	115	1	2						
2001-40-3	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-3	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-3	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-3	IND RIV	230	IND RIV	115	1	11						
2001-40-3	LARGO	230	LARGO A	69	1	2						
2001-40-3	SHELD	230	SHELD-NW	69	1	16						
2001-40-3	CLMT EST	230	CLMT EST	69	1	2						
2001-40-3	WINDERME	230	WINDERME	69	1	2						
2001-40-3	RIVER-S	230	RIVER-S	69	1	16						
2001-40-3	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-3	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-3	JASPER	115	JASPER	69	1	2						
2001-40-4	SN PLANT	230	SYLVAN	230	1	1						
2001-40-4	SYLVAN	230	N LONGWD	230	1	1						
2001-40-4	IND RIV	230	STANTON	230	1	11						
2001-40-4	SILVR SP	230	SILV SPN	230	1	2						
2001-40-4	SILVR SP	230	SILV SPN	230	2	2						
2001-40-4	RIO PINR	230	CURRY FD	230	1	2						
2001-40-4	JUNEAU-W	138	GANNON	138	1	16						
2001-40-4	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-4	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-4	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-4	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-4	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-4	SN PLANT	115	TURNER	115	1	1						
2001-40-4	PASADENA	115	40ST-DUM	115	1	2						
2001-40-4	MICHIGAN	115	KALEY	115	1	11						
2001-40-4	MICHIGAN	115	GRANT	115	1	11						
2001-40-4	PERSHING	115	GRANT	115	1	11						
2001-40-4	AMERICA	115	KALEY	115	1	11						
2001-40-4	JASPER	115	WGHTCHPL	115	1	2						
2001-40-4	AZALEA	115	BENNETT	115	1	11						
2001-40-4	FLORALTP	69	INVERNTP	69	1	2						
2001-40-4	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-4	PASADENA	230	PASADENA	115	1	2						
2001-40-4	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-4	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-4	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-4	IND RIV	230	IND RIV	115	1	11						
2001-40-4	LARGO	230	LARGO A	69	1	2						
2001-40-4	SHELD	230	SHELD-NW	69	1	16						
2001-40-4	CLMT EST	230	CLMT EST	69	1	2						
2001-40-4	WINDERME	230	WINDERME	69	1	2						
2001-40-4	RIVER-S	230	RIVER-S	69	1	16						
2001-40-4	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-4	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-4	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-5	SN PLANT	230	SYLVAN	230	1	1						
2001-40-5	SYLVAN	230	N LONGWD	230	1	1						
2001-40-5	IND RIV	230	STANTON	230	1	11						
2001-40-5	SILVR SP	230	SILV SPN	230	1	2						
2001-40-5	SILVR SP	230	SILV SPN	230	2	2						
2001-40-5	RIO PINR	230	CURRY FD	230	1	2						
2001-40-5	JUNEAU-W	138	GANNON	138	1	16						
2001-40-5	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-5	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-5	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-5	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-5	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-5	SN PLANT	115	TURNER	115	1	1						
2001-40-5	PASADENA	115	40ST-DUM	115	1	2						
2001-40-5	MICHIGAN	115	KALEY	115	1	11						
2001-40-5	MICHIGAN	115	GRANT	115	1	11						
2001-40-5	PERSHING	115	GRANT	115	1	11						
2001-40-5	AMERICA	115	KALEY	115	1	11						
2001-40-5	JASPER	115	WGHTCHPL	115	1	2						
2001-40-5	AZALEA	115	BENNETT	115	1	11						
2001-40-5	FLORALTP	69	INVERNTP	69	1	2						
2001-40-5	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-5	PASADENA	230	PASADENA	115	1	2						
2001-40-5	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-5	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-5	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-5	IND RIV	230	IND RIV	115	1	11						
2001-40-5	LARGO	230	LARGO A	69	1	2						
2001-40-5	SHELD	230	SHELD-NW	69	1	16						
2001-40-5	CLMT EST	230	CLMT EST	69	1	2						
2001-40-5	WINDERME	230	WINDERME	69	1	2						
2001-40-5	RIVER-S	230	RIVER-S	69	1	16						
2001-40-5	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-5	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-5	JASPER	115	JASPER	69	1	2						
2001-40-6	SN PLANT	230	SYLVAN	230	1	1						
2001-40-6	SYLVAN	230	N LONGWD	230	1	1						
2001-40-6	IND RIV	230	STANTON	230	1	11						
2001-40-6	SILVR SP	230	SILV SPN	230	1	2						
2001-40-6	SILVR SP	230	SILV SPN	230	2	2						
2001-40-6	RIO PINR	230	CURRY FD	230	1	2						
2001-40-6	JUNEAU-W	138	GANNON	138	1	16						
2001-40-6	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-6	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-6	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-6	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-6	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-6	SN PLANT	115	TURNER	115	1	1						
2001-40-6	PASADENA	115	40ST-DUM	115	1	2						
2001-40-6	MICHIGAN	115	KALEY	115	1	11						
2001-40-6	MICHIGAN	115	GRANT	115	1	11						
2001-40-6	PERSHING	115	GRANT	115	1	11						
2001-40-6	AMERICA	115	KALEY	115	1	11						
2001-40-6	JASPER	115	WGHTCHPL	115	1	2						
2001-40-6	AZALEA	115	BENNETT	115	1	11						
2001-40-6	FLORALTP	69	INVERNTP	69	1	2						
2001-40-6	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-6	PASADENA	230	PASADENA	115	1	2						
2001-40-6	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-6	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-6	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-6	IND RIV	230	IND RIV	115	1	11						
2001-40-6	LARGO	230	LARGO A	69	1	2						
2001-40-6	SHELD	230	SHELD-NW	69	1	16						
2001-40-6	CLMT EST	230	CLMT EST	69	1	2						
2001-40-6	WINDERME	230	WINDERME	69	1	2						
2001-40-6	RIVER-S	230	RIVER-S	69	1	16						
2001-40-6	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-6	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-6	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-7	SN PLANT	230	SYLVAN	230	1	1						
2001-40-7	SYLVAN	230	N LONGWD	230	1	1						
2001-40-7	IND RIV	230	STANTON	230	1	11						
2001-40-7	SILVR SP	230	SILV SPN	230	1	2						
2001-40-7	SILVR SP	230	SILV SPN	230	2	2						
2001-40-7	RIO PINR	230	CURRY FD	230	1	2						
2001-40-7	JUNEAU-W	138	GANNON	138	1	16						
2001-40-7	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-7	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-7	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-7	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-7	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-7	SN PLANT	115	TURNER	115	1	1						
2001-40-7	PASADENA	115	40ST-DUM	115	1	2						
2001-40-7	MICHIGAN	115	KALEY	115	1	11						
2001-40-7	MICHIGAN	115	GRANT	115	1	11						
2001-40-7	PERSHING	115	GRANT	115	1	11						
2001-40-7	AMERICA	115	KALEY	115	1	11						
2001-40-7	JASPER	115	WGHTCHPL	115	1	2						
2001-40-7	AZALEA	115	BENNETT	115	1	11						
2001-40-7	FLORALTP	69	INVERNTP	69	1	2						
2001-40-7	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-7	PASADENA	230	PASADENA	115	1	2						
2001-40-7	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-7	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-7	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-7	IND RIV	230	IND RIV	115	1	11						
2001-40-7	LARGO	230	LARGO A	69	1	2						
2001-40-7	SHELD	230	SHELD-NW	69	1	16						
2001-40-7	CLMT EST	230	CLMT EST	69	1	2						
2001-40-7	WINDERME	230	WINDERME	69	1	2						
2001-40-7	RIVER-S	230	RIVER-S	69	1	16						
2001-40-7	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-7	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-7	JASPER	115	JASPER	69	1	2						
2001-40-8	SN PLANT	230	SYLVAN	230	1	1						
2001-40-8	SYLVAN	230	N LONGWD	230	1	1						
2001-40-8	IND RIV	230	STANTON	230	1	11						
2001-40-8	SILVR SP	230	SILV SPN	230	1	2						
2001-40-8	SILVR SP	230	SILV SPN	230	2	2						
2001-40-8	RIO PINR	230	CURRY FD	230	1	2						
2001-40-8	JUNEAU-W	138	GANNON	138	1	16						
2001-40-8	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-8	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-8	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-8	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-8	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-8	SN PLANT	115	TURNER	115	1	1						
2001-40-8	PASADENA	115	40ST-DUM	115	1	2						
2001-40-8	MICHIGAN	115	KALEY	115	1	11						
2001-40-8	MICHIGAN	115	GRANT	115	1	11						
2001-40-8	PERSHING	115	GRANT	115	1	11						
2001-40-8	AMERICA	115	KALEY	115	1	11						
2001-40-8	JASPER	115	WGHTCHPL	115	1	2						
2001-40-8	AZALEA	115	BENNETT	115	1	11						
2001-40-8	FLORALTP	69	INVERNTP	69	1	2						
2001-40-8	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-8	PASADENA	230	PASADENA	115	1	2						
2001-40-8	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-8	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-8	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-8	IND RIV	230	IND RIV	115	1	11						
2001-40-8	LARGO	230	LARGO A	69	1	2						
2001-40-8	SHELD	230	SHELD-NW	69	1	16						
2001-40-8	CLMT EST	230	CLMT EST	69	1	2						
2001-40-8	WINDERME	230	WINDERME	69	1	2						
2001-40-8	RIVER-S	230	RIVER-S	69	1	16						
2001-40-8	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-8	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-8	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-9	SN PLANT	230	SYLVAN	230	1	1						
2001-40-9	SYLVAN	230	N LONGWD	230	1	1						
2001-40-9	IND RIV	230	STANTON	230	1	11						
2001-40-9	SILVR SP	230	SILV SPN	230	1	2						
2001-40-9	SILVR SP	230	SILV SPN	230	2	2						
2001-40-9	RIO PINR	230	CURRY FD	230	1	2						
2001-40-9	JUNEAU-W	138	GANNON	138	1	16						
2001-40-9	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-9	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-9	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-9	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-9	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-9	SN PLANT	115	TURNER	115	1	1						
2001-40-9	PASADENA	115	40ST-DUM	115	1	2						
2001-40-9	MICHIGAN	115	KALEY	115	1	11						
2001-40-9	MICHIGAN	115	GRANT	115	1	11						
2001-40-9	PERSHING	115	GRANT	115	1	11						
2001-40-9	AMERICA	115	KALEY	115	1	11						
2001-40-9	JASPER	115	WGHTCHPL	115	1	2						
2001-40-9	AZALEA	115	BENNETT	115	1	11						
2001-40-9	FLORALTP	69	INVERNTP	69	1	2						
2001-40-9	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-9	PASADENA	230	PASADENA	115	1	2						
2001-40-9	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-9	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-9	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-9	IND RIV	230	IND RIV	115	1	11						
2001-40-9	LARGO	230	LARGO A	69	1	2						
2001-40-9	SHELD	230	SHELD-NW	69	1	16						
2001-40-9	CLMT EST	230	CLMT EST	69	1	2						
2001-40-9	WINDERME	230	WINDERME	69	1	2						
2001-40-9	RIVER-S	230	RIVER-S	69	1	16						
2001-40-9	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-9	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-9	JASPER	115	JASPER	69	1	2						
2001-40-10	SN PLANT	230	SYLVAN	230	1	1						
2001-40-10	SYLVAN	230	N LONGWD	230	1	1						
2001-40-10	IND RIV	230	STANTON	230	1	11						
2001-40-10	SILVR SP	230	SILV SPN	230	1	2						
2001-40-10	SILVR SP	230	SILV SPN	230	2	2						
2001-40-10	RIO PINR	230	CURRY FD	230	1	2						
2001-40-10	JUNEAU-W	138	GANNON	138	1	16						
2001-40-10	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-10	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-10	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-10	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-10	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-10	SN PLANT	115	TURNER	115	1	1						
2001-40-10	PASADENA	115	40ST-DUM	115	1	2						
2001-40-10	MICHIGAN	115	KALEY	115	1	11						
2001-40-10	MICHIGAN	115	GRANT	115	1	11						
2001-40-10	PERSHING	115	GRANT	115	1	11						
2001-40-10	AMERICA	115	KALEY	115	1	11						
2001-40-10	JASPER	115	WGHTCHPL	115	1	2						
2001-40-10	AZALEA	115	BENNETT	115	1	11						
2001-40-10	FLORALTP	69	INVERNTP	69	1	2						
2001-40-10	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-10	PASADENA	230	PASADENA	115	1	2						
2001-40-10	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-10	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-10	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-10	IND RIV	230	IND RIV	115	1	11						
2001-40-10	LARGO	230	LARGO A	69	1	2						
2001-40-10	SHELD	230	SHELD-NW	69	1	16						
2001-40-10	CLMT EST	230	CLMT EST	69	1	2						
2001-40-10	WINDERME	230	WINDERME	69	1	2						
2001-40-10	RIVER-S	230	RIVER-S	69	1	16						
2001-40-10	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-10	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-10	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-11	SN PLANT	230	SYLVAN	230	1	1						
2001-40-11	SYLVAN	230	N LONGWD	230	1	1						
2001-40-11	IND RIV	230	STANTON	230	1	11						
2001-40-11	SILVR SP	230	SILV SPN	230	1	2						
2001-40-11	SILVR SP	230	SILV SPN	230	2	2						
2001-40-11	RIO PINR	230	CURRY FD	230	1	2						
2001-40-11	JUNEAU-W	138	GANNON	138	1	16						
2001-40-11	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-11	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-11	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-11	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-11	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-11	SN PLANT	115	TURNER	115	1	1						
2001-40-11	PASADENA	115	40ST-DUM	115	1	2						
2001-40-11	MICHIGAN	115	KALEY	115	1	11						
2001-40-11	MICHIGAN	115	GRANT	115	1	11						
2001-40-11	PERSHING	115	GRANT	115	1	11						
2001-40-11	AMERICA	115	KALEY	115	1	11						
2001-40-11	JASPER	115	WGHTCHPL	115	1	2						
2001-40-11	AZALEA	115	BENNETT	115	1	11						
2001-40-11	FLORALTP	69	INVERNTP	69	1	2						
2001-40-11	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-11	PASADENA	230	PASADENA	115	1	2						
2001-40-11	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-11	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-11	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-11	IND RIV	230	IND RIV	115	1	11						
2001-40-11	LARGO	230	LARGO A	69	1	2						
2001-40-11	SHELD	230	SHELD-NW	69	1	16						
2001-40-11	CLMT EST	230	CLMT EST	69	1	2						
2001-40-11	WINDERME	230	WINDERME	69	1	2						
2001-40-11	RIVER-S	230	RIVER-S	69	1	16						
2001-40-11	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-11	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-11	JASPER	115	JASPER	69	1	2						
2001-40-12	SN PLANT	230	SYLVAN	230	1	1						
2001-40-12	SYLVAN	230	N LONGWD	230	1	1						
2001-40-12	IND RIV	230	STANTON	230	1	11						
2001-40-12	SILVR SP	230	SILV SPN	230	1	2						
2001-40-12	SILVR SP	230	SILV SPN	230	2	2						
2001-40-12	RIO PINR	230	CURRY FD	230	1	2						
2001-40-12	JUNEAU-W	138	GANNON	138	1	16						
2001-40-12	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-12	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-12	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-12	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-12	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-12	SN PLANT	115	TURNER	115	1	1						
2001-40-12	PASADENA	115	40ST-DUM	115	1	2						
2001-40-12	MICHIGAN	115	KALEY	115	1	11						
2001-40-12	MICHIGAN	115	GRANT	115	1	11						
2001-40-12	PERSHING	115	GRANT	115	1	11						
2001-40-12	AMERICA	115	KALEY	115	1	11						
2001-40-12	JASPER	115	WGHTCHPL	115	1	2						
2001-40-12	AZALEA	115	BENNETT	115	1	11						
2001-40-12	FLORALTP	69	INVERNTP	69	1	2						
2001-40-12	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-12	PASADENA	230	PASADENA	115	1	2						
2001-40-12	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-12	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-12	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-12	IND RIV	230	IND RIV	115	1	11						
2001-40-12	LARGO	230	LARGO A	69	1	2						
2001-40-12	SHELD	230	SHELD-NW	69	1	16						
2001-40-12	CLMT EST	230	CLMT EST	69	1	2						
2001-40-12	WINDERME	230	WINDERME	69	1	2						
2001-40-12	RIVER-S	230	RIVER-S	69	1	16						
2001-40-12	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-12	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-12	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-13	SN PLANT	230	SYLVAN	230	1	1						
2001-40-13	SYLVAN	230	N LONGWD	230	1	1						
2001-40-13	IND RIV	230	STANTON	230	1	11						
2001-40-13	SILVR SP	230	SILV SPN	230	1	2						
2001-40-13	SILVR SP	230	SILV SPN	230	2	2						
2001-40-13	RIO PINR	230	CURRY FD	230	1	2						
2001-40-13	JUNEAU-W	138	GANNON	138	1	16						
2001-40-13	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-13	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-13	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-13	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-13	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-13	SN PLANT	115	TURNER	115	1	1						
2001-40-13	PASADENA	115	40ST-DUM	115	1	2						
2001-40-13	MICHIGAN	115	KALEY	115	1	11						
2001-40-13	MICHIGAN	115	GRANT	115	1	11						
2001-40-13	PERSHING	115	GRANT	115	1	11						
2001-40-13	AMERICA	115	KALEY	115	1	11						
2001-40-13	JASPER	115	WGHTCHPL	115	1	2						
2001-40-13	AZALEA	115	BENNETT	115	1	11						
2001-40-13	FLORALTP	69	INVERNTP	69	1	2						
2001-40-13	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-13	PASADENA	230	PASADENA	115	1	2						
2001-40-13	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-13	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-13	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-13	IND RIV	230	IND RIV	115	1	11						
2001-40-13	LARGO	230	LARGO A	69	1	2						
2001-40-13	SHELD	230	SHELD-NW	69	1	16						
2001-40-13	CLMT EST	230	CLMT EST	69	1	2						
2001-40-13	WINDERME	230	WINDERME	69	1	2						
2001-40-13	RIVER-S	230	RIVER-S	69	1	16						
2001-40-13	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-13	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-13	JASPER	115	JASPER	69	1	2						
2001-40-14	SN PLANT	230	SYLVAN	230	1	1						
2001-40-14	SYLVAN	230	N LONGWD	230	1	1						
2001-40-14	IND RIV	230	STANTON	230	1	11						
2001-40-14	SILVR SP	230	SILV SPN	230	1	2						
2001-40-14	SILVR SP	230	SILV SPN	230	2	2						
2001-40-14	RIO PINR	230	CURRY FD	230	1	2						
2001-40-14	JUNEAU-W	138	GANNON	138	1	16						
2001-40-14	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-14	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-14	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-14	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-14	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-14	SN PLANT	115	TURNER	115	1	1						
2001-40-14	PASADENA	115	40ST-DUM	115	1	2						
2001-40-14	MICHIGAN	115	KALEY	115	1	11						
2001-40-14	MICHIGAN	115	GRANT	115	1	11						
2001-40-14	PERSHING	115	GRANT	115	1	11						
2001-40-14	AMERICA	115	KALEY	115	1	11						
2001-40-14	JASPER	115	WGHTCHPL	115	1	2						
2001-40-14	AZALEA	115	BENNETT	115	1	11						
2001-40-14	FLORALTP	69	INVERNTP	69	1	2						
2001-40-14	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-14	PASADENA	230	PASADENA	115	1	2						
2001-40-14	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-14	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-14	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-14	IND RIV	230	IND RIV	115	1	11						
2001-40-14	LARGO	230	LARGO A	69	1	2						
2001-40-14	SHELD	230	SHELD-NW	69	1	16						
2001-40-14	CLMT EST	230	CLMT EST	69	1	2						
2001-40-14	WINDERME	230	WINDERME	69	1	2						
2001-40-14	RIVER-S	230	RIVER-S	69	1	16						
2001-40-14	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-14	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-14	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40E Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-15	SN PLANT	230	SYLVAN	230	1	1						
2001-40-15	SYLVAN	230	N LONGWD	230	1	1						
2001-40-15	IND RIV	230	STANTON	230	1	11						
2001-40-15	SILVR SP	230	SILV SPN	230	1	2						
2001-40-15	SILVR SP	230	SILV SPN	230	2	2						
2001-40-15	RIO PINR	230	CURRY FD	230	1	2						
2001-40-15	JUNEAU-W	138	GANNON	138	1	16						
2001-40-15	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-15	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-15	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-15	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-15	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-15	SN PLANT	115	TURNER	115	1	1						
2001-40-15	PASADENA	115	40ST-DUM	115	1	2						
2001-40-15	MICHIGAN	115	KALEY	115	1	11						
2001-40-15	MICHIGAN	115	GRANT	115	1	11						
2001-40-15	PERSHING	115	GRANT	115	1	11						
2001-40-15	AMERICA	115	KALEY	115	1	11						
2001-40-15	JASPER	115	WGHTCHPL	115	1	2						
2001-40-15	AZALEA	115	BENNETT	115	1	11						
2001-40-15	FLORALTP	69	INVERNTP	69	1	2						
2001-40-15	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-15	PASADENA	230	PASADENA	115	1	2						
2001-40-15	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-15	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-15	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-15	IND RIV	230	IND RIV	115	1	11						
2001-40-15	LARGO	230	LARGO A	69	1	2						
2001-40-15	SHELD	230	SHELD-NW	69	1	16						
2001-40-15	CLMT EST	230	CLMT EST	69	1	2						
2001-40-15	WINDERME	230	WINDERME	69	1	2						
2001-40-15	RIVER-S	230	RIVER-S	69	1	16						
2001-40-15	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-15	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-15	JASPER	115	JASPER	69	1	2						
2001-40-16	SN PLANT	230	SYLVAN	230	1	1						
2001-40-16	SYLVAN	230	N LONGWD	230	1	1						
2001-40-16	IND RIV	230	STANTON	230	1	11						
2001-40-16	SILVR SP	230	SILV SPN	230	1	2						
2001-40-16	SILVR SP	230	SILV SPN	230	2	2						
2001-40-16	RIO PINR	230	CURRY FD	230	1	2						
2001-40-16	JUNEAU-W	138	GANNON	138	1	16						
2001-40-16	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-16	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-16	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-16	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-16	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-16	SN PLANT	115	TURNER	115	1	1						
2001-40-16	PASADENA	115	40ST-DUM	115	1	2						
2001-40-16	MICHIGAN	115	KALEY	115	1	11						
2001-40-16	MICHIGAN	115	GRANT	115	1	11						
2001-40-16	PERSHING	115	GRANT	115	1	11						
2001-40-16	AMERICA	115	KALEY	115	1	11						
2001-40-16	JASPER	115	WGHTCHPL	115	1	2						
2001-40-16	AZALEA	115	BENNETT	115	1	11						
2001-40-16	FLORALTP	69	INVERNTP	69	1	2						
2001-40-16	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-16	PASADENA	230	PASADENA	115	1	2						
2001-40-16	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-16	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-16	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-16	IND RIV	230	IND RIV	115	1	11						
2001-40-16	LARGO	230	LARGO A	69	1	2						
2001-40-16	SHELD	230	SHELD-NW	69	1	16						
2001-40-16	CLMT EST	230	CLMT EST	69	1	2						
2001-40-16	WINDERME	230	WINDERME	69	1	2						
2001-40-16	RIVER-S	230	RIVER-S	69	1	16						
2001-40-16	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-16	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-16	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-17	SN PLANT	230	SYLVAN	230	1	1						
2001-40-17	SYLVAN	230	N LONGWD	230	1	1						
2001-40-17	IND RIV	230	STANTON	230	1	11						
2001-40-17	SILVR SP	230	SILV SPN	230	1	2						
2001-40-17	SILVR SP	230	SILV SPN	230	2	2						
2001-40-17	RIO PINR	230	CURRY FD	230	1	2						
2001-40-17	JUNEAU-W	138	GANNON	138	1	16						
2001-40-17	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-17	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-17	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-17	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-17	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-17	SN PLANT	115	TURNER	115	1	1						
2001-40-17	PASADENA	115	40ST-DUM	115	1	2						
2001-40-17	MICHIGAN	115	KALEY	115	1	11						
2001-40-17	MICHIGAN	115	GRANT	115	1	11						
2001-40-17	PERSHING	115	GRANT	115	1	11						
2001-40-17	AMERICA	115	KALEY	115	1	11						
2001-40-17	JASPER	115	WGHTCHPL	115	1	2						
2001-40-17	AZALEA	115	BENNETT	115	1	11						
2001-40-17	FLORALTP	69	INVERNTP	69	1	2						
2001-40-17	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-17	PASADENA	230	PASADENA	115	1	2						
2001-40-17	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-17	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-17	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-17	IND RIV	230	IND RIV	115	1	11						
2001-40-17	LARGO	230	LARGO A	69	1	2						
2001-40-17	SHELD	230	SHELD-NW	69	1	16						
2001-40-17	CLMT EST	230	CLMT EST	69	1	2						
2001-40-17	WINDERME	230	WINDERME	69	1	2						
2001-40-17	RIVER-S	230	RIVER-S	69	1	16						
2001-40-17	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-17	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-17	JASPER	115	JASPER	69	1	2						
2001-40-18	SN PLANT	230	SYLVAN	230	1	1						
2001-40-18	SYLVAN	230	N LONGWD	230	1	1						
2001-40-18	IND RIV	230	STANTON	230	1	11						
2001-40-18	SILVR SP	230	SILV SPN	230	1	2						
2001-40-18	SILVR SP	230	SILV SPN	230	2	2						
2001-40-18	RIO PINR	230	CURRY FD	230	1	2						
2001-40-18	JUNEAU-W	138	GANNON	138	1	16						
2001-40-18	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-18	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-18	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-18	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-18	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-18	SN PLANT	115	TURNER	115	1	1						
2001-40-18	PASADENA	115	40ST-DUM	115	1	2						
2001-40-18	MICHIGAN	115	KALEY	115	1	11						
2001-40-18	MICHIGAN	115	GRANT	115	1	11						
2001-40-18	PERSHING	115	GRANT	115	1	11						
2001-40-18	AMERICA	115	KALEY	115	1	11						
2001-40-18	JASPER	115	WGHTCHPL	115	1	2						
2001-40-18	AZALEA	115	BENNETT	115	1	11						
2001-40-18	FLORALTP	69	INVERNTP	69	1	2						
2001-40-18	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-18	PASADENA	230	PASADENA	115	1	2						
2001-40-18	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-18	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-18	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-18	IND RIV	230	IND RIV	115	1	11						
2001-40-18	LARGO	230	LARGO A	69	1	2						
2001-40-18	SHELD	230	SHELD-NW	69	1	16						
2001-40-18	CLMT EST	230	CLMT EST	69	1	2						
2001-40-18	WINDERME	230	WINDERME	69	1	2						
2001-40-18	RIVER-S	230	RIVER-S	69	1	16						
2001-40-18	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-18	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-18	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-19	SN PLANT	230	SYLVAN	230	1	1						
2001-40-19	SYLVAN	230	N LONGWD	230	1	1						
2001-40-19	IND RIV	230	STANTON	230	1	11						
2001-40-19	SILVR SP	230	SILV SPN	230	1	2						
2001-40-19	SILVR SP	230	SILV SPN	230	2	2						
2001-40-19	RIO PINR	230	CURRY FD	230	1	2						
2001-40-19	JUNEAU-W	138	GANNON	138	1	16						
2001-40-19	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-19	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-19	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-19	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-19	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-19	SN PLANT	115	TURNER	115	1	1						
2001-40-19	PASADENA	115	40ST-DUM	115	1	2						
2001-40-19	MICHIGAN	115	KALEY	115	1	11						
2001-40-19	MICHIGAN	115	GRANT	115	1	11						
2001-40-19	PERSHING	115	GRANT	115	1	11						
2001-40-19	AMERICA	115	KALEY	115	1	11						
2001-40-19	JASPER	115	WGHTCHPL	115	1	2						
2001-40-19	AZALEA	115	BENNETT	115	1	11						
2001-40-19	FLORALTP	69	INVERNTP	69	1	2						
2001-40-19	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-19	PASADENA	230	PASADENA	115	1	2						
2001-40-19	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-19	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-19	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-19	IND RIV	230	IND RIV	115	1	11						
2001-40-19	LARGO	230	LARGO A	69	1	2						
2001-40-19	SHELD	230	SHELD-NW	69	1	16						
2001-40-19	CLMT EST	230	CLMT EST	69	1	2						
2001-40-19	WINDERME	230	WINDERME	69	1	2						
2001-40-19	RIVER-S	230	RIVER-S	69	1	16						
2001-40-19	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-19	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-19	JASPER	115	JASPER	69	1	2						
2001-40-20	SN PLANT	230	SYLVAN	230	1	1						
2001-40-20	SYLVAN	230	N LONGWD	230	1	1						
2001-40-20	IND RIV	230	STANTON	230	1	11						
2001-40-20	SILVR SP	230	SILV SPN	230	1	2						
2001-40-20	SILVR SP	230	SILV SPN	230	2	2						
2001-40-20	RIO PINR	230	CURRY FD	230	1	2						
2001-40-20	JUNEAU-W	138	GANNON	138	1	16						
2001-40-20	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-20	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-20	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-20	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-20	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-20	SN PLANT	115	TURNER	115	1	1						
2001-40-20	PASADENA	115	40ST-DUM	115	1	2						
2001-40-20	MICHIGAN	115	KALEY	115	1	11						
2001-40-20	MICHIGAN	115	GRANT	115	1	11						
2001-40-20	PERSHING	115	GRANT	115	1	11						
2001-40-20	AMERICA	115	KALEY	115	1	11						
2001-40-20	JASPER	115	WGHTCHPL	115	1	2						
2001-40-20	AZALEA	115	BENNETT	115	1	11						
2001-40-20	FLORALTP	69	INVERNTP	69	1	2						
2001-40-20	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-20	PASADENA	230	PASADENA	115	1	2						
2001-40-20	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-20	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-20	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-20	IND RIV	230	IND RIV	115	1	11						
2001-40-20	LARGO	230	LARGO A	69	1	2						
2001-40-20	SHELD	230	SHELD-NW	69	1	16						
2001-40-20	CLMT EST	230	CLMT EST	69	1	2						
2001-40-20	WINDERME	230	WINDERME	69	1	2						
2001-40-20	RIVER-S	230	RIVER-S	69	1	16						
2001-40-20	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-20	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-20	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-21	SN PLANT	230	SYLVAN	230	1	1						
2001-40-21	SYLVAN	230	N LONGWD	230	1	1						
2001-40-21	IND RIV	230	STANTON	230	1	11						
2001-40-21	SILVR SP	230	SILV SPN	230	1	2						
2001-40-21	SILVR SP	230	SILV SPN	230	2	2						
2001-40-21	RIO PINR	230	CURRY FD	230	1	2						
2001-40-21	JUNEAU-W	138	GANNON	138	1	16						
2001-40-21	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-21	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-21	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-21	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-21	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-21	SN PLANT	115	TURNER	115	1	1						
2001-40-21	PASADENA	115	40ST-DUM	115	1	2						
2001-40-21	MICHIGAN	115	KALEY	115	1	11						
2001-40-21	MICHIGAN	115	GRANT	115	1	11						
2001-40-21	PERSHING	115	GRANT	115	1	11						
2001-40-21	AMERICA	115	KALEY	115	1	11						
2001-40-21	JASPER	115	WGHTCHPL	115	1	2						
2001-40-21	AZALEA	115	BENNETT	115	1	11						
2001-40-21	FLORALTP	69	INVERNTP	69	1	2						
2001-40-21	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-21	PASADENA	230	PASADENA	115	1	2						
2001-40-21	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-21	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-21	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-21	IND RIV	230	IND RIV	115	1	11						
2001-40-21	LARGO	230	LARGO A	69	1	2						
2001-40-21	SHELD	230	SHELD-NW	69	1	16						
2001-40-21	CLMT EST	230	CLMT EST	69	1	2						
2001-40-21	WINDERME	230	WINDERME	69	1	2						
2001-40-21	RIVER-S	230	RIVER-S	69	1	16						
2001-40-21	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-21	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-21	JASPER	115	JASPER	69	1	2						
2001-40-22	SN PLANT	230	SYLVAN	230	1	1						
2001-40-22	SYLVAN	230	N LONGWD	230	1	1						
2001-40-22	IND RIV	230	STANTON	230	1	11						
2001-40-22	SILVR SP	230	SILV SPN	230	1	2						
2001-40-22	SILVR SP	230	SILV SPN	230	2	2						
2001-40-22	RIO PINR	230	CURRY FD	230	1	2						
2001-40-22	JUNEAU-W	138	GANNON	138	1	16						
2001-40-22	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-22	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-22	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-22	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-22	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-22	SN PLANT	115	TURNER	115	1	1						
2001-40-22	PASADENA	115	40ST-DUM	115	1	2						
2001-40-22	MICHIGAN	115	KALEY	115	1	11						
2001-40-22	MICHIGAN	115	GRANT	115	1	11						
2001-40-22	PERSHING	115	GRANT	115	1	11						
2001-40-22	AMERICA	115	KALEY	115	1	11						
2001-40-22	JASPER	115	WGHTCHPL	115	1	2						
2001-40-22	AZALEA	115	BENNETT	115	1	11						
2001-40-22	FLORALTP	69	INVERNTP	69	1	2						
2001-40-22	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-22	PASADENA	230	PASADENA	115	1	2						
2001-40-22	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-22	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-22	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-22	IND RIV	230	IND RIV	115	1	11						
2001-40-22	LARGO	230	LARGO A	69	1	2						
2001-40-22	SHELD	230	SHELD-NW	69	1	16						
2001-40-22	CLMT EST	230	CLMT EST	69	1	2						
2001-40-22	WINDERME	230	WINDERME	69	1	2						
2001-40-22	RIVER-S	230	RIVER-S	69	1	16						
2001-40-22	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-22	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-22	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-23	SN PLANT	230	SYLVAN	230	1	1						
2001-40-23	SYLVAN	230	N LONGWD	230	1	1						
2001-40-23	IND RIV	230	STANTON	230	1	11						
2001-40-23	SILVR SP	230	SILV SPN	230	1	2						
2001-40-23	SILVR SP	230	SILV SPN	230	2	2						
2001-40-23	RIO PINR	230	CURRY FD	230	1	2						
2001-40-23	JUNEAU-W	138	GANNON	138	1	16						
2001-40-23	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-23	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-23	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-23	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-23	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-23	SN PLANT	115	TURNER	115	1	1						
2001-40-23	PASADENA	115	40ST-DUM	115	1	2						
2001-40-23	MICHIGAN	115	KALEY	115	1	11						
2001-40-23	MICHIGAN	115	GRANT	115	1	11						
2001-40-23	PERSHING	115	GRANT	115	1	11						
2001-40-23	AMERICA	115	KALEY	115	1	11						
2001-40-23	JASPER	115	WGHTCHPL	115	1	2						
2001-40-23	AZALEA	115	BENNETT	115	1	11						
2001-40-23	FLORALTP	69	INVERNTP	69	1	2						
2001-40-23	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-23	PASADENA	230	PASADENA	115	1	2						
2001-40-23	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-23	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-23	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-23	IND RIV	230	IND RIV	115	1	11						
2001-40-23	LARGO	230	LARGO A	69	1	2						
2001-40-23	SHELD	230	SHELD-NW	69	1	16						
2001-40-23	CLMT EST	230	CLMT EST	69	1	2						
2001-40-23	WINDERME	230	WINDERME	69	1	2						
2001-40-23	RIVER-S	230	RIVER-S	69	1	16						
2001-40-23	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-23	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-23	JASPER	115	JASPER	69	1	2						
2001-40-24	SN PLANT	230	SYLVAN	230	1	1						
2001-40-24	SYLVAN	230	N LONGWD	230	1	1						
2001-40-24	IND RIV	230	STANTON	230	1	11						
2001-40-24	SILVR SP	230	SILV SPN	230	1	2						
2001-40-24	SILVR SP	230	SILV SPN	230	2	2						
2001-40-24	RIO PINR	230	CURRY FD	230	1	2						
2001-40-24	JUNEAU-W	138	GANNON	138	1	16						
2001-40-24	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-24	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-24	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-24	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-24	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-24	SN PLANT	115	TURNER	115	1	1						
2001-40-24	PASADENA	115	40ST-DUM	115	1	2						
2001-40-24	MICHIGAN	115	KALEY	115	1	11						
2001-40-24	MICHIGAN	115	GRANT	115	1	11						
2001-40-24	PERSHING	115	GRANT	115	1	11						
2001-40-24	AMERICA	115	KALEY	115	1	11						
2001-40-24	JASPER	115	WGHTCHPL	115	1	2						
2001-40-24	AZALEA	115	BENNETT	115	1	11						
2001-40-24	FLORALTP	69	INVERNTP	69	1	2						
2001-40-24	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-24	PASADENA	230	PASADENA	115	1	2						
2001-40-24	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-24	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-24	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-24	IND RIV	230	IND RIV	115	1	11						
2001-40-24	LARGO	230	LARGO A	69	1	2						
2001-40-24	SHELD	230	SHELD-NW	69	1	16						
2001-40-24	CLMT EST	230	CLMT EST	69	1	2						
2001-40-24	WINDERME	230	WINDERME	69	1	2						
2001-40-24	RIVER-S	230	RIVER-S	69	1	16						
2001-40-24	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-24	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-24	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-25	SN PLANT	230	SYLVAN	230	1	1						
2001-40-25	SYLVAN	230	N LONGWD	230	1	1						
2001-40-25	IND RIV	230	STANTON	230	1	11						
2001-40-25	SILVR SP	230	SILV SPN	230	1	2						
2001-40-25	SILVR SP	230	SILV SPN	230	2	2						
2001-40-25	RIO PINR	230	CURRY FD	230	1	2						
2001-40-25	JUNEAU-W	138	GANNON	138	1	16						
2001-40-25	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-25	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-25	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-25	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-25	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-25	SN PLANT	115	TURNER	115	1	1						
2001-40-25	PASADENA	115	40ST-DUM	115	1	2						
2001-40-25	MICHIGAN	115	KALEY	115	1	11						
2001-40-25	MICHIGAN	115	GRANT	115	1	11						
2001-40-25	PERSHING	115	GRANT	115	1	11						
2001-40-25	AMERICA	115	KALEY	115	1	11						
2001-40-25	JASPER	115	WGHTCHPL	115	1	2						
2001-40-25	AZALEA	115	BENNETT	115	1	11						
2001-40-25	FLORALTP	69	INVERNTP	69	1	2						
2001-40-25	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-25	PASADENA	230	PASADENA	115	1	2						
2001-40-25	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-25	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-25	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-25	IND RIV	230	IND RIV	115	1	11						
2001-40-25	LARGO	230	LARGO A	69	1	2						
2001-40-25	SHELD	230	SHELD-NW	69	1	16						
2001-40-25	CLMT EST	230	CLMT EST	69	1	2						
2001-40-25	WINDERME	230	WINDERME	69	1	2						
2001-40-25	RIVER-S	230	RIVER-S	69	1	16						
2001-40-25	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-25	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-25	JASPER	115	JASPER	69	1	2						
2001-40-26	SN PLANT	230	SYLVAN	230	1	1						
2001-40-26	SYLVAN	230	N LONGWD	230	1	1						
2001-40-26	IND RIV	230	STANTON	230	1	11						
2001-40-26	SILVR SP	230	SILV SPN	230	1	2						
2001-40-26	SILVR SP	230	SILV SPN	230	2	2						
2001-40-26	RIO PINR	230	CURRY FD	230	1	2						
2001-40-26	JUNEAU-W	138	GANNON	138	1	16						
2001-40-26	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-26	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-26	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-26	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-26	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-26	SN PLANT	115	TURNER	115	1	1						
2001-40-26	PASADENA	115	40ST-DUM	115	1	2						
2001-40-26	MICHIGAN	115	KALEY	115	1	11						
2001-40-26	MICHIGAN	115	GRANT	115	1	11						
2001-40-26	PERSHING	115	GRANT	115	1	11						
2001-40-26	AMERICA	115	KALEY	115	1	11						
2001-40-26	JASPER	115	WGHTCHPL	115	1	2						
2001-40-26	AZALEA	115	BENNETT	115	1	11						
2001-40-26	FLORALTP	69	INVERNTP	69	1	2						
2001-40-26	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-26	PASADENA	230	PASADENA	115	1	2						
2001-40-26	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-26	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-26	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-26	IND RIV	230	IND RIV	115	1	11						
2001-40-26	LARGO	230	LARGO A	69	1	2						
2001-40-26	SHELD	230	SHELD-NW	69	1	16						
2001-40-26	CLMT EST	230	CLMT EST	69	1	2						
2001-40-26	WINDERME	230	WINDERME	69	1	2						
2001-40-26	RIVER-S	230	RIVER-S	69	1	16						
2001-40-26	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-26	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-26	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-27	SN PLANT	230	SYLVAN	230	1	1						
2001-40-27	SYLVAN	230	N LONGWD	230	1	1						
2001-40-27	IND RIV	230	STANTON	230	1	11						
2001-40-27	SILVR SP	230	SILV SPN	230	1	2						
2001-40-27	SILVR SP	230	SILV SPN	230	2	2						
2001-40-27	RIO PINR	230	CURRY FD	230	1	2						
2001-40-27	JUNEAU-W	138	GANNON	138	1	16						
2001-40-27	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-27	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-27	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-27	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-27	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-27	SN PLANT	115	TURNER	115	1	1						
2001-40-27	PASADENA	115	40ST-DUM	115	1	2						
2001-40-27	MICHIGAN	115	KALEY	115	1	11						
2001-40-27	MICHIGAN	115	GRANT	115	1	11						
2001-40-27	PERSHING	115	GRANT	115	1	11						
2001-40-27	AMERICA	115	KALEY	115	1	11						
2001-40-27	JASPER	115	WGHTCHPL	115	1	2						
2001-40-27	AZALEA	115	BENNETT	115	1	11						
2001-40-27	FLORALTP	69	INVERNTP	69	1	2						
2001-40-27	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-27	PASADENA	230	PASADENA	115	1	2						
2001-40-27	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-27	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-27	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-27	IND RIV	230	IND RIV	115	1	11						
2001-40-27	LARGO	230	LARGO A	69	1	2						
2001-40-27	SHELD	230	SHELD-NW	69	1	16						
2001-40-27	CLMT EST	230	CLMT EST	69	1	2						
2001-40-27	WINDERME	230	WINDERME	69	1	2						
2001-40-27	RIVER-S	230	RIVER-S	69	1	16						
2001-40-27	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-27	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-27	JASPER	115	JASPER	69	1	2						
2001-40-28	SN PLANT	230	SYLVAN	230	1	1						
2001-40-28	SYLVAN	230	N LONGWD	230	1	1						
2001-40-28	IND RIV	230	STANTON	230	1	11						
2001-40-28	SILVR SP	230	SILV SPN	230	1	2						
2001-40-28	SILVR SP	230	SILV SPN	230	2	2						
2001-40-28	RIO PINR	230	CURRY FD	230	1	2						
2001-40-28	JUNEAU-W	138	GANNON	138	1	16						
2001-40-28	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-28	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-28	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-28	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-28	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-28	SN PLANT	115	TURNER	115	1	1						
2001-40-28	PASADENA	115	40ST-DUM	115	1	2						
2001-40-28	MICHIGAN	115	KALEY	115	1	11						
2001-40-28	MICHIGAN	115	GRANT	115	1	11						
2001-40-28	PERSHING	115	GRANT	115	1	11						
2001-40-28	AMERICA	115	KALEY	115	1	11						
2001-40-28	JASPER	115	WGHTCHPL	115	1	2						
2001-40-28	AZALEA	115	BENNETT	115	1	11						
2001-40-28	FLORALTP	69	INVERNTP	69	1	2						
2001-40-28	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-28	PASADENA	230	PASADENA	115	1	2						
2001-40-28	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-28	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-28	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-28	IND RIV	230	IND RIV	115	1	11						
2001-40-28	LARGO	230	LARGO A	69	1	2						
2001-40-28	SHELD	230	SHELD-NW	69	1	16						
2001-40-28	CLMT EST	230	CLMT EST	69	1	2						
2001-40-28	WINDERME	230	WINDERME	69	1	2						
2001-40-28	RIVER-S	230	RIVER-S	69	1	16						
2001-40-28	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-28	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-28	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-29	SN PLANT	230	SYLVAN	230	1	1						
2001-40-29	SYLVAN	230	N LONGWD	230	1	1						
2001-40-29	IND RIV	230	STANTON	230	1	11						
2001-40-29	SILVR SP	230	SILV SPN	230	1	2						
2001-40-29	SILVR SP	230	SILV SPN	230	2	2						
2001-40-29	RIO PINR	230	CURRY FD	230	1	2						
2001-40-29	JUNEAU-W	138	GANNON	138	1	16						
2001-40-29	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-29	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-29	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-29	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-29	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-29	SN PLANT	115	TURNER	115	1	1						
2001-40-29	PASADENA	115	40ST-DUM	115	1	2						
2001-40-29	MICHIGAN	115	KALEY	115	1	11						
2001-40-29	MICHIGAN	115	GRANT	115	1	11						
2001-40-29	PERSHING	115	GRANT	115	1	11						
2001-40-29	AMERICA	115	KALEY	115	1	11						
2001-40-29	JASPER	115	WGHTCHPL	115	1	2						
2001-40-29	AZALEA	115	BENNETT	115	1	11						
2001-40-29	FLORALTP	69	INVERNTP	69	1	2						
2001-40-29	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-29	PASADENA	230	PASADENA	115	1	2						
2001-40-29	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-29	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-29	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-29	IND RIV	230	IND RIV	115	1	11						
2001-40-29	LARGO	230	LARGO A	69	1	2						
2001-40-29	SHELD	230	SHELD-NW	69	1	16						
2001-40-29	CLMT EST	230	CLMT EST	69	1	2						
2001-40-29	WINDERME	230	WINDERME	69	1	2						
2001-40-29	RIVER-S	230	RIVER-S	69	1	16						
2001-40-29	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-29	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-29	JASPER	115	JASPER	69	1	2						
2001-40-30	SN PLANT	230	SYLVAN	230	1	1						
2001-40-30	SYLVAN	230	N LONGWD	230	1	1						
2001-40-30	IND RIV	230	STANTON	230	1	11						
2001-40-30	SILVR SP	230	SILV SPN	230	1	2						
2001-40-30	SILVR SP	230	SILV SPN	230	2	2						
2001-40-30	RIO PINR	230	CURRY FD	230	1	2						
2001-40-30	JUNEAU-W	138	GANNON	138	1	16						
2001-40-30	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-30	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-30	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-30	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-30	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-30	SN PLANT	115	TURNER	115	1	1						
2001-40-30	PASADENA	115	40ST-DUM	115	1	2						
2001-40-30	MICHIGAN	115	KALEY	115	1	11						
2001-40-30	MICHIGAN	115	GRANT	115	1	11						
2001-40-30	PERSHING	115	GRANT	115	1	11						
2001-40-30	AMERICA	115	KALEY	115	1	11						
2001-40-30	JASPER	115	WGHTCHPL	115	1	2						
2001-40-30	AZALEA	115	BENNETT	115	1	11						
2001-40-30	FLORALTP	69	INVERNTP	69	1	2						
2001-40-30	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-30	PASADENA	230	PASADENA	115	1	2						
2001-40-30	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-30	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-30	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-30	IND RIV	230	IND RIV	115	1	11						
2001-40-30	LARGO	230	LARGO A	69	1	2						
2001-40-30	SHELD	230	SHELD-NW	69	1	16						
2001-40-30	CLMT EST	230	CLMT EST	69	1	2						
2001-40-30	WINDERME	230	WINDERME	69	1	2						
2001-40-30	RIVER-S	230	RIVER-S	69	1	16						
2001-40-30	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-30	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-30	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-31	SN PLANT	230	SYLVAN	230	1	1						
2001-40-31	SYLVAN	230	N LONGWD	230	1	1						
2001-40-31	IND RIV	230	STANTON	230	1	11						
2001-40-31	SILVR SP	230	SILV SPN	230	1	2						
2001-40-31	SILVR SP	230	SILV SPN	230	2	2						
2001-40-31	RIO PINR	230	CURRY FD	230	1	2						
2001-40-31	JUNEAU-W	138	GANNON	138	1	16						
2001-40-31	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-31	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-31	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-31	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-31	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-31	SN PLANT	115	TURNER	115	1	1						
2001-40-31	PASADENA	115	40ST-DUM	115	1	2						
2001-40-31	MICHIGAN	115	KALEY	115	1	11						
2001-40-31	MICHIGAN	115	GRANT	115	1	11						
2001-40-31	PERSHING	115	GRANT	115	1	11						
2001-40-31	AMERICA	115	KALEY	115	1	11						
2001-40-31	JASPER	115	WGHTCHPL	115	1	2						
2001-40-31	AZALEA	115	BENNETT	115	1	11						
2001-40-31	FLORALTP	69	INVERNTP	69	1	2						
2001-40-31	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-31	PASADENA	230	PASADENA	115	1	2						
2001-40-31	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-31	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-31	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-31	IND RIV	230	IND RIV	115	1	11						
2001-40-31	LARGO	230	LARGO A	69	1	2						
2001-40-31	SHELD	230	SHELD-NW	69	1	16						
2001-40-31	CLMT EST	230	CLMT EST	69	1	2						
2001-40-31	WINDERME	230	WINDERME	69	1	2						
2001-40-31	RIVER-S	230	RIVER-S	69	1	16						
2001-40-31	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-31	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-31	JASPER	115	JASPER	69	1	2						
2001-40-32	SN PLANT	230	SYLVAN	230	1	1						
2001-40-32	SYLVAN	230	N LONGWD	230	1	1						
2001-40-32	IND RIV	230	STANTON	230	1	11						
2001-40-32	SILVR SP	230	SILV SPN	230	1	2						
2001-40-32	SILVR SP	230	SILV SPN	230	2	2						
2001-40-32	RIO PINR	230	CURRY FD	230	1	2						
2001-40-32	JUNEAU-W	138	GANNON	138	1	16						
2001-40-32	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-32	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-32	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-32	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-32	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-32	SN PLANT	115	TURNER	115	1	1						
2001-40-32	PASADENA	115	40ST-DUM	115	1	2						
2001-40-32	MICHIGAN	115	KALEY	115	1	11						
2001-40-32	MICHIGAN	115	GRANT	115	1	11						
2001-40-32	PERSHING	115	GRANT	115	1	11						
2001-40-32	AMERICA	115	KALEY	115	1	11						
2001-40-32	JASPER	115	WGHTCHPL	115	1	2						
2001-40-32	AZALEA	115	BENNETT	115	1	11						
2001-40-32	FLORALTP	69	INVERNTP	69	1	2						
2001-40-32	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-32	PASADENA	230	PASADENA	115	1	2						
2001-40-32	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-32	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-32	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-32	IND RIV	230	IND RIV	115	1	11						
2001-40-32	LARGO	230	LARGO A	69	1	2						
2001-40-32	SHELD	230	SHELD-NW	69	1	16						
2001-40-32	CLMT EST	230	CLMT EST	69	1	2						
2001-40-32	WINDERME	230	WINDERME	69	1	2						
2001-40-32	RIVER-S	230	RIVER-S	69	1	16						
2001-40-32	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-32	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-32	JASPER	115	JASPER	69	1	2						

Table VIII

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-33	SN PLANT	230	SYLVAN	230	1	1						
2001-40-33	SYLVAN	230	N LONGWD	230	1	1						
2001-40-33	IND RIV	230	STANTON	230	1	11						
2001-40-33	SILVR SP	230	SILV SPN	230	1	2						
2001-40-33	SILVR SP	230	SILV SPN	230	2	2						
2001-40-33	RIO PINR	230	CURRY FD	230	1	2						
2001-40-33	JUNEAU-W	138	GANNON	138	1	16						
2001-40-33	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-33	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-33	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-33	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-33	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-33	SN PLANT	115	TURNER	115	1	1						
2001-40-33	PASADENA	115	40ST-DUM	115	1	2						
2001-40-33	MICHIGAN	115	KALEY	115	1	11						
2001-40-33	MICHIGAN	115	GRANT	115	1	11						
2001-40-33	PERSHING	115	GRANT	115	1	11						
2001-40-33	AMERICA	115	KALEY	115	1	11						
2001-40-33	JASPER	115	WGHTCHPL	115	1	2						
2001-40-33	AZALEA	115	BENNETT	115	1	11						
2001-40-33	FLORALTP	69	INVERNTP	69	1	2						
2001-40-33	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-33	PASADENA	230	PASADENA	115	1	2						
2001-40-33	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-33	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-33	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-33	IND RIV	230	IND RIV	115	1	11						
2001-40-33	LARGO	230	LARGO A	69	1	2						
2001-40-33	SHELD	230	SHELD-NW	69	1	16						
2001-40-33	CLMT EST	230	CLMT EST	69	1	2						
2001-40-33	WINDERME	230	WINDERME	69	1	2						
2001-40-33	RIVER-S	230	RIVER-S	69	1	16						
2001-40-33	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-33	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-33	JASPER	115	JASPER	69	1	2						
2001-40-34	SN PLANT	230	SYLVAN	230	1	1						
2001-40-34	SYLVAN	230	N LONGWD	230	1	1						
2001-40-34	IND RIV	230	STANTON	230	1	11						
2001-40-34	SILVR SP	230	SILV SPN	230	1	2						
2001-40-34	SILVR SP	230	SILV SPN	230	2	2						
2001-40-34	RIO PINR	230	CURRY FD	230	1	2						
2001-40-34	JUNEAU-W	138	GANNON	138	1	16						
2001-40-34	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-34	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-34	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-34	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-34	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-34	SN PLANT	115	TURNER	115	1	1						
2001-40-34	PASADENA	115	40ST-DUM	115	1	2						
2001-40-34	MICHIGAN	115	KALEY	115	1	11						
2001-40-34	MICHIGAN	115	GRANT	115	1	11						
2001-40-34	PERSHING	115	GRANT	115	1	11						
2001-40-34	AMERICA	115	KALEY	115	1	11						
2001-40-34	JASPER	115	WGHTCHPL	115	1	2						
2001-40-34	AZALEA	115	BENNETT	115	1	11						
2001-40-34	FLORALTP	69	INVERNTP	69	1	2						
2001-40-34	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-34	PASADENA	230	PASADENA	115	1	2						
2001-40-34	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-34	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-34	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-34	IND RIV	230	IND RIV	115	1	11						
2001-40-34	LARGO	230	LARGO A	69	1	2						
2001-40-34	SHELD	230	SHELD-NW	69	1	16						
2001-40-34	CLMT EST	230	CLMT EST	69	1	2						
2001-40-34	WINDERME	230	WINDERME	69	1	2						
2001-40-34	RIVER-S	230	RIVER-S	69	1	16						
2001-40-34	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-34	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-34	JASPER	115	JASPER	69	1	2						

Table VIII

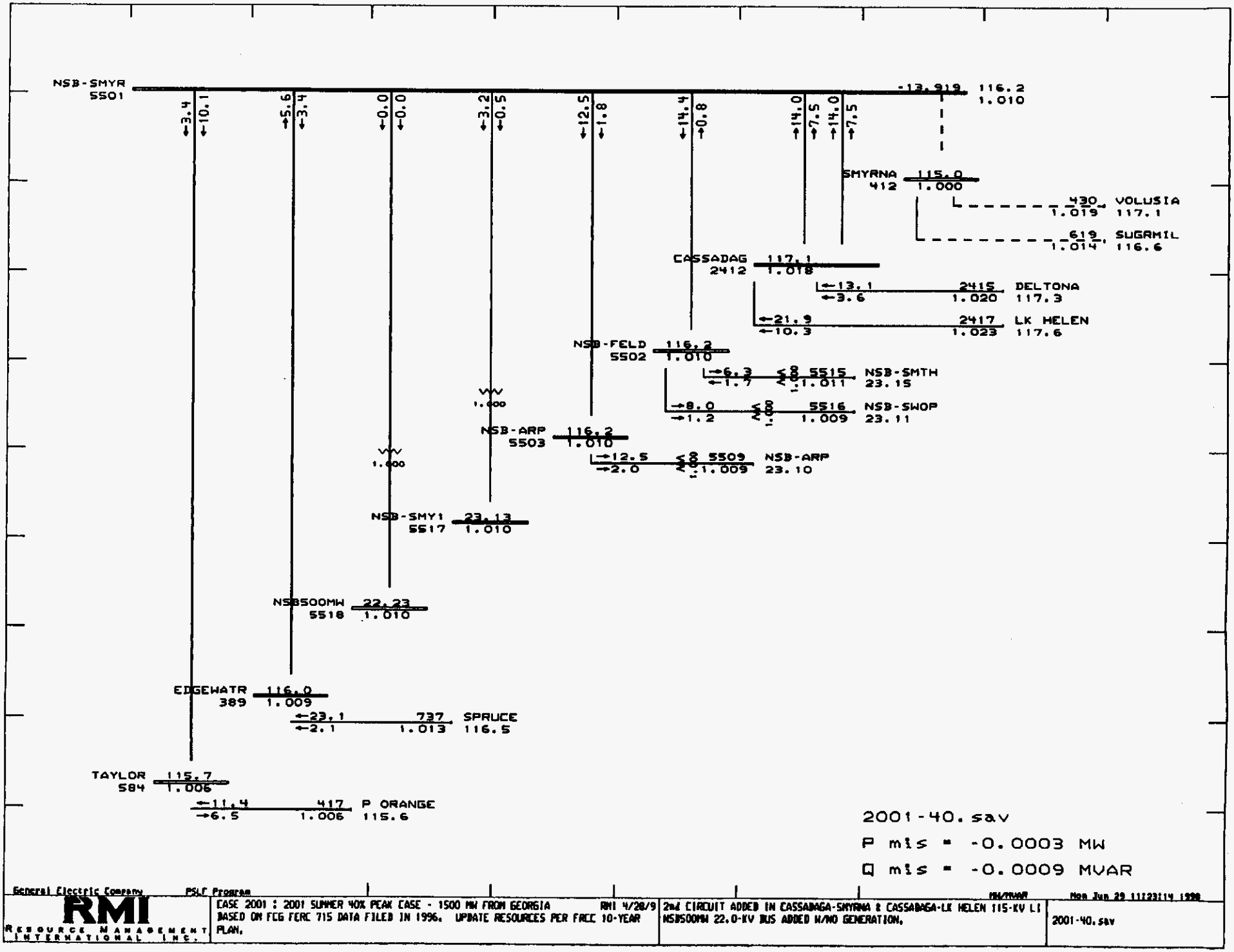
Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

40% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2001-40 Base No NSB Gen	Case 2001-40A Sell to FPL	Case 2001-40B Sell to FPC	Case 2001-40C Sell to TEC	Case 2001-40D Sell to JEA	Case 2001-40E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2001-40-35	SN PLANT	230	SYLVAN	230	1	1						
2001-40-35	SYLVAN	230	N LONGWD	230	1	1						
2001-40-35	IND RIV	230	STANTON	230	1	11						
2001-40-35	SILVR SP	230	SILV SPN	230	1	2						
2001-40-35	SILVR SP	230	SILV SPN	230	2	2						
2001-40-35	RIO PINR	230	CURRY FD	230	1	2						
2001-40-35	JUNEAU-W	138	GANNON	138	1	16						
2001-40-35	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-35	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-35	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-35	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-35	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-35	SN PLANT	115	TURNER	115	1	1						
2001-40-35	PASADENA	115	40ST-DUM	115	1	2						
2001-40-35	MICHIGAN	115	KALEY	115	1	11						
2001-40-35	MICHIGAN	115	GRANT	115	1	11						
2001-40-35	PERSHING	115	GRANT	115	1	11						
2001-40-35	AMERICA	115	KALEY	115	1	11						
2001-40-35	JASPER	115	WGHTCHPL	115	1	2						
2001-40-35	AZALEA	115	BENNETT	115	1	11						
2001-40-35	FLORALTP	69	INVERNTP	69	1	2						
2001-40-35	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-35	PASADENA	230	PASADENA	115	1	2						
2001-40-35	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-35	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-35	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-35	IND RIV	230	IND RIV	115	1	11						
2001-40-35	LARGO	230	LARGO A	69	1	2						
2001-40-35	SHELD	230	SHELD-NW	69	1	16						
2001-40-35	CLMT EST	230	CLMT EST	69	1	2						
2001-40-35	WINDERME	230	WINDERME	69	1	2						
2001-40-35	RIVER-S	230	RIVER-S	69	1	16						
2001-40-35	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-35	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-35	JASPER	115	JASPER	69	1	2						
2001-40-36	SN PLANT	230	SYLVAN	230	1	1						
2001-40-36	SYLVAN	230	N LONGWD	230	1	1						
2001-40-36	IND RIV	230	STANTON	230	1	11						
2001-40-36	SILVR SP	230	SILV SPN	230	1	2						
2001-40-36	SILVR SP	230	SILV SPN	230	2	2						
2001-40-36	RIO PINR	230	CURRY FD	230	1	2						
2001-40-36	JUNEAU-W	138	GANNON	138	1	16						
2001-40-36	NSB-SMYR	115	CASSADAG	115	1	2						
2001-40-36	NSB-SMYR	115	EDGEWATR	115	1	1						
2001-40-36	NSB-SMYR	115	TAYLOR	115	1	1						
2001-40-36	NSB-SMYR	115	NSB-ARP	115	1	10						
2001-40-36	NSB-SMYR	115	NSB-FELD	115	1	10						
2001-40-36	SN PLANT	115	TURNER	115	1	1						
2001-40-36	PASADENA	115	40ST-DUM	115	1	2						
2001-40-36	MICHIGAN	115	KALEY	115	1	11						
2001-40-36	MICHIGAN	115	GRANT	115	1	11						
2001-40-36	PERSHING	115	GRANT	115	1	11						
2001-40-36	AMERICA	115	KALEY	115	1	11						
2001-40-36	JASPER	115	WGHTCHPL	115	1	2						
2001-40-36	AZALEA	115	BENNETT	115	1	11						
2001-40-36	FLORALTP	69	INVERNTP	69	1	2						
2001-40-36	ALACH TP	69	HIGH SPG	69	1	2						
2001-40-36	PASADENA	230	PASADENA	115	1	2						
2001-40-36	SUWANNEE	230	SUWANNEE	115	1	2						
2001-40-36	SUWANNEE	230	SUWANNEE	115	2	2						
2001-40-36	E CLRWTR	230	E CLRWTR	115	1	2						
2001-40-36	IND RIV	230	IND RIV	115	1	11						
2001-40-36	LARGO	230	LARGO A	69	1	2						
2001-40-36	SHELD	230	SHELD-NW	69	1	16						
2001-40-36	CLMT EST	230	CLMT EST	69	1	2						
2001-40-36	WINDERME	230	WINDERME	69	1	2						
2001-40-36	RIVER-S	230	RIVER-S	69	1	16						
2001-40-36	ELEVEN W	230	ELEVEN-E	69	1	16						
2001-40-36	JUNEAU-E	138	JUNEAU-E	69	1	16						
2001-40-36	JASPER	115	JASPER	69	1	2						

APPENDIX IV-A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116.2
1.010
SMYRNA 115.0
412 1.000
430 VOLUSIA
1.019 117.1
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1.014 116.6
CASSADAG 117.1
2412 1.018
2415 DELTONA
1.020 117.3
2417 LK HELEN
1.023 117.6
NSB-FELD 116.2
5502 1.010
5515 NSB-SMTH
1.011 23.15
5516 NSB-SWDP
1.009 23.11
NSB-ARP 116.2
5503 1.010
5509 NSB-ARP
1.009 23.10
NSB-SMY1 23.13
5517 1.010
NSB500MW 22.23
5518 1.010
EDGEWATR 116.0
389 1.009
737 SPRUCE
1.013 116.5
TAYLOR 115.7
584 1.006
417 P ORANGE
1.006 115.6
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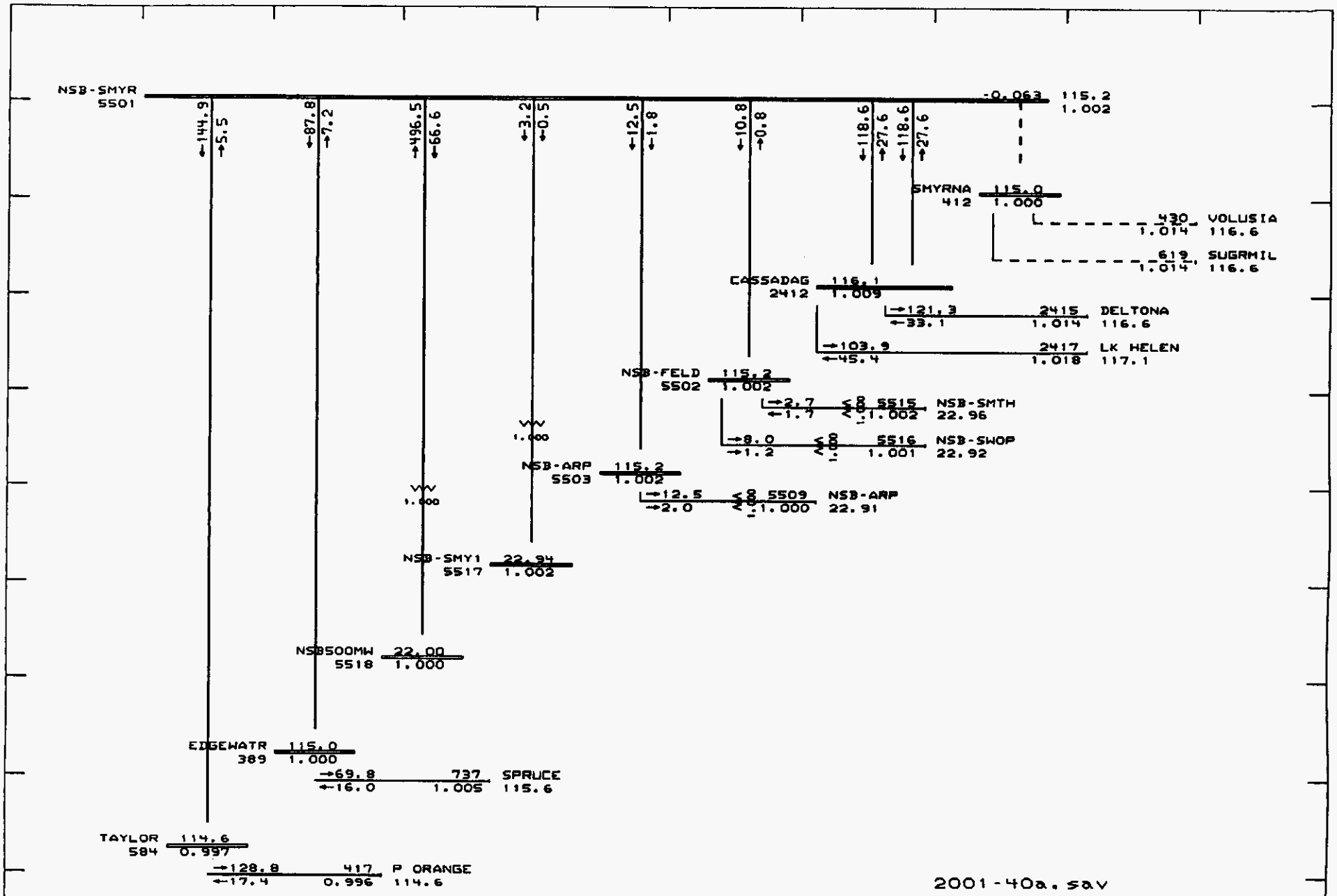
Q mis = -0.0009 MVAR
General Electric Company PSLF Program
MW/MVAR
Mon Jun 29 11:23:14 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL, INC.
CASE 2001 : 2001 SUMMER 40% PEAK CASE - 1500 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN.
RMI 4/28/9
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LK HELEN 115-KV LI
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001-40.sav



2001-40a.sav

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Q mis = -0.0020 MVAR

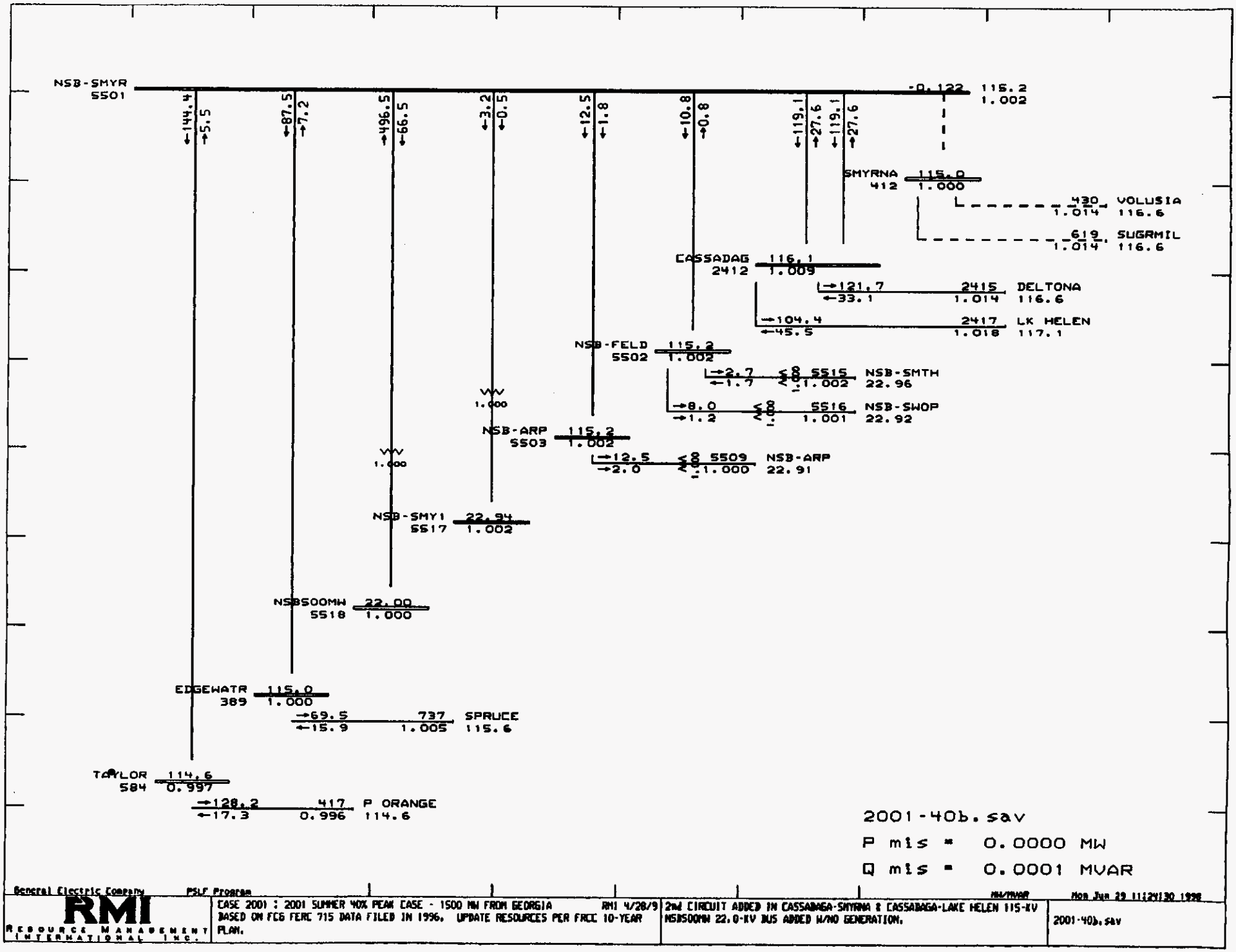
General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:23:30 1998

RMI RESOURCE MANAGEMENT INTERNATIONAL INC.

CASE 2001 : 2001 SUMMER 40% PEAK CASE - 1500 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN. RMI 4/28/9

2nd CIRCUIT ADDED IN CASSABAGA-SMYRNA & CASSABAGA-LAKE HELEN 115-KV NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.

2001-40a.sav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1.002
←144.4
→5.5
←87.5
→7.2
→496.5
←66.5
←3.2
←0.5
←12.5
←1.8
←10.8
→0.8
←119.1
→27.6
←119.1
→27.6
SMYRNA 115.0
412 1.000
430 VOLUSIA
1.014 116.6
619 SUGRMIL
1.014 116.6
CASSADAG 116.1
2412 1.009
→121.7 2415 DELTONA
←33.1 1.014 116.6
→104.4 2417 LK HELEN
←45.5 1.018 117.1
NSB-FELD 115.2
5502 1.002
→2.7 ≤8 5515 NSB-SMTH
←1.7 1.002 22.96
→8.0 ≤8 5516 NSB-SWOP
→1.2 1.001 22.92
1.000
NSB-ARP 115.2
5503 1.002
→12.5 ≤8 5509 NSB-ARP
→2.0 1.000 22.91
1.000
NSB-SMY1 22.94
5517 1.002
NSBSOOMW 22.00
5518 1.000
EDGEWATR 115.0
389 1.000
→69.5 737 SPRUCE
←15.9 1.005 115.6
TAYLOR 114.6
584 0.997
→128.2 417 P ORANGE
←17.3 0.996 114.6
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Q mis = 0.0001 MVAR
General Electric Company PSLF Program
MW/MVAR Mon Jun 29 11:24:30 1998
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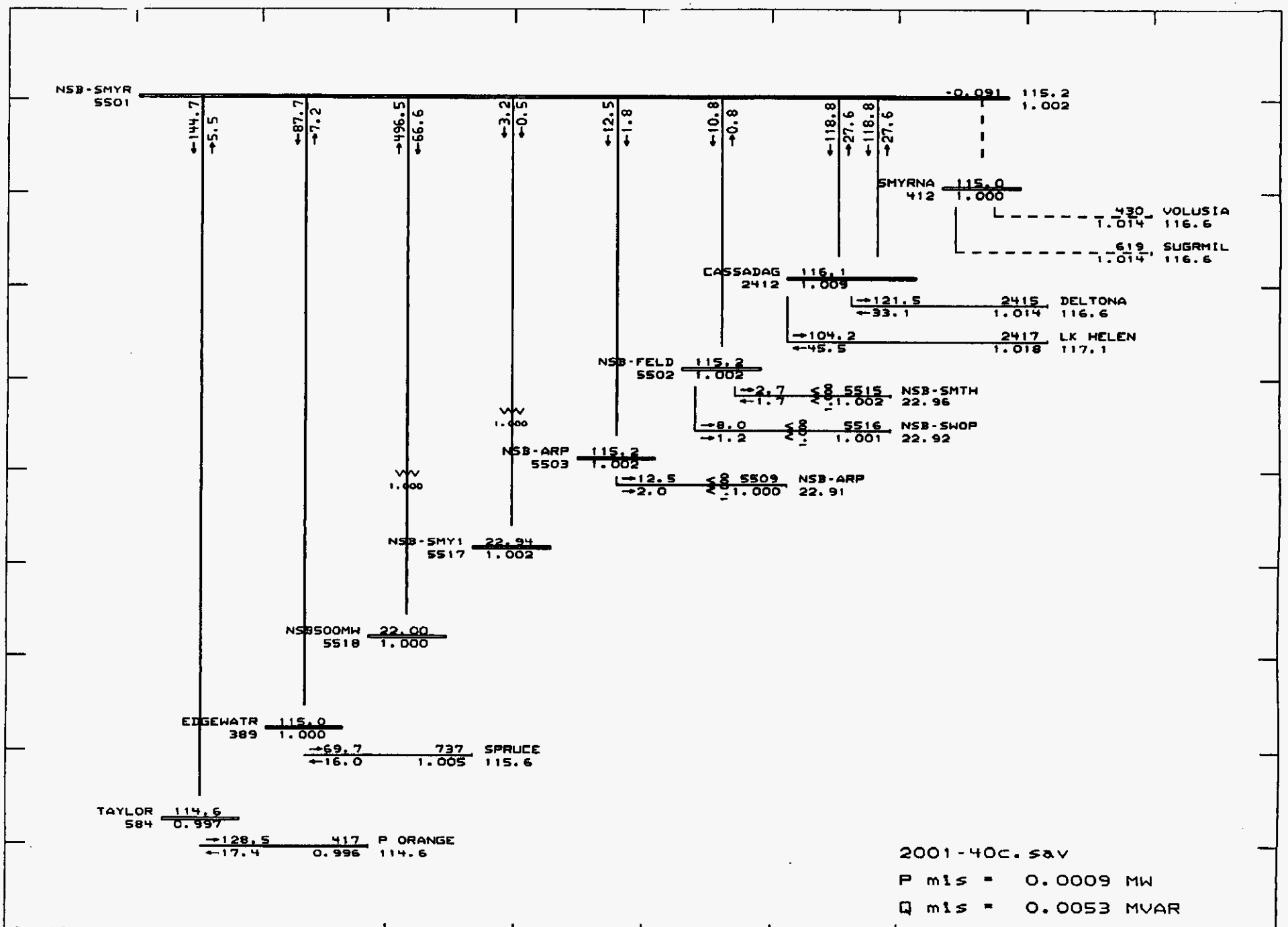
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER 40% PEAK CASE - 1500 MW FROM GEORGIA RMI 4/28/9
BASED ON FEB FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN.
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSBSOOMW 22.0-KV BUS ADDED W/NO GENERATION.
2001-40b.sav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1.002
←144.7
→5.5
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→7.2
→496.5
←66.6
←3.2
→0.5
←12.5
→1.8
←10.8
→0.8
←118.8
→27.6
←118.8
→27.6
SMYRNA 115.0
412 1.000
430 VOLUSIA
1.014 116.6
619 SUGRMIL
1.014 116.6
CASSADAG 116.1
2412 1.009
→121.5 2415 DELTONA
←33.1 1.014 116.6
→104.2 2417 LK HELEN
←45.5 1.018 117.1
NSB-FELD 115.2
5502 1.002
→2.7 5515 NSB-SMTH
←1.7 1.002 22.96
→8.0 5516 NSB-SWDP
→1.2 1.001 22.92
1.000
NSB-ARP 115.2
5503 1.002
→12.5 5509 NSB-ARP
→2.0 1.000 22.91
1.000
NSB-SMY1 22.94
5517 1.002
NSB500MW 22.00
5518 1.000
EDGEWATR 115.0
389 1.000
→69.7 737 SPRUCE
←16.0 1.005 115.6
TAYLOR 114.6
584 0.997
→128.5 417 P ORANGE
←17.4 0.996 114.6
2001-40c.sav
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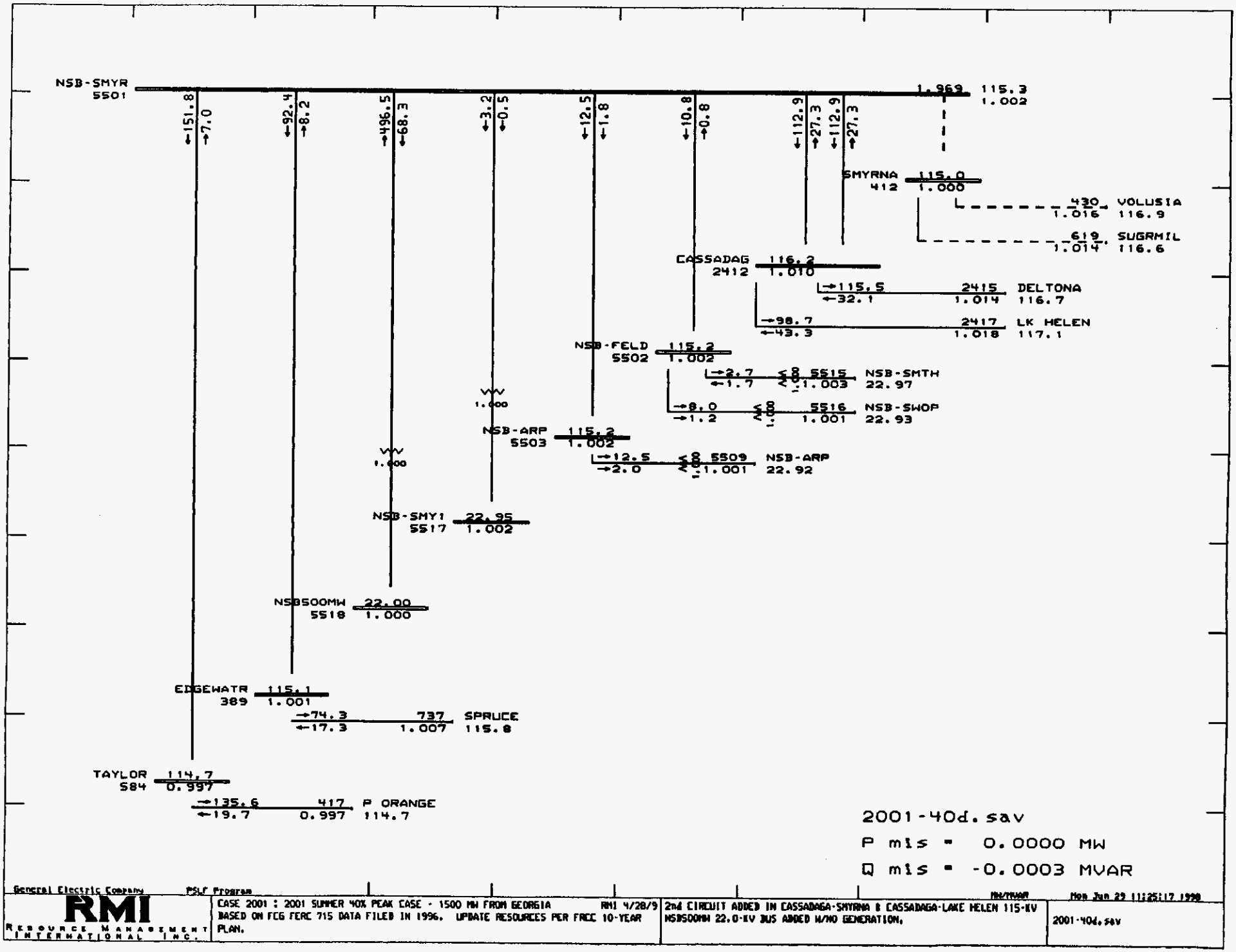
Q mis = 0.0053 MVAR
General Electric Company PSLF Program MW/MVAR Mon Jun 29 11:24:54 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER 40% PEAK CASE - 1500 MW FROM GEORGIA BASED ON FEG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN.
RMI 4/28/9
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001-40c.sav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1.002
SMYRNA 115.0
412 1.000
430 VOLUSIA
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619 SUGRMIL
1.014 116.6
CASSADAG 116.2
2412 1.010
115.5 2415 DELTONA
32.1 1.014 116.7
98.7 2417 LK HELEN
43.3 1.018 117.1
NSB-FELD 115.2
5502 1.002
2.7 5515 NSB-SMTH
1.7 1.003 22.97
8.0 5516 NSB-SWDP
1.2 1.001 22.93
NSB-ARP 115.2
5503 1.002
12.5 5509 NSB-ARP
2.0 1.001 22.92
NSB-SMY1 22.95
5517 1.002
NSB500MW 22.00
5518 1.000
EDGEWATR 115.1
389 1.001
74.3 737 SPRUCE
17.3 1.007 115.8
TAYLOR 114.7
584 0.997
135.6 417 P ORANGE
19.7 0.997 114.7
151.8
7.0
92.4
8.2
496.5
68.3
3.2
0.5
12.5
1.8
10.8
0.8
112.9
27.3
112.9
27.3
1.000
1.000
2001-40d.sav
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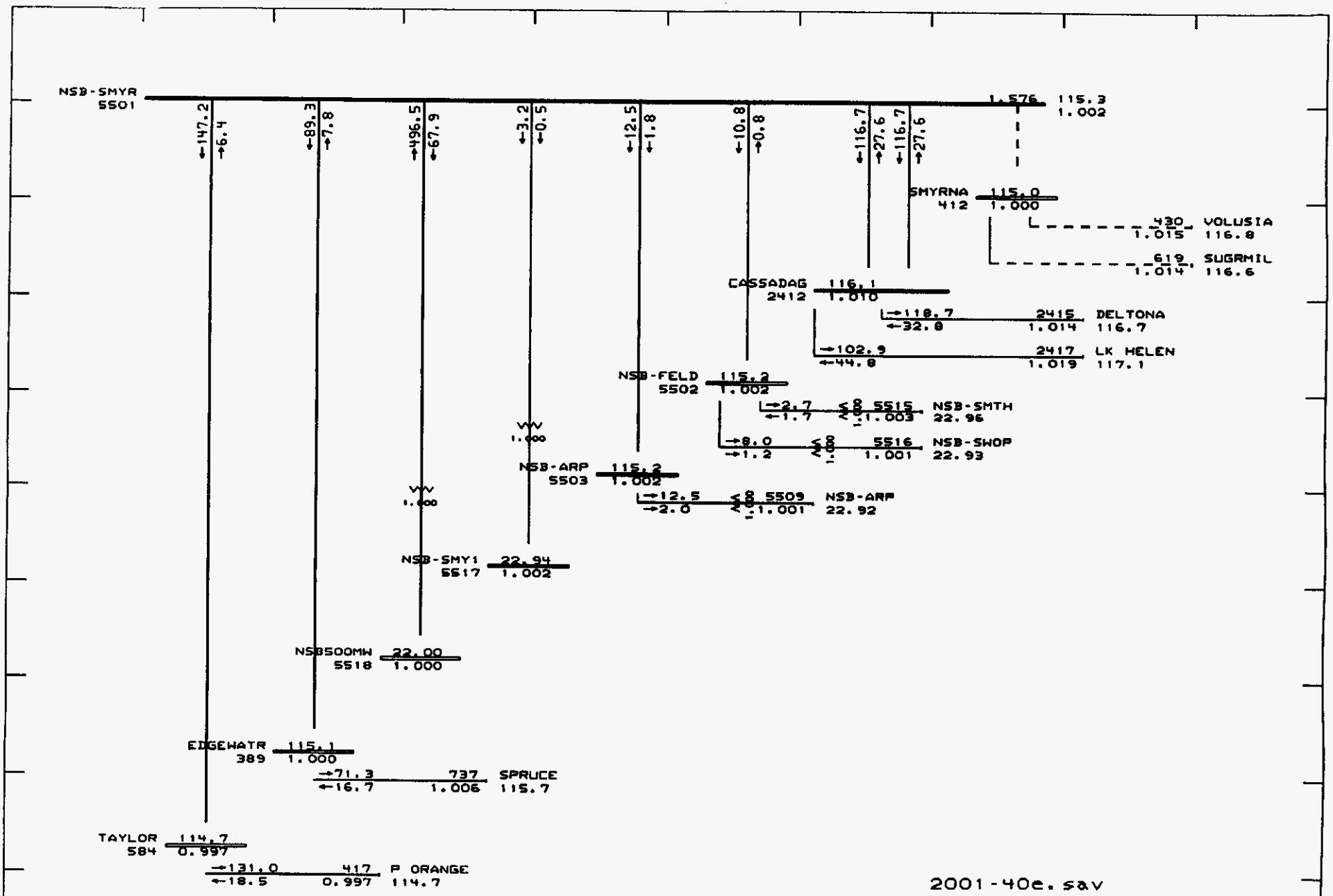
Q mis = -0.0003 MVAR
General Electric Company PSLF Program
MW/MVAR
Mon Jun 29 11:25:17 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER 40% PEAK CASE - 1500 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN.
RM1 4/28/9
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001-40d.sav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1.576 115.3
1.002
SMYRNA 115.0
412 1.000
430 VOLUSIA
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619 SUGRMIL
1.014 116.6
CASSADAG 116.1
2412 1.010
118.7 2415 DELTONA
32.8 1.014 116.7
102.9 2417 LK HELEN
44.8 1.019 117.1
NSB-FELD 115.2
5502 1.002
2.7 5515 NSB-SMTH
1.7 1.003 22.96
8.0 5516 NSB-SWDP
1.2 1.001 22.93
NSB-ARP 115.2
5503 1.002
12.5 5509 NSB-ARP
2.0 1.001 22.92
NSB-SMY1 22.94
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NSB500MW 22.00
5518 1.000
EDGEWATR 115.1
389 1.000
71.3 737 SPRUCE
16.7 1.006 115.7
TAYLOR 114.7
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131.0 417 P ORANGE
18.5 0.997 114.7
147.2
6.4
89.3
7.8
496.5
67.9
3.2
0.5
12.5
1.8
10.8
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116.7
27.6
116.7
27.6
1.000
1.000
2001-40e.sav
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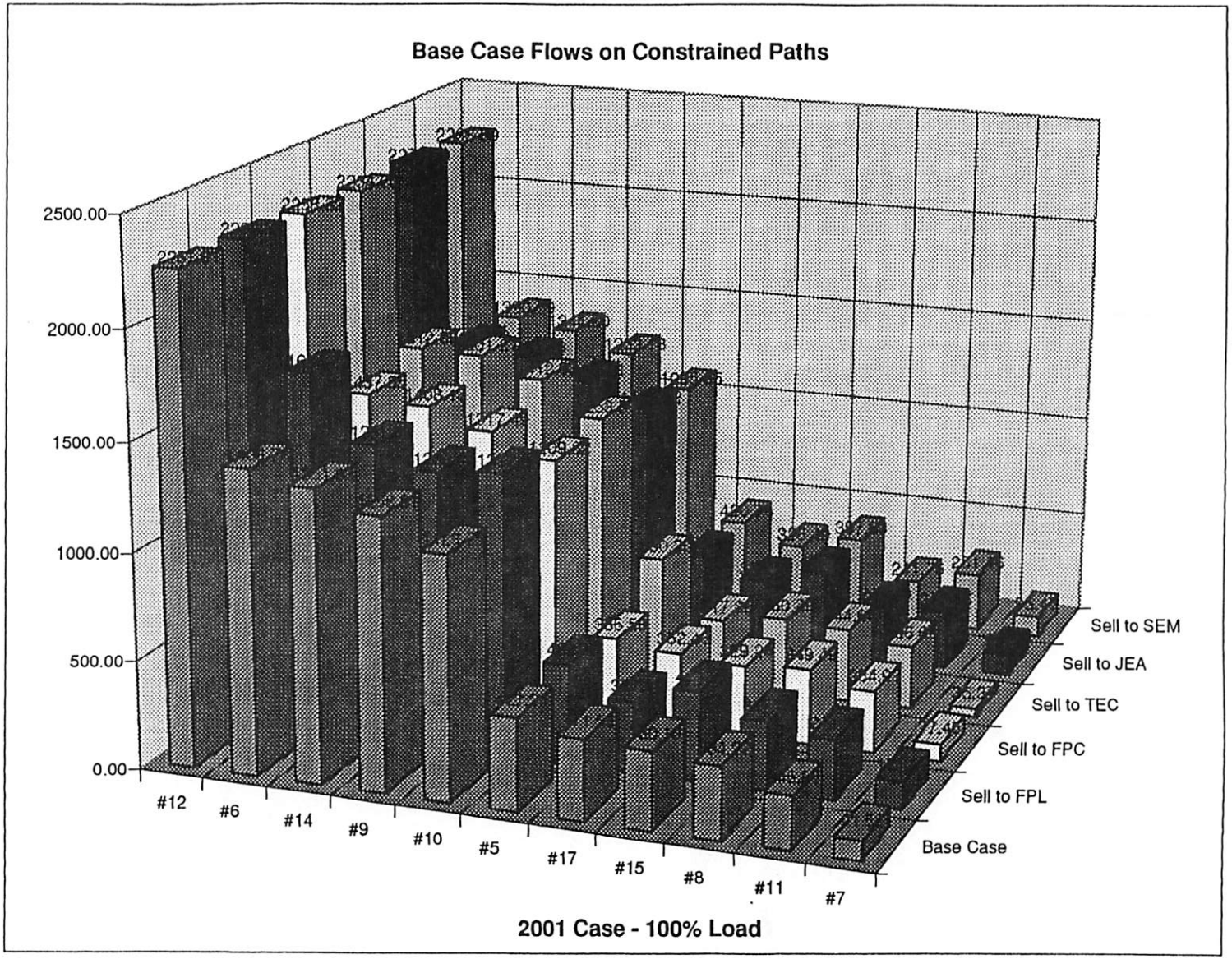
Q mis = -0.0026 MVAR
MW/MVAR
Mon Jun 29 11:25:39 1998
General Electric Company PSLF Program
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
CASE 2001 : 2001 SUMMER 40% PEAK CASE - 1500 MW FROM GEORGIA BASED ON FCG FERC 715 DATA FILED IN 1996. UPDATE RESOURCES PER FRCC 10-YEAR PLAN.
RMI 4/28/9
2nd CIRCUIT ADDED IN CASSADAGA-SMYRNA & CASSADAGA-LAKE HELEN 115-KV
NSB500MW 22.0-KV BUS ADDED W/NO GENERATION.
2001-40e.sav

APPENDIX V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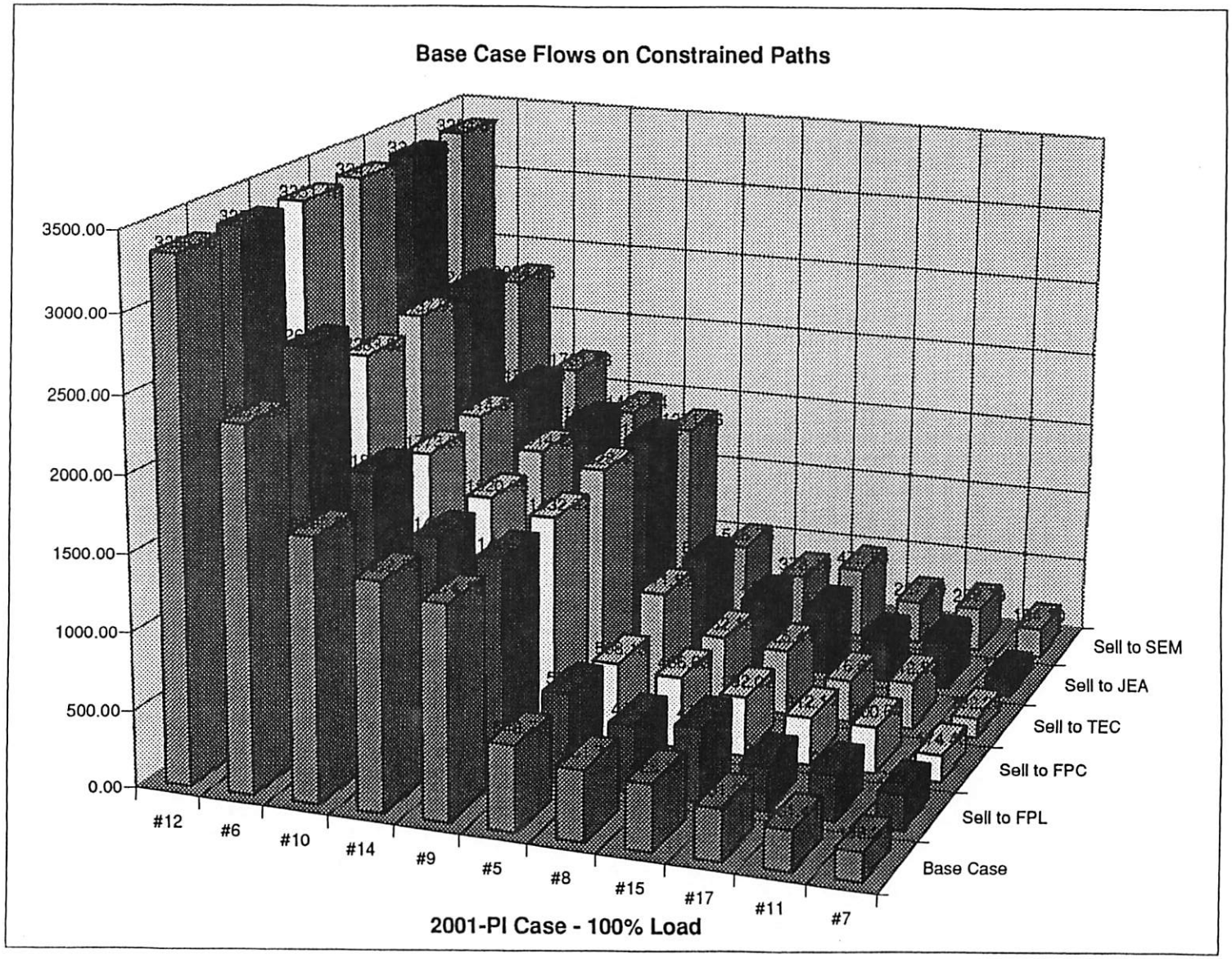
2000.00
1500.00
1000.00
500.00
0.00
#12
#6
#14
#9
#10
#5
#17
#15
#8
#11
#7
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2001 Case - 100% Load


Base Case Flows on Constrained Paths
3500.00
3000.00
2500.00
2000.00
1500.00
1000.00
500.00
0.00
#12
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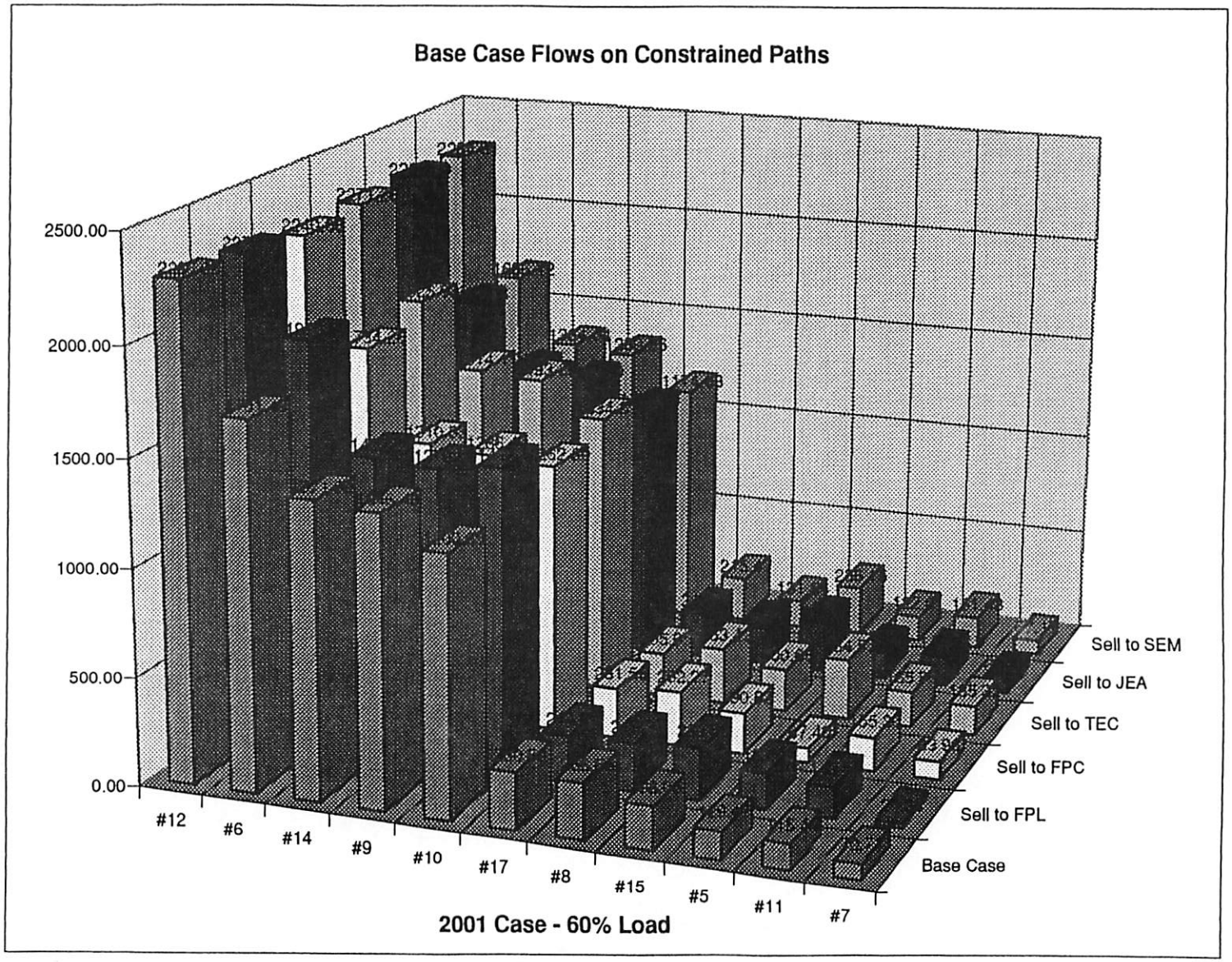
#10
#14
#9
#5
#8
#15
#17
#11
#7
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2001-PI Case - 100% Load


Base Case Flows on Constrained Paths
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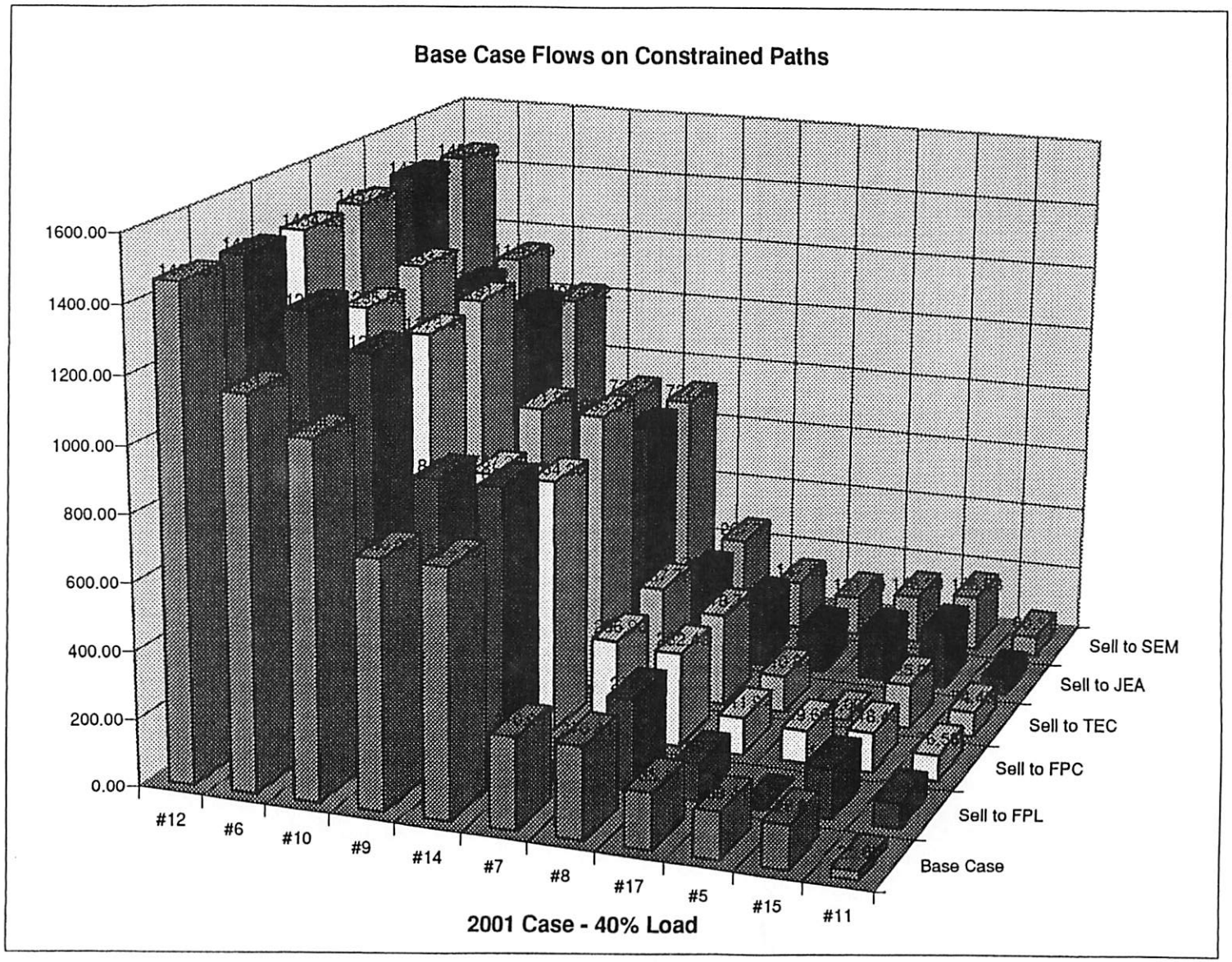
2000.00
1500.00
1000.00
500.00
0.00
#12
#6
#14
#9
#10
#17
#8
#15
#5
#11
#7
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2001 Case - 60% Load


Base Case Flows on Constrained Paths
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1200.00
1000.00
800.00
600.00
400.00
200.00
0.00
#12
#6
#10
#9
#14
#7
#8
#17
#5
#15
#11
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2001 Case - 40% Load

Table 1
Summary of Constrained Paths
in Base Case & NSB Alternatives

		NSB Sell 500 MW to :				
	Case 2001.sav	Case 2001a.sav	Case 2001b.sav	Case 2001c.sav	Case 2001d.sav	Case 2001e.sav
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
#12	2261.61	2264.97	2258.32	2254.20	2272.40	2266.89
#6	1406.78	1684.31	1437.55	1512.09	1384.70	1390.59
#14	1351.03	1381.06	1408.13	1501.27	1350.53	1344.80
#9	1258.61	1289.47	1317.49	1412.98	1258.16	1252.18
#10	1123.75	1312.64	1209.82	1253.36	1147.82	1095.85
#5	427.21	459.93	386.58	590.30	426.86	420.76
#17	371.55	327.01	352.46	317.26	327.18	326.49
#15	360.10	411.77	329.24	360.29	408.79	397.63
#8	334.22	317.49	349.49	344.64	262.20	211.76
#11	245.86	271.73	284.93	296.66	273.55	281.46
#7	91.52	124.23	77.46	35.37	98.11	95.45

Table 2
Summary of Constrained Paths
in Base Case & NSB Alternatives

		NSB Sell 500 MW to :				
	Case 2001-Pl.sav	Case 2001-Pla.sav	Case 2001-Plb.sav	Case 2001-Plc.sav	Case 2001-Pld.sav	Case 2001-Ple.sav
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
#12	3356.88	3355.02	3351.19	3347.77	3346.94	3364.87
#6	2353.87	2633.83	2383.92	2457.97	2473.40	2334.25
#10	1692.60	1866.58	1773.53	1814.81	1816.73	1731.33
#14	1463.76	1496.78	1520.95	1614.28	1600.65	1461.34
#9	1374.16	1408.09	1432.97	1528.43	1514.36	1371.96
#5	548.76	584.58	508.18	711.57	696.67	546.75
#8	451.77	436.39	466.63	462.10	458.71	378.18
#15	423.10	475.93	392.02	425.41	430.88	472.58
#17	331.24	286.48	312.17	276.62	275.39	287.59
#11	261.41	287.58	300.64	312.52	311.98	288.79
#7	188.36	223.74	174.40	132.25	120.26	194.10

Table 3
Summary of Constrained Paths
in Base Case & NSB Alternatives

	Case 2001-60.sav	NSB Sell 500 MW to :				
		Case 2001-60a.sav	Case 2001-60b.sav	Case 2001-60c.sav	Case 2001-60d.sav	Case 2001-60e.sav
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
#12	2286.96	2278.97	2240.06	2271.26	2289.00	2284.81
#6	1701.48	1910.25	1734.28	1825.93	1687.68	1686.12
#14	1371.09	1402.70	1310.83	1514.11	1370.51	1364.04
#9	1346.48	1379.01	1286.49	1493.26	1346.00	1339.26
#10	1200.65	1417.10	1262.50	1334.53	1231.01	1174.03
#17	260.60	214.69	231.55	205.65	216.82	215.47
#8	256.65	219.29	252.27	263.42	182.50	131.54
#15	198.05	239.66	190.82	200.65	243.57	236.15
#5	129.47	163.97	67.40	284.57	129.14	122.01
#11	115.44	143.55	155.30	165.86	143.26	151.43
#7	70.71	21.36	83.96	135.32	63.80	67.13

Table 4
Summary of Constrained Paths
in Base Case & NSB Alternatives

		NSB Sell 500 MW to :				
	Case 2001-40.sav	Case 2001-40a.sav	Case 2001-40b.sav	Case 2001-40c.sav	Case 2001-40d.sav	Case 2001-40e.sav
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
#12	1463.01	1459.69	1454.83	1457.97	1474.48	1464.80
#6	1161.84	1312.05	1235.66	1283.17	1140.62	1146.19
#10	1055.21	1203.98	1173.43	1191.11	1082.03	1024.22
#9	730.00	856.91	767.26	871.94	730.58	723.28
#14	729.25	851.45	764.30	865.97	729.84	722.84
#7	270.98	18.44	296.90	337.79	264.90	267.37
#8	270.81	274.26	282.43	278.75	199.52	147.68
#17	165.11	109.33	111.97	110.87	122.38	121.49
#5	139.41	4.15	99.69	0.00	138.65	146.38
#15	128.67	145.16	118.43	135.06	176.18	166.83
#11	25.60	73.12	76.56	74.48	51.89	60.31

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Armand
Exhibit ____ (MPA-5)

RESULTS OF POWER FLOW STUDIES 2004

Prepared for

DUKE ENERGY POWER SERVICES, INC.

July 28, 1998

Unpublished Work © July 1998

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 24-Part 3
COMPANY/ WITNESS: Armand
DATE: 12-2-98

RMI
RESOURCE MANAGEMENT INTERNATIONAL, INC.

RMI

RESOURCE MANAGEMENT
INTERNATIONAL, INC.

July 28, 1998

Mr. Larry Wall
Managing Director
Duke Energy Power Services, Inc.
5400 Westheimer Court
Houston, TX 77251

Subject: Transmission System Analysis in Support of
Duke Energy New Smyrna Beach Power Company

Dear Larry:

Enclosed are four copies of the subject report prepared in accordance with your instructions. We have obtained the year 2004 powerflow case from the FERC Bulletin Board. As expected, there was no representation of additional generation at Fort Myers Plant and at Sanford Plant, since the case was put together and posted by FERC on November 20, 1997 (see Appendix I). Obviously, the 1998 ten-year site plan was not yet finalized. However, FPL did show a Martin 5 combined cycle unit at 626 MW.

This powerflow case, after rigorous testing, was modified as follows:

1. Addition of the proposed 500 MW plant at New Smyrna and the associated transmission reinforcement around the plant;
2. Addition of the proposed 837 MW at Ft. Myers plant, and the associated transmission reinforcement;
3. Addition of the proposed 914 MW at Sanford plant, and the associated transmission reinforcement; and
4. Removal of the proposed 626 MW addition shown at Martin Plant. There was no associated transmission represented in the case.

The new powerflow case, after the above modifications, was renamed 2004. Two other cases were also developed: one simulating a 3600 MW import from Georgia at peak load (2004-pi.) and another simulating 60% of peak summer load and a 2400 import from Georgia (2004-60).

3100 ZINFANDEL DRIVE, SUITE 600 • SACRAMENTO, CA 95670-6026
P.O. BOX 15516 • SACRAMENTO, CA 95852-1516
(916) 852-1300 • FAX (916) 852-1073 • www.rmiinc.com

With Offices Worldwide

Therefore, the powerflow studies discussed in the enclosed report evaluated:

- Pre- and post-project transmission system performance for the year 2004 when the Florida system experience peak loading conditions and imports 3600 MW of power from Georgia.
- Pre- and post-project transmission system performance for the year 2004 when the Florida system is at peak load and imports 2400 MW from Georgia.
- Pre- and post-project transmission system performance for the year 2004 when the Florida system is loaded to 60% of summer peak load and imports 2400 MW from Georgia. This load level is considered the average of the Florida system.

Base on the preliminary studies discussed in the enclosed report, it appears that:

1. The proposed 500 MW project at New Smyrna Beach can reliably deliver its output into the Florida Transmission System.
2. The addition of 837 MW of generation at Ft. Myers and 914 MW and Sanford has no impact on the ability of the plant to deliver its output into the Florida Transmission System.
3. A reduction in the forecasted load served by the two 115kV circuits between Volusia and Smyrna substations eliminates most of the overloads noted in the peak 2001 cases for loss of the New Smyrna-Edgewater line section.

We look forward to discussing the enclosed report with you and Kelly O'Brien on August 5, 1998, in Houston. In the interim, I can be reached at 916/852-1300 should you have any questions on the enclosed.

Sincerely,

Michel P. Armand

Michel P. Armand

Enclosure

DUKE ENERGY POWER SERVICES, INC.

PROPOSED 500 MW FLORIDA GENERATING FACILITY
RESULTS OF POWER FLOW STUDIES
MODIFIED TO REFLECT THE YEAR 2004 POWERFLOW CASE

Prepared for

DUKE ENERGY POWER
SERVICES, INC.

Prepared by

RMI
RESOURCE MANAGEMENT
INTERNATIONAL, INC.

UNPUBLISHED WORK © JULY 1998

DUKE ENERGY POWER SERVICES, INC.
Results of Power Flow Studies
for the Year 2004 Powerflow Case

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DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

PROPOSED 500 MW FLORIDA GENERATING FACILITY

RESULTS OF POWER FLOW STUDIES - 2004

EXECUTIVE SUMMARY

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. is proposing to build a 500 MW merchant plant in Florida in a joint venture with the Utilities Commission, City of New Smyrna Beach, Florida. The facility will be sited adjacent to the City's Smyrna Substation in Volusia County, Florida, and is scheduled to begin commercial operation by the summer of 2001. Duke Energy New Smyrna Beach Power Company Ltd., L.L.P retained Resource Management International, Inc. (RMI) to assist them in evaluating the interconnection of the proposed project with the Florida Transmission network.

In providing this support, RMI performed additional preliminary power flow studies evaluating:

- Summer 2004 transmission system performance at peak load, importing 3,600 MW from the Southern Company, with and without the project.
- Summer 2004 transmission system performance at peak load, importing 2,400 MW from the Southern Company, with and without the project.
- Summer 2004 transmission system performance at an average 60% of peak load, importing 2,400 MW from the Southern Company, with and without the project.

We obtained the year 2004 powerflow case from the FERC Bulletin Board. As expected, there was no representation of additional generation at Fort Myers and at Sanford since the case was put together and posted by FERC on November 20, 1997 (see Appendix I). Obviously, the 1998 ten-year site plan was not yet finalized. However, FPL did show a Martin 5 combined cycle unit at 626 MW.

This powerflow case, after rigorous testing, was modified as follows:

1. Add the New Smyrna 500 MW generator, associated bus, and transformer. Add the second Smyrna to Cassadaga 115kV transmission circuit.

Add a new Cassadaga to Lake Helen 115 kV transmission circuit.
Loop the Debary-Altomonte 230kV circuit into Sanford plant.

2. Add six (6) new Combustion Turbines (837 MW summer rating) at Ft. Myers with associated buses and transformers.
   Add a second Ft. Myers to Calusa 230kV transmission circuit.
   Add a third Ft. Myers to Orange River 230kV transmission circuit.

3. Add six (6) new Combustion Turbines (914 MW summer rating) at Sanford with associated buses and transformers in a new 230kV switchyard.
   Add two new 230kV transmission lines between the new switchyard and Poinsett 230kV substation.
   Reroute the Sanford-Volusia #2 230kV transmission line from the old Sanford to the new Sanford switchyard.

4. The Martin 5 combined cycle unit was removed since it is not scheduled until 2006.

The new powerflow case, after the above modifications, was renamed 2004. Two other cases were also developed: one simulating a 3600 MW import from Georgia at peak load (2004-pi) and another simulating 60% of peak summer load and a 2400 MW import from Georgia (2004-60). Each case was then modified to represent delivery of the proposed plant output alternatively to Florida Power and Light (FPL), Florida Power Corporation (FPC), Tampa Electric Company (TEC), Jacksonville Electric Authority (JEA), and Seminole Electric Cooperative (SEC). Each of these dispatch scenarios was modeled and tested with the three base cases as shown in Table ES-1.

TABLE ES-1
SUMMARY OF POWERFLOW BASE CASES EVALUATED

Year	Case	Georgia Imports (MW)	Duke Generation (MW)	Output Delivered to:
2004	2004.PI	3,600	- 0 -	N/A
	2004.PIa	3,600	500	Florida Power & Light
	2004.PIb	3,600	500	Florida Power Corporation
	2004.PIc	3,600	500	Tampa Electric Company
	2004.PId	3,600	500	Jacksonville Electric Authority
	2004.PIe	3,600	500	Seminole Electric Cooperative
2004	2004.	2,400	- 0 -	N/A
	2004.a	2,400	500	Florida Power & Light
	2004.b	2,400	500	Florida Power Corporation
	2004.c	2,400	500	Tampa Electric Company
	2004.d	2,400	500	Jacksonville Electric Authority
	2004.e	2,400	500	Seminole Electric Cooperative
2004	2004-60	2,400	- 0 -	N/A
	2004-60a	2,400	500	Florida Power & Light
	2004-60b	2,400	500	Florida Power Corporation
	2004-60c	2,400	500	Tampa Electric Company
	2004-60d	2,400	500	Jacksonville Electric Authority
	2004-60e	2,400	500	Seminole Electric Cooperative

Therefore, the powerflow studies discussed in the enclosed report evaluated:

- Pre- and post-project transmission system performance for the year 2004 when the Florida system experiences peak loading conditions and imports 3600 MW of power from Georgia.
- Pre- and post-project transmission system performance for the year 2004 when the Florida system is at peak load and imports 2400 MW from Georgia.
- Pre-and post-project transmission system performance for the year 2004 when the Florida system is loaded to 60% of summer peak load and imports 2400

MW from Georgia. This load level is considered the average for the Florida system.

Based on the preliminary studies discussed the enclosed report, it appears that:

1. The proposed 500 MW project at New Smyrna Beach can reliably deliver its output into the Florida Transmission System.
2. The addition of 837 MW of generation at Ft. Myers and 914 MW at Sanford has no impact on the ability of the plant to deliver its output.
3. A reduction in the forecasted load served by the two 115kV circuits between Volusia and Smyrna substations eliminated most of the overloads noted in the peak 2001 cases for loss of the New Smyrna-Edgewater line section.
4. At loading levels of sixty percent modeled for the year 2006, no overload is noticed for all the contingencies simulated and for all dispatch scenarios. Since sixty percent load level is a good representation of average loading on the Florida Transmission System, there is little doubt that the plant output can be dispatched in a dispersed fashion without much difficulty.

SECTION 1 POWERFLOW BASE CASE DEVELOPMENT

As noted in the Executive Summary, the powerflow base cases used in these studies were based on the 2004 summer peak case filed with FERC by the Florida Reliability Coordinating Council (FRCC) in the spring of 1997. This powerflow case represented the system in peninsular Florida as consisting of nineteen control areas with a combined load of slightly over 39,500 MW and with approximately 38,000 MW of generation (both utility and non-utility) as being on-line. Imports into Florida from Georgia were approximately 2,400 MW and Florida system losses were approximately 860 MW. The nineteen control areas and the load and generation represented in each, are summarized in Table 1-1.

TABLE 1-1
FLORIDA CONTROL AREA LOADS AND GENERATION IN FRCC 2004 PEAK CASE

Control Area	Load (MW)	Generation (MW)
FP&L	19,633	16,576
FPC	9,832	8,434
Ft. Pierce	129	81
Gainsville	441	434
Homestead	59	32
Jacksonville	2,636	2,908
Key West	129	63
Kissimmee	258	353
Lake Worth	85	56
New Smyrna Beach	80	18
Orlando	1,129	1,346
Seminole	253	200
Lakeland	557	1,010
Starke	15	0
Talahassee	547	543
Tampa	3,416	3,895
FMP	143	43
NUG	0	250
Reedy Creek	182	0

The new 2004 base case obtained from the FERC Bulletin Board was modified, after extensive testing, to reflect the following generation and transmission additions:

1. Add the New Smyrna 500 MW generator, associated bus, and transformer.
   Add the second Smyrna to Cassadaga 115kV transmission circuit.
   Add a new Cassadaga to Lake Helen 115kV transmission circuit.
   Loop the Debary-Altamonte 230kV circuit into Sanford plant.

2. Add six (6) new Combustion Turbines (837 NW summer rating) at Fort Myers with associated buses and transformers.
   Add a second Ft. Myers to Calusa 230kV transmission circuit.
   Add a third Ft. Myers to Orange River 230kV transmission circuit.

3. Add six (6) new Combustion Turbines (914 MW summer rating) at Sanford with associated buses and transformers in a new 230kV switchyard.
   Add two new 230kV transmission lines between the new switchyard and Poinsett 230kV substation.
   Re-route the Sanford-Volusia #2 230kV transmission line from the old Sanford to the new Sanford switchyard.

4. The Martin 5 combined cycle unit was removed since, according to the latest FPL Ten Year Site Plan, this unit is not scheduled until 2006.

2004. CASES

The modified base case obtained from FERC was then further modified to represent five new base cases:

2004-a. represents 500 MW delivered to FPL;
2004-b. represents 500 MW delivered to FPC;
2004-c. represents 500 MW delivered to TEC;
2004-d. represents 500 MW delivered to JEA; and
2004-e. represents 500 MW delivered to SEC.

2004-60 CASES

The peak case was modified to represent a sixty percent load level. The load in each control area in Florida was scaled down to approximately 60% of its peak value. The generation dispatched in each area was manually and individually adjusted to reflect the most economic dispatch. A number of gas turbines in South Florida were turned off because they did not make the priority order of economic dispatch in FPL's control

area. With the proposed addition of new, more efficient units in FPC's control area, most of their older combustion turbines did not make the economic dispatch. Similarly, Tampa's older steam units were not run to accommodate their proposed units at Polk County (148 MW in 2003 and 148 MW additional in 2004). The resultant case was named 2004-60. and further modified to represent five new base cases:

2004-60a. represents 500 MW delivered to FPL;
2004-60b. represents 500 MW delivered to FPC;
2004-60c. represents 500 MW delivered to TEC;
2004-60d. represents 500 MW delivered to JEA; and
2004-60e. represents 500 MW delivered to SEC.

2004-PI. CASES

The modified base case 2004. was used to simulate a 3600 MW import from Georgia with all of the increase going to South Florida. Generation was decresed at Turkey Point and Port Everglades and increased in Georgia. Similar dispatches were obtained to deliver the output alternatively to FPL, FPC, TEC, JEA and SEC.

Those eighteen base cases were then used to simulate single contingency outages around the Florida Transmission System and resultant flows were observed on several monitored lines.

SECTION 2 RESULTS OF POWERFLOW STUDIES

As discussed in Section 1, eighteen powerflow base cases (Summarized in Table 2-1) were developed in order to evaluate the effects of the proposed 500 MW plant on the performance of the Florida system. Each of the cases summarized in Table 2-1 were used as a starting point in evaluating system performance under normal conditions by comparing pre- and post-project powerflows over key lines in the proximity of the plant and over certain lines monitored in past FCG transmission assessment studies.

In addition, a number of single line or generator outages (N-1) were simulated on all of the base cases to assess performance under other than normal conditions. RMI also checked flows over twelve of the thirteen constrained transmission paths discussed in the FRCC 1997 Final Transmission System Constraint Maps. Table 2-2 is a list of the single outages simulated on each of the eighteen base cases. Table 2-3 is tabulation of the FRCC constrained paths and the transmission circuits affected. Constrained paths #15 and #16 are the Stanton-Rio Pinar 230-kV line. Because the studies performed represent summer season peak load conditions and, therefore, power transfers from Georgia to Florida, Constraint #13 (which deals with flows from Florida to Georgia) was not checked. Appendix V is a summary of total constrained path flows in graph form, representing the pre- and post-project performance for the eighteen bases cases.

The contingencies listed in Table 2-2 represent a broad array of outages throughout the Florida system designed to test any negative impact this new plant may have. Those outages are similar to those selected for FRCC transmission assessment studies. Some were not expected to be impacted by the new plant. Others could potentially be influenced by whether the output was scheduled to the different receiving parties. In all cases, the most pessimistic conditions were modeled.

The circuits monitored as shown in Table 2-4 represent transmission lines that showed a tendency to experience loading problems in an earlier 1989 FCG study of the "1999 Long-Range Bulk Transmission Study." Those overloaded lines were localized phenomenons which seem to have since been corrected as we will see later in the discussion.

TABLE 2-1
SUMMARY OF POWERFLOW BASE CASES EVALUATED

Year	Case	Georgia Imports (MW)	Duke Generation (MW)	Output Delivered to:
2004	2004.PI	3,600	- 0 -	N/A
	2004.PIa	3,600	500	Florida Power & Light
	2004.PIb	3,600	500	Florida Power Corporation
	2004.PIc	3,600	500	Tampa Electric Company
	2004.PId	3,600	500	Jacksonville Electric Authority
	2004.PIe	3,600	500	Seminole Electric Cooperative
2004	2004.	2,400	- 0 -	N/A
	2004.a	2,400	500	Florida Power & Light
	2004.b	2,400	500	Florida Power Corporation
	2004.c	2,400	500	Tampa Electric Company
	2004.d	2,400	500	Jacksonville Electric Authority
	2004.e	2,400	500	Seminole Electric Cooperative
2004	2004-60	2,400	- 0 -	N/A
	2004-60a	2,400	500	Florida Power & Light
	2004-60b	2,400	500	Florida Power Corporation
	2004-60c	2,400	500	Tampa Electric Company
	2004-60d	2,400	500	Jacksonville Electric Authority
	2004-60e	2,400	500	Seminole Electric Cooperative

TABLE 2-2
INDEX TO OUTAGE CONTINGENCIES

Outage #	Bus 1	kV	Bus 2	kV	CKT
1	NSB-SMYR	115	CASSADAG	115	1
2	NSB-SMYR	115	EDGEWATR	115	1
3	NSB-SMYR	115	TAYLOR	115	1
4	NSB-SMYR	115	NSB-ARP	115	1
5	NSB-SMYR	115	NSB-FELD	115	1
6	CAMP LK	230	CENT FLA	230	1
7	SUWANNEE	230	SUWANNEE	115	1
8	SHELD	230	SHELD-NW	69	1
9	SHELD	230	SHELD-SE	69	1
10	OHIO	138	TMPBAY T	138	1
11	AZALEA	115	BENNETT	115	1
12	PERSHING	115	MICHIGAN	115	1
13	DUVAL	500	POINSETT	500	1
14	SILVR SP	230	SILVSPN	230	1
15	DUVAL	500	HATCH	500	1
16	ARCHER	230	HAILE	230	1
17	FT WHT N	230	SUWANNEE	230	1
18	OHIO-N	230	ELEVEN W	230	1
19	WOODSMER	230	PINEHILL	230	1
20	SO WOOD	230	SO WOOD	115	1
21	IND RIV	230	STANTON	230	1
22	CURRY FD	230	STANTON	230	1
23	BRKRIDGE	500	CRYST RV	500	1
24	KATHLEEN	500	CENT FLA	500	1
25	SUWANNEE	230	STERLING	230	1
26	KATH-DUM	500	KATHLEEN	230	1
27	NLONGWD	230	WTR SPGS	230	1
28	SKY LAKE	230	SO WOOD	230	1
29	WINDERME	230	SO WOOD	230	1
30	SO GIB	230	B BEND	230	1
31	SANFORD4	24	390 MW Gen		1
32	TP.4	22	693 MW Gen		1
33	STLUCIE1	22	839 MW Gen		1
34	MANATEE1	22	819 MW Gen		1
35	CR RV G3	22	812 MW Gen		1

TABLE 2-3
LIST OF CONSTRAINED PATHS IN FLORIDA

Const. Number	Constrained Path Name	Transmission Lines Involved
5	Lake Tarpon - Sheldon	Three Lake Tarpon-Sheldon: 230-kV lines.
6	Central-South East	Poinsett-Martin & Poinsett-Midway: 500-kV Lines Malabar-Midway & Malabar-Emerson: 230-kV Lines Malabar-West: 138-kV Line
7	Central-South	Ruskin-Manatee: 230-kV Line Big Bend-Manatee: 230-kV Line Big Bend-Ruskin: 230-kV Line
8	Northwest-Central	2 Silver Spring North-Silver Springs: 230-kv Line
9	Brookridge-South	Brookridge-Lake Tarpon: 500-kV Line Brookridge-Brooksville West: 230-kV Line Brookridge-Hudson: 230-kV Line
10	Northeast-Central	Duval-Poinsett & Rice-Poinsett: 500-kV Lines Putnam-Volusia & Burnel-Volusia: 230-kV Lines
11	Sylvan-North Longwood	Sylvan-North Longwood: 230-kV Line
12	Georgia-Florida	Hatch-Duval & Thalman-Duval: 500-kV Line Pine Grove-Sunannee & Kingsland-Yulee: 230-kV Line South Bainbridge-Tallahassee (sub 20): 230-kV Line Callaway-Port St. Joe: 230-kV Line Pine Grove-Jasper, Tarver-Jasper: 115-kV Line Scholtz-Woodruff: 115-kV Line Twin Lake-Suwannee Pl: 115-kV Line
13	Florida-Georgia	Same as 12 (flows reversed)
14	Crystal River-South	Crystal River-Brookridge: 500-kV Line CR Plant-Brookridge: 230-kV Line CR Plant-Cryst RE: 230-kV Line
15	Cape Canaveral-Indian River	Cape Canaveral-Indian River: 230-kV Line
16	Indian River-Cape Canaveral	Indian River-Cape Canaveral: 230-kV Line
17	Stanton-Central Florida	Stanton-Rio Pinar: 230-kV Line

TABLE 2-4
MONITORED BRANCHES

Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area
2004-Pl-1	SN PLANT	230	SYLVAN	230	1	1
2004-Pl-1	SYLVAN	230	N LONGWD	230	1	1
2004-Pl-1	IND RIV	230	STANTON	230	1	11
2004-Pl-1	SILVR SP	230	SILV SPN	230	1	2
2004-Pl-1	SILVR SP	230	SILV SPN	230	2	2
2004-Pl-1	RIO PINR	230	CURRY FD	230	1	2
2004-Pl-1	JUNEAU-W	138	GANNON	138	1	16
2004-Pl-1	NSB-SMYR	115	CASSADAG	115	1	2
2004-Pl-1	NSB-SMYR	115	EDGEWATR	115	1	1
2004-Pl-1	NSB-SMYR	115	TAYLOR	115	1	1
2004-Pl-1	NSB-SMYR	115	NSB-ARP	115	1	10
2004-Pl-1	NSB-SMYR	115	NSB-FELD	115	1	10
2004-Pl-1	SN PLANT	115	TURNER	115	1	1
2004-Pl-1	PASADENA	115	40ST-DUM	115	1	2
2004-Pl-1	MICHIGAN	115	KALEY	115	1	11
2004-Pl-1	MICHIGAN	115	GRANT	115	1	11
2004-Pl-1	PERSHING	115	GRANT	115	1	11
2004-Pl-1	AMERICAN	115	KALEY	115	1	11
2004-Pl-1	JASPER	115	WGHTCHPL	115	1	2
2004-Pl-1	AZALEA	115	BENNETT	115	1	11
2004-Pl-1	FLORALTP	69	INVERNTP	69	1	2
2004-Pl-1	ALACH TP	69	HIGH SPG	69	1	2
2004-Pl-1	PASADENA	230	PASADENA	115	1	2
2004-Pl-1	SUWANNEE	230	SUWANNEE	115	1	2
2004-Pl-1	SUWANNEE	230	SUWANNEE	115	2	2
2004-Pl-1	E CLRWTR	230	E CLRWTR	115	1	2
2004-Pl-1	IND RIV	230	IND RIV	115	1	11
2004-Pl-1	LARGO	230	LARGO A	69	1	2
2004-Pl-1	SHELD	230	SHELD-NW	69	1	16
2004-Pl-1	CLMT EST	230	CLMT EST	69	1	2
2004-Pl-1	WINDERME	230	WINDERME	69	1	2
2004-Pl-1	RIVER-S	230	RIVER-S	69	1	16
2004-Pl-1	ELEVEN W	230	ELEVEN-E	69	1	16
2004-Pl-1	JUNEAU-E	138	JUNEAU-E	69	1	16
2004-Pl-1	JASPER	115	JASPER	69	1	2

2000 - PI CASES

The result of these cases, representing summer peak loading in Florida and peak import of 3600 MW from Georgia, are summarized in Appendix II, which presents information about the lines monitored, the specific outage, and the five dispatch scenarios: the plant output respectively delivered to FPL, FPC, TEC, JEA, and SEC.

The analysis reveals that for the simulated outage of the Smyrna to Edgewater section of the Smyrna to Volusia No. 2 115-kV circuit, the Smyrna to Taylor Section of the Smyrna to Volusia No. 1 115-kV circuit is loaded to 100% when selling to JEA. The configuration between Volusia Substation and Smyrna Substation is described in Figure 2-1, which presents the various line sections, their impedance values, and their MVA ratings. The loading of the substations supplied by each circuit is shown in Table 2-5 for the year 2001 and in Table 2-6 for the year 2004.

Such change in load forcast is not uncommon. Revised economic forecast for a region might dramatically increase or decrease the forecasted load. Table 2-5 shows that for the year 2001, the total load served by the 115kV system between Volusia and New Smyrna substation is approximately 240 MW. The projected load in 2004 is approximately 210 MW, for the year 2004. Most of the reduction is accounted for by reduced loading at Willow, Port Orange and Taylor on the Volusia to Smyrna 115kV circuit no. 1, while loading at Spruce and Edgewater shows a moderate increase.

The distribution of flows over the various lines emanating from Smyrna Substation for the various dispatch scenarios are shown in Appendix II-A.

2001. CASES

The result of these cases representing summer peak loading in Florida and an import of 2,400 MW from Georgia are summarized in Appendix III, which presents information about the lines monitored, the specific outage, and the five dispatch scenarios: the plant output respectively delivered to FPL, FPC, TEC, JEA, and SEC.

For the simulated outage of the Smyrna to Edgewater section of the Smyrna to Volusia No. 2 115-kV circuit, the Smyrna to Taylor section of the Smyrna to Volusia No. 1, 115-kV circuit is loaded above 100% of its rating when the plant output is delivered to JEA or Seminole. No other overload was noted for the other outages under all dispatch scenarios.

Appendix III-A shows the distribution of flows over the various lines emanating from Smyrna Substation for the various dispatch scenarios.

2001-60 CASES

The result of these cases representing 60% of summer peak loading condition in Florida, and an import of 2,400 MW from Georgia are summarized in Appendix IV, which present information about the lines monitored, the specific outage and the five dispatch scenarios: the plant ouput respectively delivered to FPL, FPC, TEC, JEA, and SEC.

Review of the distribution of line flows around the plant, Appendix IV-A, reveals a more even distribution of plant output between the lines going to FPL and FPC. The Smyrna to Volusia circuits carry approximately 43% of plant output, while the Smyrna to Cassadaga circuits carry about 57% of plant output. The decreased loading of the Smyrna to Volusia circuit No. 1 makes it less prone to overload under simulated outages. The difference resides in the dispatch of generation around the proposed plant.

At peak load, cases 2001. and 2001-PI, all the generators in Central East Florida were on line at Sanford, Cape Canaveral, Debary, Turner, Indian River, and Stanton. Most units were at their peak rating. The result was a tendency of the proposed plant output to flow toward Volusia and the FPL 230-kV system. At 60% load level, with less generation on line in the Central East Area, more of the plant output is going over the Smyrna to Cassadaga circuits and less over the Smyrna to Volusia circuits.

The analysis reveals that for all the scenarios and all contingencies, no monitored line reached its maximum rating. Since 60% load level is representative of average loading of the Florida system, it appears the proposed plant can be dispatched most of the time.

TABLE 2-5
SUBSTATION LOADS BY CIRCUIT (2001 CASE)

	Substation	P Load	Q Load
Circuit No. 1			
	Willow	46.70	16.40
	Port Orange	83.00	29.30
	Taylor	38.50	10.90
	Total	168.20	56.60
Circuit No. 2			
	Edgewater	45.50	15.70
	Spruce	24.10	8.10
	Total	69.60	23.80

TABLE 2-6
SUBSTATION LOADS BY CIRCUIT (2004 CASE)

	Substation	P Load	Q Load
Circuit No. 1			
	Willow	35.60	12.60
	Port Orange	63.40	22.40
	Taylor	30.30	8.60
	Total	129.30	43.60
Circuit No. 2			
	Edgewater	50.50	14.30
	Spruce	28.10	7.20
	Total	78.60	21.50

APPENDIX I

Federal Energy Regulatory Commission

1997 Form 715 Regional Power Flow Cases And Transmission Planning Reports

ASCC | ECAR | ERCOT | FRCC | MAAC | MAIN | MAPP | NPCC | SERC | SPP | WSCC

Form 715 transmission planning reports (Form parts 1, 4, 5 and 6) for each respondent are stored in separate subdirectories in a single compressed self-expanding ".exe" files by NERC Region.To maintain the subdirectory structure, use " -d" switch after the file name when running the executable file to restore the compressed information (e.g., ECAR98R.exe -d). The following is a list of files available for downloaded.

ASCC - Anchorage & Chugach

- 1998 Power Flow Cases
- 1998 Transmission Planning Reports (use -d when exploding)

ECAR - East Central Area Reliability Coordination Agreement

- ECAR Members' 1998 Transmission Planning Report (use -d when exploding)
- 2002 Summer Peak Case (Input,Output & Data Dictionary)
- 2002/2003 Winter Peak (Input,Output & Data Dictionary)
- 2007 Summer Peak (Input,Output & Data Dictionary)
- 1997/1998 Winter Peak ECAR Assessment Study Case (Input,Output & Data Dictionary)
- 1998 Spring Peak Case (Input,Output & Data Dictionary)
- 1998 Summer Peak (Input,Output & Data Dictionary)
- 1998 Summer Peak ECAR Assessment Study Case (Input,Output & Data Dictionary)
- 1998 Fall Peak (Input,Output & Data Dictionary)
- 1998/1999 Winter Peak (Input,Output & Data Dictionary)
- 1998 Light Load Case (Input,Output & Data Dictionary)
- 1999 Summer Peak (Input,Output & Data Dictionary)
- 1999 Summer Peak ECAR Assessment Study Case (Input,Output & Data Dictionary)
- 1999/2000 Winter Peak (Input,Output & Data Dictionary)
- 1998 Wolverine Power Supply Coop, Inc. (Input,Output & Data Dictionary)

ERCOT - Electric Reliability Council of Texas

- ERCOT Members' 1998 Transmission Planning Reports (use -d when exploding)
- ERCOT 1998 Bus Identification (Data Dictionary)
- 1999 Summer Peak Case (Input & Output)
- 2000 Summer Peak Case (Input & Output)
- 2001 Summer Peak Case (Input & Output)
- 2002 Summer Peak Case (Input & Output)
- 2003 Summer Peak Case (Input & Output)
- 2008 Summer Peak Case (Input & Output)
- 2001 Minimum Case (Input & Output)
- 2001 Winter Peak Case (Input & Output)

FRCC - Florida Reliability Coordinating Council

- FRCC's Members 1998 Transmission Planning Report (use -d when exploding)
- 2000 Summer Peak Case (Input & Output)
- 2000 Winter Peak Case (Input & Output)
- 2001 Summer Peak Case (Input & Output)
- 2001 Winter Peak Case (Input & Output)
- 2002 Summer Peak Case (Input & Output)
- 2002 Winter Peak Case (Input & Output)
- 2003 Summer Peak Case (Input & Output)
- 2003 Winter Peak Case (Input)
- 2004 Summer Peak Case (Input & Output)
- 2005 Summer Peak Case (Input & Output)
- 2006 Summer Peak Case (Input & Output)
- 2007 Summer Peak Case (Input & Output)
- 1997 Summer Peak Case (Input)
- 1997 Winter Peak Case (Input & Output)
- 1998 Summer Peak Case (Input & Output)
- 1998 Winter Peak Case (Input & Output)
- 1999 Summer Peak Case (Input & Output)
- 1999 Winter Peak Case (Input & Output)

MAAC - Mid-Atlantic Area Council

- 1998 MAAC Data Dictionary (Excel)
- 2002 Summer Peak (Input & Output)
- 2002/2003 Winter Peak (Input & Output)
- 2007 Summer Peak (Input & Output)
- 1998 Summer Peak (Input & Output)
- 1998 Fall Peak (Input & Output)
- 1998/1999 Winter Peak (Input & Output)
- 1998 Light Load (Input & Output)
- 1998 Spring Peak (Input & Output)
- 1999 Summer Peak (Input & Output)
- 1999/2000 Winter Peak (Input & Output)

MAIN - Mid-America Interconnected Network

- MAIN Members' 1998 Transmission Planning Reports (use -d when exploding)
- 2002 Summer Peak Case (Output & Data Dictionary)
- 2002 Winter Peak Case (Output & Data Dictionary)
- 2007 Summer Peak Case (Output & Data Dictionary)
- 1997 Summer Peak Case Scenario 1 (Output & Data Dictionary)
- 1997 Summer Peak Case Scenario 2 (Output & Data Dictionary)
- 1997 Summer Peak Case Scenario 3 (Output & Data Dictionary)
- 1997 Winter Peak Case Scenario 1 (Output & Data Dictionary)
- 1997 Winter Peak Case Scenario 2 (Output & Data Dictionary)

- 1998 Spring Peak Case (Output & Data Dictionary)
- 1998 Fall Peak Case (Output & Data Dictionary)
- 1998 Light Load Case (Output & Data Dictionary)
- 1998 Summer Peak Case (Output & Data Dictionary)
- 1998 Winter Peak Case (Output & Data Dictionary)
- 1999 Summer Peak (Output & Data Dictionary)
- 1999 Winter Peak (Output & Data Dictionary)
- 2002 Summer Peak Case (Input)
- 2002 Winter Peak Case (Input)
- 2007 Summer Peak Case (Input)
- 1997 Summer Peak Case Scenario 1 (Input)
- 1997 Summer Peak Case Scenario 2 (Input)
- 1997 Summer Peak Case Scenario 3 (Input)
- 1997 Winter Peak Case Scenario 1 (Input)
- 1997 Winter Peak Case Scenario 2 (Input)
- 1998 Spring Peak Case (Input)
- 1998 Fall Peak Case (Input)
- 1998 Light Load Case (Input)
- 1998 Summer Peak Case (Input)
- 1998 Winter Peak Case (Input)
- 1999 Summer Peak (Input)
- 1999 Winter Peak (Input)

MAPP - Mid-Continent Area Power Pool

- MAPP Members' 1998 Transmission Planning Reports (use -d when exploding)
- 2002 Summer Off-Peak (Input & Output)
- 2002 Summer Peak (Input & Output)
- 2002 Winter Peak (Input & Output)
- 2007 Summer Peak (Input & Output)
- 2007 Winter Peak (Input & Output)
- 1998 Summer Off-Peak (Input & Output)
- 1998 Summer Peak (Input & Output)
- 1998 Winter Off-Peak (Input & Output)
- 1998 Winter Peak (Input & Output)

NPCC - Northeast Power Coordinating Council (NEPOOL, NYPP)

NEPOOL - New England Power Pool

- NEPOOL Members' 1998 Transmission Planning Reports (use -d when exploding)
- 2003 Spring Light Load (Input, Output & Solution Parameters)
- 2003 Summer Peak (Input, Output & Solution Parameters)
- 2003/2004 Winter Peak (Input, Output & Solution Parameters)
- 2008 Summer Peak (Input, Output & Solution Parameters)
- 1998 Summer Peak (Input, Output & Solution Parameters)
- 1998/1999 Winter Peak (Input, Output & Solution Parameters)

NYPP - New York Power Pool

- NYPP Members' 1998 Transmission Planning Report (use -d when exploding)
- 2003 Summer Peak Case (Input & Output)
- 2003 Spring Light Load Peak Case (Input & Output)
- 2003/2004 Winter Peak Case (Input & Output)
- 2008 Summer Peak (Input & Output)
- 2008/2009 Winter Peak (Input & Output)
- 1998 Summer Peak (Input & Output)
- 1998/1999 Winter Peak (Input & Output)

SERC - Southeastern Electric Reliability Council

- SERC Members' 1998 Transmission Planning Reports (use -d when exploding)
- 2002 Summer Peak Case (Input, Output & Data Dictionary)
- 2002/2003 Winter Peak Case (Input, Output & Data Dictionary)
- 2007 Summer Peak Case (Input, Output & Data Dictionary)
- 1998 Fall Peak Case (Input, Output & Data Dictionary)
- 1998 Light Load Case (Input, Output & Data Dictionary)
- 1998 Summer Peak Case (Input, Output & Data Dictionary)
- 1998 Spring Peak Case (Input, Output & Data Dictionary)
- 1998/1999 Winter Peak Case (Input, Output & Data Dictionary)
- 1999 Summer (Input, Output & Data Dictionary)
- 1999/2000 Winter (Input, Output & Data Dictionary)

SPP - Southwest Power Pool

- SPP Members' 1998 Transmission Planning Reports (use -d when exploding)
- 1998 SPP Expanded Bus & Terminal Names List (Data Dictionary)
- 2004 Summer Peak Case (Input Data)
- 2004 Winter Peak Case (Input Data)
- 2009 Summer Peak Case (Input Data)
- 1998 Fall Off-Peak Case (Input Data)
- 1998 Fall On-Peak Case (Input Data)
- 1998 Fall Peak Case (Input Data)
- 1998 Spring Off-Peak Case (Input Data)
- 1998 Spring On-Peak Case (Input Data)
- 1998 Summer Off-Peak Case (Input Data)
- 1998 Shoulder Off-Peak Case (Input Data)
- 1998 Summer Peak Case (Input Data)
- 1998 Spring Peak Peak Case (Input Data)
- 1998 Winter Off-Peak Case (Input Data)
- 1998 Winter On-Peak Case (Input Data)
- 1998 Winter Peak Case (Input Data)
- 1999 April Minimum Peak Case (Input Data)
- 1999 Fall Peak Case (Input Data)
- 1999 Spring Off-Peak Case (Input Data)

- 1999 Spring On-Peak Case (Input Data)
- 1999 Shoulder Off-Peak Case (Input Data)
- 1999 Summer Peak Case (Input Data)
- 1999 Spring Peak Case (Input Data)
- 1999 Winter Peak Case (Input Data)
- 2004 Summer Peak Case (Output Data)
- 2004 Winter Peak Case (Output Data)
- 2009 Summer Peak Case (Output Data)
- 1998 Fall Off-Peak Case (Output Data)
- 1998 Fall On-Peak Case (Output Data)
- 1998 Fall Peak Case (Output Data)
- 1998 Spring Off-Peak Case (Output Data)
- 1998 Spring On-Peak Case (Output Data)
- 1998 Summer Off-Peak Case (Output Data)
- 1998 Shoulder Off-Peak Case (Output Data)
- 1998 Summer Peak Case (Output Data)
- 1998 Spring Peak Peak Case (Output Data)
- 1998 Winter Off-Peak Case (Output Data)
- 1998 Winter On-Peak Case (Output Data)
- 1998 Winter Peak Case (Output Data)
- 1999 April Minimum Peak Case (Output Data)
- 1999 Fall Peak Case (Output Data)
- 1999 Spring Off-Peak Case (Output Data)
- 1999 Spring On-Peak Case (Output Data)
- 1999 Shoulder Off-Peak Case (Output Data)
- 1999 Summer Peak Case (Output Data)
- 1999 Spring Peak Case (Output Data)
- 1999 Winter Peak Case (Output Data)

WSCC - Western Systems Coordinating Council

- WSCC Region 1998 Transmission Planning Reports (use -d when exploding)
- WSCC Member Regional 1998 Transmission Planning Reports (use -d when exploding)
- WSCC Member's Separate 1998 Trans. Planning Reports (use -d when exploding)
- 2001 Heavy Autumn Demand (Input & Output), WSCC Format
- 2002 Heavy Summer Demand (Input & Output), WSCC Format
- 2002 Light Spring Demand (Input & Output), WSCC Format
- 2001/2002 Light Winter Demand (Input & Output), WSCC Format
- 1998 Heavy Summer Demand (Input & Output), WSCC Format
- 1997/1998 Heavy Winter Demand (Input & Output), WSCC Format
- 1998 Light Autumn Demand (Input), WSCC Format
- 1998 Light Summer Demand (Input & Output), WSCC Format
- 1997/1998 Light Winter Demand (Input & Output), WSCC Format
- 2001 Heavy Autumn Demand (Input & Output), PTI Format
- 2002 Heavy Summer Demand (Input & Output), PTI Format
- 2002 Light Spring Demand (Input & Output), PTI Format
- 2001/2002 Light Winter Demand (Input & Output), PTI Format
- 1998 Heavy Summer Demand (Input & Output), PTI Format

- 1997/1998 Heavy Winter Demand (Input & Output), PTI Format
- 1998 Light Autumn Demand (Input), PTI Format
- 1998 Light Summer Demand (Input & Output), PTI Format
- 1997/1998 Light Winter Demand (Input & Output), PTI Format
- EWEB 2003 Heavy Summer Demand (Input & Output), WSCC Format
- EWEB 2003/2004 Heavy Winter Demand (Input & Output), WSCC Format
- EWEB 2009 Heavy Summer Demand (Input & Output), WSCC Format
- EWEB 2008/2009 Heavy Winter Demand (Input & Output), WSCC Format
- EWEB 1998 Heavy Summer Demand (Input & Output), WSCC Format
- EWEB 1998/1999 Heavy Winter Demand (Input & Output), WSCC Format
- PSE 1998 Peak Case Demand, PTI Format
- STCL 1997 Peak Case Demand (Input & Output)

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Updated 11/20/1997

APPENDIX II

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-1	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-1	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-1	IND RIV	230	STANTON	230	1	11						
2004-PI-1	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-1	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-1	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-1	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-1	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-1	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-1	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-1	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-1	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-1	SN PLANT	115	TURNER	115	1	1						
2004-PI-1	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-1	MICHIGAN	115	KALEY	115	1	11						
2004-PI-1	MICHIGAN	115	GRANT	115	1	11						
2004-PI-1	PERSHING	115	GRANT	115	1	11						
2004-PI-1	AMERICA	115	KALEY	115	1	11						
2004-PI-1	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-1	AZALEA	115	BENNETT	115	1	11						
2004-PI-1	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-1	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-1	PASADENA	230	PASADENA	115	1	2						
2004-PI-1	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-1	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-1	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-1	IND RIV	230	IND RIV	115	1	11						
2004-PI-1	LARGO	230	LARGO A	69	1	2						
2004-PI-1	SHELD	230	SHELD-NW	69	1	16						
2004-PI-1	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-1	WINDERME	230	WINDERME	69	1	2						
2004-PI-1	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-1	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-1	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-1	JASPER	115	JASPER	69	1	2						
2004-PI-2	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-2	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-2	IND RIV	230	STANTON	230	1	11						
2004-PI-2	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-2	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-2	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-2	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-2	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-2	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-2	NSB-SMYR	115	TAYLOR	115	1	1					100.6	
2004-PI-2	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-2	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-2	SN PLANT	115	TURNER	115	1	1						
2004-PI-2	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-2	MICHIGAN	115	KALEY	115	1	11						
2004-PI-2	MICHIGAN	115	GRANT	115	1	11						
2004-PI-2	PERSHING	115	GRANT	115	1	11						
2004-PI-2	AMERICA	115	KALEY	115	1	11						
2004-PI-2	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-2	AZALEA	115	BENNETT	115	1	11						
2004-PI-2	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-2	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-2	PASADENA	230	PASADENA	115	1	2						
2004-PI-2	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-2	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-2	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-2	IND RIV	230	IND RIV	115	1	11						
2004-PI-2	LARGO	230	LARGO A	69	1	2						
2004-PI-2	SHELD	230	SHELD-NW	69	1	16						
2004-PI-2	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-2	WINDERME	230	WINDERME	69	1	2						
2004-PI-2	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-2	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-2	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-2	JASPER	115	JASPER	69	1	2						

Table I

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Following N-1 Disturbances
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100% Load Base Case

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Monitored Branches							Case 2004-PI Base *No NSB Gen*	Case 2004-PIA Sell to *FPL*	Case 2004-PIB Sell to *FPC*	Case 2004-PIC Sell to *TEC*	Case 2004-PID Sell to *JEA*	Case 2004-PIE Sell to *SEM*
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-3	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-3	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-3	IND RIV	230	STANTON	230	1	11						
2004-PI-3	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-3	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-3	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-3	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-3	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-3	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-3	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-3	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-3	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-3	SN PLANT	115	TURNER	115	1	1						
2004-PI-3	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-3	MICHIGAN	115	KALEY	115	1	11						
2004-PI-3	MICHIGAN	115	GRANT	115	1	11						
2004-PI-3	PERSHING	115	GRANT	115	1	11						
2004-PI-3	AMERICA	115	KALEY	115	1	11						
2004-PI-3	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-3	AZALEA	115	BENNETT	115	1	11						
2004-PI-3	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-3	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-3	PASADENA	230	PASADENA	115	1	2						
2004-PI-3	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-3	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-3	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-3	IND RIV	230	IND RIV	115	1	11						
2004-PI-3	LARGO	230	LARGO A	69	1	2						
2004-PI-3	SHELD	230	SHELD-NW	69	1	16						
2004-PI-3	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-3	WINDERME	230	WINDERME	69	1	2						
2004-PI-3	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-3	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-3	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-3	JASPER	115	JASPER	69	1	2						
2004-PI-4	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-4	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-4	IND RIV	230	STANTON	230	1	11						
2004-PI-4	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-4	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-4	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-4	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-4	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-4	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-4	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-4	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-4	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-4	SN PLANT	115	TURNER	115	1	1						
2004-PI-4	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-4	MICHIGAN	115	KALEY	115	1	11						
2004-PI-4	MICHIGAN	115	GRANT	115	1	11						
2004-PI-4	PERSHING	115	GRANT	115	1	11						
2004-PI-4	AMERICA	115	KALEY	115	1	11						
2004-PI-4	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-4	AZALEA	115	BENNETT	115	1	11						
2004-PI-4	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-4	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-4	PASADENA	230	PASADENA	115	1	2						
2004-PI-4	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-4	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-4	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-4	IND RIV	230	IND RIV	115	1	11						
2004-PI-4	LARGO	230	LARGO A	69	1	2						
2004-PI-4	SHELD	230	SHELD-NW	69	1	16						
2004-PI-4	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-4	WINDERME	230	WINDERME	69	1	2						
2004-PI-4	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-4	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-4	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-4	JASPER	115	JASPER	69	1	2						

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Following N-1 Disturbances
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100% Load Base Case

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Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-5	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-5	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-5	IND RIV	230	STANTON	230	1	11						
2004-PI-5	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-5	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-5	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-5	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-5	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-5	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-5	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-5	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-5	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-5	SN PLANT	115	TURNER	115	1	1						
2004-PI-5	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-5	MICHIGAN	115	KALEY	115	1	11						
2004-PI-5	MICHIGAN	115	GRANT	115	1	11						
2004-PI-5	PERSHING	115	GRANT	115	1	11						
2004-PI-5	AMERICA	115	KALEY	115	1	11						
2004-PI-5	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-5	AZALEA	115	BENNETT	115	1	11						
2004-PI-5	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-5	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-5	PASADENA	230	PASADENA	115	1	2						
2004-PI-5	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-5	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-5	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-5	IND RIV	230	IND RIV	115	1	11						
2004-PI-5	LARGO	230	LARGO A	69	1	2						
2004-PI-5	SHELD	230	SHELD-NW	69	1	16						
2004-PI-5	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-5	WINDERME	230	WINDERME	69	1	2						
2004-PI-5	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-5	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-5	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-5	JASPER	115	JASPER	69	1	2						
2004-PI-6	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-6	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-6	IND RIV	230	STANTON	230	1	11						
2004-PI-6	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-6	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-6	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-6	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-6	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-6	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-6	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-6	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-6	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-6	SN PLANT	115	TURNER	115	1	1						
2004-PI-6	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-6	MICHIGAN	115	KALEY	115	1	11						
2004-PI-6	MICHIGAN	115	GRANT	115	1	11						
2004-PI-6	PERSHING	115	GRANT	115	1	11						
2004-PI-6	AMERICA	115	KALEY	115	1	11						
2004-PI-6	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-6	AZALEA	115	BENNETT	115	1	11						
2004-PI-6	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-6	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-6	PASADENA	230	PASADENA	115	1	2						
2004-PI-6	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-6	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-6	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-6	IND RIV	230	IND RIV	115	1	11						
2004-PI-6	LARGO	230	LARGO A	69	1	2						
2004-PI-6	SHELD	230	SHELD-NW	69	1	16						
2004-PI-6	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-6	WINDERME	230	WINDERME	69	1	2						
2004-PI-6	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-6	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-6	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-6	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-7	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-7	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-7	IND RIV	230	STANTON	230	1	11						
2004-PI-7	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-7	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-7	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-7	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-7	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-7	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-7	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-7	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-7	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-7	SN PLANT	115	TURNER	115	1	1						
2004-PI-7	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-7	MICHIGAN	115	KALEY	115	1	11						
2004-PI-7	MICHIGAN	115	GRANT	115	1	11						
2004-PI-7	PERSHING	115	GRANT	115	1	11						
2004-PI-7	AMERICA	115	KALEY	115	1	11						
2004-PI-7	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-7	AZALEA	115	BENNETT	115	1	11						
2004-PI-7	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-7	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-7	PASADENA	230	PASADENA	115	1	2						
2004-PI-7	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-7	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-7	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-7	IND RIV	230	IND RIV	115	1	11						
2004-PI-7	LARGO	230	LARGO A	69	1	2						
2004-PI-7	SHELD	230	SHELD-NW	69	1	16						
2004-PI-7	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-7	WINDERME	230	WINDERME	69	1	2						
2004-PI-7	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-7	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-7	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-7	JASPER	115	JASPER	69	1	2						
2004-PI-8	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-8	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-8	IND RIV	230	STANTON	230	1	11						
2004-PI-8	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-8	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-8	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-8	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-8	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-8	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-8	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-8	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-8	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-8	SN PLANT	115	TURNER	115	1	1						
2004-PI-8	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-8	MICHIGAN	115	KALEY	115	1	11						
2004-PI-8	MICHIGAN	115	GRANT	115	1	11						
2004-PI-8	PERSHING	115	GRANT	115	1	11						
2004-PI-8	AMERICA	115	KALEY	115	1	11						
2004-PI-8	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-8	AZALEA	115	BENNETT	115	1	11						
2004-PI-8	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-8	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-8	PASADENA	230	PASADENA	115	1	2						
2004-PI-8	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-8	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-8	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-8	IND RIV	230	IND RIV	115	1	11						
2004-PI-8	LARGO	230	LARGO A	69	1	2						
2004-PI-8	SHELD	230	SHELD-NW	69	1	16						
2004-PI-8	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-8	WINDERME	230	WINDERME	69	1	2						
2004-PI-8	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-8	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-8	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-8	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-9	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-9	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-9	IND RIV	230	STANTON	230	1	11						
2004-PI-9	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-9	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-9	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-9	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-9	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-9	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-9	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-9	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-9	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-9	SN PLANT	115	TURNER	115	1	1						
2004-PI-9	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-9	MICHIGAN	115	KALEY	115	1	11						
2004-PI-9	MICHIGAN	115	GRANT	115	1	11						
2004-PI-9	PERSHING	115	GRANT	115	1	11						
2004-PI-9	AMERICA	115	KALEY	115	1	11						
2004-PI-9	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-9	AZALEA	115	BENNETT	115	1	11						
2004-PI-9	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-9	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-9	PASADENA	230	PASADENA	115	1	2						
2004-PI-9	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-9	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-9	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-9	IND RIV	230	IND RIV	115	1	11						
2004-PI-9	LARGO	230	LARGO A	69	1	2						
2004-PI-9	SHELD	230	SHELD-NW	69	1	16						
2004-PI-9	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-9	WINDERME	230	WINDERME	69	1	2						
2004-PI-9	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-9	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-9	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-9	JASPER	115	JASPER	69	1	2						
2004-PI-10	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-10	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-10	IND RIV	230	STANTON	230	1	11						
2004-PI-10	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-10	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-10	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-10	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-10	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-10	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-10	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-10	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-10	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-10	SN PLANT	115	TURNER	115	1	1						
2004-PI-10	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-10	MICHIGAN	115	KALEY	115	1	11						
2004-PI-10	MICHIGAN	115	GRANT	115	1	11						
2004-PI-10	PERSHING	115	GRANT	115	1	11						
2004-PI-10	AMERICA	115	KALEY	115	1	11						
2004-PI-10	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-10	AZALEA	115	BENNETT	115	1	11						
2004-PI-10	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-10	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-10	PASADENA	230	PASADENA	115	1	2						
2004-PI-10	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-10	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-10	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-10	IND RIV	230	IND RIV	115	1	11						
2004-PI-10	LARGO	230	LARGO A	69	1	2						
2004-PI-10	SHELD	230	SHELD-NW	69	1	16						
2004-PI-10	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-10	WINDERME	230	WINDERME	69	1	2						
2004-PI-10	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-10	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-10	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-10	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-11	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-11	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-11	IND RIV	230	STANTON	230	1	11						
2004-PI-11	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-11	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-11	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-11	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-11	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-11	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-11	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-11	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-11	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-11	SN PLANT	115	TURNER	115	1	1						
2004-PI-11	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-11	MICHIGAN	115	KALEY	115	1	11						
2004-PI-11	MICHIGAN	115	GRANT	115	1	11						
2004-PI-11	PERSHING	115	GRANT	115	1	11						
2004-PI-11	AMERICA	115	KALEY	115	1	11						
2004-PI-11	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-11	AZALEA	115	BENNETT	115	1	11						
2004-PI-11	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-11	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-11	PASADENA	230	PASADENA	115	1	2						
2004-PI-11	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-11	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-11	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-11	IND RIV	230	IND RIV	115	1	11						
2004-PI-11	LARGO	230	LARGO A	69	1	2						
2004-PI-11	SHELD	230	SHELD-NW	69	1	16						
2004-PI-11	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-11	WINDERME	230	WINDERME	69	1	2						
2004-PI-11	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-11	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-11	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-11	JASPER	115	JASPER	69	1	2						
2004-PI-12	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-12	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-12	IND RIV	230	STANTON	230	1	11						
2004-PI-12	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-12	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-12	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-12	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-12	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-12	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-12	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-12	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-12	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-12	SN PLANT	115	TURNER	115	1	1						
2004-PI-12	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-12	MICHIGAN	115	KALEY	115	1	11						
2004-PI-12	MICHIGAN	115	GRANT	115	1	11						
2004-PI-12	PERSHING	115	GRANT	115	1	11						
2004-PI-12	AMERICA	115	KALEY	115	1	11						
2004-PI-12	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-12	AZALEA	115	BENNETT	115	1	11						
2004-PI-12	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-12	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-12	PASADENA	230	PASADENA	115	1	2						
2004-PI-12	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-12	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-12	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-12	IND RIV	230	IND RIV	115	1	11						
2004-PI-12	LARGO	230	LARGO A	69	1	2						
2004-PI-12	SHELD	230	SHELD-NW	69	1	16						
2004-PI-12	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-12	WINDERME	230	WINDERME	69	1	2						
2004-PI-12	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-12	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-12	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-12	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-13	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-13	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-13	IND RIV	230	STANTON	230	1	11						
2004-PI-13	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-13	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-13	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-13	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-13	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-13	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-13	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-13	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-13	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-13	SN PLANT	115	TURNER	115	1	1						
2004-PI-13	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-13	MICHIGAN	115	KALEY	115	1	11						
2004-PI-13	MICHIGAN	115	GRANT	115	1	11						
2004-PI-13	PERSHING	115	GRANT	115	1	11						
2004-PI-13	AMERICA	115	KALEY	115	1	11						
2004-PI-13	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-13	AZALEA	115	BENNETT	115	1	11						
2004-PI-13	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-13	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-13	PASADENA	230	PASADENA	115	1	2						
2004-PI-13	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-13	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-13	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-13	IND RIV	230	IND RIV	115	1	11						
2004-PI-13	LARGO	230	LARGO A	69	1	2						
2004-PI-13	SHELD	230	SHELD-NW	69	1	16						
2004-PI-13	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-13	WINDERME	230	WINDERME	69	1	2						
2004-PI-13	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-13	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-13	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-13	JASPER	115	JASPER	69	1	2						
2004-PI-14	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-14	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-14	IND RIV	230	STANTON	230	1	11						
2004-PI-14	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-14	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-14	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-14	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-14	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-14	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-14	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-14	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-14	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-14	SN PLANT	115	TURNER	115	1	1						
2004-PI-14	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-14	MICHIGAN	115	KALEY	115	1	11						
2004-PI-14	MICHIGAN	115	GRANT	115	1	11						
2004-PI-14	PERSHING	115	GRANT	115	1	11						
2004-PI-14	AMERICA	115	KALEY	115	1	11						
2004-PI-14	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-14	AZALEA	115	BENNETT	115	1	11						
2004-PI-14	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-14	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-14	PASADENA	230	PASADENA	115	1	2						
2004-PI-14	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-14	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-14	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-14	IND RIV	230	IND RIV	115	1	11						
2004-PI-14	LARGO	230	LARGO A	69	1	2						
2004-PI-14	SHELD	230	SHELD-NW	69	1	16						
2004-PI-14	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-14	WINDERME	230	WINDERME	69	1	2						
2004-PI-14	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-14	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-14	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-14	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-15	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-15	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-15	IND RIV	230	STANTON	230	1	11						
2004-PI-15	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-15	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-15	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-15	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-15	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-15	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-15	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-15	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-15	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-15	SN PLANT	115	TURNER	115	1	1						
2004-PI-15	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-15	MICHIGAN	115	KALEY	115	1	11						
2004-PI-15	MICHIGAN	115	GRANT	115	1	11						
2004-PI-15	PERSHING	115	GRANT	115	1	11						
2004-PI-15	AMERICA	115	KALEY	115	1	11						
2004-PI-15	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-15	AZALEA	115	BENNETT	115	1	11						
2004-PI-15	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-15	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-15	PASADENA	230	PASADENA	115	1	2						
2004-PI-15	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-15	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-15	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-15	IND RIV	230	IND RIV	115	1	11						
2004-PI-15	LARGO	230	LARGO A	69	1	2						
2004-PI-15	SHELD	230	SHELD-NW	69	1	16						
2004-PI-15	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-15	WINDERME	230	WINDERME	69	1	2						
2004-PI-15	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-15	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-15	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-15	JASPER	115	JASPER	69	1	2						
2004-PI-16	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-16	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-16	IND RIV	230	STANTON	230	1	11						
2004-PI-16	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-16	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-16	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-16	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-16	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-16	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-16	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-16	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-16	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-16	SN PLANT	115	TURNER	115	1	1						
2004-PI-16	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-16	MICHIGAN	115	KALEY	115	1	11						
2004-PI-16	MICHIGAN	115	GRANT	115	1	11						
2004-PI-16	PERSHING	115	GRANT	115	1	11						
2004-PI-16	AMERICA	115	KALEY	115	1	11						
2004-PI-16	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-16	AZALEA	115	BENNETT	115	1	11						
2004-PI-16	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-16	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-16	PASADENA	230	PASADENA	115	1	2						
2004-PI-16	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-16	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-16	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-16	IND RIV	230	IND RIV	115	1	11						
2004-PI-16	LARGO	230	LARGO A	69	1	2						
2004-PI-16	SHELD	230	SHELD-NW	69	1	16						
2004-PI-16	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-16	WINDERME	230	WINDERME	69	1	2						
2004-PI-16	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-16	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-16	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-16	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-17	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-17	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-17	IND RIV	230	STANTON	230	1	11						
2004-PI-17	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-17	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-17	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-17	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-17	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-17	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-17	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-17	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-17	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-17	SN PLANT	115	TURNER	115	1	1						
2004-PI-17	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-17	MICHIGAN	115	KALEY	115	1	11						
2004-PI-17	MICHIGAN	115	GRANT	115	1	11						
2004-PI-17	PERSHING	115	GRANT	115	1	11						
2004-PI-17	AMERICA	115	KALEY	115	1	11						
2004-PI-17	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-17	AZALEA	115	BENNETT	115	1	11						
2004-PI-17	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-17	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-17	PASADENA	230	PASADENA	115	1	2						
2004-PI-17	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-17	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-17	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-17	IND RIV	230	IND RIV	115	1	11						
2004-PI-17	LARGO	230	LARGO A	69	1	2						
2004-PI-17	SHELD	230	SHELD-NW	69	1	16						
2004-PI-17	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-17	WINDERME	230	WINDERME	69	1	2						
2004-PI-17	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-17	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-17	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-17	JASPER	115	JASPER	69	1	2						
2004-PI-18	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-18	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-18	IND RIV	230	STANTON	230	1	11						
2004-PI-18	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-18	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-18	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-18	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-18	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-18	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-18	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-18	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-18	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-18	SN PLANT	115	TURNER	115	1	1						
2004-PI-18	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-18	MICHIGAN	115	KALEY	115	1	11						
2004-PI-18	MICHIGAN	115	GRANT	115	1	11						
2004-PI-18	PERSHING	115	GRANT	115	1	11						
2004-PI-18	AMERICA	115	KALEY	115	1	11						
2004-PI-18	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-18	AZALEA	115	BENNETT	115	1	11						
2004-PI-18	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-18	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-18	PASADENA	230	PASADENA	115	1	2						
2004-PI-18	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-18	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-18	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-18	IND RIV	230	IND RIV	115	1	11						
2004-PI-18	LARGO	230	LARGO A	69	1	2						
2004-PI-18	SHELD	230	SHELD-NW	69	1	16						
2004-PI-18	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-18	WINDERME	230	WINDERME	69	1	2						
2004-PI-18	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-18	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-18	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-18	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-19	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-19	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-19	IND RIV	230	STANTON	230	1	11						
2004-PI-19	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-19	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-19	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-19	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-19	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-19	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-19	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-19	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-19	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-19	SN PLANT	115	TURNER	115	1	1						
2004-PI-19	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-19	MICHIGAN	115	KALEY	115	1	11						
2004-PI-19	MICHIGAN	115	GRANT	115	1	11						
2004-PI-19	PERSHING	115	GRANT	115	1	11						
2004-PI-19	AMERICA	115	KALEY	115	1	11						
2004-PI-19	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-19	AZALEA	115	BENNETT	115	1	11						
2004-PI-19	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-19	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-19	PASADENA	230	PASADENA	115	1	2						
2004-PI-19	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-19	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-19	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-19	IND RIV	230	IND RIV	115	1	11						
2004-PI-19	LARGO	230	LARGO A	69	1	2						
2004-PI-19	SHELD	230	SHELD-NW	69	1	16						
2004-PI-19	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-19	WINDERME	230	WINDERME	69	1	2						
2004-PI-19	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-19	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-19	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-19	JASPER	115	JASPER	69	1	2						
2004-PI-20	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-20	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-20	IND RIV	230	STANTON	230	1	11						
2004-PI-20	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-20	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-20	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-20	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-20	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-20	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-20	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-20	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-20	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-20	SN PLANT	115	TURNER	115	1	1						
2004-PI-20	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-20	MICHIGAN	115	KALEY	115	1	11						
2004-PI-20	MICHIGAN	115	GRANT	115	1	11						
2004-PI-20	PERSHING	115	GRANT	115	1	11						
2004-PI-20	AMERICA	115	KALEY	115	1	11						
2004-PI-20	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-20	AZALEA	115	BENNETT	115	1	11						
2004-PI-20	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-20	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-20	PASADENA	230	PASADENA	115	1	2						
2004-PI-20	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-20	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-20	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-20	IND RIV	230	IND RIV	115	1	11						
2004-PI-20	LARGO	230	LARGO A	69	1	2						
2004-PI-20	SHELD	230	SHELD-NW	69	1	16						
2004-PI-20	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-20	WINDERME	230	WINDERME	69	1	2						
2004-PI-20	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-20	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-20	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-20	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-21	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-21	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-21	IND RIV	230	STANTON	230	1	11						
2004-PI-21	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-21	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-21	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-21	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-21	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-21	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-21	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-21	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-21	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-21	SN PLANT	115	TURNER	115	1	1						
2004-PI-21	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-21	MICHIGAN	115	KALEY	115	1	11						
2004-PI-21	MICHIGAN	115	GRANT	115	1	11						
2004-PI-21	PERSHING	115	GRANT	115	1	11						
2004-PI-21	AMERICA	115	KALEY	115	1	11						
2004-PI-21	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-21	AZALEA	115	BENNETT	115	1	11						
2004-PI-21	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-21	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-21	PASADENA	230	PASADENA	115	1	2						
2004-PI-21	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-21	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-21	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-21	IND RIV	230	IND RIV	115	1	11						
2004-PI-21	LARGO	230	LARGO A	69	1	2						
2004-PI-21	SHELD	230	SHELD-NW	69	1	16						
2004-PI-21	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-21	WINDERME	230	WINDERME	69	1	2						
2004-PI-21	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-21	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-21	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-21	JASPER	115	JASPER	69	1	2						
2004-PI-22	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-22	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-22	IND RIV	230	STANTON	230	1	11						
2004-PI-22	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-22	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-22	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-22	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-22	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-22	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-22	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-22	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-22	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-22	SN PLANT	115	TURNER	115	1	1						
2004-PI-22	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-22	MICHIGAN	115	KALEY	115	1	11						
2004-PI-22	MICHIGAN	115	GRANT	115	1	11						
2004-PI-22	PERSHING	115	GRANT	115	1	11						
2004-PI-22	AMERICA	115	KALEY	115	1	11						
2004-PI-22	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-22	AZALEA	115	BENNETT	115	1	11						
2004-PI-22	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-22	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-22	PASADENA	230	PASADENA	115	1	2						
2004-PI-22	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-22	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-22	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-22	IND RIV	230	IND RIV	115	1	11						
2004-PI-22	LARGO	230	LARGO A	69	1	2						
2004-PI-22	SHELD	230	SHELD-NW	69	1	16						
2004-PI-22	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-22	WINDERME	230	WINDERME	69	1	2						
2004-PI-22	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-22	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-22	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-22	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-23	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-23	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-23	IND RIV	230	STANTON	230	1	11						
2004-PI-23	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-23	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-23	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-23	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-23	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-23	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-23	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-23	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-23	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-23	SN PLANT	115	TURNER	115	1	1						
2004-PI-23	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-23	MICHIGAN	115	KALEY	115	1	11						
2004-PI-23	MICHIGAN	115	GRANT	115	1	11						
2004-PI-23	PERSHING	115	GRANT	115	1	11						
2004-PI-23	AMERICA	115	KALEY	115	1	11						
2004-PI-23	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-23	AZALEA	115	BENNETT	115	1	11						
2004-PI-23	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-23	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-23	PASADENA	230	PASADENA	115	1	2						
2004-PI-23	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-23	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-23	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-23	IND RIV	230	IND RIV	115	1	11						
2004-PI-23	LARGO	230	LARGO A	69	1	2						
2004-PI-23	SHELD	230	SHELD-NW	69	1	16						
2004-PI-23	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-23	WINDERME	230	WINDERME	69	1	2						
2004-PI-23	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-23	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-23	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-23	JASPER	115	JASPER	69	1	2						
2004-PI-24	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-24	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-24	IND RIV	230	STANTON	230	1	11						
2004-PI-24	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-24	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-24	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-24	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-24	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-24	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-24	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-24	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-24	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-24	SN PLANT	115	TURNER	115	1	1						
2004-PI-24	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-24	MICHIGAN	115	KALEY	115	1	11						
2004-PI-24	MICHIGAN	115	GRANT	115	1	11						
2004-PI-24	PERSHING	115	GRANT	115	1	11						
2004-PI-24	AMERICA	115	KALEY	115	1	11						
2004-PI-24	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-24	AZALEA	115	BENNETT	115	1	11						
2004-PI-24	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-24	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-24	PASADENA	230	PASADENA	115	1	2						
2004-PI-24	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-24	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-24	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-24	IND RIV	230	IND RIV	115	1	11						
2004-PI-24	LARGO	230	LARGO A	69	1	2						
2004-PI-24	SHELD	230	SHELD-NW	69	1	16						
2004-PI-24	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-24	WINDERME	230	WINDERME	69	1	2						
2004-PI-24	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-24	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-24	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-24	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-25	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-25	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-25	IND RIV	230	STANTON	230	1	11						
2004-PI-25	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-25	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-25	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-25	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-25	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-25	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-25	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-25	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-25	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-25	SN PLANT	115	TURNER	115	1	1						
2004-PI-25	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-25	MICHIGAN	115	KALEY	115	1	11						
2004-PI-25	MICHIGAN	115	GRANT	115	1	11						
2004-PI-25	PERSHING	115	GRANT	115	1	11						
2004-PI-25	AMERICA	115	KALEY	115	1	11						
2004-PI-25	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-25	AZALEA	115	BENNETT	115	1	11						
2004-PI-25	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-25	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-25	PASADENA	230	PASADENA	115	1	2						
2004-PI-25	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-25	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-25	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-25	IND RIV	230	IND RIV	115	1	11						
2004-PI-25	LARGO	230	LARGO A	69	1	2						
2004-PI-25	SHELD	230	SHELD-NW	69	1	16						
2004-PI-25	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-25	WINDERME	230	WINDERME	69	1	2						
2004-PI-25	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-25	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-25	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-25	JASPER	115	JASPER	69	1	2						
2004-PI-26	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-26	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-26	IND RIV	230	STANTON	230	1	11						
2004-PI-26	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-26	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-26	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-26	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-26	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-26	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-26	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-26	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-26	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-26	SN PLANT	115	TURNER	115	1	1						
2004-PI-26	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-26	MICHIGAN	115	KALEY	115	1	11						
2004-PI-26	MICHIGAN	115	GRANT	115	1	11						
2004-PI-26	PERSHING	115	GRANT	115	1	11						
2004-PI-26	AMERICA	115	KALEY	115	1	11						
2004-PI-26	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-26	AZALEA	115	BENNETT	115	1	11						
2004-PI-26	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-26	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-26	PASADENA	230	PASADENA	115	1	2						
2004-PI-26	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-26	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-26	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-26	IND RIV	230	IND RIV	115	1	11						
2004-PI-26	LARGO	230	LARGO A	69	1	2						
2004-PI-26	SHELD	230	SHELD-NW	69	1	16						
2004-PI-26	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-26	WINDERME	230	WINDERME	69	1	2						
2004-PI-26	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-26	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-26	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-26	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-27	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-27	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-27	IND RIV	230	STANTON	230	1	11						
2004-PI-27	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-27	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-27	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-27	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-27	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-27	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-27	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-27	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-27	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-27	SN PLANT	115	TURNER	115	1	1						
2004-PI-27	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-27	MICHIGAN	115	KALEY	115	1	11						
2004-PI-27	MICHIGAN	115	GRANT	115	1	11						
2004-PI-27	PERSHING	115	GRANT	115	1	11						
2004-PI-27	AMERICA	115	KALEY	115	1	11						
2004-PI-27	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-27	AZALEA	115	BENNETT	115	1	11						
2004-PI-27	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-27	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-27	PASADENA	230	PASADENA	115	1	2						
2004-PI-27	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-27	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-27	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-27	IND RIV	230	IND RIV	115	1	11						
2004-PI-27	LARGO	230	LARGO A	69	1	2						
2004-PI-27	SHELD	230	SHELD-NW	69	1	16						
2004-PI-27	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-27	WINDERME	230	WINDERME	69	1	2						
2004-PI-27	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-27	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-27	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-27	JASPER	115	JASPER	69	1	2						
2004-PI-28	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-28	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-28	IND RIV	230	STANTON	230	1	11						
2004-PI-28	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-28	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-28	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-28	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-28	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-28	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-28	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-28	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-28	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-28	SN PLANT	115	TURNER	115	1	1						
2004-PI-28	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-28	MICHIGAN	115	KALEY	115	1	11						
2004-PI-28	MICHIGAN	115	GRANT	115	1	11						
2004-PI-28	PERSHING	115	GRANT	115	1	11						
2004-PI-28	AMERICA	115	KALEY	115	1	11						
2004-PI-28	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-28	AZALEA	115	BENNETT	115	1	11						
2004-PI-28	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-28	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-28	PASADENA	230	PASADENA	115	1	2						
2004-PI-28	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-28	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-28	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-28	IND RIV	230	IND RIV	115	1	11						
2004-PI-28	LARGO	230	LARGO A	69	1	2						
2004-PI-28	SHELD	230	SHELD-NW	69	1	16						
2004-PI-28	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-28	WINDERME	230	WINDERME	69	1	2						
2004-PI-28	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-28	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-28	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-28	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-29	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-29	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-29	IND RIV	230	STANTON	230	1	11						
2004-PI-29	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-29	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-29	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-29	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-29	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-29	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-29	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-29	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-29	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-29	SN PLANT	115	TURNER	115	1	1						
2004-PI-29	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-29	MICHIGAN	115	KALEY	115	1	11						
2004-PI-29	MICHIGAN	115	GRANT	115	1	11						
2004-PI-29	PERSHING	115	GRANT	115	1	11						
2004-PI-29	AMERICA	115	KALEY	115	1	11						
2004-PI-29	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-29	AZALEA	115	BENNETT	115	1	11						
2004-PI-29	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-29	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-29	PASADENA	230	PASADENA	115	1	2						
2004-PI-29	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-29	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-29	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-29	IND RIV	230	IND RIV	115	1	11						
2004-PI-29	LARGO	230	LARGO A	69	1	2						
2004-PI-29	SHELD	230	SHELD-NW	69	1	16						
2004-PI-29	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-29	WINDERME	230	WINDERME	69	1	2						
2004-PI-29	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-29	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-29	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-29	JASPER	115	JASPER	69	1	2						
2004-PI-30	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-30	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-30	IND RIV	230	STANTON	230	1	11						
2004-PI-30	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-30	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-30	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-30	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-30	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-30	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-30	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-30	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-30	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-30	SN PLANT	115	TURNER	115	1	1						
2004-PI-30	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-30	MICHIGAN	115	KALEY	115	1	11						
2004-PI-30	MICHIGAN	115	GRANT	115	1	11						
2004-PI-30	PERSHING	115	GRANT	115	1	11						
2004-PI-30	AMERICA	115	KALEY	115	1	11						
2004-PI-30	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-30	AZALEA	115	BENNETT	115	1	11						
2004-PI-30	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-30	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-30	PASADENA	230	PASADENA	115	1	2						
2004-PI-30	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-30	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-30	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-30	IND RIV	230	IND RIV	115	1	11						
2004-PI-30	LARGO	230	LARGO A	69	1	2						
2004-PI-30	SHELD	230	SHELD-NW	69	1	16						
2004-PI-30	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-30	WINDERME	230	WINDERME	69	1	2						
2004-PI-30	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-30	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-30	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-30	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-31	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-31	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-31	IND RIV	230	STANTON	230	1	11						
2004-PI-31	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-31	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-31	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-31	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-31	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-31	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-31	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-31	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-31	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-31	SN PLANT	115	TURNER	115	1	1						
2004-PI-31	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-31	MICHIGAN	115	KALEY	115	1	11						
2004-PI-31	MICHIGAN	115	GRANT	115	1	11						
2004-PI-31	PERSHING	115	GRANT	115	1	11						
2004-PI-31	AMERICA	115	KALEY	115	1	11						
2004-PI-31	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-31	AZALEA	115	BENNETT	115	1	11						
2004-PI-31	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-31	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-31	PASADENA	230	PASADENA	115	1	2						
2004-PI-31	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-31	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-31	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-31	IND RIV	230	IND RIV	115	1	11						
2004-PI-31	LARGO	230	LARGO A	69	1	2						
2004-PI-31	SHELD	230	SHELD-NW	69	1	16						
2004-PI-31	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-31	WINDERME	230	WINDERME	69	1	2						
2004-PI-31	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-31	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-31	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-31	JASPER	115	JASPER	69	1	2						
2004-PI-32	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-32	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-32	IND RIV	230	STANTON	230	1	11						
2004-PI-32	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-32	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-32	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-32	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-32	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-32	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-32	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-32	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-32	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-32	SN PLANT	115	TURNER	115	1	1						
2004-PI-32	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-32	MICHIGAN	115	KALEY	115	1	11						
2004-PI-32	MICHIGAN	115	GRANT	115	1	11						
2004-PI-32	PERSHING	115	GRANT	115	1	11						
2004-PI-32	AMERICA	115	KALEY	115	1	11						
2004-PI-32	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-32	AZALEA	115	BENNETT	115	1	11						
2004-PI-32	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-32	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-32	PASADENA	230	PASADENA	115	1	2						
2004-PI-32	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-32	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-32	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-32	IND RIV	230	IND RIV	115	1	11						
2004-PI-32	LARGO	230	LARGO A	69	1	2						
2004-PI-32	SHELD	230	SHELD-NW	69	1	16						
2004-PI-32	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-32	WINDERME	230	WINDERME	69	1	2						
2004-PI-32	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-32	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-32	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-32	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-33	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-33	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-33	IND RIV	230	STANTON	230	1	11						
2004-PI-33	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-33	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-33	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-33	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-33	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-33	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-33	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-33	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-33	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-33	SN PLANT	115	TURNER	115	1	1						
2004-PI-33	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-33	MICHIGAN	115	KALEY	115	1	11						
2004-PI-33	MICHIGAN	115	GRANT	115	1	11						
2004-PI-33	PERSHING	115	GRANT	115	1	11						
2004-PI-33	AMERICA	115	KALEY	115	1	11						
2004-PI-33	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-33	AZALEA	115	BENNETT	115	1	11						
2004-PI-33	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-33	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-33	PASADENA	230	PASADENA	115	1	2						
2004-PI-33	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-33	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-33	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-33	IND RIV	230	IND RIV	115	1	11						
2004-PI-33	LARGO	230	LARGO A	69	1	2						
2004-PI-33	SHELD	230	SHELD-NW	69	1	16						
2004-PI-33	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-33	WINDERME	230	WINDERME	69	1	2						
2004-PI-33	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-33	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-33	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-33	JASPER	115	JASPER	69	1	2						
2004-PI-34	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-34	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-34	IND RIV	230	STANTON	230	1	11						
2004-PI-34	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-34	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-34	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-34	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-34	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-34	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-34	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-34	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-34	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-34	SN PLANT	115	TURNER	115	1	1						
2004-PI-34	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-34	MICHIGAN	115	KALEY	115	1	11						
2004-PI-34	MICHIGAN	115	GRANT	115	1	11						
2004-PI-34	PERSHING	115	GRANT	115	1	11						
2004-PI-34	AMERICA	115	KALEY	115	1	11						
2004-PI-34	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-34	AZALEA	115	BENNETT	115	1	11						
2004-PI-34	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-34	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-34	PASADENA	230	PASADENA	115	1	2						
2004-PI-34	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-34	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-34	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-34	IND RIV	230	IND RIV	115	1	11						
2004-PI-34	LARGO	230	LARGO A	69	1	2						
2004-PI-34	SHELD	230	SHELD-NW	69	1	16						
2004-PI-34	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-34	WINDERME	230	WINDERME	69	1	2						
2004-PI-34	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-34	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-34	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-34	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-PI Base No NSB Gen	Case 2004-PIA Sell to FPL	Case 2004-PIB Sell to FPC	Case 2004-PIC Sell to TEC	Case 2004-PID Sell to JEA	Case 2004-PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-PI-35	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-35	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-35	IND RIV	230	STANTON	230	1	11						
2004-PI-35	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-35	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-35	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-35	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-35	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-35	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-35	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-35	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-35	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-35	SN PLANT	115	TURNER	115	1	1						
2004-PI-35	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-35	MICHIGAN	115	KALEY	115	1	11						
2004-PI-35	MICHIGAN	115	GRANT	115	1	11						
2004-PI-35	PERSHING	115	GRANT	115	1	11						
2004-PI-35	AMERICA	115	KALEY	115	1	11						
2004-PI-35	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-35	AZALEA	115	BENNETT	115	1	11						
2004-PI-35	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-35	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-35	PASADENA	230	PASADENA	115	1	2						
2004-PI-35	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-35	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-35	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-35	IND RIV	230	IND RIV	115	1	11						
2004-PI-35	LARGO	230	LARGO A	69	1	2						
2004-PI-35	SHELD	230	SHELD-NW	69	1	16						
2004-PI-35	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-35	WINDERME	230	WINDERME	69	1	2						
2004-PI-35	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-35	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-35	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-35	JASPER	115	JASPER	69	1	2						
2004-PI-36	SN PLANT	230	SYLVAN	230	1	1						
2004-PI-36	SYLVAN	230	N LONGWD	230	1	1						
2004-PI-36	IND RIV	230	STANTON	230	1	11						
2004-PI-36	SILVR SP	230	SILV SPN	230	1	2						
2004-PI-36	SILVR SP	230	SILV SPN	230	2	2						
2004-PI-36	RIO PINR	230	CURRY FD	230	1	2						
2004-PI-36	JUNEAU-W	138	GANNON	138	1	16						
2004-PI-36	NSB-SMYR	115	CASSADAG	115	1	2						
2004-PI-36	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-PI-36	NSB-SMYR	115	TAYLOR	115	1	1						
2004-PI-36	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-PI-36	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-PI-36	SN PLANT	115	TURNER	115	1	1						
2004-PI-36	PASADENA	115	40ST-DUM	115	1	2						
2004-PI-36	MICHIGAN	115	KALEY	115	1	11						
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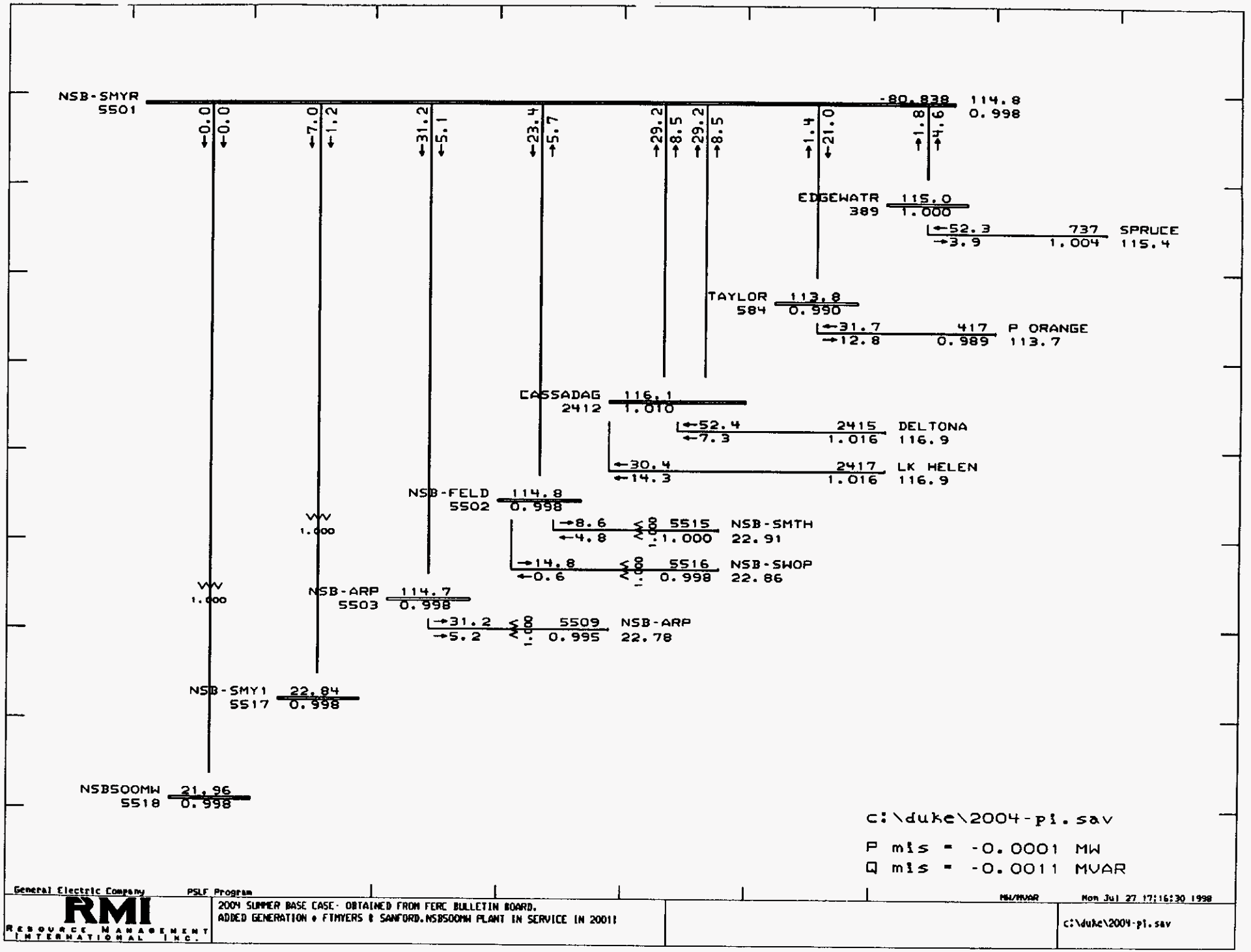
2004-PI-36	JASPER	115	WGHTCHPL	115	1	2						
2004-PI-36	AZALEA	115	BENNETT	115	1	11						
2004-PI-36	FLORALTP	69	INVERNTP	69	1	2						
2004-PI-36	ALACH TP	69	HIGH SPG	69	1	2						
2004-PI-36	PASADENA	230	PASADENA	115	1	2						
2004-PI-36	SUWANNEE	230	SUWANNEE	115	1	2						
2004-PI-36	SUWANNEE	230	SUWANNEE	115	2	2						
2004-PI-36	E CLRWTR	230	E CLRWTR	115	1	2						
2004-PI-36	IND RIV	230	IND RIV	115	1	11						
2004-PI-36	LARGO	230	LARGO A	69	1	2						
2004-PI-36	SHELD	230	SHELD-NW	69	1	16						
2004-PI-36	CLMT EST	230	CLMT EST	69	1	2						
2004-PI-36	WINDERME	230	WINDERME	69	1	2						
2004-PI-36	RIVER-S	230	RIVER-S	69	1	16						
2004-PI-36	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-PI-36	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-PI-36	JASPER	115	JASPER	69	1	2						

APPENDIX II-A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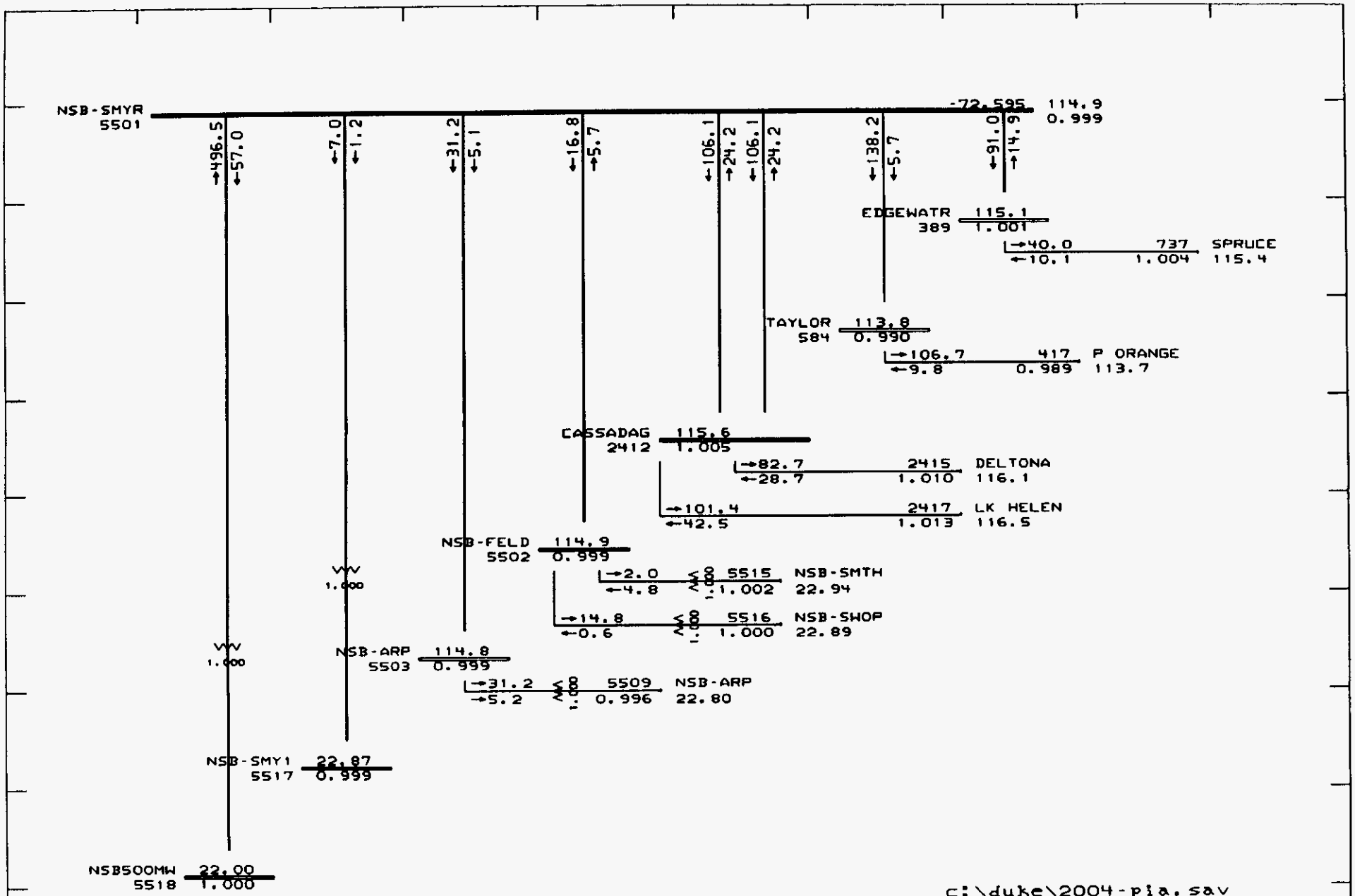
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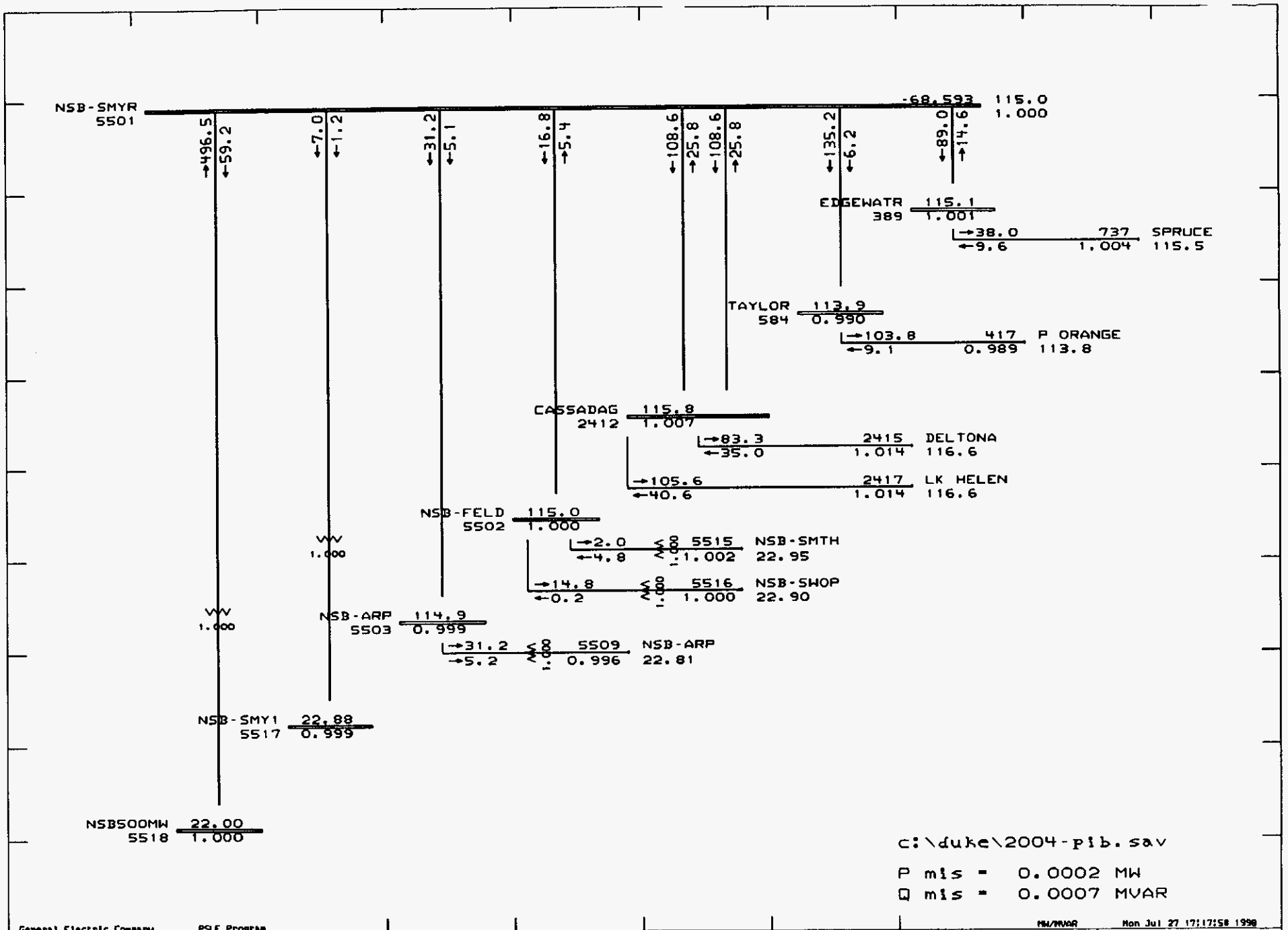
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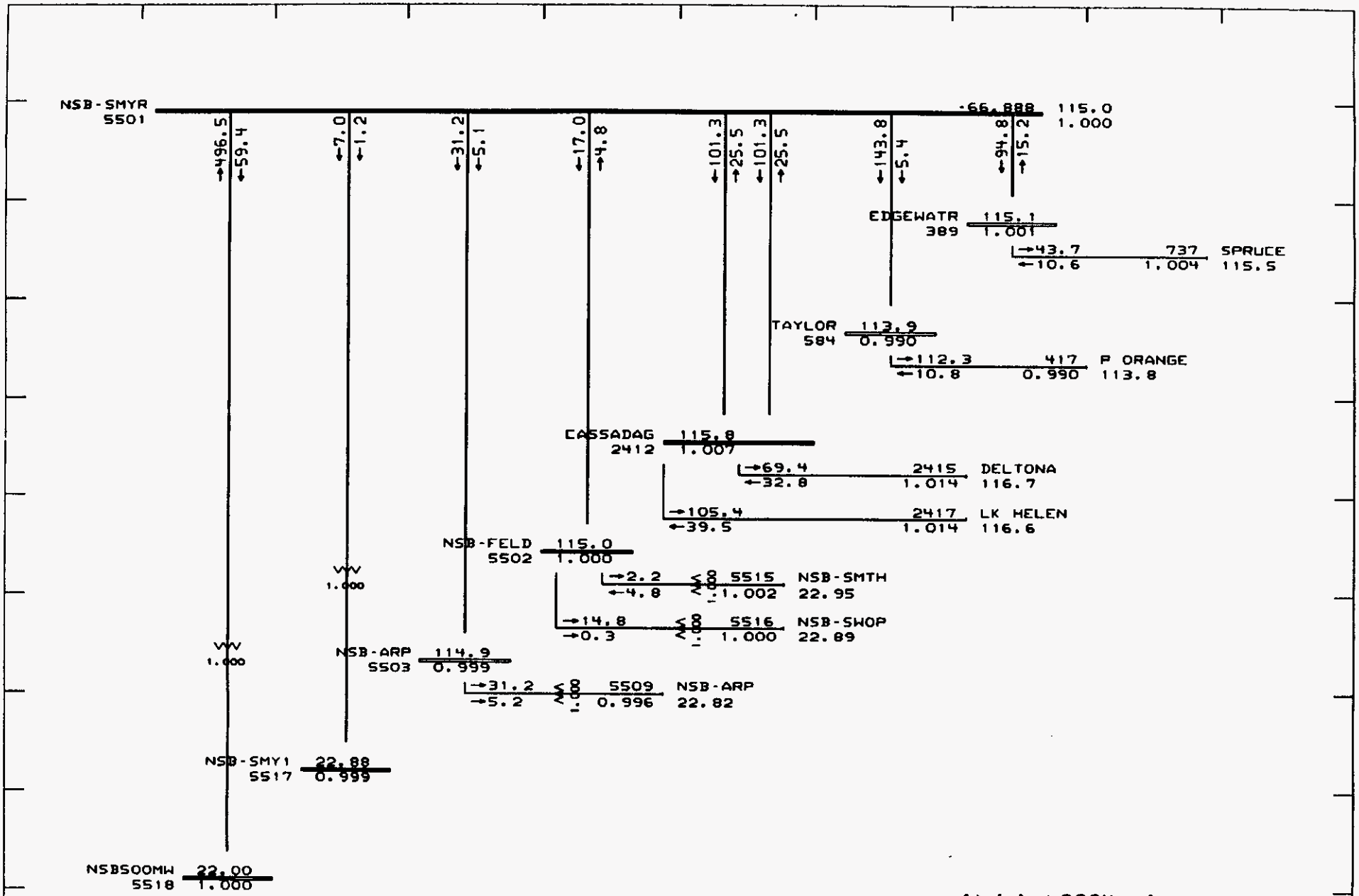
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2004 SUMMER BASE CASE - FY9697 - FINAL REV.
CASE OBTAINED FROM FERC BULLETIN BOARD. MODIFIED TO REFLECT ADDITION OF GENERATION AT FTMYERS (2002) & AT SANFORD (2004) AND ASSOCIATED
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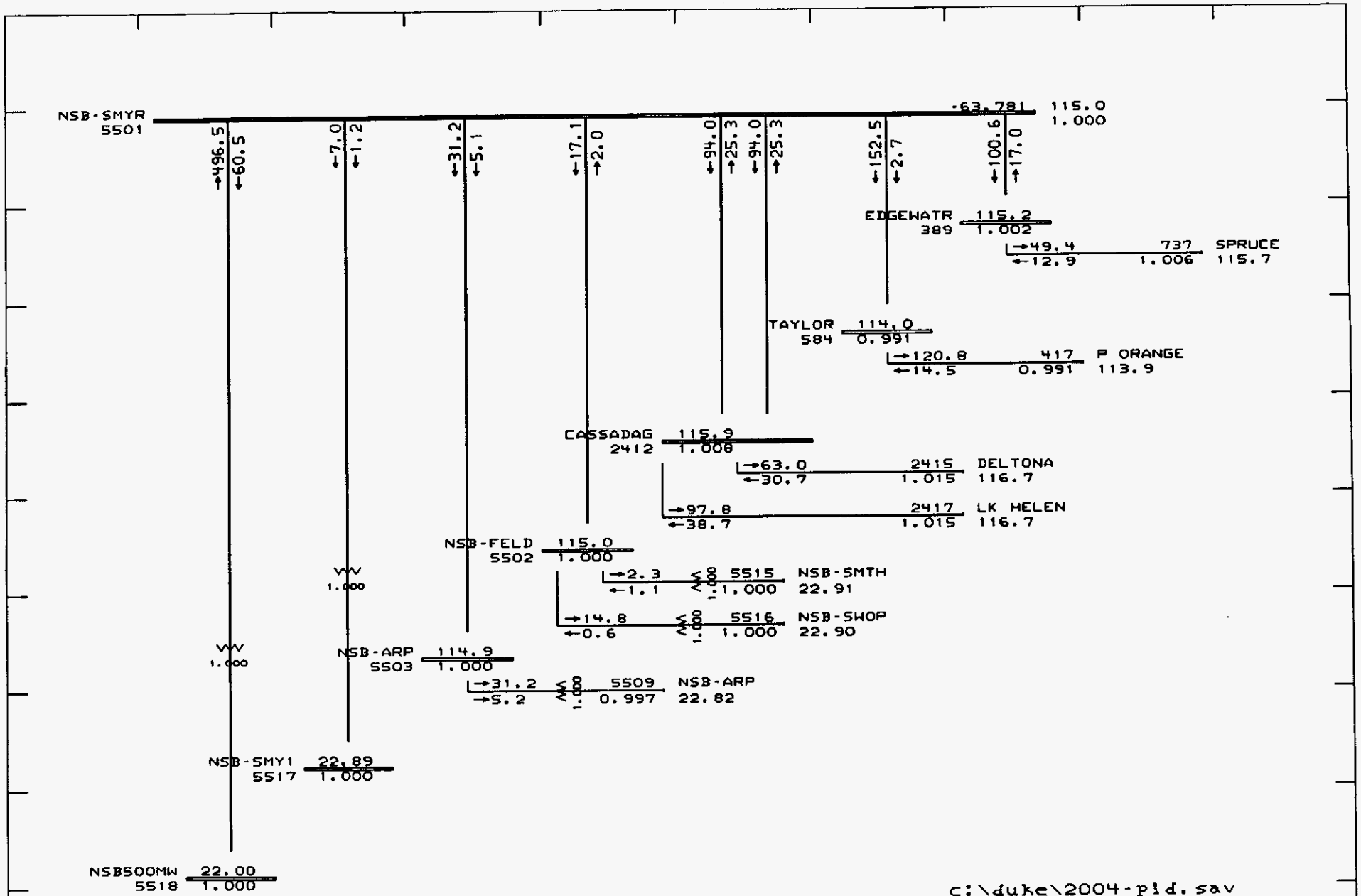
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CASSADAG 115.9
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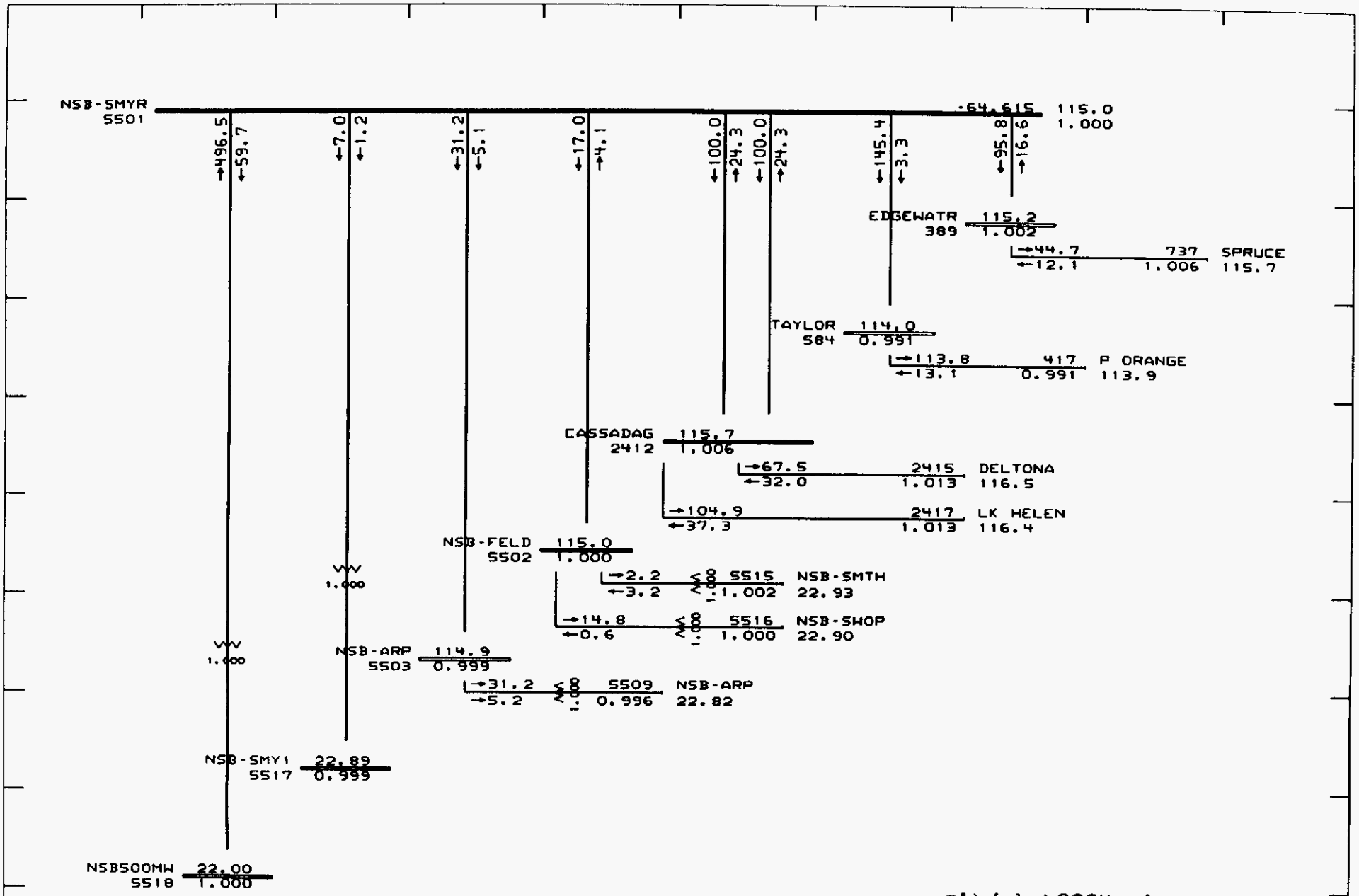
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113.9
CASSADAG 115.7
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DELTONA
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NSB-ARP 114.9
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2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD. NSB500MW PLANT IN SERVICE IN 2001!
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APPENDIX III

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-1	SN PLANT	230	SYLVAN	230	1	1						
2004-1	SYLVAN	230	N LONGWD	230	1	1						
2004-1	IND RIV	230	STANTON	230	1	11						
2004-1	SILVR SP	230	SILV SPN	230	1	2						
2004-1	SILVR SP	230	SILV SPN	230	2	2						
2004-1	RIO PINR	230	CURRY FD	230	1	2						
2004-1	JUNEAU-W	138	GANNON	138	1	16						
2004-1	NSB-SMYR	115	CASSADAG	115	1	2						
2004-1	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-1	NSB-SMYR	115	TAYLOR	115	1	1						
2004-1	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-1	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-1	SN PLANT	115	TURNER	115	1	1						
2004-1	PASADENA	115	40ST-DUM	115	1	2						
2004-1	MICHIGAN	115	KALEY	115	1	11						
2004-1	MICHIGAN	115	GRANT	115	1	11						
2004-1	PERSHING	115	GRANT	115	1	11						
2004-1	AMERICA	115	KALEY	115	1	11						
2004-1	JASPER	115	WGHTCHPL	115	1	2						
2004-1	AZALEA	115	BENNETT	115	1	11						
2004-1	FLORALTP	69	INVERNTP	69	1	2						
2004-1	ALACH TP	69	HIGH SPG	69	1	2						
2004-1	PASADENA	230	PASADENA	115	1	2						
2004-1	SUWANNEE	230	SUWANNEE	115	1	2						
2004-1	SUWANNEE	230	SUWANNEE	115	2	2						
2004-1	E CLRWTR	230	E CLRWTR	115	1	2						
2004-1	IND RIV	230	IND RIV	115	1	11						
2004-1	LARGO	230	LARGO A	69	1	2						
2004-1	SHELD	230	SHELD-NW	69	1	16						
2004-1	CLMT EST	230	CLMT EST	69	1	2						
2004-1	WINDERME	230	WINDERME	69	1	2						
2004-1	RIVER-S	230	RIVER-S	69	1	16						
2004-1	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-1	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-1	JASPER	115	JASPER	69	1	2						
2004-2	SN PLANT	230	SYLVAN	230	1	1						
2004-2	SYLVAN	230	N LONGWD	230	1	1						
2004-2	IND RIV	230	STANTON	230	1	11						
2004-2	SILVR SP	230	SILV SPN	230	1	2						
2004-2	SILVR SP	230	SILV SPN	230	2	2						
2004-2	RIO PINR	230	CURRY FD	230	1	2						
2004-2	JUNEAU-W	138	GANNON	138	1	16						
2004-2	NSB-SMYR	115	CASSADAG	115	1	2						
2004-2	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-2	NSB-SMYR	115	TAYLOR	115	1	1					104.6	101.5
2004-2	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-2	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-2	SN PLANT	115	TURNER	115	1	1						
2004-2	PASADENA	115	40ST-DUM	115	1	2						
2004-2	MICHIGAN	115	KALEY	115	1	11						
2004-2	MICHIGAN	115	GRANT	115	1	11						
2004-2	PERSHING	115	GRANT	115	1	11						
2004-2	AMERICA	115	KALEY	115	1	11						
2004-2	JASPER	115	WGHTCHPL	115	1	2						
2004-2	AZALEA	115	BENNETT	115	1	11						
2004-2	FLORALTP	69	INVERNTP	69	1	2						
2004-2	ALACH TP	69	HIGH SPG	69	1	2						
2004-2	PASADENA	230	PASADENA	115	1	2						
2004-2	SUWANNEE	230	SUWANNEE	115	1	2						
2004-2	SUWANNEE	230	SUWANNEE	115	2	2						
2004-2	E CLRWTR	230	E CLRWTR	115	1	2						
2004-2	IND RIV	230	IND RIV	115	1	11						
2004-2	LARGO	230	LARGO A	69	1	2						
2004-2	SHELD	230	SHELD-NW	69	1	16						
2004-2	CLMT EST	230	CLMT EST	69	1	2						
2004-2	WINDERME	230	WINDERME	69	1	2						
2004-2	RIVER-S	230	RIVER-S	69	1	16						
2004-2	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-2	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-2	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-3	SN PLANT	230	SYLVAN	230	1	1						
2004-3	SYLVAN	230	N LONGWD	230	1	1						
2004-3	IND RIV	230	STANTON	230	1	11						
2004-3	SILVR SP	230	SILV SPN	230	1	2						
2004-3	SILVR SP	230	SILV SPN	230	2	2						
2004-3	RIO PINR	230	CURRY FD	230	1	2						
2004-3	JUNEAU-W	138	GANNON	138	1	16						
2004-3	NSB-SMYR	115	CASSADAG	115	1	2						
2004-3	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-3	NSB-SMYR	115	TAYLOR	115	1	1						
2004-3	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-3	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-3	SN PLANT	115	TURNER	115	1	1						
2004-3	PASADENA	115	40ST-DUM	115	1	2						
2004-3	MICHIGAN	115	KALEY	115	1	11						
2004-3	MICHIGAN	115	GRANT	115	1	11						
2004-3	PERSHING	115	GRANT	115	1	11						
2004-3	AMERICA	115	KALEY	115	1	11						
2004-3	JASPER	115	WGHTCHPL	115	1	2						
2004-3	AZALEA	115	BENNETT	115	1	11						
2004-3	FLORALTP	69	INVERNTP	69	1	2						
2004-3	ALACH TP	69	HIGH SPG	69	1	2						
2004-3	PASADENA	230	PASADENA	115	1	2						
2004-3	SUWANNEE	230	SUWANNEE	115	1	2						
2004-3	SUWANNEE	230	SUWANNEE	115	2	2						
2004-3	E CLRWTR	230	E CLRWTR	115	1	2						
2004-3	IND RIV	230	IND RIV	115	1	11						
2004-3	LARGO	230	LARGO A	69	1	2						
2004-3	SHELD	230	SHELD-NW	69	1	16						
2004-3	CLMT EST	230	CLMT EST	69	1	2						
2004-3	WINDERME	230	WINDERME	69	1	2						
2004-3	RIVER-S	230	RIVER-S	69	1	16						
2004-3	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-3	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-3	JASPER	115	JASPER	69	1	2						
2004-4	SN PLANT	230	SYLVAN	230	1	1						
2004-4	SYLVAN	230	N LONGWD	230	1	1						
2004-4	IND RIV	230	STANTON	230	1	11						
2004-4	SILVR SP	230	SILV SPN	230	1	2						
2004-4	SILVR SP	230	SILV SPN	230	2	2						
2004-4	RIO PINR	230	CURRY FD	230	1	2						
2004-4	JUNEAU-W	138	GANNON	138	1	16						
2004-4	NSB-SMYR	115	CASSADAG	115	1	2						
2004-4	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-4	NSB-SMYR	115	TAYLOR	115	1	1						
2004-4	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-4	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-4	SN PLANT	115	TURNER	115	1	1						
2004-4	PASADENA	115	40ST-DUM	115	1	2						
2004-4	MICHIGAN	115	KALEY	115	1	11						
2004-4	MICHIGAN	115	GRANT	115	1	11						
2004-4	PERSHING	115	GRANT	115	1	11						
2004-4	AMERICA	115	KALEY	115	1	11						
2004-4	JASPER	115	WGHTCHPL	115	1	2						
2004-4	AZALEA	115	BENNETT	115	1	11						
2004-4	FLORALTP	69	INVERNTP	69	1	2						
2004-4	ALACH TP	69	HIGH SPG	69	1	2						
2004-4	PASADENA	230	PASADENA	115	1	2						
2004-4	SUWANNEE	230	SUWANNEE	115	1	2						
2004-4	SUWANNEE	230	SUWANNEE	115	2	2						
2004-4	E CLRWTR	230	E CLRWTR	115	1	2						
2004-4	IND RIV	230	IND RIV	115	1	11						
2004-4	LARGO	230	LARGO A	69	1	2						
2004-4	SHELD	230	SHELD-NW	69	1	16						
2004-4	CLMT EST	230	CLMT EST	69	1	2						
2004-4	WINDERME	230	WINDERME	69	1	2						
2004-4	RIVER-S	230	RIVER-S	69	1	16						
2004-4	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-4	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-4	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-5	SN PLANT	230	SYLVAN	230	1	1						
2004-5	SYLVAN	230	N LONGWD	230	1	1						
2004-5	IND RIV	230	STANTON	230	1	11						
2004-5	SILVR SP	230	SILV SPN	230	1	2						
2004-5	SILVR SP	230	SILV SPN	230	2	2						
2004-5	RIO PINR	230	CURRY FD	230	1	2						
2004-5	JUNEAU-W	138	GANNON	138	1	16						
2004-5	NSB-SMYR	115	CASSADAG	115	1	2						
2004-5	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-5	NSB-SMYR	115	TAYLOR	115	1	1						
2004-5	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-5	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-5	SN PLANT	115	TURNER	115	1	1						
2004-5	PASADENA	115	40ST-DUM	115	1	2						
2004-5	MICHIGAN	115	KALEY	115	1	11						
2004-5	MICHIGAN	115	GRANT	115	1	11						
2004-5	PERSHING	115	GRANT	115	1	11						
2004-5	AMERICA	115	KALEY	115	1	11						
2004-5	JASPER	115	WGHTCHPL	115	1	2						
2004-5	AZALEA	115	BENNETT	115	1	11						
2004-5	FLORALTP	69	INVERNTP	69	1	2						
2004-5	ALACH TP	69	HIGH SPG	69	1	2						
2004-5	PASADENA	230	PASADENA	115	1	2						
2004-5	SUWANNEE	230	SUWANNEE	115	1	2						
2004-5	SUWANNEE	230	SUWANNEE	115	2	2						
2004-5	E CLRWTR	230	E CLRWTR	115	1	2						
2004-5	IND RIV	230	IND RIV	115	1	11						
2004-5	LARGO	230	LARGO A	69	1	2						
2004-5	SHELD	230	SHELD-NW	69	1	16						
2004-5	CLMT EST	230	CLMT EST	69	1	2						
2004-5	WINDERME	230	WINDERME	69	1	2						
2004-5	RIVER-S	230	RIVER-S	69	1	16						
2004-5	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-5	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-5	JASPER	115	JASPER	69	1	2						
2004-6	SN PLANT	230	SYLVAN	230	1	1						
2004-6	SYLVAN	230	N LONGWD	230	1	1						
2004-6	IND RIV	230	STANTON	230	1	11						
2004-6	SILVR SP	230	SILV SPN	230	1	2						
2004-6	SILVR SP	230	SILV SPN	230	2	2						
2004-6	RIO PINR	230	CURRY FD	230	1	2						
2004-6	JUNEAU-W	138	GANNON	138	1	16						
2004-6	NSB-SMYR	115	CASSADAG	115	1	2						
2004-6	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-6	NSB-SMYR	115	TAYLOR	115	1	1						
2004-6	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-6	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-6	SN PLANT	115	TURNER	115	1	1						
2004-6	PASADENA	115	40ST-DUM	115	1	2						
2004-6	MICHIGAN	115	KALEY	115	1	11						
2004-6	MICHIGAN	115	GRANT	115	1	11						
2004-6	PERSHING	115	GRANT	115	1	11						
2004-6	AMERICA	115	KALEY	115	1	11						
2004-6	JASPER	115	WGHTCHPL	115	1	2						
2004-6	AZALEA	115	BENNETT	115	1	11						
2004-6	FLORALTP	69	INVERNTP	69	1	2						
2004-6	ALACH TP	69	HIGH SPG	69	1	2						
2004-6	PASADENA	230	PASADENA	115	1	2						
2004-6	SUWANNEE	230	SUWANNEE	115	1	2						
2004-6	SUWANNEE	230	SUWANNEE	115	2	2						
2004-6	E CLRWTR	230	E CLRWTR	115	1	2						
2004-6	IND RIV	230	IND RIV	115	1	11						
2004-6	LARGO	230	LARGO A	69	1	2						
2004-6	SHELD	230	SHELD-NW	69	1	16						
2004-6	CLMT EST	230	CLMT EST	69	1	2						
2004-6	WINDERME	230	WINDERME	69	1	2						
2004-6	RIVER-S	230	RIVER-S	69	1	16						
2004-6	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-6	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-6	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-7	SN PLANT	230	SYLVAN	230	1	1						
2004-7	SYLVAN	230	N LONGWD	230	1	1						
2004-7	IND RIV	230	STANTON	230	1	11						
2004-7	SILVR SP	230	SILV SPN	230	1	2						
2004-7	SILVR SP	230	SILV SPN	230	2	2						
2004-7	RIO PINR	230	CURRY FD	230	1	2						
2004-7	JUNEAU-W	138	GANNON	138	1	16						
2004-7	NSB-SMYR	115	CASSADAG	115	1	2						
2004-7	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-7	NSB-SMYR	115	TAYLOR	115	1	1						
2004-7	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-7	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-7	SN PLANT	115	TURNER	115	1	1						
2004-7	PASADENA	115	40ST-DUM	115	1	2						
2004-7	MICHIGAN	115	KALEY	115	1	11						
2004-7	MICHIGAN	115	GRANT	115	1	11						
2004-7	PERSHING	115	GRANT	115	1	11						
2004-7	AMERICA	115	KALEY	115	1	11						
2004-7	JASPER	115	WGHTCHPL	115	1	2						
2004-7	AZALEA	115	BENNETT	115	1	11						
2004-7	FLORALTP	69	INVERNTP	69	1	2						
2004-7	ALACH TP	69	HIGH SPG	69	1	2						
2004-7	PASADENA	230	PASADENA	115	1	2						
2004-7	SUWANNEE	230	SUWANNEE	115	1	2						
2004-7	SUWANNEE	230	SUWANNEE	115	2	2						
2004-7	E CLRWTR	230	E CLRWTR	115	1	2						
2004-7	IND RIV	230	IND RIV	115	1	11						
2004-7	LARGO	230	LARGO A	69	1	2						
2004-7	SHELD	230	SHELD-NW	69	1	16						
2004-7	CLMT EST	230	CLMT EST	69	1	2						
2004-7	WINDERME	230	WINDERME	69	1	2						
2004-7	RIVER-S	230	RIVER-S	69	1	16						
2004-7	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-7	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-7	JASPER	115	JASPER	69	1	2						
2004-8	SN PLANT	230	SYLVAN	230	1	1						
2004-8	SYLVAN	230	N LONGWD	230	1	1						
2004-8	IND RIV	230	STANTON	230	1	11						
2004-8	SILVR SP	230	SILV SPN	230	1	2						
2004-8	SILVR SP	230	SILV SPN	230	2	2						
2004-8	RIO PINR	230	CURRY FD	230	1	2						
2004-8	JUNEAU-W	138	GANNON	138	1	16						
2004-8	NSB-SMYR	115	CASSADAG	115	1	2						
2004-8	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-8	NSB-SMYR	115	TAYLOR	115	1	1						
2004-8	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-8	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-8	SN PLANT	115	TURNER	115	1	1						
2004-8	PASADENA	115	40ST-DUM	115	1	2						
2004-8	MICHIGAN	115	KALEY	115	1	11						
2004-8	MICHIGAN	115	GRANT	115	1	11						
2004-8	PERSHING	115	GRANT	115	1	11						
2004-8	AMERICA	115	KALEY	115	1	11						
2004-8	JASPER	115	WGHTCHPL	115	1	2						
2004-8	AZALEA	115	BENNETT	115	1	11						
2004-8	FLORALTP	69	INVERNTP	69	1	2						
2004-8	ALACH TP	69	HIGH SPG	69	1	2						
2004-8	PASADENA	230	PASADENA	115	1	2						
2004-8	SUWANNEE	230	SUWANNEE	115	1	2						
2004-8	SUWANNEE	230	SUWANNEE	115	2	2						
2004-8	E CLRWTR	230	E CLRWTR	115	1	2						
2004-8	IND RIV	230	IND RIV	115	1	11						
2004-8	LARGO	230	LARGO A	69	1	2						
2004-8	SHELD	230	SHELD-NW	69	1	16						
2004-8	CLMT EST	230	CLMT EST	69	1	2						
2004-8	WINDERME	230	WINDERME	69	1	2						
2004-8	RIVER-S	230	RIVER-S	69	1	16						
2004-8	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-8	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-8	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-9	SN PLANT	230	SYLVAN	230	1	1						
2004-9	SYLVAN	230	N LONGWD	230	1	1						
2004-9	IND RIV	230	STANTON	230	1	11						
2004-9	SILVR SP	230	SILV SPN	230	1	2						
2004-9	SILVR SP	230	SILV SPN	230	2	2						
2004-9	RIO PINR	230	CURRY FD	230	1	2						
2004-9	JUNEAU-W	138	GANNON	138	1	16						
2004-9	NSB-SMYR	115	CASSADAG	115	1	2						
2004-9	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-9	NSB-SMYR	115	TAYLOR	115	1	1						
2004-9	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-9	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-9	SN PLANT	115	TURNER	115	1	1						
2004-9	PASADENA	115	40ST-DUM	115	1	2						
2004-9	MICHIGAN	115	KALEY	115	1	11						
2004-9	MICHIGAN	115	GRANT	115	1	11						
2004-9	PERSHING	115	GRANT	115	1	11						
2004-9	AMERICA	115	KALEY	115	1	11						
2004-9	JASPER	115	WGHTCHPL	115	1	2						
2004-9	AZALEA	115	BENNETT	115	1	11						
2004-9	FLORALTP	69	INVERNTP	69	1	2						
2004-9	ALACH TP	69	HIGH SPG	69	1	2						
2004-9	PASADENA	230	PASADENA	115	1	2						
2004-9	SUWANNEE	230	SUWANNEE	115	1	2						
2004-9	SUWANNEE	230	SUWANNEE	115	2	2						
2004-9	E CLRWTR	230	E CLRWTR	115	1	2						
2004-9	IND RIV	230	IND RIV	115	1	11						
2004-9	LARGO	230	LARGO A	69	1	2						
2004-9	SHELD	230	SHELD-NW	69	1	16						
2004-9	CLMT EST	230	CLMT EST	69	1	2						
2004-9	WINDERME	230	WINDERME	69	1	2						
2004-9	RIVER-S	230	RIVER-S	69	1	16						
2004-9	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-9	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-9	JASPER	115	JASPER	69	1	2						
2004-10	SN PLANT	230	SYLVAN	230	1	1						
2004-10	SYLVAN	230	N LONGWD	230	1	1						
2004-10	IND RIV	230	STANTON	230	1	11						
2004-10	SILVR SP	230	SILV SPN	230	1	2						
2004-10	SILVR SP	230	SILV SPN	230	2	2						
2004-10	RIO PINR	230	CURRY FD	230	1	2						
2004-10	JUNEAU-W	138	GANNON	138	1	16						
2004-10	NSB-SMYR	115	CASSADAG	115	1	2						
2004-10	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-10	NSB-SMYR	115	TAYLOR	115	1	1						
2004-10	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-10	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-10	SN PLANT	115	TURNER	115	1	1						
2004-10	PASADENA	115	40ST-DUM	115	1	2						
2004-10	MICHIGAN	115	KALEY	115	1	11						
2004-10	MICHIGAN	115	GRANT	115	1	11						
2004-10	PERSHING	115	GRANT	115	1	11						
2004-10	AMERICA	115	KALEY	115	1	11						
2004-10	JASPER	115	WGHTCHPL	115	1	2						
2004-10	AZALEA	115	BENNETT	115	1	11						
2004-10	FLORALTP	69	INVERNTP	69	1	2						
2004-10	ALACH TP	69	HIGH SPG	69	1	2						
2004-10	PASADENA	230	PASADENA	115	1	2						
2004-10	SUWANNEE	230	SUWANNEE	115	1	2						
2004-10	SUWANNEE	230	SUWANNEE	115	2	2						
2004-10	E CLRWTR	230	E CLRWTR	115	1	2						
2004-10	IND RIV	230	IND RIV	115	1	11						
2004-10	LARGO	230	LARGO A	69	1	2						
2004-10	SHELD	230	SHELD-NW	69	1	16						
2004-10	CLMT EST	230	CLMT EST	69	1	2						
2004-10	WINDERME	230	WINDERME	69	1	2						
2004-10	RIVER-S	230	RIVER-S	69	1	16						
2004-10	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-10	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-10	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
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Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-11	SN PLANT	230	SYLVAN	230	1	1						
2004-11	SYLVAN	230	N LONGWD	230	1	1						
2004-11	IND RIV	230	STANTON	230	1	11						
2004-11	SILVR SP	230	SILV SPN	230	1	2						
2004-11	SILVR SP	230	SILV SPN	230	2	2						
2004-11	RIO PINR	230	CURRY FD	230	1	2						
2004-11	JUNEAU-W	138	GANNON	138	1	16						
2004-11	NSB-SMYR	115	CASSADAG	115	1	2						
2004-11	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-11	NSB-SMYR	115	TAYLOR	115	1	1						
2004-11	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-11	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-11	SN PLANT	115	TURNER	115	1	1						
2004-11	PASADENA	115	40ST-DUM	115	1	2						
2004-11	MICHIGAN	115	KALEY	115	1	11						
2004-11	MICHIGAN	115	GRANT	115	1	11						
2004-11	PERSHING	115	GRANT	115	1	11						
2004-11	AMERICA	115	KALEY	115	1	11						
2004-11	JASPER	115	WGHTCHPL	115	1	2						
2004-11	AZALEA	115	BENNETT	115	1	11						
2004-11	FLORALTP	69	INVERNTP	69	1	2						
2004-11	ALACH TP	69	HIGH SPG	69	1	2						
2004-11	PASADENA	230	PASADENA	115	1	2						
2004-11	SUWANNEE	230	SUWANNEE	115	1	2						
2004-11	SUWANNEE	230	SUWANNEE	115	2	2						
2004-11	E CLRWTR	230	E CLRWTR	115	1	2						
2004-11	IND RIV	230	IND RIV	115	1	11						
2004-11	LARGO	230	LARGO A	69	1	2						
2004-11	SHELD	230	SHELD-NW	69	1	16						
2004-11	CLMT EST	230	CLMT EST	69	1	2						
2004-11	WINDERME	230	WINDERME	69	1	2						
2004-11	RIVER-S	230	RIVER-S	69	1	16						
2004-11	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-11	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-11	JASPER	115	JASPER	69	1	2						
2004-12	SN PLANT	230	SYLVAN	230	1	1						
2004-12	SYLVAN	230	N LONGWD	230	1	1						
2004-12	IND RIV	230	STANTON	230	1	11						
2004-12	SILVR SP	230	SILV SPN	230	1	2						
2004-12	SILVR SP	230	SILV SPN	230	2	2						
2004-12	RIO PINR	230	CURRY FD	230	1	2						
2004-12	JUNEAU-W	138	GANNON	138	1	16						
2004-12	NSB-SMYR	115	CASSADAG	115	1	2						
2004-12	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-12	NSB-SMYR	115	TAYLOR	115	1	1						
2004-12	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-12	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-12	SN PLANT	115	TURNER	115	1	1						
2004-12	PASADENA	115	40ST-DUM	115	1	2						
2004-12	MICHIGAN	115	KALEY	115	1	11						
2004-12	MICHIGAN	115	GRANT	115	1	11						
2004-12	PERSHING	115	GRANT	115	1	11						
2004-12	AMERICA	115	KALEY	115	1	11						
2004-12	JASPER	115	WGHTCHPL	115	1	2						
2004-12	AZALEA	115	BENNETT	115	1	11						
2004-12	FLORALTP	69	INVERNTP	69	1	2						
2004-12	ALACH TP	69	HIGH SPG	69	1	2						
2004-12	PASADENA	230	PASADENA	115	1	2						
2004-12	SUWANNEE	230	SUWANNEE	115	1	2						
2004-12	SUWANNEE	230	SUWANNEE	115	2	2						
2004-12	E CLRWTR	230	E CLRWTR	115	1	2						
2004-12	IND RIV	230	IND RIV	115	1	11						
2004-12	LARGO	230	LARGO A	69	1	2						
2004-12	SHELD	230	SHELD-NW	69	1	16						
2004-12	CLMT EST	230	CLMT EST	69	1	2						
2004-12	WINDERME	230	WINDERME	69	1	2						
2004-12	RIVER-S	230	RIVER-S	69	1	16						
2004-12	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-12	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-12	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
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100% Load Base Case

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Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-13	SN PLANT	230	SYLVAN	230	1	1						
2004-13	SYLVAN	230	N LONGWD	230	1	1						
2004-13	IND RIV	230	STANTON	230	1	11						
2004-13	SILVR SP	230	SILV SPN	230	1	2						
2004-13	SILVR SP	230	SILV SPN	230	2	2						
2004-13	RIO PINR	230	CURRY FD	230	1	2						
2004-13	JUNEAU-W	138	GANNON	138	1	16						
2004-13	NSB-SMYR	115	CASSADAG	115	1	2						
2004-13	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-13	NSB-SMYR	115	TAYLOR	115	1	1						
2004-13	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-13	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-13	SN PLANT	115	TURNER	115	1	1						
2004-13	PASADENA	115	40ST-DUM	115	1	2						
2004-13	MICHIGAN	115	KALEY	115	1	11						
2004-13	MICHIGAN	115	GRANT	115	1	11						
2004-13	PERSHING	115	GRANT	115	1	11						
2004-13	AMERICA	115	KALEY	115	1	11						
2004-13	JASPER	115	WGHTCHPL	115	1	2						
2004-13	AZALEA	115	BENNETT	115	1	11						
2004-13	FLORALTP	69	INVERNTP	69	1	2						
2004-13	ALACH TP	69	HIGH SPG	69	1	2						
2004-13	PASADENA	230	PASADENA	115	1	2						
2004-13	SUWANNEE	230	SUWANNEE	115	1	2						
2004-13	SUWANNEE	230	SUWANNEE	115	2	2						
2004-13	E CLRWTR	230	E CLRWTR	115	1	2						
2004-13	IND RIV	230	IND RIV	115	1	11						
2004-13	LARGO	230	LARGO A	69	1	2						
2004-13	SHELD	230	SHELD-NW	69	1	16						
2004-13	CLMT EST	230	CLMT EST	69	1	2						
2004-13	WINDERME	230	WINDERME	69	1	2						
2004-13	RIVER-S	230	RIVER-S	69	1	16						
2004-13	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-13	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-13	JASPER	115	JASPER	69	1	2						
2004-14	SN PLANT	230	SYLVAN	230	1	1						
2004-14	SYLVAN	230	N LONGWD	230	1	1						
2004-14	IND RIV	230	STANTON	230	1	11						
2004-14	SILVR SP	230	SILV SPN	230	1	2						
2004-14	SILVR SP	230	SILV SPN	230	2	2						
2004-14	RIO PINR	230	CURRY FD	230	1	2						
2004-14	JUNEAU-W	138	GANNON	138	1	16						
2004-14	NSB-SMYR	115	CASSADAG	115	1	2						
2004-14	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-14	NSB-SMYR	115	TAYLOR	115	1	1						
2004-14	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-14	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-14	SN PLANT	115	TURNER	115	1	1						
2004-14	PASADENA	115	40ST-DUM	115	1	2						
2004-14	MICHIGAN	115	KALEY	115	1	11						
2004-14	MICHIGAN	115	GRANT	115	1	11						
2004-14	PERSHING	115	GRANT	115	1	11						
2004-14	AMERICA	115	KALEY	115	1	11						
2004-14	JASPER	115	WGHTCHPL	115	1	2						
2004-14	AZALEA	115	BENNETT	115	1	11						
2004-14	FLORALTP	69	INVERNTP	69	1	2						
2004-14	ALACH TP	69	HIGH SPG	69	1	2						
2004-14	PASADENA	230	PASADENA	115	1	2						
2004-14	SUWANNEE	230	SUWANNEE	115	1	2						
2004-14	SUWANNEE	230	SUWANNEE	115	2	2						
2004-14	E CLRWTR	230	E CLRWTR	115	1	2						
2004-14	IND RIV	230	IND RIV	115	1	11						
2004-14	LARGO	230	LARGO A	69	1	2						
2004-14	SHELD	230	SHELD-NW	69	1	16						
2004-14	CLMT EST	230	CLMT EST	69	1	2						
2004-14	WINDERME	230	WINDERME	69	1	2						
2004-14	RIVER-S	230	RIVER-S	69	1	16						
2004-14	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-14	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-14	JASPER	115	JASPER	69	1	2						

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100% Load Base Case

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Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-15	SN PLANT	230	SYLVAN	230	1	1						
2004-15	SYLVAN	230	N LONGWD	230	1	1						
2004-15	IND RIV	230	STANTON	230	1	11						
2004-15	SILVR SP	230	SILV SPN	230	1	2						
2004-15	SILVR SP	230	SILV SPN	230	2	2						
2004-15	RIO PINR	230	CURRY FD	230	1	2						
2004-15	JUNEAU-W	138	GANNON	138	1	16						
2004-15	NSB-SMYR	115	CASSADAG	115	1	2						
2004-15	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-15	NSB-SMYR	115	TAYLOR	115	1	1						
2004-15	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-15	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-15	SN PLANT	115	TURNER	115	1	1						
2004-15	PASADENA	115	40ST-DUM	115	1	2						
2004-15	MICHIGAN	115	KALEY	115	1	11						
2004-15	MICHIGAN	115	GRANT	115	1	11						
2004-15	PERSHING	115	GRANT	115	1	11						
2004-15	AMERICA	115	KALEY	115	1	11						
2004-15	JASPER	115	WGHTCHPL	115	1	2						
2004-15	AZALEA	115	BENNETT	115	1	11						
2004-15	FLORALTP	69	INVERNTP	69	1	2						
2004-15	ALACH TP	69	HIGH SPG	69	1	2						
2004-15	PASADENA	230	PASADENA	115	1	2						
2004-15	SUWANNEE	230	SUWANNEE	115	1	2						
2004-15	SUWANNEE	230	SUWANNEE	115	2	2						
2004-15	E CLRWTR	230	E CLRWTR	115	1	2						
2004-15	IND RIV	230	IND RIV	115	1	11						
2004-15	LARGO	230	LARGO A	69	1	2						
2004-15	SHELD	230	SHELD-NW	69	1	16						
2004-15	CLMT EST	230	CLMT EST	69	1	2						
2004-15	WINDERME	230	WINDERME	69	1	2						
2004-15	RIVER-S	230	RIVER-S	69	1	16						
2004-15	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-15	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-15	JASPER	115	JASPER	69	1	2						
2004-16	SN PLANT	230	SYLVAN	230	1	1						
2004-16	SYLVAN	230	N LONGWD	230	1	1						
2004-16	IND RIV	230	STANTON	230	1	11						
2004-16	SILVR SP	230	SILV SPN	230	1	2						
2004-16	SILVR SP	230	SILV SPN	230	2	2						
2004-16	RIO PINR	230	CURRY FD	230	1	2						
2004-16	JUNEAU-W	138	GANNON	138	1	16						
2004-16	NSB-SMYR	115	CASSADAG	115	1	2						
2004-16	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-16	NSB-SMYR	115	TAYLOR	115	1	1						
2004-16	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-16	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-16	SN PLANT	115	TURNER	115	1	1						
2004-16	PASADENA	115	40ST-DUM	115	1	2						
2004-16	MICHIGAN	115	KALEY	115	1	11						
2004-16	MICHIGAN	115	GRANT	115	1	11						
2004-16	PERSHING	115	GRANT	115	1	11						
2004-16	AMERICA	115	KALEY	115	1	11						
2004-16	JASPER	115	WGHTCHPL	115	1	2						
2004-16	AZALEA	115	BENNETT	115	1	11						
2004-16	FLORALTP	69	INVERNTP	69	1	2						
2004-16	ALACH TP	69	HIGH SPG	69	1	2						
2004-16	PASADENA	230	PASADENA	115	1	2						
2004-16	SUWANNEE	230	SUWANNEE	115	1	2						
2004-16	SUWANNEE	230	SUWANNEE	115	2	2						
2004-16	E CLRWTR	230	E CLRWTR	115	1	2						
2004-16	IND RIV	230	IND RIV	115	1	11						
2004-16	LARGO	230	LARGO A	69	1	2						
2004-16	SHELD	230	SHELD-NW	69	1	16						
2004-16	CLMT EST	230	CLMT EST	69	1	2						
2004-16	WINDERME	230	WINDERME	69	1	2						
2004-16	RIVER-S	230	RIVER-S	69	1	16						
2004-16	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-16	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-16	JASPER	115	JASPER	69	1	2						

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100% Load Base Case

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Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-17	SN PLANT	230	SYLVAN	230	1	1						
2004-17	SYLVAN	230	N LONGWD	230	1	1						
2004-17	IND RIV	230	STANTON	230	1	11						
2004-17	SILVR SP	230	SILV SPN	230	1	2						
2004-17	SILVR SP	230	SILV SPN	230	2	2						
2004-17	RIO PINR	230	CURRY FD	230	1	2						
2004-17	JUNEAU-W	138	GANNON	138	1	16						
2004-17	NSB-SMYR	115	CASSADAG	115	1	2						
2004-17	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-17	NSB-SMYR	115	TAYLOR	115	1	1						
2004-17	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-17	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-17	SN PLANT	115	TURNER	115	1	1						
2004-17	PASADENA	115	40ST-DUM	115	1	2						
2004-17	MICHIGAN	115	KALEY	115	1	11						
2004-17	MICHIGAN	115	GRANT	115	1	11						
2004-17	PERSHING	115	GRANT	115	1	11						
2004-17	AMERICA	115	KALEY	115	1	11						
2004-17	JASPER	115	WGHTCHPL	115	1	2						
2004-17	AZALEA	115	BENNETT	115	1	11						
2004-17	FLORALTP	69	INVERNTP	69	1	2						
2004-17	ALACH TP	69	HIGH SPG	69	1	2						
2004-17	PASADENA	230	PASADENA	115	1	2						
2004-17	SUWANNEE	230	SUWANNEE	115	1	2						
2004-17	SUWANNEE	230	SUWANNEE	115	2	2						
2004-17	E CLRWTR	230	E CLRWTR	115	1	2						
2004-17	IND RIV	230	IND RIV	115	1	11						
2004-17	LARGO	230	LARGO A	69	1	2						
2004-17	SHELD	230	SHELD-NW	69	1	16						
2004-17	CLMT EST	230	CLMT EST	69	1	2						
2004-17	WINDERME	230	WINDERME	69	1	2						
2004-17	RIVER-S	230	RIVER-S	69	1	16						
2004-17	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-17	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-17	JASPER	115	JASPER	69	1	2						
2004-18	SN PLANT	230	SYLVAN	230	1	1						
2004-18	SYLVAN	230	N LONGWD	230	1	1						
2004-18	IND RIV	230	STANTON	230	1	11						
2004-18	SILVR SP	230	SILV SPN	230	1	2						
2004-18	SILVR SP	230	SILV SPN	230	2	2						
2004-18	RIO PINR	230	CURRY FD	230	1	2						
2004-18	JUNEAU-W	138	GANNON	138	1	16						
2004-18	NSB-SMYR	115	CASSADAG	115	1	2						
2004-18	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-18	NSB-SMYR	115	TAYLOR	115	1	1						
2004-18	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-18	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-18	SN PLANT	115	TURNER	115	1	1						
2004-18	PASADENA	115	40ST-DUM	115	1	2						
2004-18	MICHIGAN	115	KALEY	115	1	11						
2004-18	MICHIGAN	115	GRANT	115	1	11						
2004-18	PERSHING	115	GRANT	115	1	11						
2004-18	AMERICA	115	KALEY	115	1	11						
2004-18	JASPER	115	WGHTCHPL	115	1	2						
2004-18	AZALEA	115	BENNETT	115	1	11						
2004-18	FLORALTP	69	INVERNTP	69	1	2						
2004-18	ALACH TP	69	HIGH SPG	69	1	2						
2004-18	PASADENA	230	PASADENA	115	1	2						
2004-18	SUWANNEE	230	SUWANNEE	115	1	2						
2004-18	SUWANNEE	230	SUWANNEE	115	2	2						
2004-18	E CLRWTR	230	E CLRWTR	115	1	2						
2004-18	IND RIV	230	IND RIV	115	1	11						
2004-18	LARGO	230	LARGO A	69	1	2						
2004-18	SHELD	230	SHELD-NW	69	1	16						
2004-18	CLMT EST	230	CLMT EST	69	1	2						
2004-18	WINDERME	230	WINDERME	69	1	2						
2004-18	RIVER-S	230	RIVER-S	69	1	16						
2004-18	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-18	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-18	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base *No NSB Gen*	Case 2004A Sell to *FPL*	Case 2004B Sell to *FPC*	Case 2004C Sell to *TEC*	Case 2004D Sell to *JEA*	Case 2004E Sell to *SEM*
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-19	SN PLANT	230	SYLVAN	230	1	1						
2004-19	SYLVAN	230	N LONGWD	230	1	1						
2004-19	IND RIV	230	STANTON	230	1	11						
2004-19	SILVR SP	230	SILV SPN	230	1	2						
2004-19	SILVR SP	230	SILV SPN	230	2	2						
2004-19	RIO PINR	230	CURRY FD	230	1	2						
2004-19	JUNEAU-W	138	GANNON	138	1	16						
2004-19	NSB-SMYR	115	CASSADAG	115	1	2						
2004-19	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-19	NSB-SMYR	115	TAYLOR	115	1	1						
2004-19	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-19	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-19	SN PLANT	115	TURNER	115	1	1						
2004-19	PASADENA	115	40ST-DUM	115	1	2						
2004-19	MICHIGAN	115	KALEY	115	1	11						
2004-19	MICHIGAN	115	GRANT	115	1	11						
2004-19	PERSHING	115	GRANT	115	1	11						
2004-19	AMERICA	115	KALEY	115	1	11						
2004-19	JASPER	115	WGHTCHPL	115	1	2						
2004-19	AZALEA	115	BENNETT	115	1	11						
2004-19	FLORALTP	69	INVERNTP	69	1	2						
2004-19	ALACH TP	69	HIGH SPG	69	1	2						
2004-19	PASADENA	230	PASADENA	115	1	2						
2004-19	SUWANNEE	230	SUWANNEE	115	1	2						
2004-19	SUWANNEE	230	SUWANNEE	115	2	2						
2004-19	E CLRWTR	230	E CLRWTR	115	1	2						
2004-19	IND RIV	230	IND RIV	115	1	11						
2004-19	LARGO	230	LARGO A	69	1	2						
2004-19	SHELD	230	SHELD-NW	69	1	16						
2004-19	CLMT EST	230	CLMT EST	69	1	2						
2004-19	WINDERME	230	WINDERME	69	1	2						
2004-19	RIVER-S	230	RIVER-S	69	1	16						
2004-19	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-19	*JUNEAU-E*	138	*JUNEAU-E*	69	1	16						
2004-19	JASPER	115	JASPER	69	1	2						
2004-20	SN PLANT	230	SYLVAN	230	1	1						
2004-20	SYLVAN	230	N LONGWD	230	1	1						
2004-20	IND RIV	230	STANTON	230	1	11						
2004-20	SILVR SP	230	SILV SPN	230	1	2						
2004-20	SILVR SP	230	SILV SPN	230	2	2						
2004-20	RIO PINR	230	CURRY FD	230	1	2						
2004-20	JUNEAU-W	138	GANNON	138	1	16						
2004-20	NSB-SMYR	115	CASSADAG	115	1	2						
2004-20	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-20	NSB-SMYR	115	TAYLOR	115	1	1						
2004-20	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-20	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-20	SN PLANT	115	TURNER	115	1	1						
2004-20	PASADENA	115	40ST-DUM	115	1	2						
2004-20	MICHIGAN	115	KALEY	115	1	11						
2004-20	MICHIGAN	115	GRANT	115	1	11						
2004-20	PERSHING	115	GRANT	115	1	11						
2004-20	AMERICA	115	KALEY	115	1	11						
2004-20	JASPER	115	WGHTCHPL	115	1	2						
2004-20	AZALEA	115	BENNETT	115	1	11						
2004-20	FLORALTP	69	INVERNTP	69	1	2						
2004-20	ALACH TP	69	HIGH SPG	69	1	2						
2004-20	PASADENA	230	PASADENA	115	1	2						
2004-20	SUWANNEE	230	SUWANNEE	115	1	2						
2004-20	SUWANNEE	230	SUWANNEE	115	2	2						
2004-20	E CLRWTR	230	E CLRWTR	115	1	2						
2004-20	IND RIV	230	IND RIV	115	1	11						
2004-20	LARGO	230	LARGO A	69	1	2						
2004-20	SHELD	230	SHELD-NW	69	1	16						
2004-20	CLMT EST	230	CLMT EST	69	1	2						
2004-20	WINDERME	230	WINDERME	69	1	2						
2004-20	RIVER-S	230	RIVER-S	69	1	16						
2004-20	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-20	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-20	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-21	SN PLANT	230	SYLVAN	230	1	1						
2004-21	SYLVAN	230	N LONGWD	230	1	1						
2004-21	IND RIV	230	STANTON	230	1	11						
2004-21	SILVR SP	230	SILV SPN	230	1	2						
2004-21	SILVR SP	230	SILV SPN	230	2	2						
2004-21	RIO PINR	230	CURRY FD	230	1	2						
2004-21	JUNEAU-W	138	GANNON	138	1	16						
2004-21	NSB-SMYR	115	CASSADAG	115	1	2						
2004-21	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-21	NSB-SMYR	115	TAYLOR	115	1	1						
2004-21	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-21	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-21	SN PLANT	115	TURNER	115	1	1						
2004-21	PASADENA	115	40ST-DUM	115	1	2						
2004-21	MICHIGAN	115	KALEY	115	1	11						
2004-21	MICHIGAN	115	GRANT	115	1	11						
2004-21	PERSHING	115	GRANT	115	1	11						
2004-21	AMERICA	115	KALEY	115	1	11						
2004-21	JASPER	115	WGHTCHPL	115	1	2						
2004-21	AZALEA	115	BENNETT	115	1	11						
2004-21	FLORALTP	69	INVERNTP	69	1	2						
2004-21	ALACH TP	69	HIGH SPG	69	1	2						
2004-21	PASADENA	230	PASADENA	115	1	2						
2004-21	SUWANNEE	230	SUWANNEE	115	1	2						
2004-21	SUWANNEE	230	SUWANNEE	115	2	2						
2004-21	E CLRWTR	230	E CLRWTR	115	1	2						
2004-21	IND RIV	230	IND RIV	115	1	11						
2004-21	LARGO	230	LARGO A	69	1	2						
2004-21	SHELD	230	SHELD-NW	69	1	16						
2004-21	CLMT EST	230	CLMT EST	69	1	2						
2004-21	WINDERME	230	WINDERME	69	1	2						
2004-21	RIVER-S	230	RIVER-S	69	1	16						
2004-21	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-21	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-21	JASPER	115	JASPER	69	1	2						
2004-22	SN PLANT	230	SYLVAN	230	1	1						
2004-22	SYLVAN	230	N LONGWD	230	1	1						
2004-22	IND RIV	230	STANTON	230	1	11						
2004-22	SILVR SP	230	SILV SPN	230	1	2						
2004-22	SILVR SP	230	SILV SPN	230	2	2						
2004-22	RIO PINR	230	CURRY FD	230	1	2						
2004-22	JUNEAU-W	138	GANNON	138	1	16						
2004-22	NSB-SMYR	115	CASSADAG	115	1	2						
2004-22	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-22	NSB-SMYR	115	TAYLOR	115	1	1						
2004-22	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-22	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-22	SN PLANT	115	TURNER	115	1	1						
2004-22	PASADENA	115	40ST-DUM	115	1	2						
2004-22	MICHIGAN	115	KALEY	115	1	11						
2004-22	MICHIGAN	115	GRANT	115	1	11						
2004-22	PERSHING	115	GRANT	115	1	11						
2004-22	AMERICA	115	KALEY	115	1	11						
2004-22	JASPER	115	WGHTCHPL	115	1	2						
2004-22	AZALEA	115	BENNETT	115	1	11						
2004-22	FLORALTP	69	INVERNTP	69	1	2						
2004-22	ALACH TP	69	HIGH SPG	69	1	2						
2004-22	PASADENA	230	PASADENA	115	1	2						
2004-22	SUWANNEE	230	SUWANNEE	115	1	2						
2004-22	SUWANNEE	230	SUWANNEE	115	2	2						
2004-22	E CLRWTR	230	E CLRWTR	115	1	2						
2004-22	IND RIV	230	IND RIV	115	1	11						
2004-22	LARGO	230	LARGO A	69	1	2						
2004-22	SHELD	230	SHELD-NW	69	1	16						
2004-22	CLMT EST	230	CLMT EST	69	1	2						
2004-22	WINDERME	230	WINDERME	69	1	2						
2004-22	RIVER-S	230	RIVER-S	69	1	16						
2004-22	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-22	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-22	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-23	SN PLANT	230	SYLVAN	230	1	1						
2004-23	SYLVAN	230	N LONGWD	230	1	1						
2004-23	IND RIV	230	STANTON	230	1	11						
2004-23	SILVR SP	230	SILV SPN	230	1	2						
2004-23	SILVR SP	230	SILV SPN	230	2	2						
2004-23	RIO PINR	230	CURRY FD	230	1	2						
2004-23	JUNEAU-W	138	GANNON	138	1	16						
2004-23	NSB-SMYR	115	CASSADAG	115	1	2						
2004-23	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-23	NSB-SMYR	115	TAYLOR	115	1	1						
2004-23	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-23	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-23	SN PLANT	115	TURNER	115	1	1						
2004-23	PASADENA	115	40ST-DUM	115	1	2						
2004-23	MICHIGAN	115	KALEY	115	1	11						
2004-23	MICHIGAN	115	GRANT	115	1	11						
2004-23	PERSHING	115	GRANT	115	1	11						
2004-23	AMERICA	115	KALEY	115	1	11						
2004-23	JASPER	115	WGHTCHPL	115	1	2						
2004-23	AZALEA	115	BENNETT	115	1	11						
2004-23	FLORALTP	69	INVERNTP	69	1	2						
2004-23	ALACH TP	69	HIGH SPG	69	1	2						
2004-23	PASADENA	230	PASADENA	115	1	2						
2004-23	SUWANNEE	230	SUWANNEE	115	1	2						
2004-23	SUWANNEE	230	SUWANNEE	115	2	2						
2004-23	E CLRWTR	230	E CLRWTR	115	1	2						
2004-23	IND RIV	230	IND RIV	115	1	11						
2004-23	LARGO	230	LARGO A	69	1	2						
2004-23	SHELD	230	SHELD-NW	69	1	16						
2004-23	CLMT EST	230	CLMT EST	69	1	2						
2004-23	WINDERME	230	WINDERME	69	1	2						
2004-23	RIVER-S	230	RIVER-S	69	1	16						
2004-23	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-23	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-23	JASPER	115	JASPER	69	1	2						
2004-24	SN PLANT	230	SYLVAN	230	1	1						
2004-24	SYLVAN	230	N LONGWD	230	1	1						
2004-24	IND RIV	230	STANTON	230	1	11						
2004-24	SILVR SP	230	SILV SPN	230	1	2						
2004-24	SILVR SP	230	SILV SPN	230	2	2						
2004-24	RIO PINR	230	CURRY FD	230	1	2						
2004-24	JUNEAU-W	138	GANNON	138	1	16						
2004-24	NSB-SMYR	115	CASSADAG	115	1	2						
2004-24	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-24	NSB-SMYR	115	TAYLOR	115	1	1						
2004-24	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-24	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-24	SN PLANT	115	TURNER	115	1	1						
2004-24	PASADENA	115	40ST-DUM	115	1	2						
2004-24	MICHIGAN	115	KALEY	115	1	11						
2004-24	MICHIGAN	115	GRANT	115	1	11						
2004-24	PERSHING	115	GRANT	115	1	11						
2004-24	AMERICA	115	KALEY	115	1	11						
2004-24	JASPER	115	WGHTCHPL	115	1	2						
2004-24	AZALEA	115	BENNETT	115	1	11						
2004-24	FLORALTP	69	INVERNTP	69	1	2						
2004-24	ALACH TP	69	HIGH SPG	69	1	2						
2004-24	PASADENA	230	PASADENA	115	1	2						
2004-24	SUWANNEE	230	SUWANNEE	115	1	2						
2004-24	SUWANNEE	230	SUWANNEE	115	2	2						
2004-24	E CLRWTR	230	E CLRWTR	115	1	2						
2004-24	IND RIV	230	IND RIV	115	1	11						
2004-24	LARGO	230	LARGO A	69	1	2						
2004-24	SHELD	230	SHELD-NW	69	1	16						
2004-24	CLMT EST	230	CLMT EST	69	1	2						
2004-24	WINDERME	230	WINDERME	69	1	2						
2004-24	RIVER-S	230	RIVER-S	69	1	16						
2004-24	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-24	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-24	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-25	SN PLANT	230	SYLVAN	230	1	1						
2004-25	SYLVAN	230	N LONGWD	230	1	1						
2004-25	IND RIV	230	STANTON	230	1	11						
2004-25	SILVR SP	230	SILV SPN	230	1	2						
2004-25	SILVR SP	230	SILV SPN	230	2	2						
2004-25	RIO PINR	230	CURRY FD	230	1	2						
2004-25	JUNEAU-W	138	GANNON	138	1	16						
2004-25	NSB-SMYR	115	CASSADAG	115	1	2						
2004-25	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-25	NSB-SMYR	115	TAYLOR	115	1	1						
2004-25	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-25	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-25	SN PLANT	115	TURNER	115	1	1						
2004-25	PASADENA	115	40ST-DUM	115	1	2						
2004-25	MICHIGAN	115	KALEY	115	1	11						
2004-25	MICHIGAN	115	GRANT	115	1	11						
2004-25	PERSHING	115	GRANT	115	1	11						
2004-25	AMERICA	115	KALEY	115	1	11						
2004-25	JASPER	115	WGHTCHPL	115	1	2						
2004-25	AZALEA	115	BENNETT	115	1	11						
2004-25	FLORALTP	69	INVERNTP	69	1	2						
2004-25	ALACH TP	69	HIGH SPG	69	1	2						
2004-25	PASADENA	230	PASADENA	115	1	2						
2004-25	SUWANNEE	230	SUWANNEE	115	1	2						
2004-25	SUWANNEE	230	SUWANNEE	115	2	2						
2004-25	E CLRWTR	230	E CLRWTR	115	1	2						
2004-25	IND RIV	230	IND RIV	115	1	11						
2004-25	LARGO	230	LARGO A	69	1	2						
2004-25	SHELD	230	SHELD-NW	69	1	16						
2004-25	CLMT EST	230	CLMT EST	69	1	2						
2004-25	WINDERME	230	WINDERME	69	1	2						
2004-25	RIVER-S	230	RIVER-S	69	1	16						
2004-25	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-25	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-25	JASPER	115	JASPER	69	1	2						
2004-26	SN PLANT	230	SYLVAN	230	1	1						
2004-26	SYLVAN	230	N LONGWD	230	1	1						
2004-26	IND RIV	230	STANTON	230	1	11						
2004-26	SILVR SP	230	SILV SPN	230	1	2						
2004-26	SILVR SP	230	SILV SPN	230	2	2						
2004-26	RIO PINR	230	CURRY FD	230	1	2						
2004-26	JUNEAU-W	138	GANNON	138	1	16						
2004-26	NSB-SMYR	115	CASSADAG	115	1	2						
2004-26	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-26	NSB-SMYR	115	TAYLOR	115	1	1						
2004-26	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-26	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-26	SN PLANT	115	TURNER	115	1	1						
2004-26	PASADENA	115	40ST-DUM	115	1	2						
2004-26	MICHIGAN	115	KALEY	115	1	11						
2004-26	MICHIGAN	115	GRANT	115	1	11						
2004-26	PERSHING	115	GRANT	115	1	11						
2004-26	AMERICA	115	KALEY	115	1	11						
2004-26	JASPER	115	WGHTCHPL	115	1	2						
2004-26	AZALEA	115	BENNETT	115	1	11						
2004-26	FLORALTP	69	INVERNTP	69	1	2						
2004-26	ALACH TP	69	HIGH SPG	69	1	2						
2004-26	PASADENA	230	PASADENA	115	1	2						
2004-26	SUWANNEE	230	SUWANNEE	115	1	2						
2004-26	SUWANNEE	230	SUWANNEE	115	2	2						
2004-26	E CLRWTR	230	E CLRWTR	115	1	2						
2004-26	IND RIV	230	IND RIV	115	1	11						
2004-26	LARGO	230	LARGO A	69	1	2						
2004-26	SHELD	230	SHELD-NW	69	1	16						
2004-26	CLMT EST	230	CLMT EST	69	1	2						
2004-26	WINDERME	230	WINDERME	69	1	2						
2004-26	RIVER-S	230	RIVER-S	69	1	16						
2004-26	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-26	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-26	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-27	SN PLANT	230	SYLVAN	230	1	1						
2004-27	SYLVAN	230	N LONGWD	230	1	1						
2004-27	IND RIV	230	STANTON	230	1	11						
2004-27	SILVR SP	230	SILV SPN	230	1	2						
2004-27	SILVR SP	230	SILV SPN	230	2	2						
2004-27	RIO PINR	230	CURRY FD	230	1	2						
2004-27	JUNEAU-W	138	GANNON	138	1	16						
2004-27	NSB-SMYR	115	CASSADAG	115	1	2						
2004-27	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-27	NSB-SMYR	115	TAYLOR	115	1	1						
2004-27	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-27	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-27	SN PLANT	115	TURNER	115	1	1						
2004-27	PASADENA	115	40ST-DUM	115	1	2						
2004-27	MICHIGAN	115	KALEY	115	1	11						
2004-27	MICHIGAN	115	GRANT	115	1	11						
2004-27	PERSHING	115	GRANT	115	1	11						
2004-27	AMERICA	115	KALEY	115	1	11						
2004-27	JASPER	115	WGHTCHPL	115	1	2						
2004-27	AZALEA	115	BENNETT	115	1	11						
2004-27	FLORALTP	69	INVERNTP	69	1	2						
2004-27	ALACH TP	69	HIGH SPG	69	1	2						
2004-27	PASADENA	230	PASADENA	115	1	2						
2004-27	SUWANNEE	230	SUWANNEE	115	1	2						
2004-27	SUWANNEE	230	SUWANNEE	115	2	2						
2004-27	E CLRWTR	230	E CLRWTR	115	1	2						
2004-27	IND RIV	230	IND RIV	115	1	11						
2004-27	LARGO	230	LARGO A	69	1	2						
2004-27	SHELD	230	SHELD-NW	69	1	16						
2004-27	CLMT EST	230	CLMT EST	69	1	2						
2004-27	WINDERME	230	WINDERME	69	1	2						
2004-27	RIVER-S	230	RIVER-S	69	1	16						
2004-27	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-27	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-27	JASPER	115	JASPER	69	1	2						
2004-28	SN PLANT	230	SYLVAN	230	1	1						
2004-28	SYLVAN	230	N LONGWD	230	1	1						
2004-28	IND RIV	230	STANTON	230	1	11						
2004-28	SILVR SP	230	SILV SPN	230	1	2						
2004-28	SILVR SP	230	SILV SPN	230	2	2						
2004-28	RIO PINR	230	CURRY FD	230	1	2						
2004-28	JUNEAU-W	138	GANNON	138	1	16						
2004-28	NSB-SMYR	115	CASSADAG	115	1	2						
2004-28	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-28	NSB-SMYR	115	TAYLOR	115	1	1						
2004-28	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-28	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-28	SN PLANT	115	TURNER	115	1	1						
2004-28	PASADENA	115	40ST-DUM	115	1	2						
2004-28	MICHIGAN	115	KALEY	115	1	11						
2004-28	MICHIGAN	115	GRANT	115	1	11						
2004-28	PERSHING	115	GRANT	115	1	11						
2004-28	AMERICA	115	KALEY	115	1	11						
2004-28	JASPER	115	WGHTCHPL	115	1	2						
2004-28	AZALEA	115	BENNETT	115	1	11						
2004-28	FLORALTP	69	INVERNTP	69	1	2						
2004-28	ALACH TP	69	HIGH SPG	69	1	2						
2004-28	PASADENA	230	PASADENA	115	1	2						
2004-28	SUWANNEE	230	SUWANNEE	115	1	2						
2004-28	SUWANNEE	230	SUWANNEE	115	2	2						
2004-28	E CLRWTR	230	E CLRWTR	115	1	2						
2004-28	IND RIV	230	IND RIV	115	1	11						
2004-28	LARGO	230	LARGO A	69	1	2						
2004-28	SHELD	230	SHELD-NW	69	1	16						
2004-28	CLMT EST	230	CLMT EST	69	1	2						
2004-28	WINDERME	230	WINDERME	69	1	2						
2004-28	RIVER-S	230	RIVER-S	69	1	16						
2004-28	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-28	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-28	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
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100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-29	SN PLANT	230	SYLVAN	230	1	1						
2004-29	SYLVAN	230	N LONGWD	230	1	1						
2004-29	IND RIV	230	STANTON	230	1	11						
2004-29	SILVR SP	230	SILV SPN	230	1	2						
2004-29	SILVR SP	230	SILV SPN	230	2	2						
2004-29	RIO PINR	230	CURRY FD	230	1	2						
2004-29	JUNEAU-W	138	GANNON	138	1	16						
2004-29	NSB-SMYR	115	CASSADAG	115	1	2						
2004-29	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-29	NSB-SMYR	115	TAYLOR	115	1	1						
2004-29	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-29	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-29	SN PLANT	115	TURNER	115	1	1						
2004-29	PASADENA	115	40ST-DUM	115	1	2						
2004-29	MICHIGAN	115	KALEY	115	1	11						
2004-29	MICHIGAN	115	GRANT	115	1	11						
2004-29	PERSHING	115	GRANT	115	1	11						
2004-29	AMERICA	115	KALEY	115	1	11						
2004-29	JASPER	115	WGHTCHPL	115	1	2						
2004-29	AZALEA	115	BENNETT	115	1	11						
2004-29	FLORALTP	69	INVERNTP	69	1	2						
2004-29	ALACH TP	69	HIGH SPG	69	1	2						
2004-29	PASADENA	230	PASADENA	115	1	2						
2004-29	SUWANNEE	230	SUWANNEE	115	1	2						
2004-29	SUWANNEE	230	SUWANNEE	115	2	2						
2004-29	E CLRWTR	230	E CLRWTR	115	1	2						
2004-29	IND RIV	230	IND RIV	115	1	11						
2004-29	LARGO	230	LARGO A	69	1	2						
2004-29	SHELD	230	SHELD-NW	69	1	16						
2004-29	CLMT EST	230	CLMT EST	69	1	2						
2004-29	WINDERME	230	WINDERME	69	1	2						
2004-29	RIVER-S	230	RIVER-S	69	1	16						
2004-29	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-29	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-29	JASPER	115	JASPER	69	1	2						
2004-30	SN PLANT	230	SYLVAN	230	1	1						
2004-30	SYLVAN	230	N LONGWD	230	1	1						
2004-30	IND RIV	230	STANTON	230	1	11						
2004-30	SILVR SP	230	SILV SPN	230	1	2						
2004-30	SILVR SP	230	SILV SPN	230	2	2						
2004-30	RIO PINR	230	CURRY FD	230	1	2						
2004-30	JUNEAU-W	138	GANNON	138	1	16						
2004-30	NSB-SMYR	115	CASSADAG	115	1	2						
2004-30	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-30	NSB-SMYR	115	TAYLOR	115	1	1						
2004-30	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-30	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-30	SN PLANT	115	TURNER	115	1	1						
2004-30	PASADENA	115	40ST-DUM	115	1	2						
2004-30	MICHIGAN	115	KALEY	115	1	11						
2004-30	MICHIGAN	115	GRANT	115	1	11						
2004-30	PERSHING	115	GRANT	115	1	11						
2004-30	AMERICA	115	KALEY	115	1	11						
2004-30	JASPER	115	WGHTCHPL	115	1	2						
2004-30	AZALEA	115	BENNETT	115	1	11						
2004-30	FLORALTP	69	INVERNTP	69	1	2						
2004-30	ALACH TP	69	HIGH SPG	69	1	2						
2004-30	PASADENA	230	PASADENA	115	1	2						
2004-30	SUWANNEE	230	SUWANNEE	115	1	2						
2004-30	SUWANNEE	230	SUWANNEE	115	2	2						
2004-30	E CLRWTR	230	E CLRWTR	115	1	2						
2004-30	IND RIV	230	IND RIV	115	1	11						
2004-30	LARGO	230	LARGO A	69	1	2						
2004-30	SHELD	230	SHELD-NW	69	1	16						
2004-30	CLMT EST	230	CLMT EST	69	1	2						
2004-30	WINDERME	230	WINDERME	69	1	2						
2004-30	RIVER-S	230	RIVER-S	69	1	16						
2004-30	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-30	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-30	JASPER	115	JASPER	69	1	2						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
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100% Load Base Case

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Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-31	SN PLANT	230	SYLVAN	230	1	1						
2004-31	SYLVAN	230	N LONGWD	230	1	1						
2004-31	IND RIV	230	STANTON	230	1	11						
2004-31	SILVR SP	230	SILV SPN	230	1	2						
2004-31	SILVR SP	230	SILV SPN	230	2	2						
2004-31	RIO PINR	230	CURRY FD	230	1	2						
2004-31	JUNEAU-W	138	GANNON	138	1	16						
2004-31	NSB-SMYR	115	CASSADAG	115	1	2						
2004-31	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-31	NSB-SMYR	115	TAYLOR	115	1	1						
2004-31	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-31	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-31	SN PLANT	115	TURNER	115	1	1						
2004-31	PASADENA	115	40ST-DUM	115	1	2						
2004-31	MICHIGAN	115	KALEY	115	1	11						
2004-31	MICHIGAN	115	GRANT	115	1	11						
2004-31	PERSHING	115	GRANT	115	1	11						
2004-31	AMERICA	115	KALEY	115	1	11						
2004-31	JASPER	115	WGHTCHPL	115	1	2						
2004-31	AZALEA	115	BENNETT	115	1	11						
2004-31	FLORALTP	69	INVERNTP	69	1	2						
2004-31	ALACH TP	69	HIGH SPG	69	1	2						
2004-31	PASADENA	230	PASADENA	115	1	2						
2004-31	SUWANNEE	230	SUWANNEE	115	1	2						
2004-31	SUWANNEE	230	SUWANNEE	115	2	2						
2004-31	E CLRWTR	230	E CLRWTR	115	1	2						
2004-31	IND RIV	230	IND RIV	115	1	11						
2004-31	LARGO	230	LARGO A	69	1	2						
2004-31	SHELD	230	SHELD-NW	69	1	16						
2004-31	CLMT EST	230	CLMT EST	69	1	2						
2004-31	WINDERME	230	WINDERME	69	1	2						
2004-31	RIVER-S	230	RIVER-S	69	1	16						
2004-31	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-31	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-31	JASPER	115	JASPER	69	1	2						
2004-32	SN PLANT	230	SYLVAN	230	1	1						
2004-32	SYLVAN	230	N LONGWD	230	1	1						
2004-32	IND RIV	230	STANTON	230	1	11						
2004-32	SILVR SP	230	SILV SPN	230	1	2						
2004-32	SILVR SP	230	SILV SPN	230	2	2						
2004-32	RIO PINR	230	CURRY FD	230	1	2						
2004-32	JUNEAU-W	138	GANNON	138	1	16						
2004-32	NSB-SMYR	115	CASSADAG	115	1	2						
2004-32	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-32	NSB-SMYR	115	TAYLOR	115	1	1						
2004-32	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-32	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-32	SN PLANT	115	TURNER	115	1	1						
2004-32	PASADENA	115	40ST-DUM	115	1	2						
2004-32	MICHIGAN	115	KALEY	115	1	11						
2004-32	MICHIGAN	115	GRANT	115	1	11						
2004-32	PERSHING	115	GRANT	115	1	11						
2004-32	AMERICA	115	KALEY	115	1	11						
2004-32	JASPER	115	WGHTCHPL	115	1	2						
2004-32	AZALEA	115	BENNETT	115	1	11						
2004-32	FLORALTP	69	INVERNTP	69	1	2						
2004-32	ALACH TP	69	HIGH SPG	69	1	2						
2004-32	PASADENA	230	PASADENA	115	1	2						
2004-32	SUWANNEE	230	SUWANNEE	115	1	2						
2004-32	SUWANNEE	230	SUWANNEE	115	2	2						
2004-32	E CLRWTR	230	E CLRWTR	115	1	2						
2004-32	IND RIV	230	IND RIV	115	1	11						
2004-32	LARGO	230	LARGO A	69	1	2						
2004-32	SHELD	230	SHELD-NW	69	1	16						
2004-32	CLMT EST	230	CLMT EST	69	1	2						
2004-32	WINDERME	230	WINDERME	69	1	2						
2004-32	RIVER-S	230	RIVER-S	69	1	16						
2004-32	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-32	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-32	JASPER	115	JASPER	69	1	2						

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Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-33	SN PLANT	230	SYLVAN	230	1	1						
2004-33	SYLVAN	230	N LONGWD	230	1	1						
2004-33	IND RIV	230	STANTON	230	1	11						
2004-33	SILVR SP	230	SILV SPN	230	1	2						
2004-33	SILVR SP	230	SILV SPN	230	2	2						
2004-33	RIO PINR	230	CURRY FD	230	1	2						
2004-33	JUNEAU-W	138	GANNON	138	1	16						
2004-33	NSB-SMYR	115	CASSADAG	115	1	2						
2004-33	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-33	NSB-SMYR	115	TAYLOR	115	1	1						
2004-33	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-33	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-33	SN PLANT	115	TURNER	115	1	1						
2004-33	PASADENA	115	40ST-DUM	115	1	2						
2004-33	MICHIGAN	115	KALEY	115	1	11						
2004-33	MICHIGAN	115	GRANT	115	1	11						
2004-33	PERSHING	115	GRANT	115	1	11						
2004-33	AMERICA	115	KALEY	115	1	11						
2004-33	JASPER	115	WGHTCHPL	115	1	2						
2004-33	AZALEA	115	BENNETT	115	1	11						
2004-33	FLORALTP	69	INVERNTP	69	1	2						
2004-33	ALACH TP	69	HIGH SPG	69	1	2						
2004-33	PASADENA	230	PASADENA	115	1	2						
2004-33	SUWANNEE	230	SUWANNEE	115	1	2						
2004-33	SUWANNEE	230	SUWANNEE	115	2	2						
2004-33	E CLRWTR	230	E CLRWTR	115	1	2						
2004-33	IND RIV	230	IND RIV	115	1	11						
2004-33	LARGO	230	LARGO A	69	1	2						
2004-33	SHELD	230	SHELD-NW	69	1	16						
2004-33	CLMT EST	230	CLMT EST	69	1	2						
2004-33	WINDERME	230	WINDERME	69	1	2						
2004-33	RIVER-S	230	RIVER-S	69	1	16						
2004-33	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-33	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-33	JASPER	115	JASPER	69	1	2						
2004-34	SN PLANT	230	SYLVAN	230	1	1						
2004-34	SYLVAN	230	N LONGWD	230	1	1						
2004-34	IND RIV	230	STANTON	230	1	11						
2004-34	SILVR SP	230	SILV SPN	230	1	2						
2004-34	SILVR SP	230	SILV SPN	230	2	2						
2004-34	RIO PINR	230	CURRY FD	230	1	2						
2004-34	JUNEAU-W	138	GANNON	138	1	16						
2004-34	NSB-SMYR	115	CASSADAG	115	1	2						
2004-34	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-34	NSB-SMYR	115	TAYLOR	115	1	1						
2004-34	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-34	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-34	SN PLANT	115	TURNER	115	1	1						
2004-34	PASADENA	115	40ST-DUM	115	1	2						
2004-34	MICHIGAN	115	KALEY	115	1	11						
2004-34	MICHIGAN	115	GRANT	115	1	11						
2004-34	PERSHING	115	GRANT	115	1	11						
2004-34	AMERICA	115	KALEY	115	1	11						
2004-34	JASPER	115	WGHTCHPL	115	1	2						
2004-34	AZALEA	115	BENNETT	115	1	11						
2004-34	FLORALTP	69	INVERNTP	69	1	2						
2004-34	ALACH TP	69	HIGH SPG	69	1	2						
2004-34	PASADENA	230	PASADENA	115	1	2						
2004-34	SUWANNEE	230	SUWANNEE	115	1	2						
2004-34	SUWANNEE	230	SUWANNEE	115	2	2						
2004-34	E CLRWTR	230	E CLRWTR	115	1	2						
2004-34	IND RIV	230	IND RIV	115	1	11						
2004-34	LARGO	230	LARGO A	69	1	2						
2004-34	SHELD	230	SHELD-NW	69	1	16						
2004-34	CLMT EST	230	CLMT EST	69	1	2						
2004-34	WINDERME	230	WINDERME	69	1	2						
2004-34	RIVER-S	230	RIVER-S	69	1	16						
2004-34	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-34	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-34	JASPER	115	JASPER	69	1	2						

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Monitored Branches							Case 2004 Base No NSB Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-35	SN PLANT	230	SYLVAN	230	1	1						
2004-35	SYLVAN	230	N LONGWD	230	1	1						
2004-35	IND RIV	230	STANTON	230	1	11						
2004-35	SILVR SP	230	SILV SPN	230	1	2						
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2004-35	AMERICA	115	KALEY	115	1	11						
2004-35	JASPER	115	WGHTCHPL	115	1	2						
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2004-35	SUWANNEE	230	SUWANNEE	115	2	2						
2004-35	E CLRWTR	230	E CLRWTR	115	1	2						
2004-35	IND RIV	230	IND RIV	115	1	11						
2004-35	LARGO	230	LARGO A	69	1	2						
2004-35	SHELD	230	SHELD-NW	69	1	16						
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2004-35	WINDERME	230	WINDERME	69	1	2						
2004-35	RIVER-S	230	RIVER-S	69	1	16						
2004-35	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-35	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-35	JASPER	115	JASPER	69	1	2						
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2004-36	RIO PINR	230	CURRY FD	230	1	2						
2004-36	JUNEAU-W	138	GANNON	138	1	16						
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2004-36	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-36	NSB-SMYR	115	TAYLOR	115	1	1						
2004-36	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-36	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-36	SN PLANT	115	TURNER	115	1	1						
2004-36	PASADENA	115	40ST-DUM	115	1	2						
2004-36	MICHIGAN	115	KALEY	115	1	11						
2004-36	MICHIGAN	115	GRANT	115	1	11						
2004-36	PERSHING	115	GRANT	115	1	11						
2004-36	AMERICA	115	KALEY	115	1	11						
2004-36	JASPER	115	WGHTCHPL	115	1	2						
2004-36	AZALEA	115	BENNETT	115	1	11						
2004-36	FLORALTP	69	INVERNTP	69	1	2						
2004-36	ALACH TP	69	HIGH SPG	69	1	2						
2004-36	PASADENA	230	PASADENA	115	1	2						
2004-36	SUWANNEE	230	SUWANNEE	115	1	2						
2004-36	SUWANNEE	230	SUWANNEE	115	2	2						
2004-36	E CLRWTR	230	E CLRWTR	115	1	2						
2004-36	IND RIV	230	IND RIV	115	1	11						
2004-36	LARGO	230	LARGO A	69	1	2						
2004-36	SHELD	230	SHELD-NW	69	1	16						
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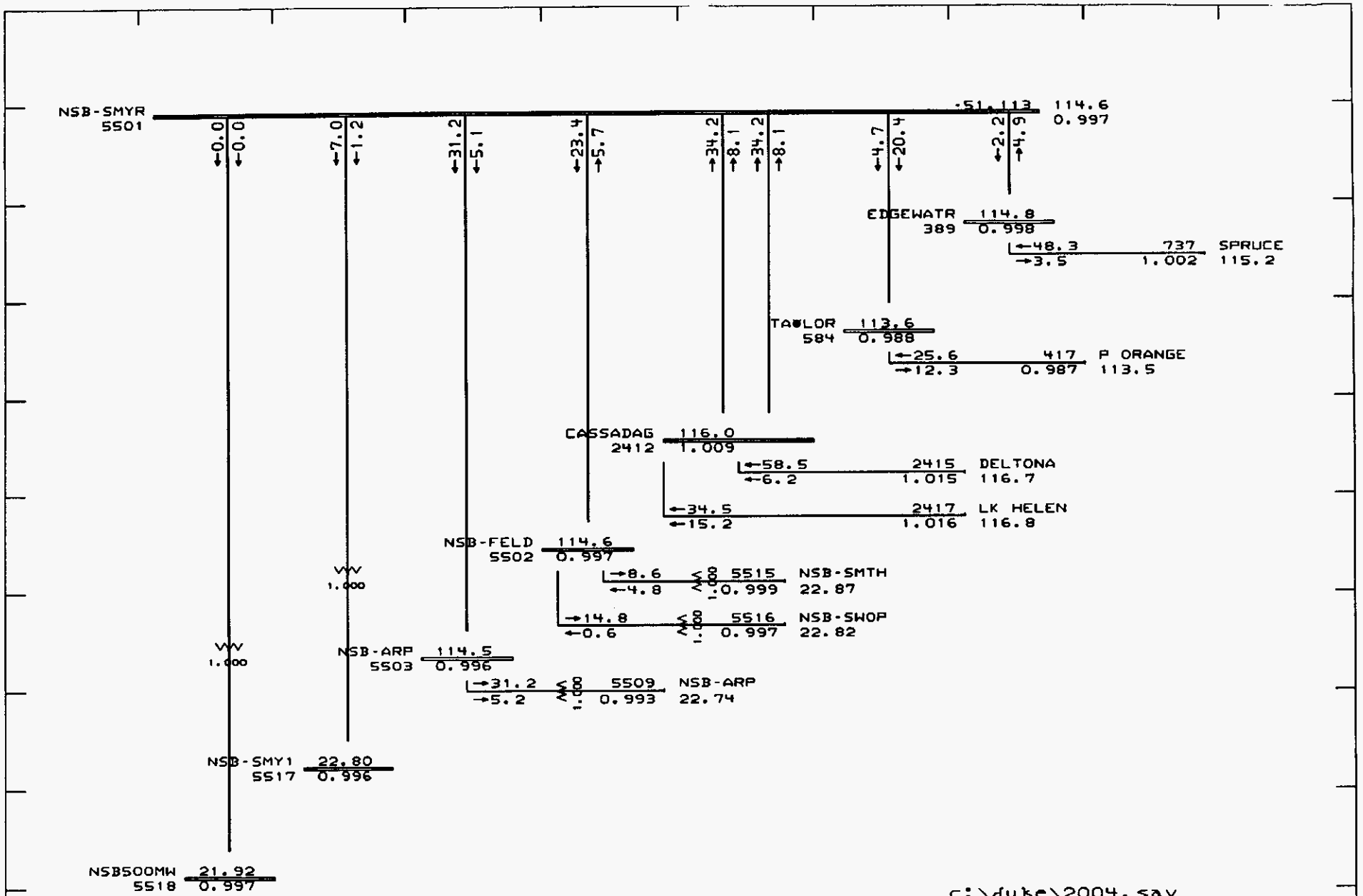
2004-36	WINDERME	230	WINDERME	69	1	2						
2004-36	RIVER-S	230	RIVER-S	69	1	16						
2004-36	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-36	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-36	JASPER	115	JASPER	69	1	2						

APPENDIX III-A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RESOURCE MANAGEMENT INTERNATIONAL INC.
2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD.NSB500MW PLANT IN SERVICE IN 2001!
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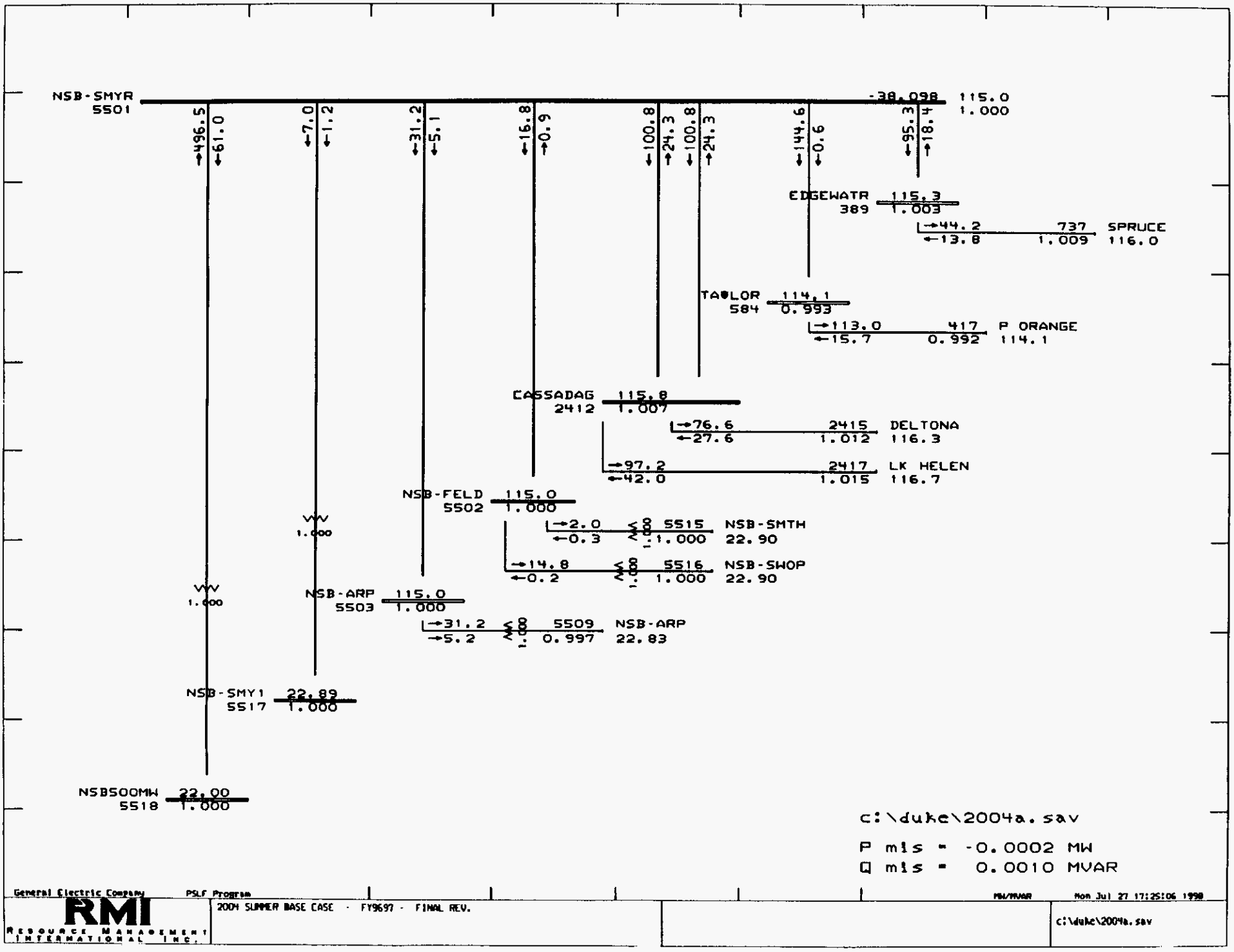
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1.009
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PSLF Program
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2004 SUMMER BASE CASE - FY9697 - FINAL REV.
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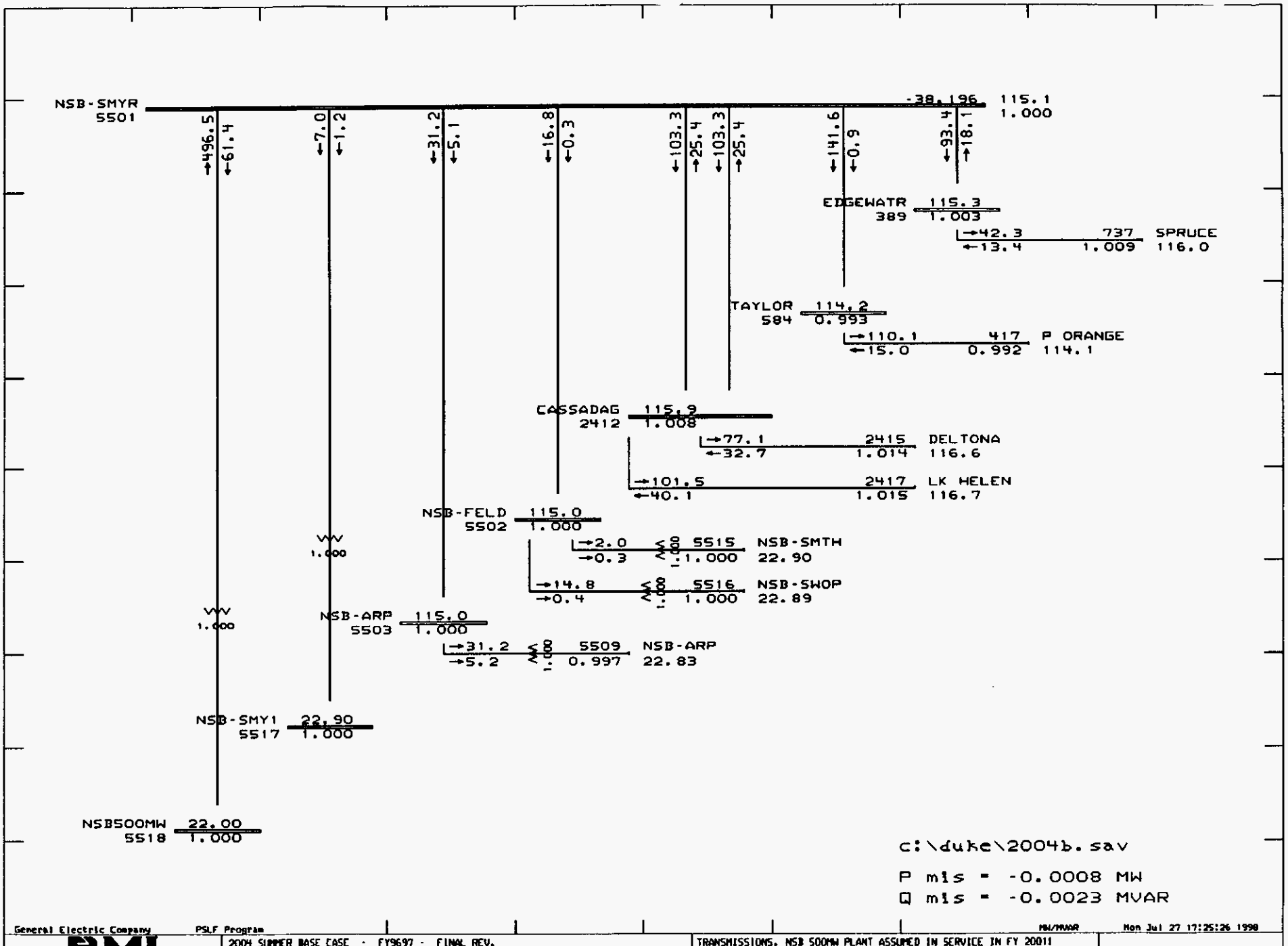
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NSB-SMTH
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PSLF Program
MW/MVAR
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RMI
Resource Management International, Inc.
2004 SUMMER BASE CASE - FY9697 - FINAL REV.
CASE OBTAINED FROM FERC BULLETIN BOARD. MODIFIED TO REFLECT ADDITION OF
GENERATION AT FTMYERS (2002) & AT SANFORD (2004) AND ASSOCIATED
TRANSMISSIONS. NSB 500MW PLANT ASSUMED IN SERVICE IN FY 2001!
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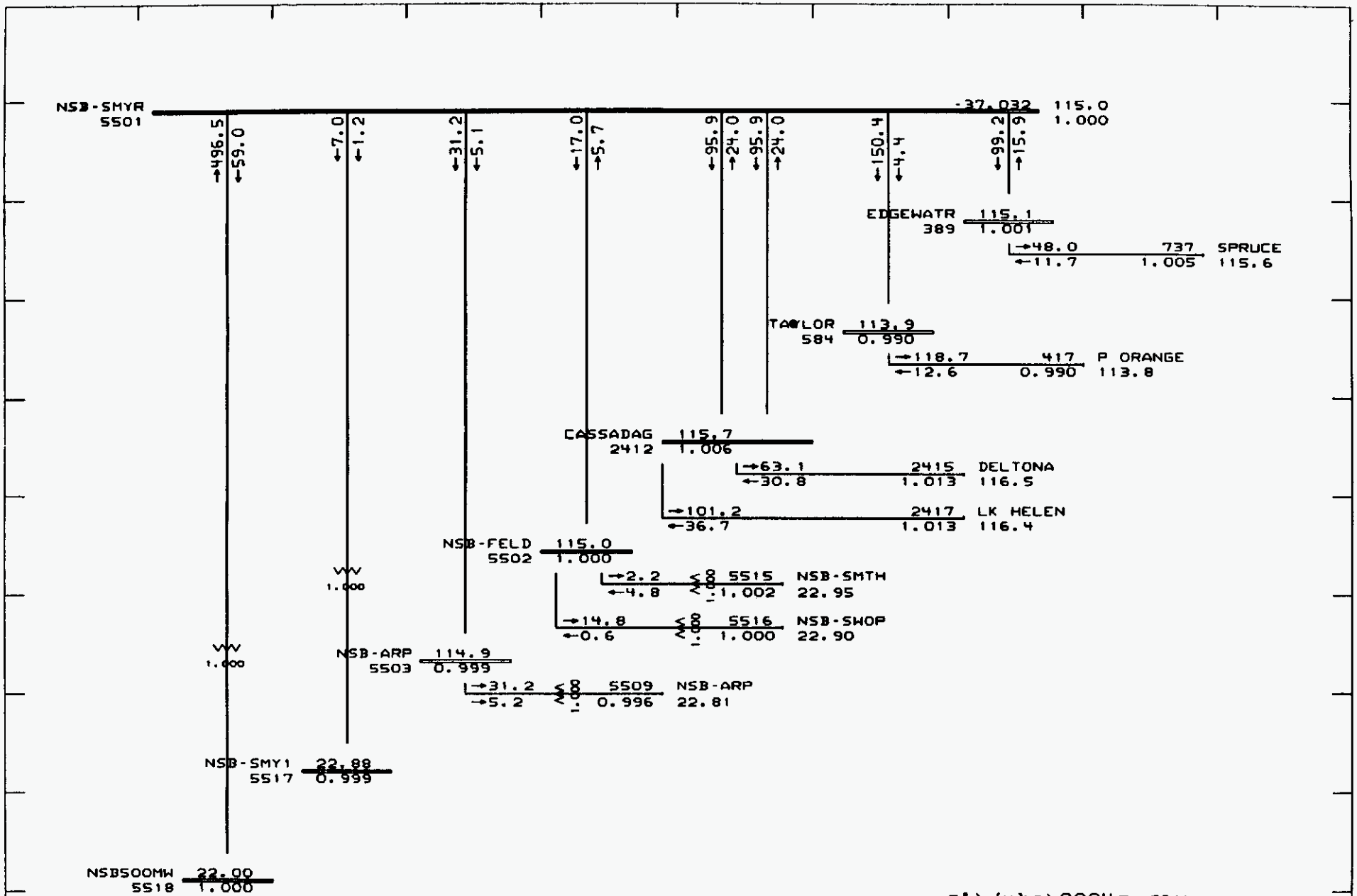

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General Electric Company PSLF Program MW/MVAR Mon Jul 27 17:25:47 1998

RMI RESOURCE MANAGEMENT INTERNATIONAL, INC.

2004 SUMMER BASE CASE - FY9697 - FINAL REV.
CASE OBTAINED FROM FERC BULLETIN BOARD. MODIFIED TO REFLECT ADDITION OF GENERATION AT FTMYERS (2002) & AT SANFORD (2004) AND ASSOCIATED TRANSMISSIONS. NSB 500MW PLANT ASSUMED IN SERVICE IN FY 2001!

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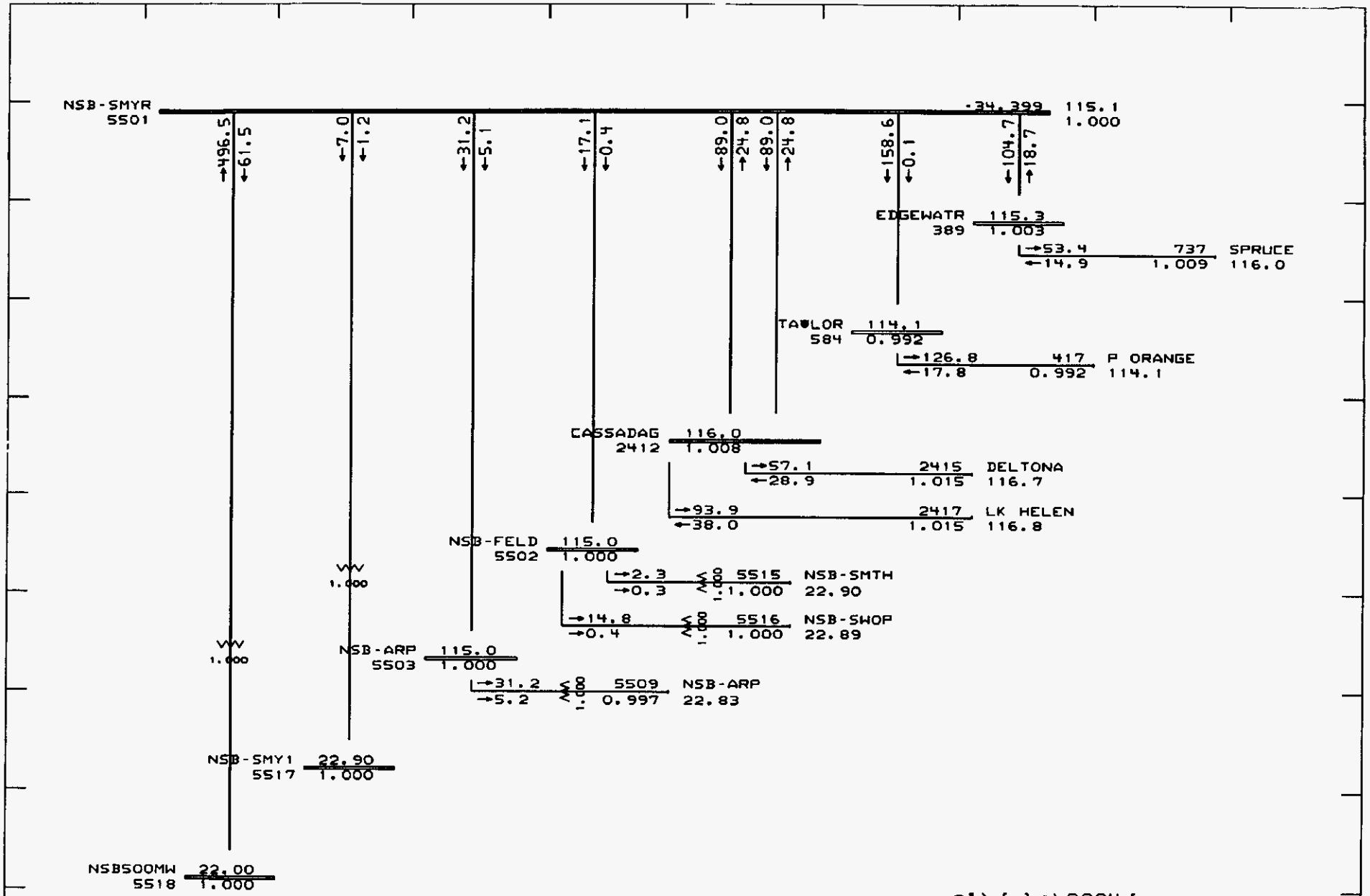
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DELTONA
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LK HELEN
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NSB-SMTH
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PSLF Program
MW/MVAR
Mon Jul 27 17:26:06 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD, NSBSOOMW PLANT IN SERVICE IN 2001!
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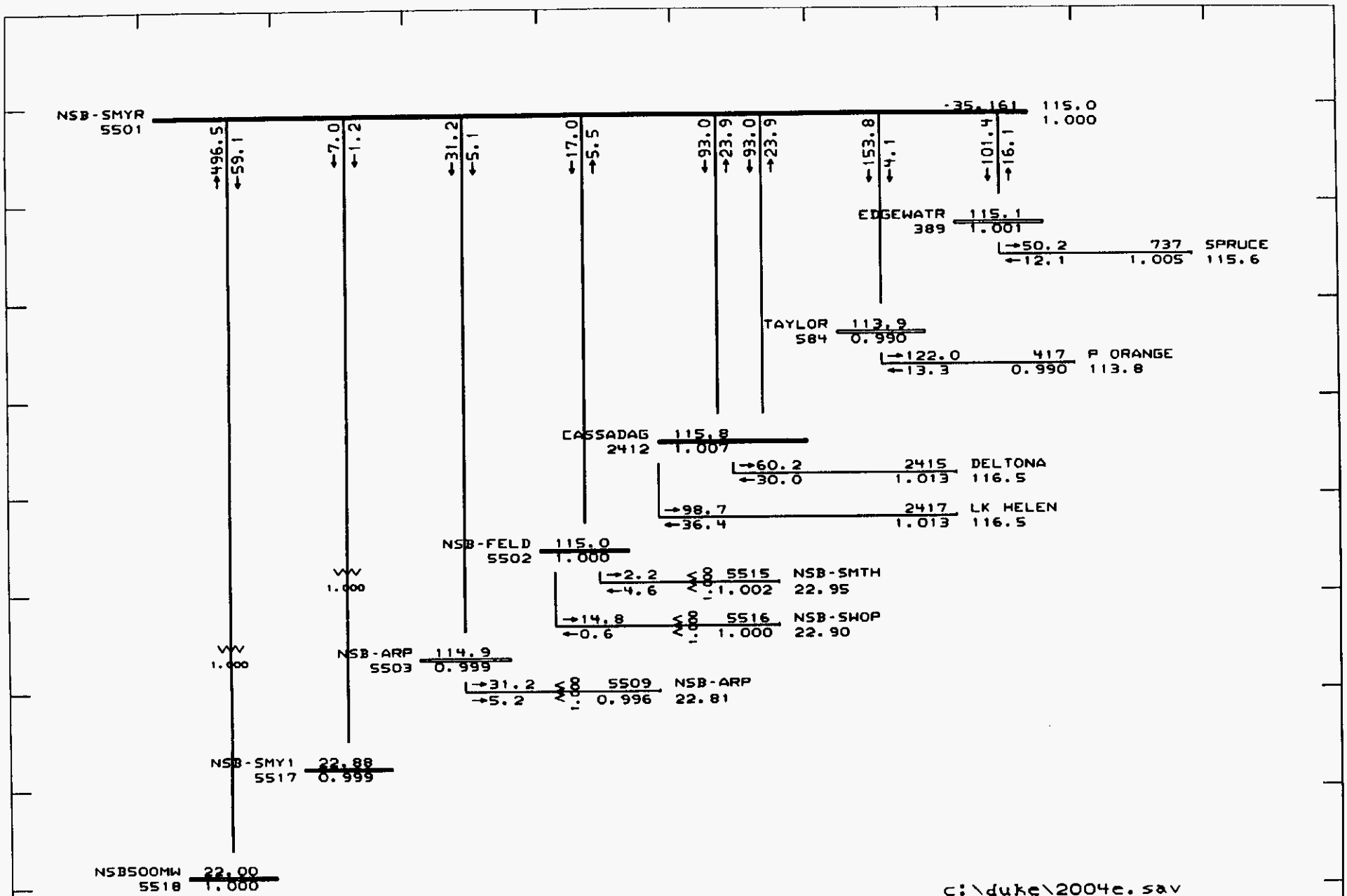

General Electric Company PSLF Program

RMI
Resource Management International, Inc.

2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD. NSB500MW PLANT IN SERVICE IN 2001!

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APPENDIX IV

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-1	SN PLANT	230	SYLVAN	230	1	1						
2004-60-1	SYLVAN	230	N LONGWD	230	1	1						
2004-60-1	IND RIV	230	STANTON	230	1	11						
2004-60-1	SILVR SP	230	SILV SPN	230	1	2						
2004-60-1	SILVR SP	230	SILV SPN	230	2	2						
2004-60-1	RIO PINR	230	CURRY FD	230	1	2						
2004-60-1	JUNEAU-W	138	GANNON	138	1	16						
2004-60-1	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-1	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-1	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-1	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-1	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-1	SN PLANT	115	TURNER	115	1	1						
2004-60-1	PASADENA	115	40ST-DUM	115	1	2						
2004-60-1	MICHIGAN	115	KALEY	115	1	11						
2004-60-1	MICHIGAN	115	GRANT	115	1	11						
2004-60-1	PERSHING	115	GRANT	115	1	11						
2004-60-1	AMERICA	115	KALEY	115	1	11						
2004-60-1	JASPER	115	WGHTCHPL	115	1	2						
2004-60-1	AZALEA	115	BENNETT	115	1	11						
2004-60-1	FLORALTP	69	INVERNTP	69	1	2						
2004-60-1	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-1	PASADENA	230	PASADENA	115	1	2						
2004-60-1	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-1	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-1	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-1	IND RIV	230	IND RIV	115	1	11						
2004-60-1	LARGO	230	LARGO A	69	1	2						
2004-60-1	SHELD	230	SHELD-NW	69	1	16						
2004-60-1	CLMT EST	230	CLMT EST	69	1	2						
2004-60-1	WINDERME	230	WINDERME	69	1	2						
2004-60-1	RIVER-S	230	RIVER-S	69	1	16						
2004-60-1	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-1	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-1	JASPER	115	JASPER	69	1	2						
2004-60-2	SN PLANT	230	SYLVAN	230	1	1						
2004-60-2	SYLVAN	230	N LONGWD	230	1	1						
2004-60-2	IND RIV	230	STANTON	230	1	11						
2004-60-2	SILVR SP	230	SILV SPN	230	1	2						
2004-60-2	SILVR SP	230	SILV SPN	230	2	2						
2004-60-2	RIO PINR	230	CURRY FD	230	1	2						
2004-60-2	JUNEAU-W	138	GANNON	138	1	16						
2004-60-2	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-2	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-2	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-2	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-2	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-2	SN PLANT	115	TURNER	115	1	1						
2004-60-2	PASADENA	115	40ST-DUM	115	1	2						
2004-60-2	MICHIGAN	115	KALEY	115	1	11						
2004-60-2	MICHIGAN	115	GRANT	115	1	11						
2004-60-2	PERSHING	115	GRANT	115	1	11						
2004-60-2	AMERICA	115	KALEY	115	1	11						
2004-60-2	JASPER	115	WGHTCHPL	115	1	2						
2004-60-2	AZALEA	115	BENNETT	115	1	11						
2004-60-2	FLORALTP	69	INVERNTP	69	1	2						
2004-60-2	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-2	PASADENA	230	PASADENA	115	1	2						
2004-60-2	SUWANNEE	230	SUWANNEE	115	1	2						
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2004-60-2	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-2	IND RIV	230	IND RIV	115	1	11						
2004-60-2	LARGO	230	LARGO A	69	1	2						
2004-60-2	SHELD	230	SHELD-NW	69	1	16						
2004-60-2	CLMT EST	230	CLMT EST	69	1	2						
2004-60-2	WINDERME	230	WINDERME	69	1	2						
2004-60-2	RIVER-S	230	RIVER-S	69	1	16						
2004-60-2	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-2	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-2	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-3	SN PLANT	230	SYLVAN	230	1	1						
2004-60-3	SYLVAN	230	N LONGWD	230	1	1						
2004-60-3	IND RIV	230	STANTON	230	1	11						
2004-60-3	SILVR SP	230	SILV SPN	230	1	2						
2004-60-3	SILVR SP	230	SILV SPN	230	2	2						
2004-60-3	RIO PINR	230	CURRY FD	230	1	2						
2004-60-3	JUNEAU-W	138	GANNON	138	1	16						
2004-60-3	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-3	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-3	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-3	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-3	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-3	SN PLANT	115	TURNER	115	1	1						
2004-60-3	PASADENA	115	40ST-DUM	115	1	2						
2004-60-3	MICHIGAN	115	KALEY	115	1	11						
2004-60-3	MICHIGAN	115	GRANT	115	1	11						
2004-60-3	PERSHING	115	GRANT	115	1	11						
2004-60-3	AMERICA	115	KALEY	115	1	11						
2004-60-3	JASPER	115	WGHTCHPL	115	1	2						
2004-60-3	AZALEA	115	BENNETT	115	1	11						
2004-60-3	FLORALTP	69	INVERNTP	69	1	2						
2004-60-3	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-3	PASADENA	230	PASADENA	115	1	2						
2004-60-3	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-3	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-3	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-3	IND RIV	230	IND RIV	115	1	11						
2004-60-3	LARGO	230	LARGO A	69	1	2						
2004-60-3	SHELD	230	SHELD-NW	69	1	16						
2004-60-3	CLMT EST	230	CLMT EST	69	1	2						
2004-60-3	WINDERME	230	WINDERME	69	1	2						
2004-60-3	RIVER-S	230	RIVER-S	69	1	16						
2004-60-3	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-3	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-3	JASPER	115	JASPER	69	1	2						
2004-60-4	SN PLANT	230	SYLVAN	230	1	1						
2004-60-4	SYLVAN	230	N LONGWD	230	1	1						
2004-60-4	IND RIV	230	STANTON	230	1	11						
2004-60-4	SILVR SP	230	SILV SPN	230	1	2						
2004-60-4	SILVR SP	230	SILV SPN	230	2	2						
2004-60-4	RIO PINR	230	CURRY FD	230	1	2						
2004-60-4	JUNEAU-W	138	GANNON	138	1	16						
2004-60-4	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-4	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-4	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-4	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-4	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-4	SN PLANT	115	TURNER	115	1	1						
2004-60-4	PASADENA	115	40ST-DUM	115	1	2						
2004-60-4	MICHIGAN	115	KALEY	115	1	11						
2004-60-4	MICHIGAN	115	GRANT	115	1	11						
2004-60-4	PERSHING	115	GRANT	115	1	11						
2004-60-4	AMERICA	115	KALEY	115	1	11						
2004-60-4	JASPER	115	WGHTCHPL	115	1	2						
2004-60-4	AZALEA	115	BENNETT	115	1	11						
2004-60-4	FLORALTP	69	INVERNTP	69	1	2						
2004-60-4	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-4	PASADENA	230	PASADENA	115	1	2						
2004-60-4	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-4	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-4	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-4	IND RIV	230	IND RIV	115	1	11						
2004-60-4	LARGO	230	LARGO A	69	1	2						
2004-60-4	SHELD	230	SHELD-NW	69	1	16						
2004-60-4	CLMT EST	230	CLMT EST	69	1	2						
2004-60-4	WINDERME	230	WINDERME	69	1	2						
2004-60-4	RIVER-S	230	RIVER-S	69	1	16						
2004-60-4	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-4	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-4	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-5	SN PLANT	230	SYLVAN	230	1	1						
2004-60-5	SYLVAN	230	N LONGWD	230	1	1						
2004-60-5	IND RIV	230	STANTON	230	1	11						
2004-60-5	SILVR SP	230	SILV SPN	230	1	2						
2004-60-5	SILVR SP	230	SILV SPN	230	2	2						
2004-60-5	RIO PINR	230	CURRY FD	230	1	2						
2004-60-5	JUNEAU-W	138	GANNON	138	1	16						
2004-60-5	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-5	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-5	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-5	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-5	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-5	SN PLANT	115	TURNER	115	1	1						
2004-60-5	PASADENA	115	40ST-DUM	115	1	2						
2004-60-5	MICHIGAN	115	KALEY	115	1	11						
2004-60-5	MICHIGAN	115	GRANT	115	1	11						
2004-60-5	PERSHING	115	GRANT	115	1	11						
2004-60-5	AMERICA	115	KALEY	115	1	11						
2004-60-5	JASPER	115	WGHTCHPL	115	1	2						
2004-60-5	AZALEA	115	BENNETT	115	1	11						
2004-60-5	FLORALTP	69	INVERNTP	69	1	2						
2004-60-5	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-5	PASADENA	230	PASADENA	115	1	2						
2004-60-5	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-5	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-5	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-5	IND RIV	230	IND RIV	115	1	11						
2004-60-5	LARGO	230	LARGO A	69	1	2						
2004-60-5	SHELD	230	SHELD-NW	69	1	16						
2004-60-5	CLMT EST	230	CLMT EST	69	1	2						
2004-60-5	WINDERME	230	WINDERME	69	1	2						
2004-60-5	RIVER-S	230	RIVER-S	69	1	16						
2004-60-5	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-5	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-5	JASPER	115	JASPER	69	1	2						
2004-60-6	SN PLANT	230	SYLVAN	230	1	1						
2004-60-6	SYLVAN	230	N LONGWD	230	1	1						
2004-60-6	IND RIV	230	STANTON	230	1	11						
2004-60-6	SILVR SP	230	SILV SPN	230	1	2						
2004-60-6	SILVR SP	230	SILV SPN	230	2	2						
2004-60-6	RIO PINR	230	CURRY FD	230	1	2						
2004-60-6	JUNEAU-W	138	GANNON	138	1	16						
2004-60-6	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-6	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-6	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-6	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-6	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-6	SN PLANT	115	TURNER	115	1	1						
2004-60-6	PASADENA	115	40ST-DUM	115	1	2						
2004-60-6	MICHIGAN	115	KALEY	115	1	11						
2004-60-6	MICHIGAN	115	GRANT	115	1	11						
2004-60-6	PERSHING	115	GRANT	115	1	11						
2004-60-6	AMERICA	115	KALEY	115	1	11						
2004-60-6	JASPER	115	WGHTCHPL	115	1	2						
2004-60-6	AZALEA	115	BENNETT	115	1	11						
2004-60-6	FLORALTP	69	INVERNTP	69	1	2						
2004-60-6	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-6	PASADENA	230	PASADENA	115	1	2						
2004-60-6	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-6	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-6	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-6	IND RIV	230	IND RIV	115	1	11						
2004-60-6	LARGO	230	LARGO A	69	1	2						
2004-60-6	SHELD	230	SHELD-NW	69	1	16						
2004-60-6	CLMT EST	230	CLMT EST	69	1	2						
2004-60-6	WINDERME	230	WINDERME	69	1	2						
2004-60-6	RIVER-S	230	RIVER-S	69	1	16						
2004-60-6	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-6	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-6	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-7	SN PLANT	230	SYLVAN	230	1	1						
2004-60-7	SYLVAN	230	N LONGWD	230	1	1						
2004-60-7	IND RIV	230	STANTON	230	1	11						
2004-60-7	SILVR SP	230	SILV SPN	230	1	2						
2004-60-7	SILVR SP	230	SILV SPN	230	2	2						
2004-60-7	RIO PINR	230	CURRY FD	230	1	2						
2004-60-7	JUNEAU-W	138	GANNON	138	1	16						
2004-60-7	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-7	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-7	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-7	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-7	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-7	SN PLANT	115	TURNER	115	1	1						
2004-60-7	PASADENA	115	40ST-DUM	115	1	2						
2004-60-7	MICHIGAN	115	KALEY	115	1	11						
2004-60-7	MICHIGAN	115	GRANT	115	1	11						
2004-60-7	PERSHING	115	GRANT	115	1	11						
2004-60-7	AMERICA	115	KALEY	115	1	11						
2004-60-7	JASPER	115	WGHTCHPL	115	1	2						
2004-60-7	AZALEA	115	BENNETT	115	1	11						
2004-60-7	FLORALTP	69	INVERNTP	69	1	2						
2004-60-7	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-7	PASADENA	230	PASADENA	115	1	2						
2004-60-7	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-7	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-7	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-7	IND RIV	230	IND RIV	115	1	11						
2004-60-7	LARGO	230	LARGO A	69	1	2						
2004-60-7	SHELD	230	SHELD-NW	69	1	16						
2004-60-7	CLMT EST	230	CLMT EST	69	1	2						
2004-60-7	WINDERME	230	WINDERME	69	1	2						
2004-60-7	RIVER-S	230	RIVER-S	69	1	16						
2004-60-7	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-7	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-7	JASPER	115	JASPER	69	1	2						
2004-60-8	SN PLANT	230	SYLVAN	230	1	1						
2004-60-8	SYLVAN	230	N LONGWD	230	1	1						
2004-60-8	IND RIV	230	STANTON	230	1	11						
2004-60-8	SILVR SP	230	SILV SPN	230	1	2						
2004-60-8	SILVR SP	230	SILV SPN	230	2	2						
2004-60-8	RIO PINR	230	CURRY FD	230	1	2						
2004-60-8	JUNEAU-W	138	GANNON	138	1	16						
2004-60-8	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-8	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-8	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-8	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-8	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-8	SN PLANT	115	TURNER	115	1	1						
2004-60-8	PASADENA	115	40ST-DUM	115	1	2						
2004-60-8	MICHIGAN	115	KALEY	115	1	11						
2004-60-8	MICHIGAN	115	GRANT	115	1	11						
2004-60-8	PERSHING	115	GRANT	115	1	11						
2004-60-8	AMERICA	115	KALEY	115	1	11						
2004-60-8	JASPER	115	WGHTCHPL	115	1	2						
2004-60-8	AZALEA	115	BENNETT	115	1	11						
2004-60-8	FLORALTP	69	INVERNTP	69	1	2						
2004-60-8	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-8	PASADENA	230	PASADENA	115	1	2						
2004-60-8	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-8	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-8	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-8	IND RIV	230	IND RIV	115	1	11						
2004-60-8	LARGO	230	LARGO A	69	1	2						
2004-60-8	SHELD	230	SHELD-NW	69	1	16						
2004-60-8	CLMT EST	230	CLMT EST	69	1	2						
2004-60-8	WINDERME	230	WINDERME	69	1	2						
2004-60-8	RIVER-S	230	RIVER-S	69	1	16						
2004-60-8	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-8	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-8	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-9	SN PLANT	230	SYLVAN	230	1	1						
2004-60-9	SYLVAN	230	N LONGWD	230	1	1						
2004-60-9	IND RIV	230	STANTON	230	1	11						
2004-60-9	SILVR SP	230	SILV SPN	230	1	2						
2004-60-9	SILVR SP	230	SILV SPN	230	2	2						
2004-60-9	RIO PINR	230	CURRY FD	230	1	2						
2004-60-9	JUNEAU-W	138	GANNON	138	1	16						
2004-60-9	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-9	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-9	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-9	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-9	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-9	SN PLANT	115	TURNER	115	1	1						
2004-60-9	PASADENA	115	40ST-DUM	115	1	2						
2004-60-9	MICHIGAN	115	KALEY	115	1	11						
2004-60-9	MICHIGAN	115	GRANT	115	1	11						
2004-60-9	PERSHING	115	GRANT	115	1	11						
2004-60-9	AMERICA	115	KALEY	115	1	11						
2004-60-9	JASPER	115	WGHTCHPL	115	1	2						
2004-60-9	AZALEA	115	BENNETT	115	1	11						
2004-60-9	FLORALTP	69	INVERNTP	69	1	2						
2004-60-9	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-9	PASADENA	230	PASADENA	115	1	2						
2004-60-9	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-9	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-9	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-9	IND RIV	230	IND RIV	115	1	11						
2004-60-9	LARGO	230	LARGO A	69	1	2						
2004-60-9	SHELD	230	SHELD-NW	69	1	16						
2004-60-9	CLMT EST	230	CLMT EST	69	1	2						
2004-60-9	WINDERME	230	WINDERME	69	1	2						
2004-60-9	RIVER-S	230	RIVER-S	69	1	16						
2004-60-9	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-9	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-9	JASPER	115	JASPER	69	1	2						
2004-60-10	SN PLANT	230	SYLVAN	230	1	1						
2004-60-10	SYLVAN	230	N LONGWD	230	1	1						
2004-60-10	IND RIV	230	STANTON	230	1	11						
2004-60-10	SILVR SP	230	SILV SPN	230	1	2						
2004-60-10	SILVR SP	230	SILV SPN	230	2	2						
2004-60-10	RIO PINR	230	CURRY FD	230	1	2						
2004-60-10	JUNEAU-W	138	GANNON	138	1	16						
2004-60-10	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-10	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-10	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-10	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-10	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-10	SN PLANT	115	TURNER	115	1	1						
2004-60-10	PASADENA	115	40ST-DUM	115	1	2						
2004-60-10	MICHIGAN	115	KALEY	115	1	11						
2004-60-10	MICHIGAN	115	GRANT	115	1	11						
2004-60-10	PERSHING	115	GRANT	115	1	11						
2004-60-10	AMERICA	115	KALEY	115	1	11						
2004-60-10	JASPER	115	WGHTCHPL	115	1	2						
2004-60-10	AZALEA	115	BENNETT	115	1	11						
2004-60-10	FLORALTP	69	INVERNTP	69	1	2						
2004-60-10	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-10	PASADENA	230	PASADENA	115	1	2						
2004-60-10	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-10	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-10	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-10	IND RIV	230	IND RIV	115	1	11						
2004-60-10	LARGO	230	LARGO A	69	1	2						
2004-60-10	SHELD	230	SHELD-NW	69	1	16						
2004-60-10	CLMT EST	230	CLMT EST	69	1	2						
2004-60-10	WINDERME	230	WINDERME	69	1	2						
2004-60-10	RIVER-S	230	RIVER-S	69	1	16						
2004-60-10	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-10	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-10	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-11	SN PLANT	230	SYLVAN	230	1	1						
2004-60-11	SYLVAN	230	N LONGWD	230	1	1						
2004-60-11	IND RIV	230	STANTON	230	1	11						
2004-60-11	SILVR SP	230	SILV SPN	230	1	2						
2004-60-11	SILVR SP	230	SILV SPN	230	2	2						
2004-60-11	RIO PINR	230	CURRY FD	230	1	2						
2004-60-11	*JUNEAU-W*	*138*	*GANNON*	*138*	*1*	*16*						
2004-60-11	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-11	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-11	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-11	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-11	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-11	SN PLANT	115	TURNER	115	1	1						
2004-60-11	PASADENA	115	40ST-DUM	115	1	2						
2004-60-11	MICHIGAN	115	KALEY	115	1	11						
2004-60-11	MICHIGAN	115	GRANT	115	1	11						
2004-60-11	PERSHING	115	GRANT	115	1	11						
2004-60-11	AMERICA	115	KALEY	115	1	11						
2004-60-11	JASPER	115	WGHTCHPL	115	1	2						
2004-60-11	*AZALEA*	*115*	*BENNETT*	*115*	*1*	*11*						
2004-60-11	FLORALTP	69	INVERNTP	69	1	2						
2004-60-11	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-11	PASADENA	230	PASADENA	115	1	2						
2004-60-11	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-11	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-11	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-11	IND RIV	230	IND RIV	115	1	11						
2004-60-11	LARGO	230	LARGO A	69	1	2						
2004-60-11	SHELD	230	SHELD-NW	69	1	16						
2004-60-11	CLMT EST	230	CLMT EST	69	1	2						
2004-60-11	WINDERME	230	WINDERME	69	1	2						
2004-60-11	RIVER-S	230	RIVER-S	69	1	16						
2004-60-11	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-11	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-11	JASPER	115	JASPER	69	1	2						
2004-60-12	SN PLANT	230	SYLVAN	230	1	1						
2004-60-12	SYLVAN	230	N LONGWD	230	1	1						
2004-60-12	IND RIV	230	STANTON	230	1	11						
2004-60-12	SILVR SP	230	SILV SPN	230	1	2						
2004-60-12	SILVR SP	230	SILV SPN	230	2	2						
2004-60-12	RIO PINR	230	CURRY FD	230	1	2						
2004-60-12	JUNEAU-W	138	GANNON	138	1	16						
2004-60-12	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-12	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-12	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-12	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-12	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-12	SN PLANT	115	TURNER	115	1	1						
2004-60-12	PASADENA	115	40ST-DUM	115	1	2						
2004-60-12	MICHIGAN	115	KALEY	115	1	11						
2004-60-12	MICHIGAN	115	GRANT	115	1	11						
2004-60-12	PERSHING	115	GRANT	115	1	11						
2004-60-12	AMERICA	115	KALEY	115	1	11						
2004-60-12	JASPER	115	WGHTCHPL	115	1	2						
2004-60-12	AZALEA	115	BENNETT	115	1	11						
2004-60-12	FLORALTP	69	INVERNTP	69	1	2						
2004-60-12	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-12	PASADENA	230	PASADENA	115	1	2						
2004-60-12	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-12	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-12	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-12	IND RIV	230	IND RIV	115	1	11						
2004-60-12	LARGO	230	LARGO A	69	1	2						
2004-60-12	SHELD	230	SHELD-NW	69	1	16						
2004-60-12	CLMT EST	230	CLMT EST	69	1	2						
2004-60-12	WINDERME	230	WINDERME	69	1	2						
2004-60-12	RIVER-S	230	RIVER-S	69	1	16						
2004-60-12	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-12	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-12	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-13	SN PLANT	230	SYLVAN	230	1	1						
2004-60-13	SYLVAN	230	N LONGWD	230	1	1						
2004-60-13	IND RIV	230	STANTON	230	1	11						
2004-60-13	SILVR SP	230	SILV SPN	230	1	2						
2004-60-13	SILVR SP	230	SILV SPN	230	2	2						
2004-60-13	RIO PINR	230	CURRY FD	230	1	2						
2004-60-13	JUNEAU-W	138	GANNON	138	1	16						
2004-60-13	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-13	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-13	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-13	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-13	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-13	SN PLANT	115	TURNER	115	1	1						
2004-60-13	PASADENA	115	40ST-DUM	115	1	2						
2004-60-13	MICHIGAN	115	KALEY	115	1	11						
2004-60-13	MICHIGAN	115	GRANT	115	1	11						
2004-60-13	PERSHING	115	GRANT	115	1	11						
2004-60-13	AMERICA	115	KALEY	115	1	11						
2004-60-13	JASPER	115	WGHTCHPL	115	1	2						
2004-60-13	AZALEA	115	BENNETT	115	1	11						
2004-60-13	FLORALTP	69	INVERNTP	69	1	2						
2004-60-13	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-13	PASADENA	230	PASADENA	115	1	2						
2004-60-13	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-13	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-13	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-13	IND RIV	230	IND RIV	115	1	11						
2004-60-13	LARGO	230	LARGO A	69	1	2						
2004-60-13	SHELD	230	SHELD-NW	69	1	16						
2004-60-13	CLMT EST	230	CLMT EST	69	1	2						
2004-60-13	WINDERME	230	WINDERME	69	1	2						
2004-60-13	RIVER-S	230	RIVER-S	69	1	16						
2004-60-13	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-13	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-13	JASPER	115	JASPER	69	1	2						
2004-60-14	SN PLANT	230	SYLVAN	230	1	1						
2004-60-14	SYLVAN	230	N LONGWD	230	1	1						
2004-60-14	IND RIV	230	STANTON	230	1	11						
2004-60-14	SILVR SP	230	SILV SPN	230	1	2						
2004-60-14	SILVR SP	230	SILV SPN	230	2	2						
2004-60-14	RIO PINR	230	CURRY FD	230	1	2						
2004-60-14	JUNEAU-W	138	GANNON	138	1	16						
2004-60-14	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-14	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-14	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-14	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-14	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-14	SN PLANT	115	TURNER	115	1	1						
2004-60-14	PASADENA	115	40ST-DUM	115	1	2						
2004-60-14	MICHIGAN	115	KALEY	115	1	11						
2004-60-14	MICHIGAN	115	GRANT	115	1	11						
2004-60-14	PERSHING	115	GRANT	115	1	11						
2004-60-14	AMERICA	115	KALEY	115	1	11						
2004-60-14	JASPER	115	WGHTCHPL	115	1	2						
2004-60-14	AZALEA	115	BENNETT	115	1	11						
2004-60-14	FLORALTP	69	INVERNTP	69	1	2						
2004-60-14	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-14	PASADENA	230	PASADENA	115	1	2						
2004-60-14	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-14	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-14	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-14	IND RIV	230	IND RIV	115	1	11						
2004-60-14	LARGO	230	LARGO A	69	1	2						
2004-60-14	SHELD	230	SHELD-NW	69	1	16						
2004-60-14	CLMT EST	230	CLMT EST	69	1	2						
2004-60-14	WINDERME	230	WINDERME	69	1	2						
2004-60-14	RIVER-S	230	RIVER-S	69	1	16						
2004-60-14	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-14	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-14	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-15	SN PLANT	230	SYLVAN	230	1	1						
2004-60-15	SYLVAN	230	N LONGWD	230	1	1						
2004-60-15	IND RIV	230	STANTON	230	1	11						
2004-60-15	SILVR SP	230	SILV SPN	230	1	2						
2004-60-15	SILVR SP	230	SILV SPN	230	2	2						
2004-60-15	RIO PINR	230	CURRY FD	230	1	2						
2004-60-15	JUNEAU-W	138	GANNON	138	1	16						
2004-60-15	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-15	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-15	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-15	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-15	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-15	SN PLANT	115	TURNER	115	1	1						
2004-60-15	PASADENA	115	40ST-DUM	115	1	2						
2004-60-15	MICHIGAN	115	KALEY	115	1	11						
2004-60-15	MICHIGAN	115	GRANT	115	1	11						
2004-60-15	PERSHING	115	GRANT	115	1	11						
2004-60-15	AMERICA	115	KALEY	115	1	11						
2004-60-15	JASPER	115	WGHTCHPL	115	1	2						
2004-60-15	AZALEA	115	BENNETT	115	1	11						
2004-60-15	FLORALTP	69	INVERNTP	69	1	2						
2004-60-15	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-15	PASADENA	230	PASADENA	115	1	2						
2004-60-15	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-15	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-15	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-15	IND RIV	230	IND RIV	115	1	11						
2004-60-15	LARGO	230	LARGO A	69	1	2						
2004-60-15	SHELD	230	SHELD-NW	69	1	16						
2004-60-15	CLMT EST	230	CLMT EST	69	1	2						
2004-60-15	WINDERME	230	WINDERME	69	1	2						
2004-60-15	RIVER-S	230	RIVER-S	69	1	16						
2004-60-15	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-15	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-15	JASPER	115	JASPER	69	1	2						
2004-60-16	SN PLANT	230	SYLVAN	230	1	1						
2004-60-16	SYLVAN	230	N LONGWD	230	1	1						
2004-60-16	IND RIV	230	STANTON	230	1	11						
2004-60-16	SILVR SP	230	SILV SPN	230	1	2						
2004-60-16	SILVR SP	230	SILV SPN	230	2	2						
2004-60-16	RIO PINR	230	CURRY FD	230	1	2						
2004-60-16	JUNEAU-W	138	GANNON	138	1	16						
2004-60-16	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-16	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-16	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-16	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-16	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-16	SN PLANT	115	TURNER	115	1	1						
2004-60-16	PASADENA	115	40ST-DUM	115	1	2						
2004-60-16	MICHIGAN	115	KALEY	115	1	11						
2004-60-16	MICHIGAN	115	GRANT	115	1	11						
2004-60-16	PERSHING	115	GRANT	115	1	11						
2004-60-16	AMERICA	115	KALEY	115	1	11						
2004-60-16	JASPER	115	WGHTCHPL	115	1	2						
2004-60-16	AZALEA	115	BENNETT	115	1	11						
2004-60-16	FLORALTP	69	INVERNTP	69	1	2						
2004-60-16	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-16	PASADENA	230	PASADENA	115	1	2						
2004-60-16	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-16	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-16	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-16	IND RIV	230	IND RIV	115	1	11						
2004-60-16	LARGO	230	LARGO A	69	1	2						
2004-60-16	SHELD	230	SHELD-NW	69	1	16						
2004-60-16	CLMT EST	230	CLMT EST	69	1	2						
2004-60-16	WINDERME	230	WINDERME	69	1	2						
2004-60-16	RIVER-S	230	RIVER-S	69	1	16						
2004-60-16	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-16	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-16	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-17	SN PLANT	230	SYLVAN	230	1	1						
2004-60-17	SYLVAN	230	N LONGWD	230	1	1						
2004-60-17	IND RIV	230	STANTON	230	1	11						
2004-60-17	SILVR SP	230	SILV SPN	230	1	2						
2004-60-17	SILVR SP	230	SILV SPN	230	2	2						
2004-60-17	RIO PINR	230	CURRY FD	230	1	2						
2004-60-17	JUNEAU-W	138	GANNON	138	1	16						
2004-60-17	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-17	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-17	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-17	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-17	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-17	SN PLANT	115	TURNER	115	1	1						
2004-60-17	PASADENA	115	40ST-DUM	115	1	2						
2004-60-17	MICHIGAN	115	KALEY	115	1	11						
2004-60-17	MICHIGAN	115	GRANT	115	1	11						
2004-60-17	PERSHING	115	GRANT	115	1	11						
2004-60-17	AMERICA	115	KALEY	115	1	11						
2004-60-17	JASPER	115	WGHTCHPL	115	1	2						
2004-60-17	AZALEA	115	BENNETT	115	1	11						
2004-60-17	FLORALTP	69	INVERNTP	69	1	2						
2004-60-17	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-17	PASADENA	230	PASADENA	115	1	2						
2004-60-17	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-17	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-17	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-17	IND RIV	230	IND RIV	115	1	11						
2004-60-17	LARGO	230	LARGO A	69	1	2						
2004-60-17	SHELD	230	SHELD-NW	69	1	16						
2004-60-17	CLMT EST	230	CLMT EST	69	1	2						
2004-60-17	WINDERME	230	WINDERME	69	1	2						
2004-60-17	RIVER-S	230	RIVER-S	69	1	16						
2004-60-17	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-17	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-17	JASPER	115	JASPER	69	1	2						
2004-60-18	SN PLANT	230	SYLVAN	230	1	1						
2004-60-18	SYLVAN	230	N LONGWD	230	1	1						
2004-60-18	IND RIV	230	STANTON	230	1	11						
2004-60-18	SILVR SP	230	SILV SPN	230	1	2						
2004-60-18	SILVR SP	230	SILV SPN	230	2	2						
2004-60-18	RIO PINR	230	CURRY FD	230	1	2						
2004-60-18	JUNEAU-W	138	GANNON	138	1	16						
2004-60-18	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-18	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-18	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-18	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-18	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-18	SN PLANT	115	TURNER	115	1	1						
2004-60-18	PASADENA	115	40ST-DUM	115	1	2						
2004-60-18	MICHIGAN	115	KALEY	115	1	11						
2004-60-18	MICHIGAN	115	GRANT	115	1	11						
2004-60-18	PERSHING	115	GRANT	115	1	11						
2004-60-18	AMERICA	115	KALEY	115	1	11						
2004-60-18	JASPER	115	WGHTCHPL	115	1	2						
2004-60-18	AZALEA	115	BENNETT	115	1	11						
2004-60-18	FLORALTP	69	INVERNTP	69	1	2						
2004-60-18	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-18	PASADENA	230	PASADENA	115	1	2						
2004-60-18	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-18	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-18	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-18	IND RIV	230	IND RIV	115	1	11						
2004-60-18	LARGO	230	LARGO A	69	1	2						
2004-60-18	SHELD	230	SHELD-NW	69	1	16						
2004-60-18	CLMT EST	230	CLMT EST	69	1	2						
2004-60-18	WINDERME	230	WINDERME	69	1	2						
2004-60-18	RIVER-S	230	RIVER-S	69	1	16						
2004-60-18	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-18	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-18	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-19	SN PLANT	230	SYLVAN	230	1	1						
2004-60-19	SYLVAN	230	N LONGWD	230	1	1						
2004-60-19	IND RIV	230	STANTON	230	1	11						
2004-60-19	SILVR SP	230	SILV SPN	230	1	2						
2004-60-19	SILVR SP	230	SILV SPN	230	2	2						
2004-60-19	RIO PINR	230	CURRY FD	230	1	2						
2004-60-19	JUNEAU-W	138	GANNON	138	1	16						
2004-60-19	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-19	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-19	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-19	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-19	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-19	SN PLANT	115	TURNER	115	1	1						
2004-60-19	PASADENA	115	40ST-DUM	115	1	2						
2004-60-19	MICHIGAN	115	KALEY	115	1	11						
2004-60-19	MICHIGAN	115	GRANT	115	1	11						
2004-60-19	PERSHING	115	GRANT	115	1	11						
2004-60-19	AMERICA	115	KALEY	115	1	11						
2004-60-19	JASPER	115	WGHTCHPL	115	1	2						
2004-60-19	AZALEA	115	BENNETT	115	1	11						
2004-60-19	FLORALTP	69	INVERNTP	69	1	2						
2004-60-19	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-19	PASADENA	230	PASADENA	115	1	2						
2004-60-19	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-19	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-19	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-19	IND RIV	230	IND RIV	115	1	11						
2004-60-19	LARGO	230	LARGO A	69	1	2						
2004-60-19	SHELD	230	SHELD-NW	69	1	16						
2004-60-19	CLMT EST	230	CLMT EST	69	1	2						
2004-60-19	WINDERME	230	WINDERME	69	1	2						
2004-60-19	RIVER-S	230	RIVER-S	69	1	16						
2004-60-19	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-19	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-19	JASPER	115	JASPER	69	1	2						
2004-60-20	SN PLANT	230	SYLVAN	230	1	1						
2004-60-20	SYLVAN	230	N LONGWD	230	1	1						
2004-60-20	IND RIV	230	STANTON	230	1	11						
2004-60-20	SILVR SP	230	SILV SPN	230	1	2						
2004-60-20	SILVR SP	230	SILV SPN	230	2	2						
2004-60-20	RIO PINR	230	CURRY FD	230	1	2						
2004-60-20	JUNEAU-W	138	GANNON	138	1	16						
2004-60-20	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-20	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-20	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-20	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-20	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-20	SN PLANT	115	TURNER	115	1	1						
2004-60-20	PASADENA	115	40ST-DUM	115	1	2						
2004-60-20	MICHIGAN	115	KALEY	115	1	11						
2004-60-20	MICHIGAN	115	GRANT	115	1	11						
2004-60-20	PERSHING	115	GRANT	115	1	11						
2004-60-20	AMERICA	115	KALEY	115	1	11						
2004-60-20	JASPER	115	WGHTCHPL	115	1	2						
2004-60-20	AZALEA	115	BENNETT	115	1	11						
2004-60-20	FLORALTP	69	INVERNTP	69	1	2						
2004-60-20	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-20	PASADENA	230	PASADENA	115	1	2						
2004-60-20	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-20	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-20	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-20	IND RIV	230	IND RIV	115	1	11						
2004-60-20	LARGO	230	LARGO A	69	1	2						
2004-60-20	SHELD	230	SHELD-NW	69	1	16						
2004-60-20	CLMT EST	230	CLMT EST	69	1	2						
2004-60-20	WINDERME	230	WINDERME	69	1	2						
2004-60-20	RIVER-S	230	RIVER-S	69	1	16						
2004-60-20	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-20	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-20	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-21	SN PLANT	230	SYLVAN	230	1	1						
2004-60-21	SYLVAN	230	N LONGWD	230	1	1						
2004-60-21	IND RIV	230	STANTON	230	1	11						
2004-60-21	SILVR SP	230	SILV SPN	230	1	2						
2004-60-21	SILVR SP	230	SILV SPN	230	2	2						
2004-60-21	RIO PINR	230	CURRY FD	230	1	2						
2004-60-21	JUNEAU-W	138	GANNON	138	1	16						
2004-60-21	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-21	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-21	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-21	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-21	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-21	SN PLANT	115	TURNER	115	1	1						
2004-60-21	PASADENA	115	40ST-DUM	115	1	2						
2004-60-21	MICHIGAN	115	KALEY	115	1	11						
2004-60-21	MICHIGAN	115	GRANT	115	1	11						
2004-60-21	PERSHING	115	GRANT	115	1	11						
2004-60-21	AMERICA	115	KALEY	115	1	11						
2004-60-21	JASPER	115	WGHTCHPL	115	1	2						
2004-60-21	AZALEA	115	BENNETT	115	1	11						
2004-60-21	FLORALTP	69	INVERNTP	69	1	2						
2004-60-21	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-21	PASADENA	230	PASADENA	115	1	2						
2004-60-21	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-21	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-21	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-21	IND RIV	230	IND RIV	115	1	11						
2004-60-21	LARGO	230	LARGO A	69	1	2						
2004-60-21	SHELD	230	SHELD-NW	69	1	16						
2004-60-21	CLMT EST	230	CLMT EST	69	1	2						
2004-60-21	WINDERME	230	WINDERME	69	1	2						
2004-60-21	RIVER-S	230	RIVER-S	69	1	16						
2004-60-21	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-21	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-21	JASPER	115	JASPER	69	1	2						
2004-60-22	SN PLANT	230	SYLVAN	230	1	1						
2004-60-22	SYLVAN	230	N LONGWD	230	1	1						
2004-60-22	IND RIV	230	STANTON	230	1	11						
2004-60-22	SILVR SP	230	SILV SPN	230	1	2						
2004-60-22	SILVR SP	230	SILV SPN	230	2	2						
2004-60-22	RIO PINR	230	CURRY FD	230	1	2						
2004-60-22	JUNEAU-W	138	GANNON	138	1	16						
2004-60-22	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-22	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-22	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-22	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-22	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-22	SN PLANT	115	TURNER	115	1	1						
2004-60-22	PASADENA	115	40ST-DUM	115	1	2						
2004-60-22	MICHIGAN	115	KALEY	115	1	11						
2004-60-22	MICHIGAN	115	GRANT	115	1	11						
2004-60-22	PERSHING	115	GRANT	115	1	11						
2004-60-22	AMERICA	115	KALEY	115	1	11						
2004-60-22	JASPER	115	WGHTCHPL	115	1	2						
2004-60-22	AZALEA	115	BENNETT	115	1	11						
2004-60-22	FLORALTP	69	INVERNTP	69	1	2						
2004-60-22	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-22	PASADENA	230	PASADENA	115	1	2						
2004-60-22	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-22	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-22	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-22	IND RIV	230	IND RIV	115	1	11						
2004-60-22	LARGO	230	LARGO A	69	1	2						
2004-60-22	SHELD	230	SHELD-NW	69	1	16						
2004-60-22	CLMT EST	230	CLMT EST	69	1	2						
2004-60-22	WINDERME	230	WINDERME	69	1	2						
2004-60-22	RIVER-S	230	RIVER-S	69	1	16						
2004-60-22	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-22	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-22	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-23	SN PLANT	230	SYLVAN	230	1	1						
2004-60-23	SYLVAN	230	N LONGWD	230	1	1						
2004-60-23	IND RIV	230	STANTON	230	1	11						
2004-60-23	SILVR SP	230	SILV SPN	230	1	2						
2004-60-23	SILVR SP	230	SILV SPN	230	2	2						
2004-60-23	RIO PINR	230	CURRY FD	230	1	2						
2004-60-23	JUNEAU-W	138	GANNON	138	1	16						
2004-60-23	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-23	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-23	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-23	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-23	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-23	SN PLANT	115	TURNER	115	1	1						
2004-60-23	PASADENA	115	40ST-DUM	115	1	2						
2004-60-23	MICHIGAN	115	KALEY	115	1	11						
2004-60-23	MICHIGAN	115	GRANT	115	1	11						
2004-60-23	PERSHING	115	GRANT	115	1	11						
2004-60-23	AMERICA	115	KALEY	115	1	11						
2004-60-23	JASPER	115	WGHTCHPL	115	1	2						
2004-60-23	AZALEA	115	BENNETT	115	1	11						
2004-60-23	FLORALTP	69	INVERNTP	69	1	2						
2004-60-23	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-23	PASADENA	230	PASADENA	115	1	2						
2004-60-23	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-23	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-23	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-23	IND RIV	230	IND RIV	115	1	11						
2004-60-23	LARGO	230	LARGO A	69	1	2						
2004-60-23	SHELD	230	SHELD-NW	69	1	16						
2004-60-23	CLMT EST	230	CLMT EST	69	1	2						
2004-60-23	WINDERME	230	WINDERME	69	1	2						
2004-60-23	RIVER-S	230	RIVER-S	69	1	16						
2004-60-23	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-23	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-23	JASPER	115	JASPER	69	1	2						
2004-60-24	SN PLANT	230	SYLVAN	230	1	1						
2004-60-24	SYLVAN	230	N LONGWD	230	1	1						
2004-60-24	IND RIV	230	STANTON	230	1	11						
2004-60-24	SILVR SP	230	SILV SPN	230	1	2						
2004-60-24	SILVR SP	230	SILV SPN	230	2	2						
2004-60-24	RIO PINR	230	CURRY FD	230	1	2						
2004-60-24	JUNEAU-W	138	GANNON	138	1	16						
2004-60-24	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-24	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-24	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-24	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-24	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-24	SN PLANT	115	TURNER	115	1	1						
2004-60-24	PASADENA	115	40ST-DUM	115	1	2						
2004-60-24	MICHIGAN	115	KALEY	115	1	11						
2004-60-24	MICHIGAN	115	GRANT	115	1	11						
2004-60-24	PERSHING	115	GRANT	115	1	11						
2004-60-24	AMERICA	115	KALEY	115	1	11						
2004-60-24	JASPER	115	WGHTCHPL	115	1	2						
2004-60-24	AZALEA	115	BENNETT	115	1	11						
2004-60-24	FLORALTP	69	INVERNTP	69	1	2						
2004-60-24	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-24	PASADENA	230	PASADENA	115	1	2						
2004-60-24	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-24	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-24	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-24	IND RIV	230	IND RIV	115	1	11						
2004-60-24	LARGO	230	LARGO A	69	1	2						
2004-60-24	SHELD	230	SHELD-NW	69	1	16						
2004-60-24	CLMT EST	230	CLMT EST	69	1	2						
2004-60-24	WINDERME	230	WINDERME	69	1	2						
2004-60-24	RIVER-S	230	RIVER-S	69	1	16						
2004-60-24	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-24	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-24	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-25	SN PLANT	230	SYLVAN	230	1	1						
2004-60-25	SYLVAN	230	N LONGWD	230	1	1						
2004-60-25	IND RIV	230	STANTON	230	1	11						
2004-60-25	SILVR SP	230	SILV SPN	230	1	2						
2004-60-25	SILVR SP	230	SILV SPN	230	2	2						
2004-60-25	RIO PINR	230	CURRY FD	230	1	2						
2004-60-25	JUNEAU-W	138	GANNON	138	1	16						
2004-60-25	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-25	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-25	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-25	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-25	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-25	SN PLANT	115	TURNER	115	1	1						
2004-60-25	PASADENA	115	40ST-DUM	115	1	2						
2004-60-25	MICHIGAN	115	KALEY	115	1	11						
2004-60-25	MICHIGAN	115	GRANT	115	1	11						
2004-60-25	PERSHING	115	GRANT	115	1	11						
2004-60-25	AMERICA	115	KALEY	115	1	11						
2004-60-25	JASPER	115	WGHTCHPL	115	1	2						
2004-60-25	AZALEA	115	BENNETT	115	1	11						
2004-60-25	FLORALTP	69	INVERNTP	69	1	2						
2004-60-25	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-25	PASADENA	230	PASADENA	115	1	2						
2004-60-25	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-25	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-25	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-25	IND RIV	230	IND RIV	115	1	11						
2004-60-25	LARGO	230	LARGO A	69	1	2						
2004-60-25	SHELD	230	SHELD-NW	69	1	16						
2004-60-25	CLMT EST	230	CLMT EST	69	1	2						
2004-60-25	WINDERME	230	WINDERME	69	1	2						
2004-60-25	RIVER-S	230	RIVER-S	69	1	16						
2004-60-25	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-25	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-25	JASPER	115	JASPER	69	1	2						
2004-60-26	SN PLANT	230	SYLVAN	230	1	1						
2004-60-26	SYLVAN	230	N LONGWD	230	1	1						
2004-60-26	IND RIV	230	STANTON	230	1	11						
2004-60-26	SILVR SP	230	SILV SPN	230	1	2						
2004-60-26	SILVR SP	230	SILV SPN	230	2	2						
2004-60-26	RIO PINR	230	CURRY FD	230	1	2						
2004-60-26	JUNEAU-W	138	GANNON	138	1	16						
2004-60-26	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-26	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-26	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-26	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-26	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-26	SN PLANT	115	TURNER	115	1	1						
2004-60-26	PASADENA	115	40ST-DUM	115	1	2						
2004-60-26	MICHIGAN	115	KALEY	115	1	11						
2004-60-26	MICHIGAN	115	GRANT	115	1	11						
2004-60-26	PERSHING	115	GRANT	115	1	11						
2004-60-26	AMERICA	115	KALEY	115	1	11						
2004-60-26	JASPER	115	WGHTCHPL	115	1	2						
2004-60-26	AZALEA	115	BENNETT	115	1	11						
2004-60-26	FLORALTP	69	INVERNTP	69	1	2						
2004-60-26	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-26	PASADENA	230	PASADENA	115	1	2						
2004-60-26	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-26	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-26	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-26	IND RIV	230	IND RIV	115	1	11						
2004-60-26	LARGO	230	LARGO A	69	1	2						
2004-60-26	SHELD	230	SHELD-NW	69	1	16						
2004-60-26	CLMT EST	230	CLMT EST	69	1	2						
2004-60-26	WINDERME	230	WINDERME	69	1	2						
2004-60-26	RIVER-S	230	RIVER-S	69	1	16						
2004-60-26	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-26	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-26	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-27	SN PLANT	230	SYLVAN	230	1	1						
2004-60-27	SYLVAN	230	N LONGWD	230	1	1						
2004-60-27	IND RIV	230	STANTON	230	1	11						
2004-60-27	SILVR SP	230	SILV SPN	230	1	2						
2004-60-27	SILVR SP	230	SILV SPN	230	2	2						
2004-60-27	RIO PINR	230	CURRY FD	230	1	2						
2004-60-27	JUNEAU-W	138	GANNON	138	1	16						
2004-60-27	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-27	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-27	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-27	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-27	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-27	SN PLANT	115	TURNER	115	1	1						
2004-60-27	PASADENA	115	40ST-DUM	115	1	2						
2004-60-27	MICHIGAN	115	KALEY	115	1	11						
2004-60-27	MICHIGAN	115	GRANT	115	1	11						
2004-60-27	PERSHING	115	GRANT	115	1	11						
2004-60-27	AMERICA	115	KALEY	115	1	11						
2004-60-27	JASPER	115	WGHTCHPL	115	1	2						
2004-60-27	AZALEA	115	BENNETT	115	1	11						
2004-60-27	FLORALTP	69	INVERNTP	69	1	2						
2004-60-27	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-27	PASADENA	230	PASADENA	115	1	2						
2004-60-27	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-27	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-27	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-27	IND RIV	230	IND RIV	115	1	11						
2004-60-27	LARGO	230	LARGO A	69	1	2						
2004-60-27	SHELD	230	SHELD-NW	69	1	16						
2004-60-27	CLMT EST	230	CLMT EST	69	1	2						
2004-60-27	WINDERME	230	WINDERME	69	1	2						
2004-60-27	RIVER-S	230	RIVER-S	69	1	16						
2004-60-27	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-27	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-27	JASPER	115	JASPER	69	1	2						
2004-60-28	SN PLANT	230	SYLVAN	230	1	1						
2004-60-28	SYLVAN	230	N LONGWD	230	1	1						
2004-60-28	IND RIV	230	STANTON	230	1	11						
2004-60-28	SILVR SP	230	SILV SPN	230	1	2						
2004-60-28	SILVR SP	230	SILV SPN	230	2	2						
2004-60-28	RIO PINR	230	CURRY FD	230	1	2						
2004-60-28	JUNEAU-W	138	GANNON	138	1	16						
2004-60-28	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-28	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-28	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-28	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-28	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-28	SN PLANT	115	TURNER	115	1	1						
2004-60-28	PASADENA	115	40ST-DUM	115	1	2						
2004-60-28	MICHIGAN	115	KALEY	115	1	11						
2004-60-28	MICHIGAN	115	GRANT	115	1	11						
2004-60-28	PERSHING	115	GRANT	115	1	11						
2004-60-28	AMERICA	115	KALEY	115	1	11						
2004-60-28	JASPER	115	WGHTCHPL	115	1	2						
2004-60-28	AZALEA	115	BENNETT	115	1	11						
2004-60-28	FLORALTP	69	INVERNTP	69	1	2						
2004-60-28	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-28	PASADENA	230	PASADENA	115	1	2						
2004-60-28	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-28	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-28	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-28	IND RIV	230	IND RIV	115	1	11						
2004-60-28	LARGO	230	LARGO A	69	1	2						
2004-60-28	SHELD	230	SHELD-NW	69	1	16						
2004-60-28	CLMT EST	230	CLMT EST	69	1	2						
2004-60-28	WINDERME	230	WINDERME	69	1	2						
2004-60-28	RIVER-S	230	RIVER-S	69	1	16						
2004-60-28	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-28	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-28	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-29	SN PLANT	230	SYLVAN	230	1	1						
2004-60-29	SYLVAN	230	N LONGWD	230	1	1						
2004-60-29	IND RIV	230	STANTON	230	1	11						
2004-60-29	SILVR SP	230	SILV SPN	230	1	2						
2004-60-29	SILVR SP	230	SILV SPN	230	2	2						
2004-60-29	RIO PINR	230	CURRY FD	230	1	2						
2004-60-29	JUNEAU-W	138	GANNON	138	1	16						
2004-60-29	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-29	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-29	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-29	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-29	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-29	SN PLANT	115	TURNER	115	1	1						
2004-60-29	PASADENA	115	40ST-DUM	115	1	2						
2004-60-29	MICHIGAN	115	KALEY	115	1	11						
2004-60-29	MICHIGAN	115	GRANT	115	1	11						
2004-60-29	PERSHING	115	GRANT	115	1	11						
2004-60-29	AMERICA	115	KALEY	115	1	11						
2004-60-29	JASPER	115	WGHTCHPL	115	1	2						
2004-60-29	AZALEA	115	BENNETT	115	1	11						
2004-60-29	FLORALTP	69	INVERNTP	69	1	2						
2004-60-29	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-29	PASADENA	230	PASADENA	115	1	2						
2004-60-29	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-29	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-29	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-29	IND RIV	230	IND RIV	115	1	11						
2004-60-29	LARGO	230	LARGO A	69	1	2						
2004-60-29	SHELD	230	SHELD-NW	69	1	16						
2004-60-29	CLMT EST	230	CLMT EST	69	1	2						
2004-60-29	WINDERME	230	WINDERME	69	1	2						
2004-60-29	RIVER-S	230	RIVER-S	69	1	16						
2004-60-29	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-29	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-29	JASPER	115	JASPER	69	1	2						
2004-60-30	SN PLANT	230	SYLVAN	230	1	1						
2004-60-30	SYLVAN	230	N LONGWD	230	1	1						
2004-60-30	IND RIV	230	STANTON	230	1	11						
2004-60-30	SILVR SP	230	SILV SPN	230	1	2						
2004-60-30	SILVR SP	230	SILV SPN	230	2	2						
2004-60-30	RIO PINR	230	CURRY FD	230	1	2						
2004-60-30	JUNEAU-W	138	GANNON	138	1	16						
2004-60-30	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-30	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-30	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-30	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-30	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-30	SN PLANT	115	TURNER	115	1	1						
2004-60-30	PASADENA	115	40ST-DUM	115	1	2						
2004-60-30	MICHIGAN	115	KALEY	115	1	11						
2004-60-30	MICHIGAN	115	GRANT	115	1	11						
2004-60-30	PERSHING	115	GRANT	115	1	11						
2004-60-30	AMERICA	115	KALEY	115	1	11						
2004-60-30	JASPER	115	WGHTCHPL	115	1	2						
2004-60-30	AZALEA	115	BENNETT	115	1	11						
2004-60-30	FLORALTP	69	INVERNTP	69	1	2						
2004-60-30	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-30	PASADENA	230	PASADENA	115	1	2						
2004-60-30	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-30	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-30	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-30	IND RIV	230	IND RIV	115	1	11						
2004-60-30	LARGO	230	LARGO A	69	1	2						
2004-60-30	SHELD	230	SHELD-NW	69	1	16						
2004-60-30	CLMT EST	230	CLMT EST	69	1	2						
2004-60-30	WINDERME	230	WINDERME	69	1	2						
2004-60-30	RIVER-S	230	RIVER-S	69	1	16						
2004-60-30	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-30	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-30	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-31	SN PLANT	230	SYLVAN	230	1	1						
2004-60-31	SYLVAN	230	N LONGWD	230	1	1						
2004-60-31	IND RIV	230	STANTON	230	1	11						
2004-60-31	SILVR SP	230	SILV SPN	230	1	2						
2004-60-31	SILVR SP	230	SILV SPN	230	2	2						
2004-60-31	RIO PINR	230	CURRY FD	230	1	2						
2004-60-31	JUNEAU-W	138	GANNON	138	1	16						
2004-60-31	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-31	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-31	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-31	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-31	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-31	SN PLANT	115	TURNER	115	1	1						
2004-60-31	PASADENA	115	40ST-DUM	115	1	2						
2004-60-31	MICHIGAN	115	KALEY	115	1	11						
2004-60-31	MICHIGAN	115	GRANT	115	1	11						
2004-60-31	PERSHING	115	GRANT	115	1	11						
2004-60-31	AMERICA	115	KALEY	115	1	11						
2004-60-31	JASPER	115	WGHTCHPL	115	1	2						
2004-60-31	AZALEA	115	BENNETT	115	1	11						
2004-60-31	FLORALTP	69	INVERNTP	69	1	2						
2004-60-31	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-31	PASADENA	230	PASADENA	115	1	2						
2004-60-31	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-31	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-31	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-31	IND RIV	230	IND RIV	115	1	11						
2004-60-31	LARGO	230	LARGO A	69	1	2						
2004-60-31	SHELD	230	SHELD-NW	69	1	16						
2004-60-31	CLMT EST	230	CLMT EST	69	1	2						
2004-60-31	WINDERME	230	WINDERME	69	1	2						
2004-60-31	RIVER-S	230	RIVER-S	69	1	16						
2004-60-31	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-31	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-31	JASPER	115	JASPER	69	1	2						
2004-60-32	SN PLANT	230	SYLVAN	230	1	1						
2004-60-32	SYLVAN	230	N LONGWD	230	1	1						
2004-60-32	IND RIV	230	STANTON	230	1	11						
2004-60-32	SILVR SP	230	SILV SPN	230	1	2						
2004-60-32	SILVR SP	230	SILV SPN	230	2	2						
2004-60-32	RIO PINR	230	CURRY FD	230	1	2						
2004-60-32	JUNEAU-W	138	GANNON	138	1	16						
2004-60-32	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-32	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-32	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-32	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-32	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-32	SN PLANT	115	TURNER	115	1	1						
2004-60-32	PASADENA	115	40ST-DUM	115	1	2						
2004-60-32	MICHIGAN	115	KALEY	115	1	11						
2004-60-32	MICHIGAN	115	GRANT	115	1	11						
2004-60-32	PERSHING	115	GRANT	115	1	11						
2004-60-32	AMERICA	115	KALEY	115	1	11						
2004-60-32	JASPER	115	WGHTCHPL	115	1	2						
2004-60-32	AZALEA	115	BENNETT	115	1	11						
2004-60-32	FLORALTP	69	INVERNTP	69	1	2						
2004-60-32	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-32	PASADENA	230	PASADENA	115	1	2						
2004-60-32	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-32	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-32	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-32	IND RIV	230	IND RIV	115	1	11						
2004-60-32	LARGO	230	LARGO A	69	1	2						
2004-60-32	SHELD	230	SHELD-NW	69	1	16						
2004-60-32	CLMT EST	230	CLMT EST	69	1	2						
2004-60-32	WINDERME	230	WINDERME	69	1	2						
2004-60-32	RIVER-S	230	RIVER-S	69	1	16						
2004-60-32	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-32	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-32	JASPER	115	JASPER	69	1	2						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-33	SN PLANT	230	SYLVAN	230	1	1						
2004-60-33	SYLVAN	230	N LONGWD	230	1	1						
2004-60-33	IND RIV	230	STANTON	230	1	11						
2004-60-33	SILVR SP	230	SILV SPN	230	1	2						
2004-60-33	SILVR SP	230	SILV SPN	230	2	2						
2004-60-33	RIO PINR	230	CURRY FD	230	1	2						
2004-60-33	JUNEAU-W	138	GANNON	138	1	16						
2004-60-33	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-33	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-33	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-33	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-33	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-33	SN PLANT	115	TURNER	115	1	1						
2004-60-33	PASADENA	115	40ST-DUM	115	1	2						
2004-60-33	MICHIGAN	115	KALEY	115	1	11						
2004-60-33	MICHIGAN	115	GRANT	115	1	11						
2004-60-33	PERSHING	115	GRANT	115	1	11						
2004-60-33	AMERICA	115	KALEY	115	1	11						
2004-60-33	JASPER	115	WGHTCHPL	115	1	2						
2004-60-33	AZALEA	115	BENNETT	115	1	11						
2004-60-33	FLORALTP	69	INVERNTP	69	1	2						
2004-60-33	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-33	PASADENA	230	PASADENA	115	1	2						
2004-60-33	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-33	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-33	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-33	IND RIV	230	IND RIV	115	1	11						
2004-60-33	LARGO	230	LARGO A	69	1	2						
2004-60-33	SHELD	230	SHELD-NW	69	1	16						
2004-60-33	CLMT EST	230	CLMT EST	69	1	2						
2004-60-33	WINDERME	230	WINDERME	69	1	2						
2004-60-33	RIVER-S	230	RIVER-S	69	1	16						
2004-60-33	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-33	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-33	JASPER	115	JASPER	69	1	2						
2004-60-34	SN PLANT	230	SYLVAN	230	1	1						
2004-60-34	SYLVAN	230	N LONGWD	230	1	1						
2004-60-34	IND RIV	230	STANTON	230	1	11						
2004-60-34	SILVR SP	230	SILV SPN	230	1	2						
2004-60-34	SILVR SP	230	SILV SPN	230	2	2						
2004-60-34	RIO PINR	230	CURRY FD	230	1	2						
2004-60-34	JUNEAU-W	138	GANNON	138	1	16						
2004-60-34	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-34	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-34	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-34	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-34	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-34	SN PLANT	115	TURNER	115	1	1						
2004-60-34	PASADENA	115	40ST-DUM	115	1	2						
2004-60-34	MICHIGAN	115	KALEY	115	1	11						
2004-60-34	MICHIGAN	115	GRANT	115	1	11						
2004-60-34	PERSHING	115	GRANT	115	1	11						
2004-60-34	AMERICA	115	KALEY	115	1	11						
2004-60-34	JASPER	115	WGHTCHPL	115	1	2						
2004-60-34	AZALEA	115	BENNETT	115	1	11						
2004-60-34	FLORALTP	69	INVERNTP	69	1	2						
2004-60-34	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-34	PASADENA	230	PASADENA	115	1	2						
2004-60-34	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-34	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-34	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-34	IND RIV	230	IND RIV	115	1	11						
2004-60-34	LARGO	230	LARGO A	69	1	2						
2004-60-34	SHELD	230	SHELD-NW	69	1	16						
2004-60-34	CLMT EST	230	CLMT EST	69	1	2						
2004-60-34	WINDERME	230	WINDERME	69	1	2						
2004-60-34	RIVER-S	230	RIVER-S	69	1	16						
2004-60-34	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-34	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-34	JASPER	115	JASPER	69	1	2						

Table I

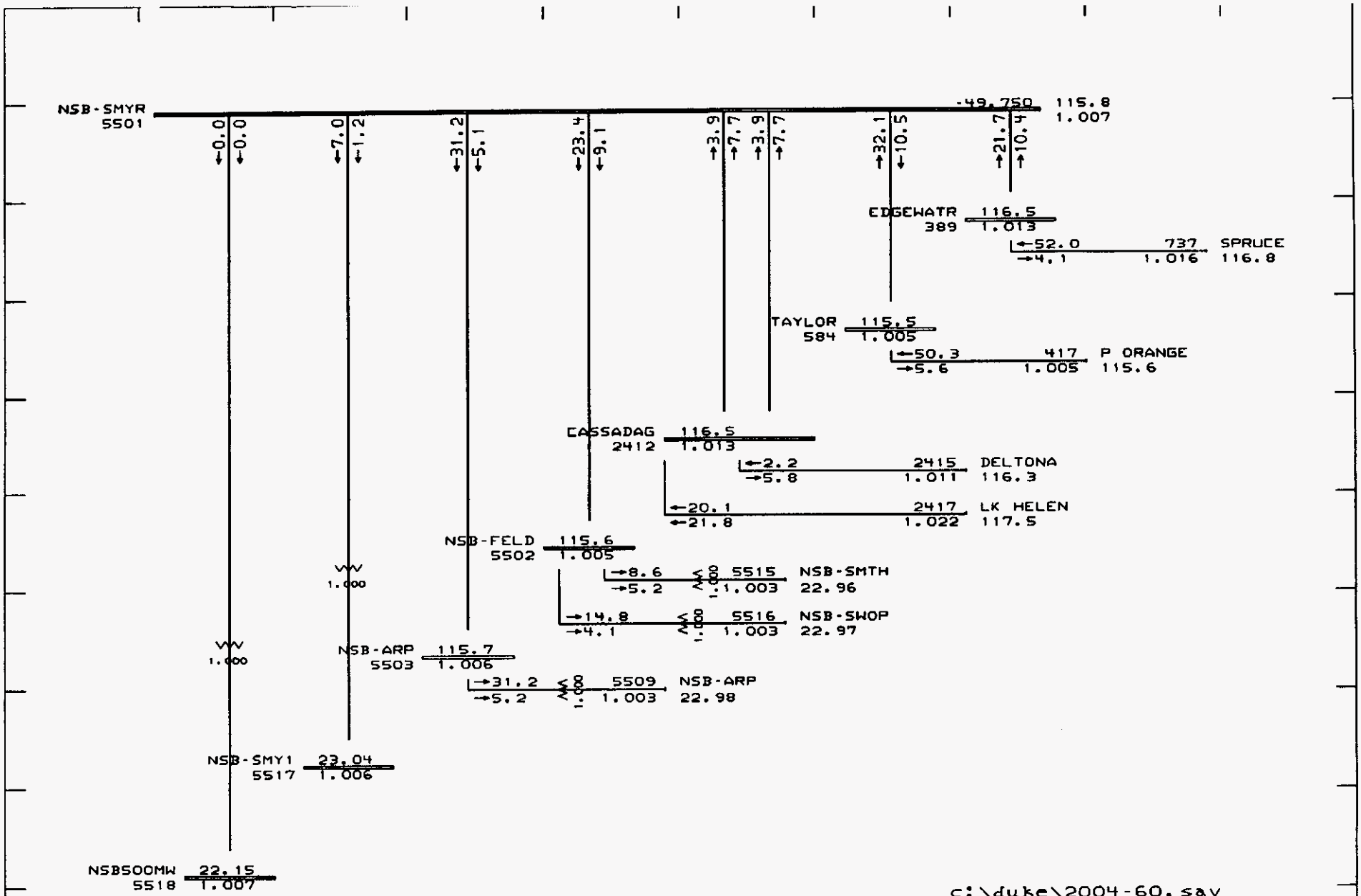
Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various NSB 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No NSB Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-35	SN PLANT	230	SYLVAN	230	1	1						
2004-60-35	SYLVAN	230	N LONGWD	230	1	1						
2004-60-35	IND RIV	230	STANTON	230	1	11						
2004-60-35	SILVR SP	230	SILV SPN	230	1	2						
2004-60-35	SILVR SP	230	SILV SPN	230	2	2						
2004-60-35	RIO PINR	230	CURRY FD	230	1	2						
2004-60-35	JUNEAU-W	138	GANNON	138	1	16						
2004-60-35	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-35	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-35	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-35	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-35	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-35	SN PLANT	115	TURNER	115	1	1						
2004-60-35	PASADENA	115	40ST-DUM	115	1	2						
2004-60-35	MICHIGAN	115	KALEY	115	1	11						
2004-60-35	MICHIGAN	115	GRANT	115	1	11						
2004-60-35	PERSHING	115	GRANT	115	1	11						
2004-60-35	AMERICA	115	KALEY	115	1	11						
2004-60-35	JASPER	115	WGHTCHPL	115	1	2						
2004-60-35	AZALEA	115	BENNETT	115	1	11						
2004-60-35	FLORALTP	69	INVERNTP	69	1	2						
2004-60-35	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-35	PASADENA	230	PASADENA	115	1	2						
2004-60-35	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-35	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-35	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-35	IND RIV	230	IND RIV	115	1	11						
2004-60-35	LARGO	230	LARGO A	69	1	2						
2004-60-35	SHELD	230	SHELD-NW	69	1	16						
2004-60-35	CLMT EST	230	CLMT EST	69	1	2						
2004-60-35	WINDERME	230	WINDERME	69	1	2						
2004-60-35	RIVER-S	230	RIVER-S	69	1	16						
2004-60-35	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-35	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-35	JASPER	115	JASPER	69	1	2						
2004-60-36	SN PLANT	230	SYLVAN	230	1	1						
2004-60-36	SYLVAN	230	N LONGWD	230	1	1						
2004-60-36	IND RIV	230	STANTON	230	1	11						
2004-60-36	SILVR SP	230	SILV SPN	230	1	2						
2004-60-36	SILVR SP	230	SILV SPN	230	2	2						
2004-60-36	RIO PINR	230	CURRY FD	230	1	2						
2004-60-36	JUNEAU-W	138	GANNON	138	1	16						
2004-60-36	NSB-SMYR	115	CASSADAG	115	1	2						
2004-60-36	NSB-SMYR	115	EDGEWATR	115	1	1						
2004-60-36	NSB-SMYR	115	TAYLOR	115	1	1						
2004-60-36	NSB-SMYR	115	NSB-ARP	115	1	10						
2004-60-36	NSB-SMYR	115	NSB-FELD	115	1	10						
2004-60-36	SN PLANT	115	TURNER	115	1	1						
2004-60-36	PASADENA	115	40ST-DUM	115	1	2						
2004-60-36	MICHIGAN	115	KALEY	115	1	11						
2004-60-36	MICHIGAN	115	GRANT	115	1	11						
2004-60-36	PERSHING	115	GRANT	115	1	11						
2004-60-36	AMERICA	115	KALEY	115	1	11						
2004-60-36	JASPER	115	WGHTCHPL	115	1	2						
2004-60-36	AZALEA	115	BENNETT	115	1	11						
2004-60-36	FLORALTP	69	INVERNTP	69	1	2						
2004-60-36	ALACH TP	69	HIGH SPG	69	1	2						
2004-60-36	PASADENA	230	PASADENA	115	1	2						
2004-60-36	SUWANNEE	230	SUWANNEE	115	1	2						
2004-60-36	SUWANNEE	230	SUWANNEE	115	2	2						
2004-60-36	E CLRWTR	230	E CLRWTR	115	1	2						
2004-60-36	IND RIV	230	IND RIV	115	1	11						
2004-60-36	LARGO	230	LARGO A	69	1	2						
2004-60-36	SHELD	230	SHELD-NW	69	1	16						
2004-60-36	CLMT EST	230	CLMT EST	69	1	2						
2004-60-36	WINDERME	230	WINDERME	69	1	2						
2004-60-36	RIVER-S	230	RIVER-S	69	1	16						
2004-60-36	ELEVEN W	230	ELEVEN-E	69	1	16						
2004-60-36	JUNEAU-E	138	JUNEAU-E	69	1	16						
2004-60-36	JASPER	115	JASPER	69	1	2						

APPENDIX IV-A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1.013
SPRUCE
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116.8
TAYLOR
584
115.5
1.005
P ORANGE
417
1.005
115.6
CASSADAG
2412
116.5
1.013
DELTONA
2415
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116.3
LK HELEN
2417
1.022
117.5
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1.005
NSB-SMTH
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1.003
22.96
NSB-SWOP
5516
1.003
22.97
NSB-ARP
5503
115.7
1.006
NSB-ARP
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General Electric Company
PSLF Program
MW/MVAR
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RESOURCE MANAGEMENT INTERNATIONAL INC.
2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD. NSB500MW PLANT IN SERVICE IN 2001
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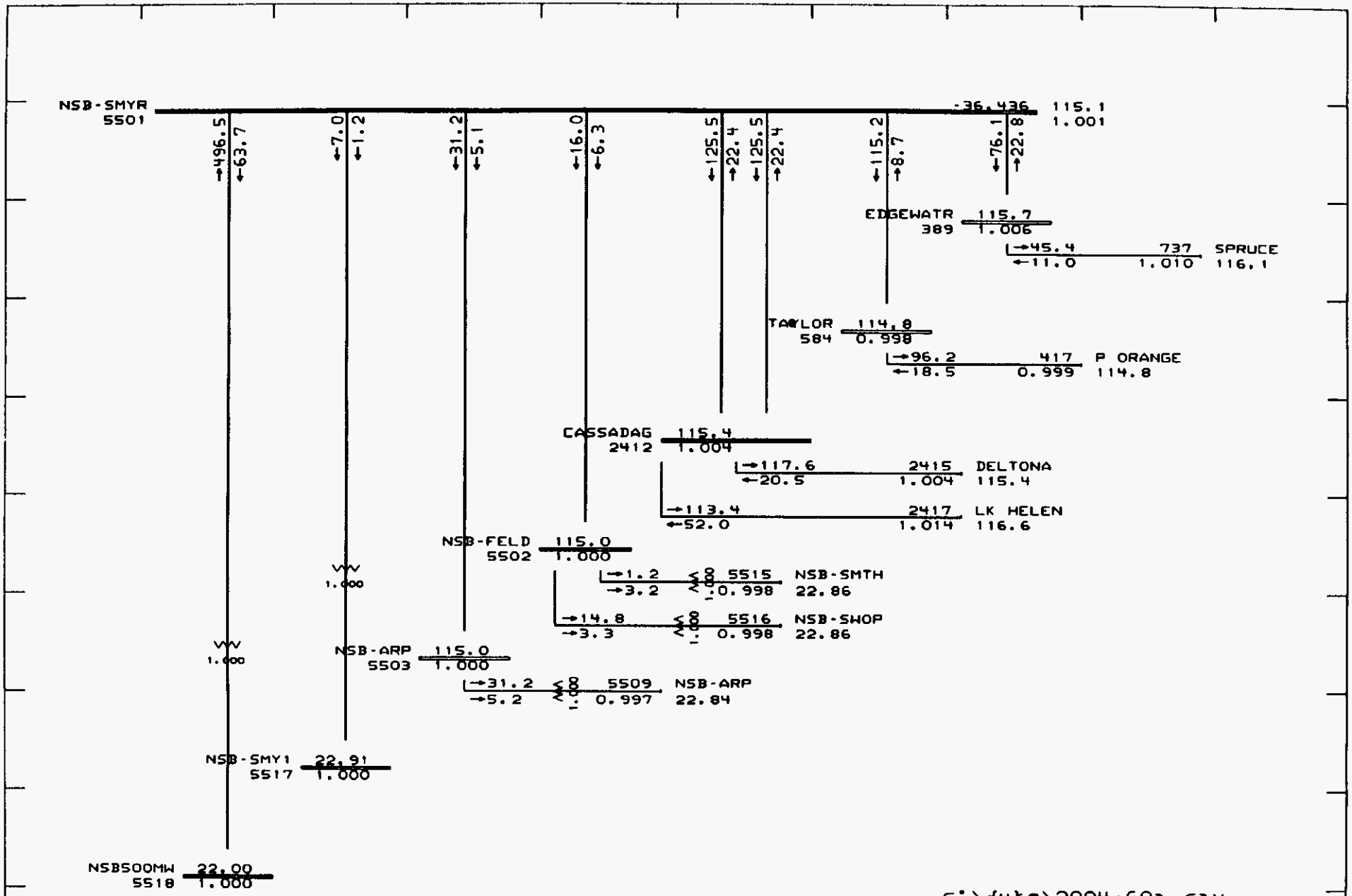
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389 1.006
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←11.0
737
1.010
SPRUCE
116.1
TAYLOR 114.8
584 0.998
→96.2
←18.5
417
0.999
P ORANGE
114.8
CASSADAG 115.4
2412 1.004
→117.6
←20.5
2415
1.004
DELTONA
115.4
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→3.2
5515
0.998
NSB-SMTH
22.86
→14.8
→3.3
5516
0.998
NSB-SWOP
22.86
1.000
NSB-ARP 115.0
5503 1.000
→31.2
→5.2
5509
0.997
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22.84
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General Electric Company
PSLF Program
MW/MVAR
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RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD. NSBSOOMW PLANT IN SERVICE IN 2001!
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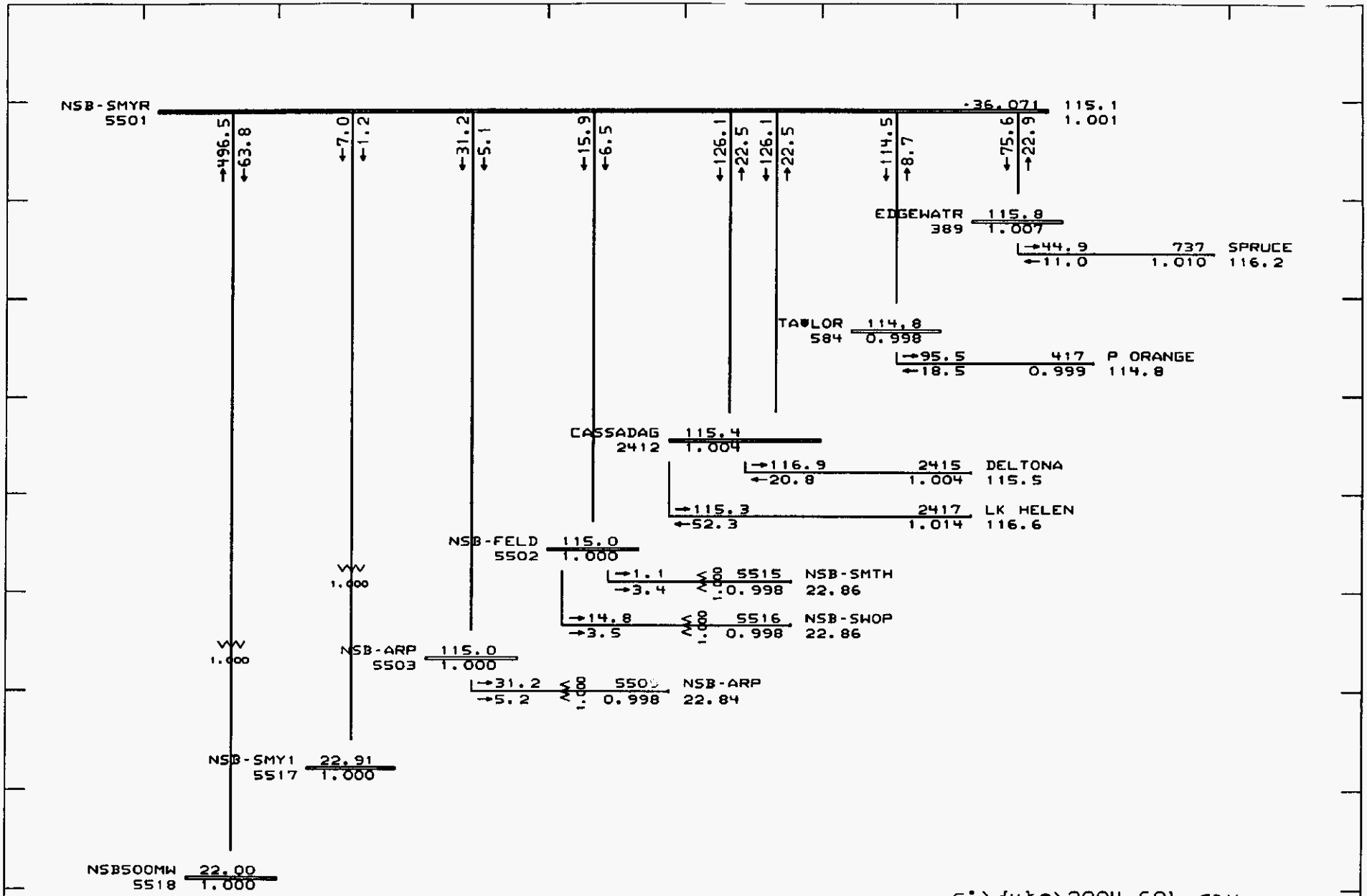

General Electric Company PSLF Program MW/MVAR Mon Jul 27 17:13:19 1998

RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.

2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD.NSB500MW PLANT IN SERVICE IN 2001!

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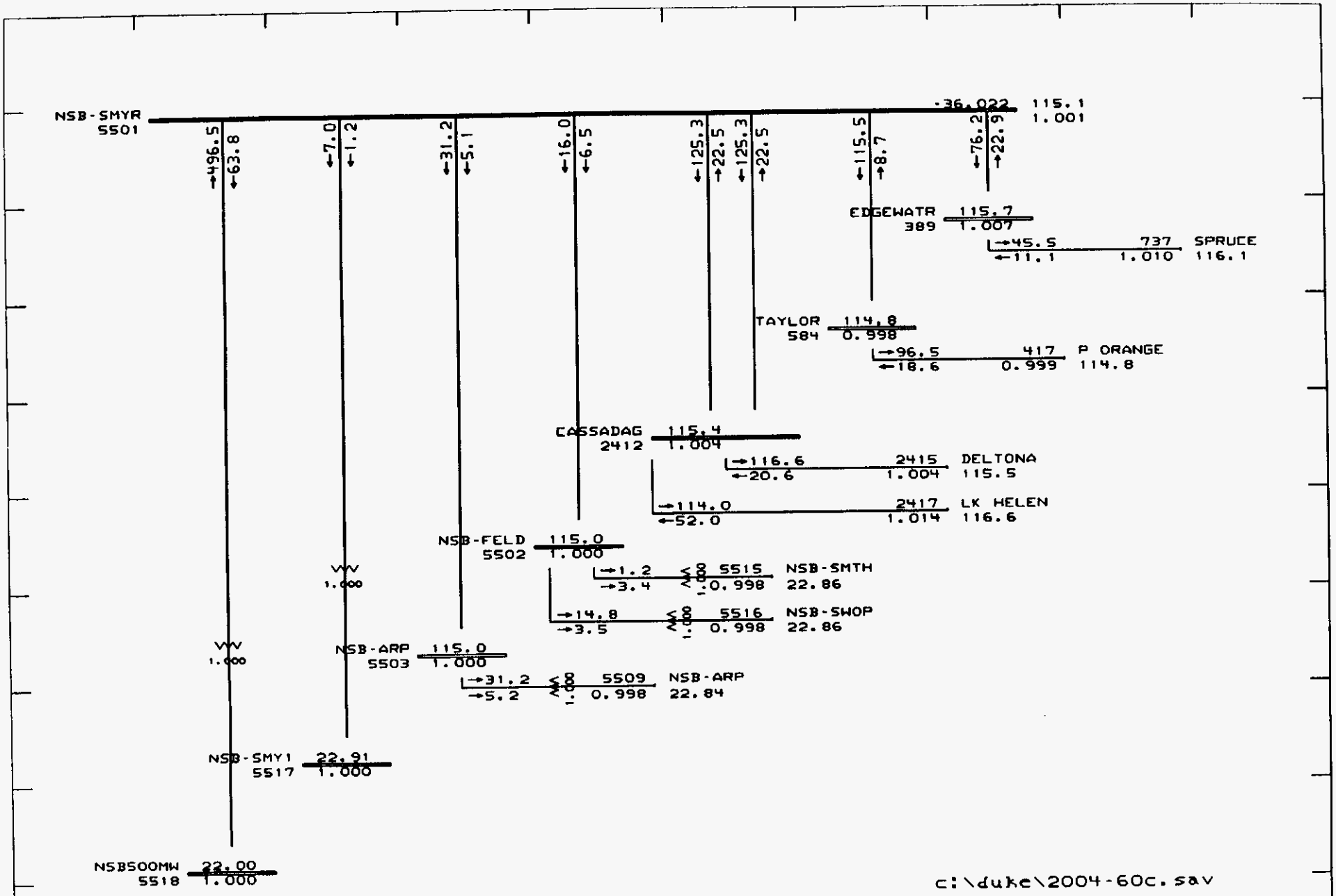

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P mis = 0.0012 MW

Q mis = 0.0015 MVAR

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RMI RESOURCE MANAGEMENT INTERNATIONAL, INC.

2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD. NSB500MW PLANT IN SERVICE IN 2001!

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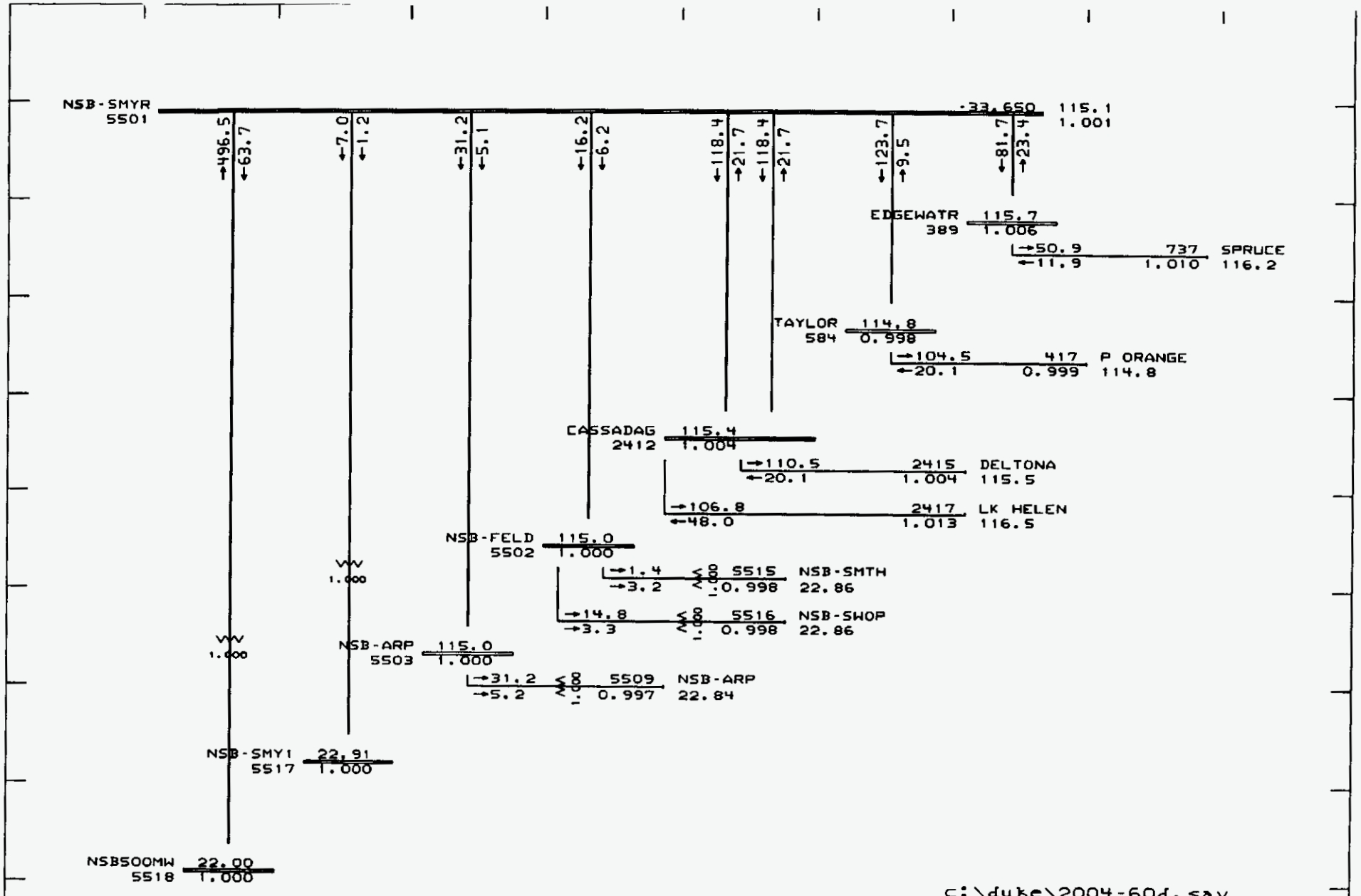
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←123.7
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EDGEWATR 115.7
389 1.006
→50.9
←11.9
737
1.010
SPRUCE
116.2
TAYLOR 114.8
584 0.998
→104.5
←20.1
417
0.999
P ORANGE
114.8
CASSADAG 115.4
2412 1.004
→110.5
←20.1
2415
1.004
DELTONA
115.5
→106.8
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2417
1.013
LK HELEN
116.5
NSB-FELD 115.0
5502 1.000
1.000
→1.4
→3.2
5515
0.998
NSB-SMTH
22.86
→14.8
→3.3
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NSB-SHOP
22.86
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NSB-ARP 115.0
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→5.2
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General Electric Company
PSLF Program
MW/MVAR
Mon Jul 27 17:14:55 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL INC.
2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD. NSB500MW PLANT IN SERVICE IN 2001!
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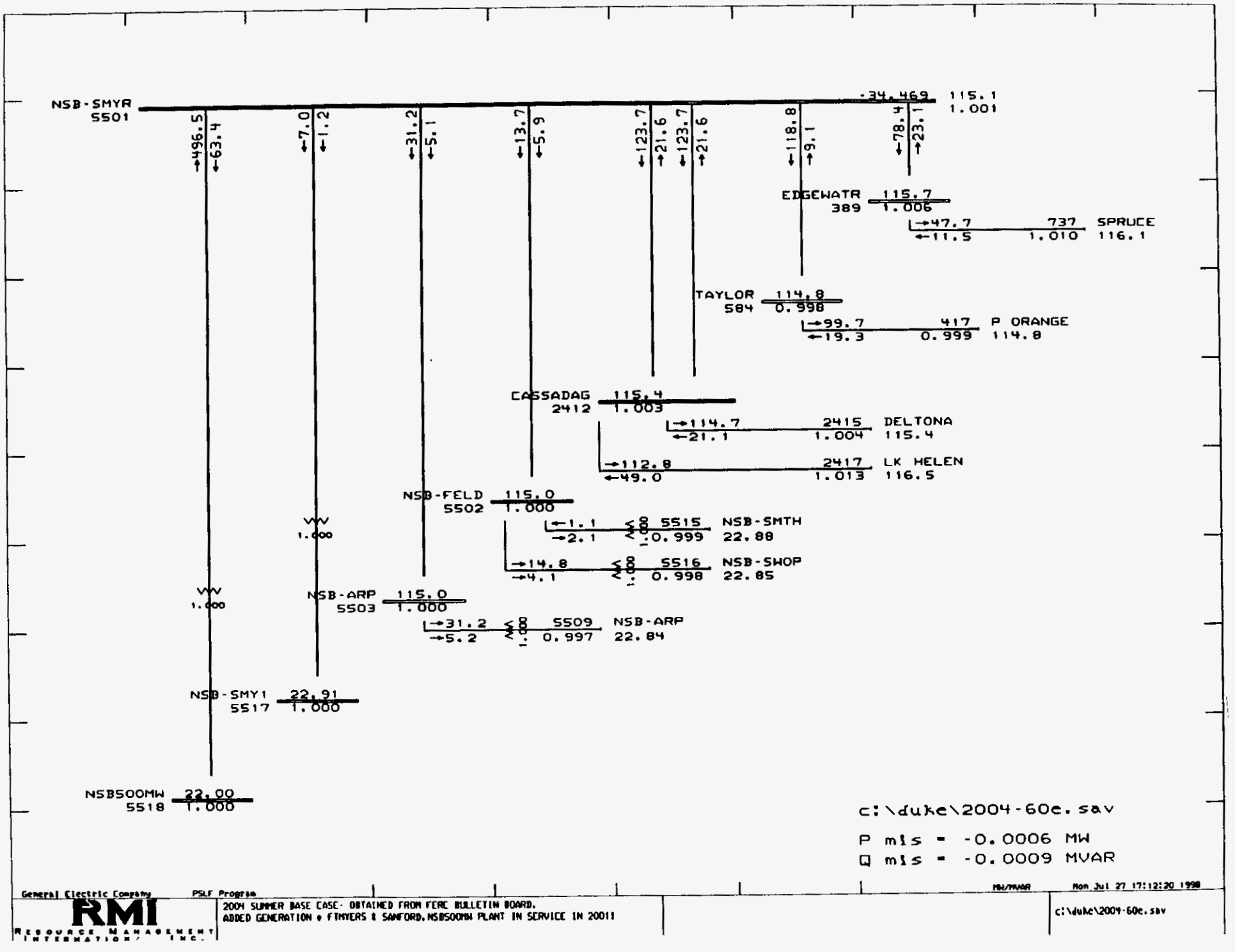
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47.7 11.5 737 1.010 SPRUCE 116.1
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99.7 19.3 417 0.999 P ORANGE 114.8
CASSADAG 2412 115.4 1.003
114.7 21.1 2415 1.004 DELTONA 115.4
112.8 49.0 2417 1.013 LK HELEN 116.5
NSB-FELD 5502 115.0 1.000
1.1 2.1 5515 0.999 NSB-SMTH 22.88
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NSB-ARP 5503 115.0 1.000
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NSBSOOMW 5518 22.00 1.000
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Q mis = -0.0009 MVAR
General Electric Company
PSLF Program
MW/MVAR
Mon Jul 27 17:12:20 1998
RMI
RESOURCE MANAGEMENT INTERNATIONAL, INC.
2004 SUMMER BASE CASE- OBTAINED FROM FERC BULLETIN BOARD.
ADDED GENERATION @ FTMYERS & SANFORD. NSBSOOMW PLANT IN SERVICE IN 2001!
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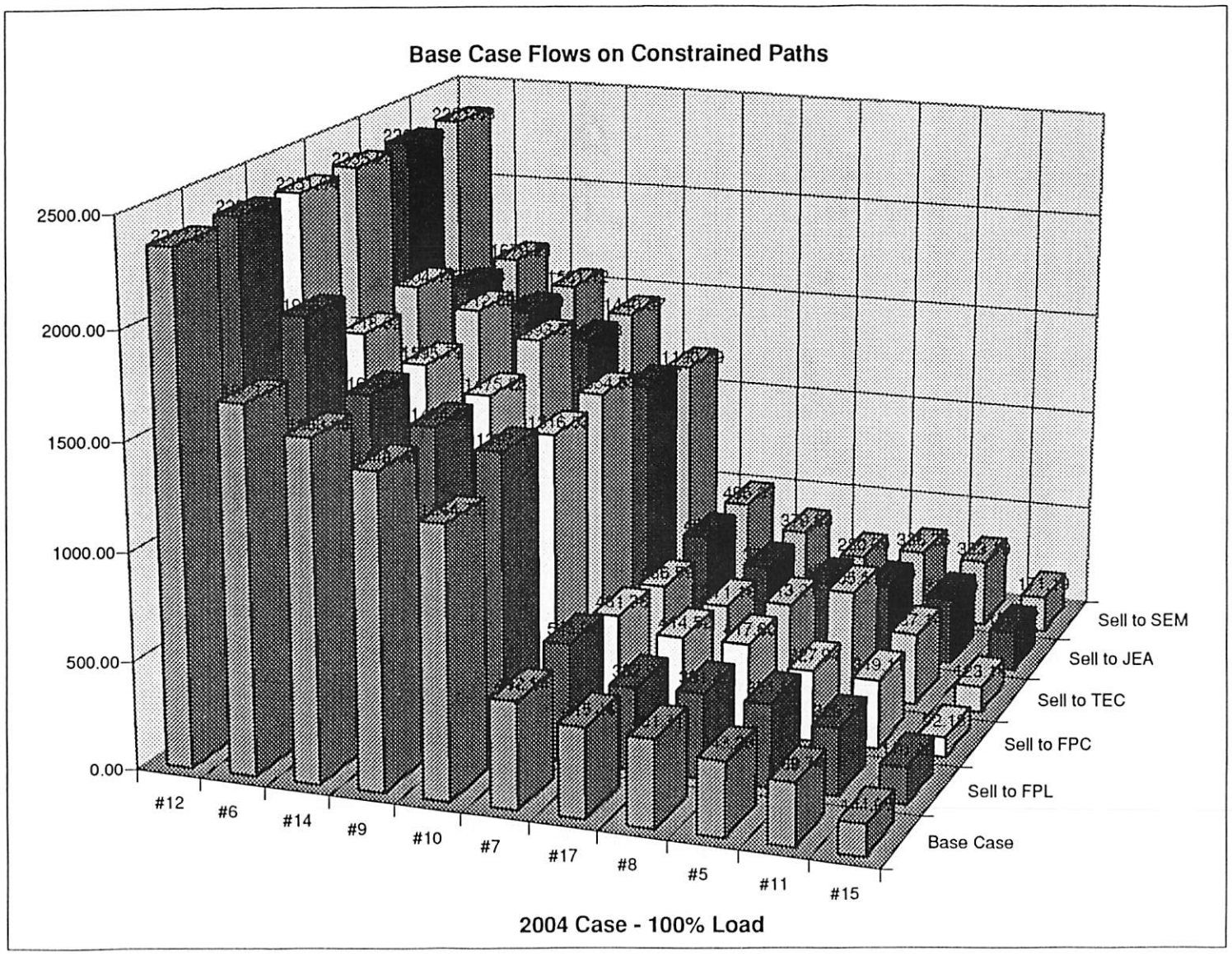
APPENDIX V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1500.00
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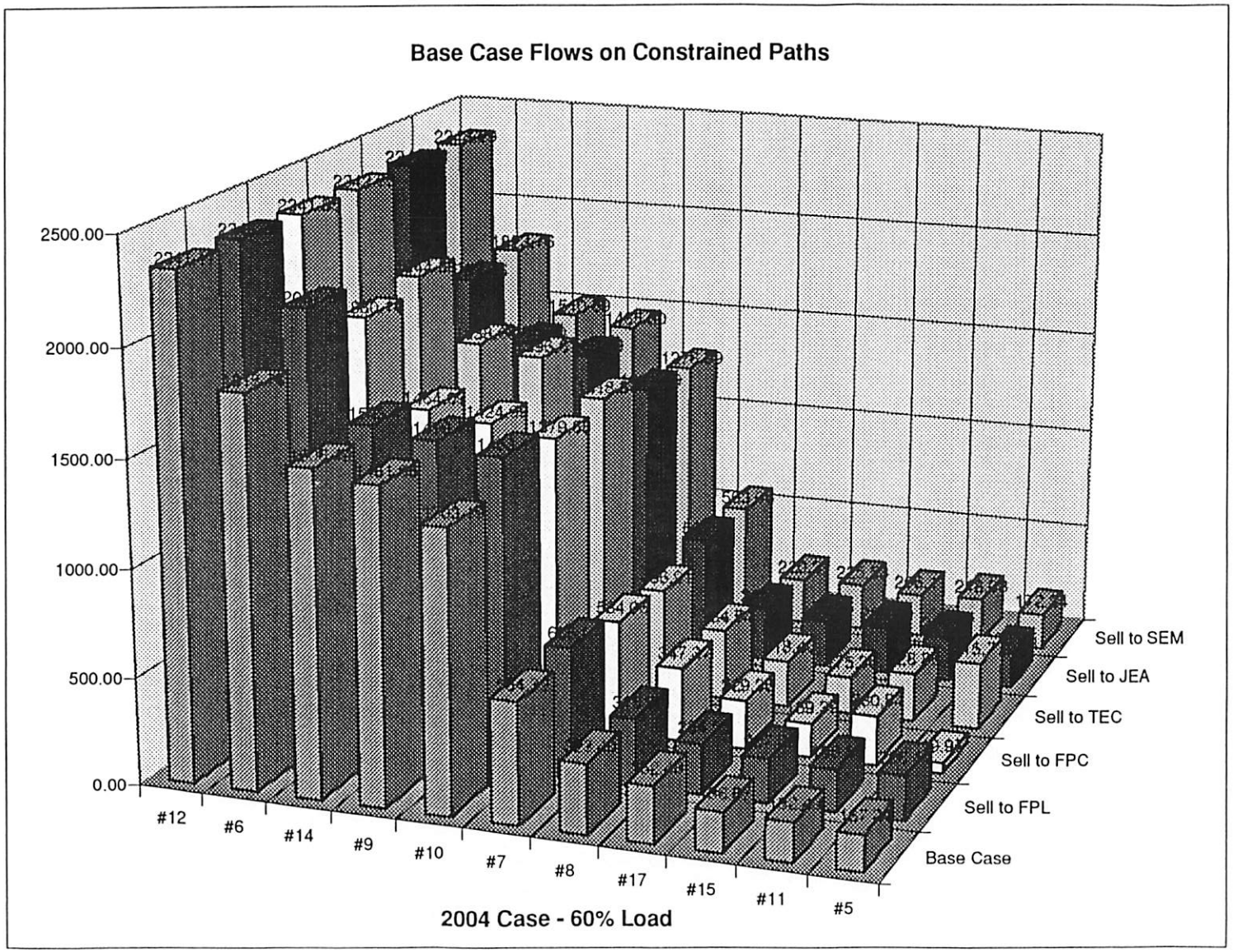
#12
#6
#14
#9
#10
#7
#17
#8
#5
#11
#15
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2004 Case - 100% Load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1500.00
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#12
#6
#14
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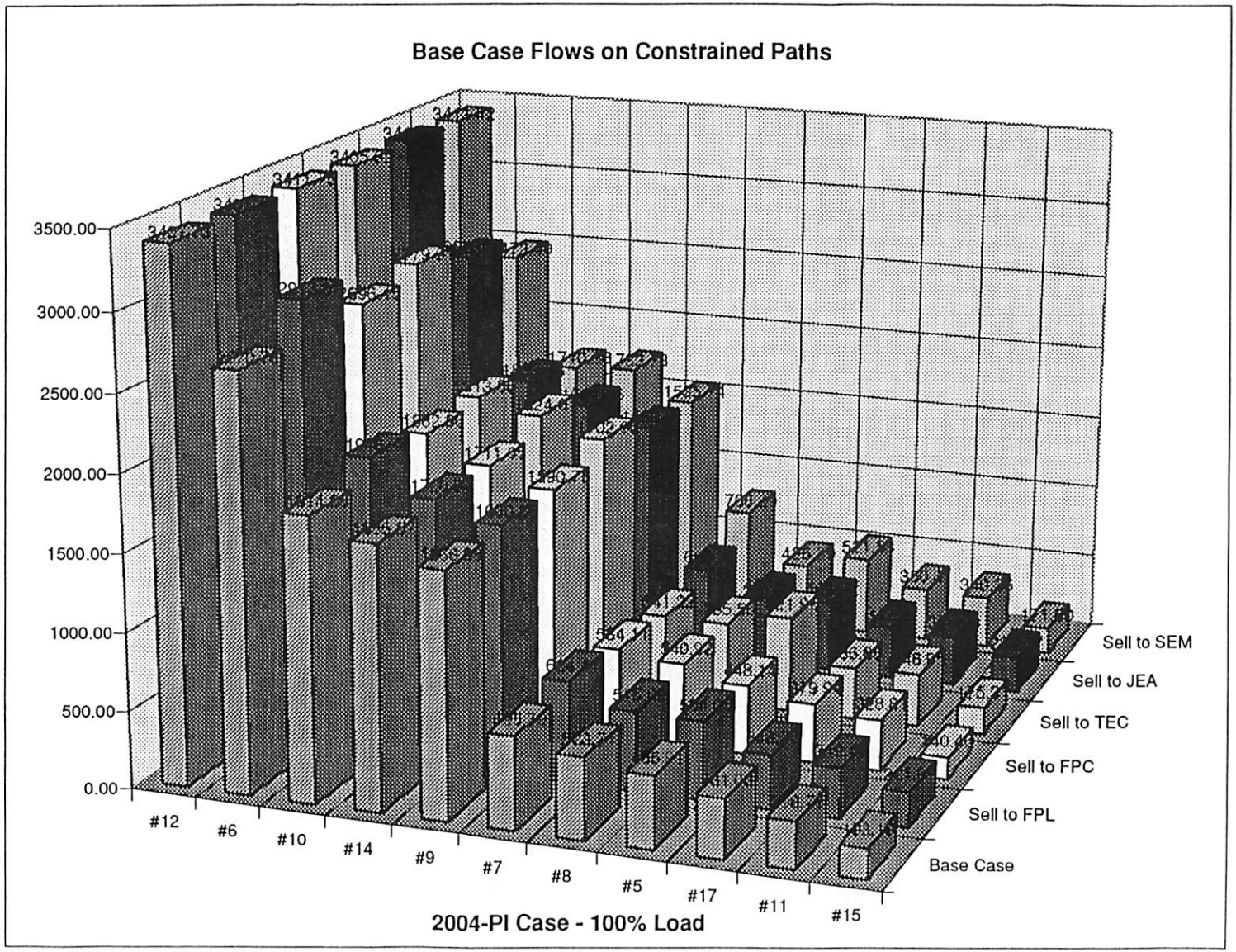
#7
#8
#17
#15
#11
#5
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2004 Case - 60% Load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3000.00
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500.00
0.00
#12
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#7
#8
#5
#17
#11
#15
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2004-PI Case - 100% Load

Table 1
Summary of Constrained Paths
in Base Case & NSB Alternatives

	Case 2004.sav	NSB Sell 500 MW to :				
		Case 2004a.sav	Case 2004b.sav	Case 2004c.sav	Case 2004d.sav	Case 2004e.sav
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
#12	2357.95	2365.45	2351.94	2355.24	2358.13	2361.68
#6	1692.71	1938.58	1718.62	1804.14	1672.08	1679.21
#14	1568.95	1603.30	1595.79	1712.09	1567.29	1561.12
#9	1448.08	1484.64	1475.25	1593.63	1446.78	1440.57
#10	1244.71	1397.11	1316.53	1354.38	1243.27	1190.59
#7	492.54	545.92	481.38	436.59	498.60	495.37
#17	415.44	382.90	414.52	371.16	377.10	379.63
#8	401.31	391.85	417.60	413.21	329.07	280.69
#5	343.28	381.69	327.94	505.51	342.79	336.26
#11	289.74	309.79	319.11	337.14	317.60	323.19
#15	144.98	170.38	92.18	123.18	185.97	171.19

Table 2
Summary of Constrained Paths
in Base Case & NSB Alternatives

	Case 2004-Pl.sav	NSB Sell 500 MW to :				
		Case 2004-Pla.sav	Case 2004-Plb.sav	Case 2004-Plc.sav	Case 2004-Pld.sav	Case 2004-Ple.sav
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
#12	3407.73	3407.40	3411.75	3405.62	3414.82	3411.42
#6	2670.76	2913.37	2696.15	2779.91	2653.58	2472.40
#10	1814.68	1946.34	1882.36	1913.66	1823.48	1710.86
#14	1685.57	1720.94	1711.05	1824.07	1681.65	1732.73
#9	1566.98	1600.86	1590.75	1702.90	1563.21	1535.74
#7	595.79	654.41	584.11	541.22	600.58	768.29
#8	523.71	515.69	540.92	535.55	450.62	425.39
#5	465.91	504.05	448.14	621.96	463.32	521.58
#17	381.03	348.75	379.94	336.68	342.47	350.31
#11	298.73	319.48	328.81	346.95	326.98	340.36
#15	193.19	221.69	140.46	175.31	233.17	171.60

Table 3
Summary of Constrained Paths
in Base Case & NSB Alternatives

	Case 2004-60.sav	NSB Sell 500 MW to :				
	Case 2004-60.sav	Case 2004-60a.sav	Case 2004-60b.sav	Case 2004-60c.sav	Case 2004-60d.sav	Case 2004-60e.sav
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
#12	2341.17	2348.36	2341.35	2342.85	2349.93	2348.29
#6	1818.74	2057.54	1880.14	1944.58	1799.35	1823.76
#14	1506.49	1543.42	1464.09	1638.08	1504.90	1510.69
#9	1461.95	1499.74	1424.99	1596.67	1460.59	1465.80
#10	1303.19	1453.13	1379.68	1418.84	1311.49	1278.99
#7	564.32	606.07	534.06	496.91	569.79	563.06
#8	323.40	315.99	347.37	334.54	250.51	220.31
#17	262.48	234.55	229.36	218.40	225.06	225.53
#15	186.87	207.28	159.39	175.36	226.20	206.11
#11	182.49	196.55	230.84	228.86	209.97	218.08
#5	167.24	208.44	49.97	315.77	166.65	172.34

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 9 EXHIBIT NO. 25
COMPANY/
WITNESS: Law
DATE: 12-2-98

Citrus Trading Corp.

P. O Box 1188 Houston, Texas 77251-1188 (713) 853-6569 Fax (713) 646-2102 (713) 646-3395

RECEIVED
JAN 9 - 1997
By

January 5, 1998

RECEIVED
FEB 3 - 1998
By

JUN 15 1998

Duke Energy Power Services, L.L.C.
10777 Westheimer, Suite 975
Houston, Texas 77042

This Transaction Agreement ("Agreement") shall form and effectuate the current transaction between Duke Energy Power Services, L.L.C. ("Customer") and Citrus Trading Corp. ("Company") regarding the firm purchase and sale of Gas under the following terms and conditions.

A. Scope

1. Gas Supply and Transportation.

Customer intends to construct and operate new Gas fired electric power generating plants in the State of Florida, initially consisting of the IMC-Agrico Generating Plant ("IMC Plant") and the New Smyrna Beach Generating Plant ("NSB Plant"), and, as a part of the Gas supply arrangements for such plants, requires a Gas supply lateral to connect each plant to the Gas pipeline system of Florida Gas Transmission Company ("FGT"), and a firm supply of Gas as part of the total Gas supply for the plants. Company agrees to provide for the installation of Gas supply laterals and to sell and deliver to Customer a firm supply of Gas consistent with FTS-2 transportation service under FGT's FERC Gas Tariff, and Customer agrees to purchase such Gas for both the IMC Plant and the NSB Plant or Successor Projects from Company pursuant to this Agreement. The Parties recognize that Customer may assign its obligations hereunder to an affiliate(s), including special purpose affiliated companies, and agree that such assignment shall relieve Customer of its obligations hereunder; provided, however, no such assignment shall relieve the obligations of the Guarantor under the Guaranty Agreement.

2. Demand Commitment.

If Customer does not proceed with construction of the IMC Plant and/or the NSB Plant, as currently contemplated herein, Customer represents and warrants to Company that Customer shall cause the volume of Gas contemplated under this Agreement to be utilized in Successor Projects. To the extent that the location, commencement, or configuration of either the IMC Plant and/or the NSB Plant is altered from the location, commencement, and configuration contemplated in this Agreement and such change affects a Party's economic costs and benefits hereunder, then the Parties shall agree to adjust the Contract Price and/or DCQ hereunder by mutual written agreement to reflect such changed circumstances. If the Parties are unable to mutually agree upon any changes to the DCQ and/or Contract Price because of changed circumstances, then such issue shall be resolved by arbitration as hereinafter provided.

3. Successor Projects.

If Customer does not proceed with construction of the IMC Plant or the NSB Plant, or both, and if Customer constructs any Successor Project, the Parties will attempt to agree as to the Contract Price and

other material terms relating to providing Gas to such additional Redelivery Point at such maximum available pressure on FGT at that location under the terms of this Agreement as to that portion of the DCQ not already committed hereunder. If the Parties are unable to mutually agree as to the Contract Price or any other material terms which shall apply to any Successor Project, then such issue shall be resolved by arbitration. In such arbitration, the arbitrators shall attempt to determine a resolution of the disputed issue(s) which would place the Parties in an economic position with respect to the Successor Project which is equivalent to that enjoyed by the Parties under this Agreement with regard to the NSB Plant and the IMC Plant, as if such projects were completed.

REDACTED

Within thirty (30) days of Customer's final technical decision, Company shall endeavor to negotiate any applicable FGT transportation contract, or amendment(s) thereto, in order to conform such contract to Customer's minimum pressure and delivery rate requirements at any Redelivery Point. Throughout the term of this Agreement, Company shall cause Gas to be delivered to Customer at each Redelivery Point at least at the minimum delivery rate and pressure required by Customer for each applicable project, which for the NSB Plant and IMC Plant are set out in Sections D.2 and D.3 hereof. With respect to pressure requirements only, Customer shall be a third party beneficiary of any contract between FGT and Customer which is assigned to Company concerning transportation of Gas to a Redelivery Point.

B. Development Schedule.

Customer has advised Company that the date of commercial operation of each of the IMC Plant and/or NSB Plant is predicated on the milestones enumerated in the Development Schedule attached as Exhibit "A" hereto. Additionally, Company has advised Customer that the completion date for each of the pipeline laterals to be constructed to deliver Gas to each of the IMC Plant and the NSB Plant is also predicated on the milestones enumerated in the Development Schedule. If a milestone is not met as to a plant or lateral, the Parties shall meet to determine any necessary adjustment in the applicable Development Schedule. If any advancement in any of the milestones becomes apparent to a Party, that Party shall notify the other and they shall meet and mutually agree, in writing, upon new milestone dates for the applicable Development Schedule. Company or Customer may propose and the Parties mutually agree, in writing, on any adjustment in the Contract Price to reflect any changed circumstances as a result of any change in the milestone dates. Additionally, the Parties agree to provide periodic, or when otherwise reasonably requested, updates on the status of the milestones enumerated in the Development Schedule. In order to facilitate timely approval of the NSB Project, the IMC Project or any Successor Project, the Parties contemplate establishing a more specific timetable, which addresses such matters as liquidated damages, termination rights or step-in rights in the event of an unexcused default in meeting such deadlines through the exercise of commercially reasonable efforts.

C. Term.

The term of this Agreement ("Term") shall run from the date set forth first above to the end of the last Period of Delivery set forth in Section D.16 (Period of Delivery) herein, unless sooner terminated pursuant to its terms.

D. Terms and Conditions.

1. Definitions.

"FGT FTS-2 Demand Charge" means the per MMBtu maximum reservation rate for firm transportation service under FGT's FTS-2 Rate Schedule (or successor tariff), including all applicable reservation surcharges.

"Gas Daily City Gate Price" means the low of the range of prices for Florida gates via FGT as published in the "Daily Price Survey" under the heading "City gate, Pooling Point prices" in Gas Daily reflecting a column of prices for the Day for which the Gas Daily City Gate Price is being determined. If no price is contained in the publication for that particular Day, or if no publication is published for that particular Day, or if the price contained in the publication for that particular Day is non-bolded, then it shall be deemed that no price or range of prices is published for that particular Day. In the event that no price or range of prices is published for that particular Day, then the Gas Daily City Gate Price shall be the average of the following: the price (determined as stated above) for each of the first Day immediately preceding and following the particular Day for which a Gas Daily City Gate Price is not published.

"Gas Daily Zone 2 High Price" means the common high postings of prices for FGT's supply zone 2 as published in the "Daily Price Survey" under the column "Common" under the heading "Louisiana Onshore South" in Gas Daily reflecting a column of prices for the Day for which the Gas Daily Zone 2 High Price is being determined. If no price is contained in the publication for that particular Day, or if no publication is published for that particular Day, or if the price contained in the publication for that particular Day is non-bolded, then it shall be deemed that no price or range of prices is published for that particular Day. In the event that no price or range of prices is published for that particular Day, then the Gas Daily Zone 2 High Price shall be the average of the following: the price (determined as stated above) for each of the first Day immediately preceding and following the particular Day for which a Gas Daily Zone 2 High Price is not published.

"Gas Daily Zone 2 Midpoint Price" means the midpoint postings of prices for FGT's supply zone 2 as published in the "Daily Price Survey" under the column "Midpoint" under the heading "Louisiana Onshore South" in Gas Daily reflecting a column of prices for the Day for which the Gas Daily Zone 2 Midpoint Price is being determined. If no price is contained in the publication for that particular Day, or if no publication is published for that particular Day, or if the price contained in the publication for that particular Day is non-bolded, then it shall be deemed that no price or range of prices is published for that particular Day. In the event that no price or range of prices is published for that particular Day, then the Gas Daily Zone 2 Midpoint Price shall be the average of the following: the price (determined as stated above) for each of the first Day immediately preceding and following the particular Day for which a Gas Daily Zone 2 Midpoint Price is not published.

"IMC Plant" means

REDACTED

"IMC Plant In Service Date" means the date REDACTED

"IMC Plant Lateral" means the pipeline and appurtenant facilities
REDACTED

"Inside FERC Index Price" means the average of the prices for FGT's supply Zones 2 and 3 in the column labeled "Index" as published in the first issue for the month in question of Inside FERC's Gas Market Report in the table titled "Prices of Spot Gas Delivered to Pipelines".

"NSB Plant" means Customer's New Smyrna Beach Generating Plant to be located 43.5 miles from the FGT system in Volusia County, Florida.

"NSB Plant In Service Date" means the date which Customer commences the commercial operation of the NSB Plant.

"NSB Plant Lateral" means the pipeline and appurtenant facilities that, when constructed in accordance herewith, will connect the NSB Plant at the NSB Plant Redelivery Point to the FGT system.

"Successor Project" means any gas-fired power generation project that Customer constructs and operates in Florida to the extent of its ownership interest; provided, however, that no project shall be considered a Successor Project if both the IMC Plant and the NSB Plant are constructed and the MaxDQ has been committed hereunder, and provided, further, that no project shall be considered a Successor Project except to the extent of the DCQ not already committed to other projects hereunder.

2. IMC Plant Lateral Pipeline Construction, Operation and Ownership.

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3. NSB Plant Lateral Pipeline Construction, Operation and Ownership.

Company, or its affiliates, shall, at Company's or its affiliates' cost, install a pipeline and meter and regulator station to satisfy (i) Customer's operating requirements for the NSB Plant, and (ii) FGT's construction specifications. Construction of the pipeline is expressly conditional upon all regulatory and environmental approvals. Customer's general operating requirements used for pipeline facility sizing are 3,500 MMBtu per hour or 80,000 MMBtu per day and the maximum pressure available from FGT, which

currently is 425 psig, at the NSB Plant Redelivery Point. Company agrees to contract with FGT for delivery capability of at least 3,500 MMBtu per hour at 425 psig delivery pressure at the NSB Plant Redelivery Point. FGT's analysis of the above provided delivery pressure is based on current system conditions, and is therefore subject to change over time. FGT has committed to inform the Parties, prior to their implementation, of any major facility changes that would adversely affect the above pressure commitment. Upon completion of the NSB Plant Lateral, FGT will own and operate the lateral as part of its overall system.

4. Nominations and Scheduling.

Customer and Company shall provide one (1) hour notice of changes prior to nomination deadlines, and shall adhere to FGT tariff requirements, and GISB or successor standards on nominating and scheduling. Company will accommodate Customer regarding intraday scheduling of Gas, and related activities, to the fullest extent permitted pursuant to firm rate schedules under the FGT tariff. Once scheduled, Customer shall purchase and take, and Company shall sell to Customer, 100% of the Gas that Customer requests each day. Customer shall be the operator of the IMC Plant Redelivery Point and the NSB Plant Redelivery Point with respect to all scheduling, nominating, balancing, and other operational matters with FGT.

5.

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6. Damages for Non-performance.

Pursuant to Section 3.4 of the ENFOLIO Master Agreement, hereinafter defined, in the event of Customer's unexcused failure to take Gas Scheduled by Customer and made available by Company on any given day, the Replacement Price Differential and liquidated damages shall be zero. Pursuant to Section 3.2 of the ENFOLIO Master Agreement, in the event of Company's unexcused failure to make available Gas Scheduled by Customer on any given day at the Redelivery Point, the Replacement Price Differential shall be Customer's cost of replacement Gas, fuel oil, or electrical energy necessary for the quantity Company failed to make available. Company agrees that a factor of 7.2 gallons per MMBtu shall be used for replacement fuel oil and a heat rate factor of 7,500 Btu per Kwh shall be used for purchased electrical energy to determine the volume of fuel oil or energy in replacement of the volume of Gas not so delivered by Company. Customer shall utilize commercially reasonable efforts to purchase replacement Gas, fuel oil or electrical energy, which choice shall be at Customer's sole discretion.

REDACTED

REDACTED

7. Shared Savings.

To the extent that Company, during the term of this Agreement, receives any reimbursement from FGT for costs previously incurred in connection with the construction of either the IMC Plant Lateral or the NSB Plant Lateral, or Successor Project, then Company and Customer shall equally share any such reimbursement.

8. Transportation Option.

Upon the expiration of the Term, Customer shall have the right to obtain the capacity rights held by Company on FGT's pipeline system delivering Gas to each of the IMC Plant and the NSB Plant, or Successor Project. Unless the Parties agree otherwise, at Customer's request Company shall transfer such capacity rights through pre-arranged relinquishment under Section 18 of FGT's FERC Gas Tariff. In addition, Company shall undertake commercially reasonable efforts to protect Customer's ability to transport Gas on each of the IMC Plant Lateral and the NSB Plant Lateral, or Successor Project lateral, after termination of this Agreement.

REDACTED

9. Customer Option on Additional Lateral Capacity.

(a) In light of Customer's role as anchor customer for construction of the IMC Plant Lateral and the NSB Plant Lateral, the Parties agree that Company shall use its reasonable best efforts to ensure that the agreements with FGT as described in Sections D.2 and D.3 provide Customer the right, upon six (6) months notice, to increase the DCQ(s) or elect capacity rights under firm service with FGT directly to the following level(s):

(i) for the IMC Plant Lateral: REDACTED

(ii) for the NSB Plant Lateral: up to 80,000 MMBtu per day (less DCQ selected on the lateral)

(b) Customer may exercise its right to increase its DCQ or obtain additional capacity on a lateral under paragraph (a) above no later than twelve (12) months after the in-service date for such lateral.

(c) Company shall ensure that any gas supply arrangements entered into with third parties during the period in which Customer is entitled to exercise any rights under paragraph (a) above and that utilizes capacity on either or both of such laterals shall be consistent with such rights.

10. Approvals and Conditions.

(a) Customer Approvals and Conditions

(i) Approvals. Customer agrees to seek Customer's Board of Directors' approval and to use all commercially reasonable efforts to obtain any approvals, consents, authorizations, environmental permits, easements, licenses, and/or permits that may be required from any necessary regulatory authority to allow Customer to build and operate each of the IMC Plant and the NSB Plant.

(ii) Conditions. Customer's obligations under this Agreement with respect to each of (1) the IMC Plant, or (2) the NSB Plant are subject to the satisfaction in full, or waiver by Customer, of the following conditions as applicable:

(A) approval by Customer's Board of Directors of Customer's construction and operation of the IMC Plant and/or the NSB Plant by . REDACTED and

(B) approval by all regulatory authorities

REDACTED

(iii) Conditions Precedent. Customer's obligations under this Agreement are subject to approval by Customer's Board of Directors of the Agreement by February 15, 1998.

(iv) Modification of Agreement. If the terms of an approval of the IMC Plant and/or NSB Plant by a regulatory authority requires the alteration of this Agreement, then the Parties shall modify this Agreement insofar and only insofar as necessary to comply with such order. To the extent a plant is removed from this Agreement for lack of regulatory authority or other approval, the Redelivery Point for such plant shall be removed from this Agreement and the applicable Contract Price discount for the remaining plant shall be derived by use of the matrix provided in Section D.15 (Contract Price).

(b) Company Approvals and Conditions

Company agrees to use all commercially reasonable efforts to obtain any approvals, consents, or authorizations that may be required from or requested of any regulatory authority, including but not limited to, any rate approvals, environmental permits, easements, licenses, and/or permits relating to the construction, ownership, and operation of the laterals. Company's obligations under this Agreement with respect to the laterals are subject to the satisfaction in full, or waiver by Company of the approval by all regulatory authorities of Company's construction, ownership and operation of the laterals prior to June 1, 2000 (or such other date applicable to any Successor Project) on terms satisfactory to Company in Company's sole discretion.

11. Daily Contract Quantity (DCQ).

(a) In establishing the Daily Contract Quantity (DCQ) for the plant(s) to be supplied under this Agreement, the Parties agree that Customer may, select any combination, up to the MaxDQ, of the following DCQ's set forth below:

(i) IMC Plant DCQ:

REDACTED

(ii) NSB Plant DCQ:

(A) 77,900 MMBtu/day
(B) 53,950 MMBtu/day
(C) 38,950 MMBtu/day
(D) 0 MMBtu/day

(b) Customer shall notify Company of its selection of the location and the DCQ for each plant no later than December 1, 1998. In making its selection, Customer shall have the right to adjust the DCQ for a plant by plus or minus ten percent (10%).

(c) Subject to the locations and DCQ selected by Customer, the following shaping factors (average of 1.000 for the year) shall be used to derive the DCQ for each calendar month:

REDACTED

12. Maximum Daily Quantity (MaxDQ).

The MaxDQ under this Agreement shall be MaxDQ is specifically excluded from Section D.18 arbitration and may be changed only through mutual agreement of the Parties.

13. Delivery Point(s).

All points immediately downstream of where Company's Gas is received into the FGT system. Company shall be responsible for and shall cause Customer's Gas to be Scheduled, transported and delivered from the Delivery Point(s) to the Redelivery Point(s). For all operational purposes under the ENFOLIO Master Agreement such as risk of loss, indemnity and balancing matters addressed in Article 7 thereof, it is expressly understood that Company shall remain in exclusive control and possession of and responsible for Gas Scheduled hereunder until such Gas is delivered at the Redelivery Point.

14. Redelivery Point(s).

IMC Plant Redelivery Point - Commencing with the IMC Plant Lateral completion date, the interconnection of the IMC Plant Lateral and the IMC Plant:

NSB Plant Redelivery Point - Commencing with the NSB Plant Lateral completion date, the interconnection of the NSB Plant Lateral and the NSB Plant;

Secondary Redelivery Points - All other Redelivery Points subject to normal limitations by FGT for secondary firm deliveries pursuant to the terms of FGT's tariffs, excluding Successor Project Redelivery Point(s).

15. Contract Price.

A two-part rate consisting of a Monthly Demand Charge and a Commodity Charge as follows:

Monthly Demand Charge. FGT FTS-2 (or successor tariff) Demand Charge in effect for any month, times the DCQ, times the number of days for such month, if such rate is stated as a daily demand charge.

Commodity Charge. The sum of (i) the Inside FERC Index Price, plus (ii) the FGT FTS-2 (or successor tariff) variable transport costs (including fuel retention) applicable to the Redelivery Point on FGT,

REDACTED

16. Period of Delivery.

Commencing with the IMC Plant In Service Date and continuing for twenty years. Thereafter, the Period of Delivery shall continue from year to year until terminated by either Party with one year prior written notice.

Commencing with the NSB Plant In Service Date and continuing for twenty years. Thereafter, the Period of Delivery shall continue from year to year until terminated by either Party with one year prior written notice.

Commencing with the Successor Project In Service Date and continuing for twenty years. Thereafter, the Period of Delivery shall continue from year to year until terminated by either Party with one year prior written notice.

17. Force Majeure.

(a) Pursuant to Article 5 of the ENFOLIO Master Agreement, the term "Force Majeure" specifically excludes the loss, interruption, or curtailment of interruptible transportation on any transporter necessary to effect receipt or delivery of Gas hereunder, unless the same event also curtails firm transportation.

(b) Neither Party shall be entitled to claim excuse of performance under the Force Majeure provisions of Article 5 of the ENFOLIO Master Agreement under either or both of the following circumstances: (i) to the extent the failure to perform was caused by the sole or contributory negligence of the Party claiming excuse; or (ii) to the extent the failure to perform was caused by the Party having failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch.

18. Arbitration.

If the Parties are unable to reach agreement regarding any issues requiring mutual agreement during the term of this Agreement, then such issue(s) shall be resolved by arbitration as set forth herein. Notwithstanding anything to the contrary contained in the Arbitration Procedures section of Appendix "1" of the ENFOLIO Master Agreement, the arbitrators once chosen shall accept sealed written resolutions of the subject dispute from each Party on a confidential basis to be submitted within twenty (20) Business Days of establishment of the arbitration panel. The written submissions shall be in the form and subject to any limitations as may be prescribed by the arbitrator(s). The arbitrator(s) shall then choose only one of the proposed solutions, (without modifications) as the fairest solution to the dispute within ten (10) Business Days of receipt of the written submissions of both Parties.

19. Prior Agreement.

The Parties acknowledge and agree that effective with the final execution of this Transaction Agreement by each of Company and Customer, that certain Transaction Agreement dated December 23, 1997, as amended, between the Parties hereto shall be deemed restated and superseded by this Transaction Agreement.

This Transaction Agreement is being provided pursuant to and in accordance with the ENFOLIO Master Firm Purchase/Sale Agreement (the "ENFOLIO Master Agreement") in effect between Customer and Company and constitutes part of and is subject to all of the terms and provisions of such Agreement. For purposes of the Transaction Agreement, the Parties stipulate that no amendment or modification of this Transaction Agreement may be formed and effectuated under Section 2.2 of the ENFOLIO Master Agreement except through a writing executed by the Parties. Customer to purchase and receive (Buyer) and Company to sell and deliver (Seller). Please execute this Transaction Agreement and return an executed copy to Company. Your execution should reflect the appropriate Party in your organization who has the authority to cause Customer to enter into this Transaction.

DUKE ENERGY POWER SERVICES, L.L.C.

Title: Senior Vice President

CITRUS TRADING CORP.

By: _____

Title: _____

Exhibit "A" - Development Schedule
For Customer and Company Activities for Customer and Company Activity Timeline
between
Duke Energy Power Services, L.L.C. and Citrus Trading Corp.

PARTY	ACTION	DESCRIPTION OF TIMING	BEST CASE DATES	WORST CASE DATES
✓COMPANY	FGT Approval of Capacity/Pressure Requirements	Between 1/01/98 and 1/15/98	01/01/98	01/15/98
CUSTOMER	Board of Directors Approval	Between 2/4/98 and 8/1/98	02/04/98	08/01/98
CUSTOMER	Permit Filing and Initial Technical Decision	Within 1 Month of Customer's Board Approval	03/01/98	09/01/98
CUSTOMER	Final Technical Decision	Within 4 Months of Customer's Board Approval	06/01/98	12/01/98
COMPANY	Permit Filing and Initial Technical Decision	Contemporaneously with Customer's Notice of Final Technical Decision	06/01/98	12/01/98
CUSTOMER	Permits Issued	Between 15 and 18 Months after Customer's Permit Filing	06/01/99	03/01/00
COMPANY	Permits Issued	Between 12 and 18 Months after Company's Permit Filing	06/01/99	06/01/00
CUSTOMER	Permits Acceptance and Commencement of Construction	Between 1 and 3 Months after Customer's Permits Issued	07/01/99	06/01/00
COMPANY	Permits Acceptance and Commencement of Construction	Between 1 and 3 Months of Company's Permits Issued	07/01/99	09/01/00
COMPANY	Completion of Construction and Date of Pipeline in Service	Between 3 and 6 Months after Permits Acceptance and Commencement of Construction by Company	10/01/99	03/01/01
CUSTOMER	Plant Fuel Testing	Between 12 and 18 Months after Permits Acceptance and Commencement of Construction by Customer	07/01/00	12/01/01
CUSTOMER	Completion of Construction and Date of Commercial Operation	Between 18 and 24 Months after Permits Acceptance and Commencement of Construction by Customer	01/01/01	06/01/02

REDACTED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EI EXHIBIT NO. 16
COMPANY/ WITNESS: Melino
DATE: 12-2-98

DOCUMENT NUMBER-DATE
10701 SEP 28 98
FPSC-RECORDS/REPORTING

ECT
Environmental Consulting & Technology, Inc.

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Meling
Exhibit 26 (JLM-1)

NEW SMYRNA BEACH POWER PROJECT
PRELIMINARY EVALUATION OF
SITE FEATURES AND POTENTIAL IMPACTS

Prepared by:

ECT
Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 98170-0400

September 1998

1.0 INTRODUCTION

Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. (Duke), is planning to construct, own, and operate a new electric power generating plant in Volusia County, Florida. The New Smyrna Beach Power Project (the Project) will be capable of producing a nominal 500 megawatts (MW) of electricity using state-of-the-art technology and clean natural gas fuel. The Utilities Commission of the City of New Smyrna Beach (UCCNSB) is a co-applicant for the Project and will receive an entitlement of capacity to cost-effectively meet the needs of its customers. Duke/UCCNSB recently filed an application with the Florida Public Service Commission (FPSC) demonstrating the need for the Project, both in meeting UCCNSB's growing needs for electrical power as well as those of Peninsula Florida. The need application showed how the Project will constitute a reliable, cost-effective, and environmentally friendly power generation resource for Florida. Following the need application will be the site certification application (SCA), which will address the Project's environmental and socioeconomic impacts.

Environmental Consulting & Technology, Inc. (ECT), was retained by Duke to take the lead in conducting the environmental impacts analyses and preparing the SCA. This report presents a preliminary summary of key features of the Project and how the Project may affect the environment. Full details regarding the potential impacts will be included in the SCA.

Section 2.0 of this report describes the important environmental features of the site and surrounding area (i.e., the *baseline* conditions). Section 3.0 provides a summary of the facilities and equipment comprising the proposed Project. In Sections 4.0 and 5.0, the impacts potentially resulting from construction and operation, respectively, of the Project are summarized. Finally, Section 6.0 presents conclusions regarding the Project's impacts.

2.0 SITE AND VICINITY CHARACTERISTICS

2.1 SITE AND ASSOCIATED FACILITIES DESCRIPTION

The proposed site for the Project is located in eastern Volusia County, approximately 5 miles west of downtown New Smyrna Beach (see Figure 2-1). The site is a 30.5-acre parcel that lies northwest of the intersection of State Road (SR) 44 and Interstate 95 (I-95), as shown in Figure 2-2. Figure 2-2 also shows the site of a new wastewater treatment plant (WWTP) currently being constructed by UCCNSB.

The site includes an existing UCCNSB 115-kilovolt (kV) electrical substation and is bisected by an existing UCCNSB and Florida Power & Light Company (FPL) transmission line easement. The Project will be served with natural gas via a new 16-inch pipeline proposed by Florida Gas Transmission (FGT). The pipeline will originate at the existing FGT system in Lake County. Licensing and permitting of the new pipeline will be the responsibility of FGT.

The site is primarily rural in nature and undeveloped. Adjacent to the northeast is UCCNSB's new 6.0-million-gallons-per-day (MGD) WWTP still under construction. To the east is I-95 and an inactive borrow pit. To the south is SR 44 and a service station at the intersection of SR 44 and I-95. To the west is undeveloped land.

2.2 LAND USE FEATURES

The site has been annexed into the City of New Smyrna Beach. Because the site was annexed recently, the City's comprehensive plan has not yet been amended to include the annexed areas. Consequently, the site is still subject to the provisions of the Volusia County comprehensive plan.

Consistent with the County's comprehensive plan, the site has been rezoned by the City as an Industrial—Planned Unit Development (I-PUD) in the Southeast Activity Center. The I-PUD zoning authorizes the construction and operation of an electrical power plant

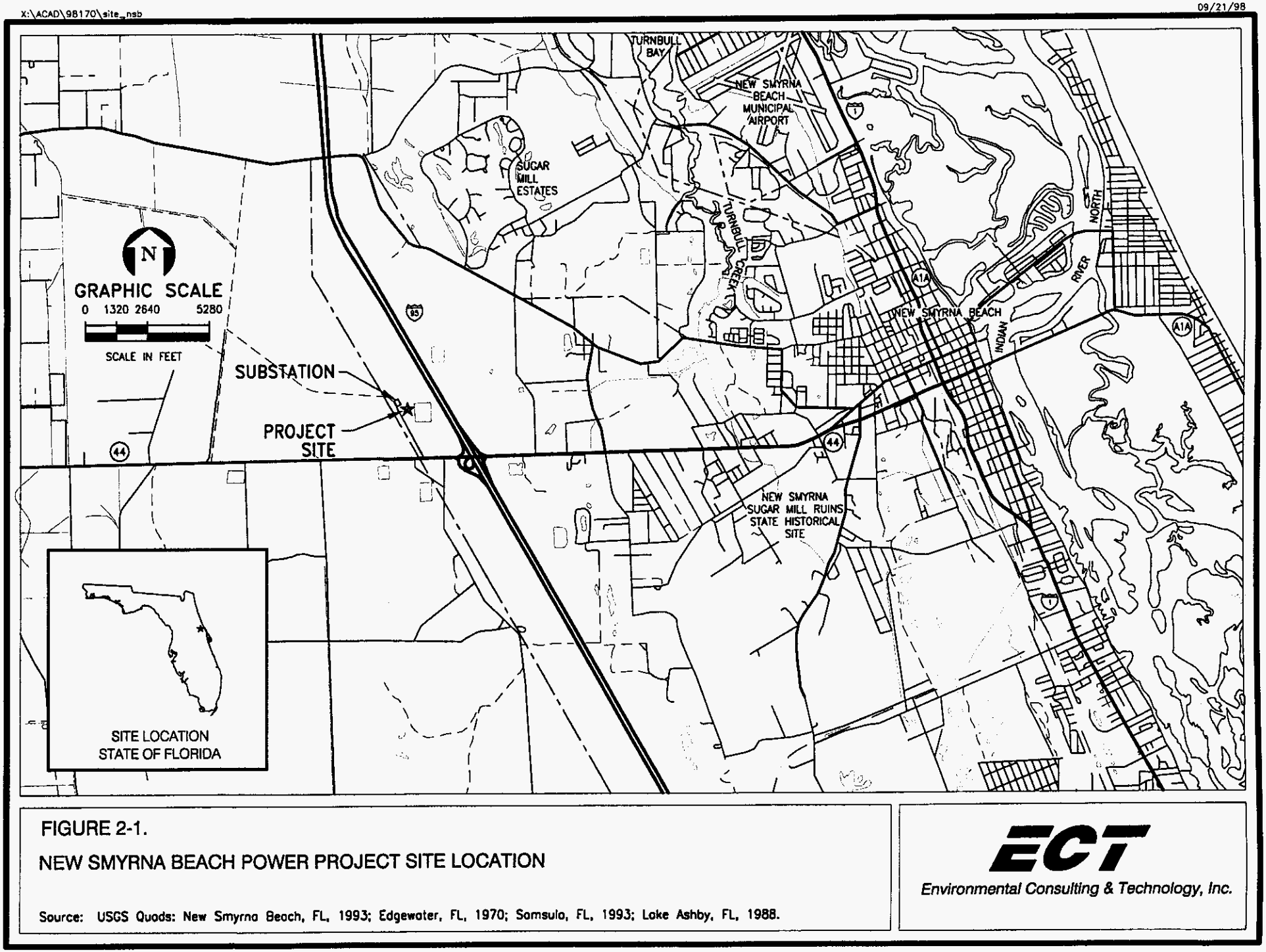

FIGURE 2-1.

NEW SMYRNA BEACH POWER PROJECT SITE LOCATION

Source: USGS Quads: New Smyrna Beach, FL, 1993; Edgewater, FL, 1970; Samsula, FL, 1993; Lake Ashby, FL, 1988.

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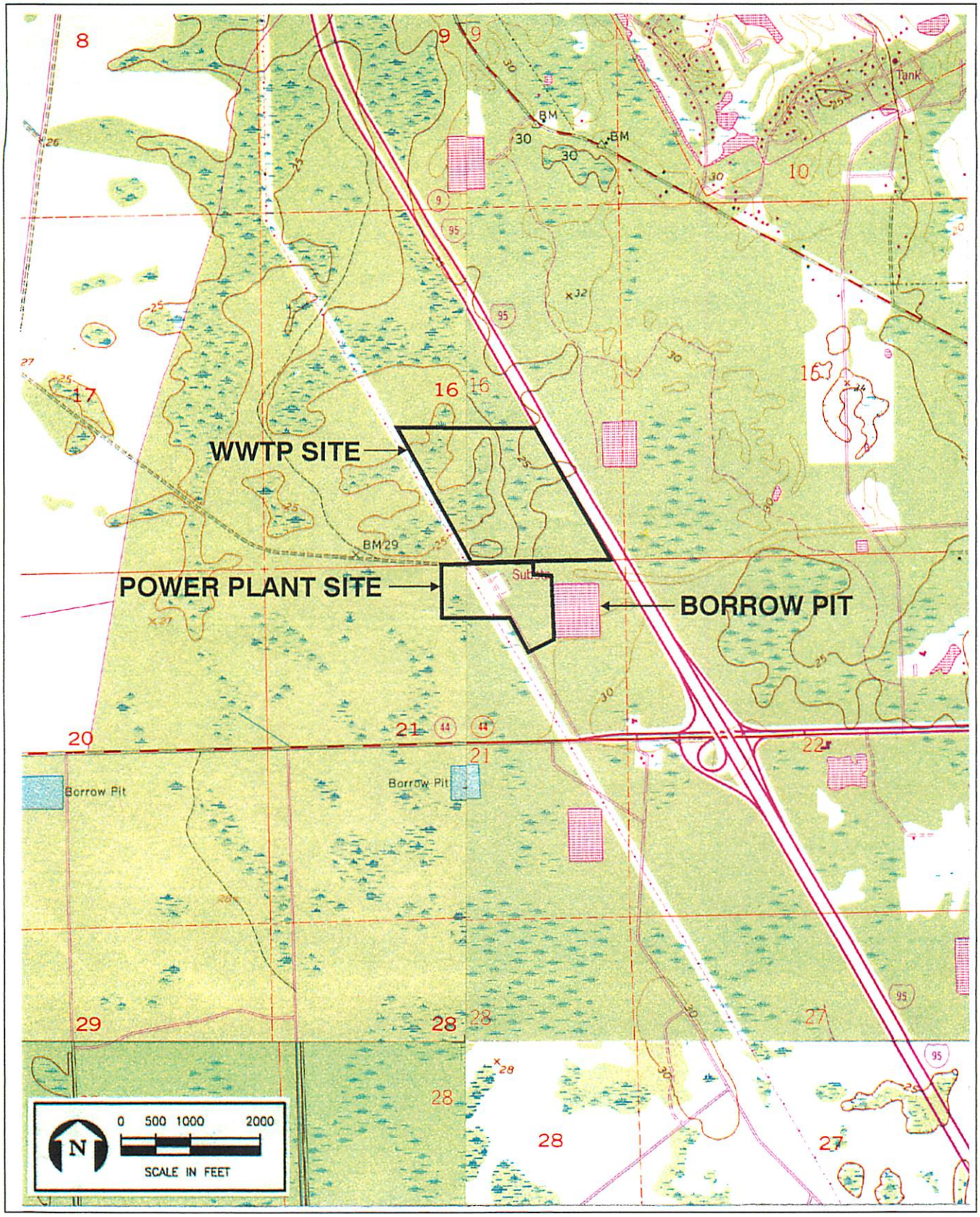

FIGURE 2-2.

PROJECT SITE LOCATION AND SURROUNDINGS

Source: USGS Quads: New Smyrna Beach, FL, 1993; Edgewater, FL, 1970; Samsula, FL, 1993; Lake Ashby, FL, 1988.

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on the site. The City also adopted a developers agreement, which establishes the land use restrictions that will govern the development of the site. The proposed Project is consistent and in compliance with the existing land use plans and zoning ordinances that are applicable to the site.

Agricultural land uses dominate the site region with some low-density residential development to the east of I-95. The proposed site is compatible with the nature of surrounding uses, which include a utility substation, electric transmission lines, WWTP facility, and transportation corridors. No sensitive natural resource, scenic, or cultural lands are found within 1 mile of the proposed site, and most are located more than 3 miles away.

2.3 SOCIOECONOMIC FEATURES

Volusia County exhibits a much lower unemployment rate than the statewide average, with services and retail trade being the major industries. Per capita income is lower than the state average, however. Almost one out of every seven persons works outside the county. Development of new housing has been steady to slightly declining within the region.

Economics of the region show the County's primary revenues come from ad valorem taxes and charges for services. Public safety is the primary expenditure for the County. The City of New Smyrna Beach enjoys the majority of its revenues from ad valorem taxes, while the majority of their expenditures go toward physical environment improvements.

Police, fire, emergency medical, and educational facilities found east of the site are all sufficient to handle this Project's demands for those services. The site will also be served by an existing potable water main, solid waste disposal services, and existing transportation facilities, including I-95 and the currently expanding SR 44. UCCNSB's

WWTP will have sufficient capacity to handle the Project's wastewater and provide a source of makeup water to the plant's operation.

2.4 GEOLOGICAL FEATURES

The Project site is located on the Pamlico Terrace with an average land surface elevation of 25 to 30 feet above mean sea level. The surficial layer under the site is unconsolidated sand, shell, and clay approximately 100 feet (ft) thick. Beneath that lies a thick sequence of sedimentary rocks. Figure 2-3 illustrates the basic geologic and hydrogeologic features of the area. No geologic faults have been mapped in the site vicinity, therefore posing no geologic hazard to the Project.

Soils in the site vicinity generally consist of poorly drained to depressional fine sands, characteristic of this region's flatwoods nature. Geotechnical investigations performed for the site are generally favorable for development of the power plant with proper site preparation.

2.5 GROUND WATER FEATURES

The subsurface hydrogeologic system at the site consists of two aquifers: the surficial and the Floridan (see Figure 2-3). These two aquifers are separated by an upper confining unit that is a variable sequence of sediments. The Floridan aquifer consists of an upper and lower aquifer separated by a middle confining unit. The Upper Floridan aquifer is generally more productive and of higher quality and, therefore, serves as the primary water source for the county. Although sinkholes are often associated with this type of geohydrologic formation, the site itself lies in an area where karst development (sinkhole formation) is low.

Recharge to ground water in the region is primarily through precipitation, irrigation water from the Upper Floridan aquifer, stream flow, and upward leakage of the Upper Floridan. Primary water use in Volusia County is from the Upper Floridan aquifer and is used for

GEOLOGIC UNITS

ERA	SYSTEM	SERIES	STRATIGRAPHIC UNIT	LITHOLOGY	AQUIFER
CENOZOIC	QUATERNARY	HOLOCENE	UNNAMED ALLUVIAL LAKE, & WINDBLOWN DEPOSITS	Thin, sand-&-gravel deposits adjacent to present-day streams; dune, estuary, and lagoon sediments contiguous to modern coast.	SURFICIAL AQUIFER
		PLEISTOCENE	PAMLICO FORMATION	Medium- to coarse-grained tan, white, or brown sand with local trace amounts of carbonaceous material and broken shell fragments.	
			ANASTASIA FORMATION	Cemented coquina reduced to small fragments, cemented by calcium carbonate, iron oxide, or other cements.	
	TERTIARY UPPER	PLIOCENE	CALOOSAHATCHEE FORMATION	Shallow marine rocks; thin sequence of interbedded clay, calcareous clay, and sand with much locally broken shelly material.	
		MIOCENE	HAWTHORN FORMATION	Marine interbedded sand, cream, white and gray, phosphatic, often clayey; clay, green to gray and white, phosphatic, often sandy; dolomite, cream to white and gray, phosphatic, sandy, clayey; and some limestone, hard, dense, in part sandy and phosphatic. Tends to be sandy in upper part and dolomitic and limy in lower part.	
	TERTIARY LOWER	EOCENE UPPER	OCALA LIMESTONE: CRYSTAL RIVER FORMATION	Marine limestone, cream to white, soft, granular, highly porous, coquinal; often consists almost entirely of tests of foraminifers; cherty in places.	FLORIDAN AQUIFER SYSTEM
			OCALA LIMESTONE: WILLISTON & INGLIS FORMATIONS	Marine limestone, cream to tan and brown, granular, soft to firm, porous, highly fossiliferous; lower part at places is dolomite, gray and brown, crystalline, saccaroidal, porous.	
		EOCENE MIDDLE	AVON PARK & LAKE CITY FORMATIONS	Marine, limestone, light brown to brown, finely fragmental, poor to good porosity, highly fossiliferous (mostly foraminifers); and dolomite, brown to dark brown, slightly porous to good porosity, crystalline, saccaroidal; both limestone and dolomite are carbonaceous or peaty; gypsum is present in small amounts. Marine limestone, light brown to brown, fragmental, highly fossiliferous, slightly carbonaceous or peaty and cherty; and dolomite, brown to dark brown with very minor amounts of gypsum and anhydrite. Unit is slightly porous to porous.	
		EOCENE LOWER	OLDSMAR FORMATION	Marine limestone, light brown to chalky, white, porous, fossiliferous, with interbedded brown, porous, crystalline dolomite; minor amounts of anhydrite and gypsum.	
		PALEOCENE	CEDAR KEYS FORMATION	Marine dolomite, light gray, hard, slightly porous to porous, crystalline, in part fossiliferous, with considerable anhydrite and gypsum, some limestone.	

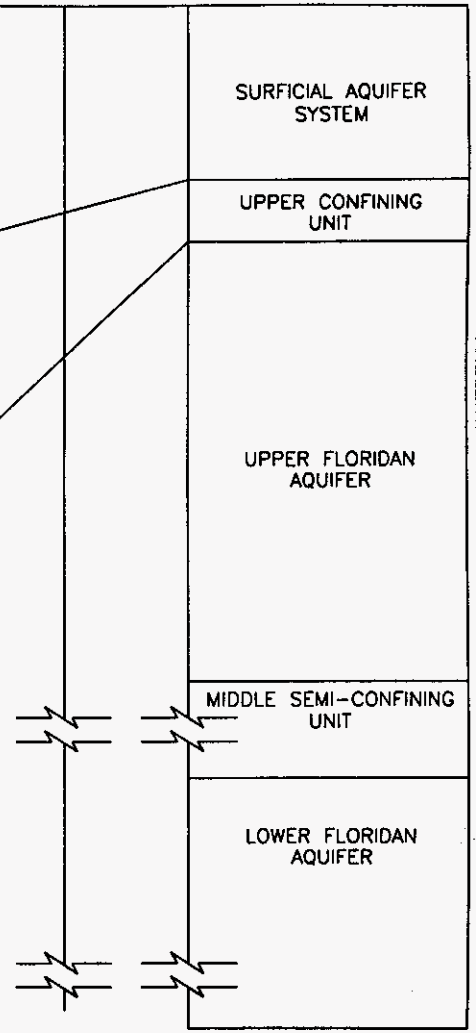

FIGURE 2-3.

PRIMARY GEOLOGIC AND HYDROGEOLOGIC UNITS IN VOLUSIA COUNTY

Source: Modified after Tibbals, 1990; Williams, 1997; McGurk, 1998; ECT, 1998.

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domestic use and agricultural irrigation. Ground water usage has increased significantly in the last 30 years primarily due to increases in public water supply and irrigation.

The Project will use 3.75 MGD of water for various plant needs on an annual average basis. Although some of this water (1.2 MGD) will be ground water from new onsite wells, the majority of the Project's water needs (up to 2.6 MGD) will be treated effluent from the adjacent WWTP.

2.6 SURFACE WATER FEATURES

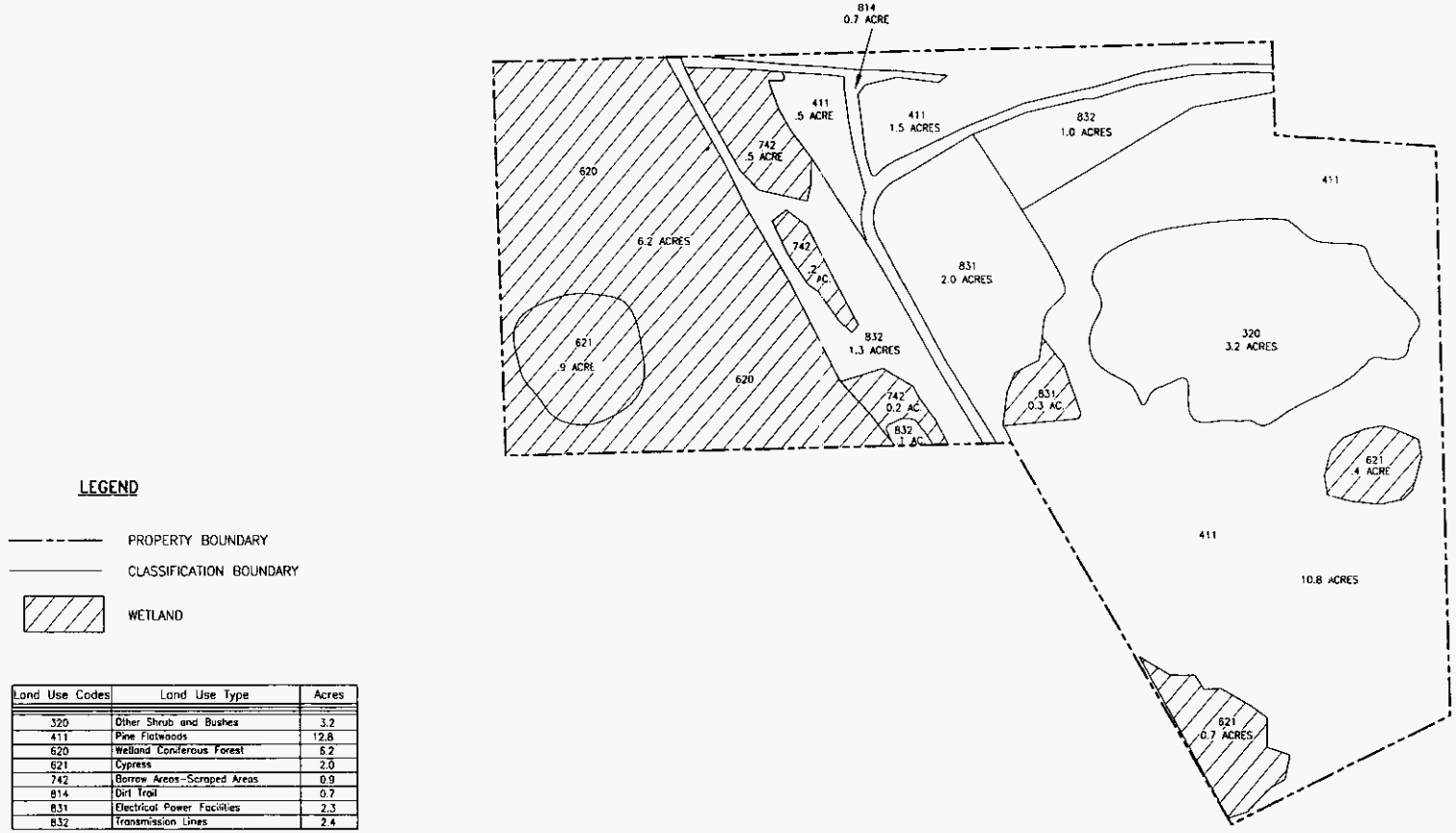
The only surface waters on or adjacent to the proposed site are wetlands and an abandoned borrow pit (just offsite to the east). Most of the wetlands drain to the north and ultimately enter an unnamed tributary to Spruce Creek. Spruce Creek is approximately 4 miles from the site and is classified as an Outstanding Florida Water. The onsite wetlands and borrow pit are classified as Class III surface waters.

Overall drainage of the site is to the north (Spruce Creek drainage basin). Portions of the site fall within the 100-year floodplain according to the Federal Emergency Management Agency.

2.7 ECOLOGICAL FEATURES

The existing land use and vegetation types occurring on the site are shown in Figure 2-4. No lakes or streams exist on the site; the nearest is the adjacent abandoned borrow pit. Approximately 79 percent of the site is currently vegetated. Wetlands comprise approximately 30 percent of the site; however, only 1.4 acres lie within the portion of the site to be developed (17.9 acres).

Upland vegetation is primarily pine flatwoods and shrub lands (palmetto, immature pine trees). Certain cleared uplands exist on roads, trails, the areas under the transmission lines, and areas around the substation. Wetlands consist of wetland coniferous forest



Land Use Codes	Land Use Type	Acres
320	Other Shrub and Bushes	3.2
411	Pine Flatwoods	12.8
620	Wetland Coniferous Forest	6.2
621	Cypress	2.0
742	Borrow Areas-Scraped Areas	0.9
814	Dirt Trail	0.7
831	Electrical Power Facilities	2.3
832	Transmission Lines	2.4

FIGURE 2.4.

VEGETATION AND LAND USE MAP

Source: ECT, 1998.

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(slash pine) and cypress domes. Some borrow areas around the substation and on the transmission right-of-way have been scraped, and herbaceous wetlands are found.

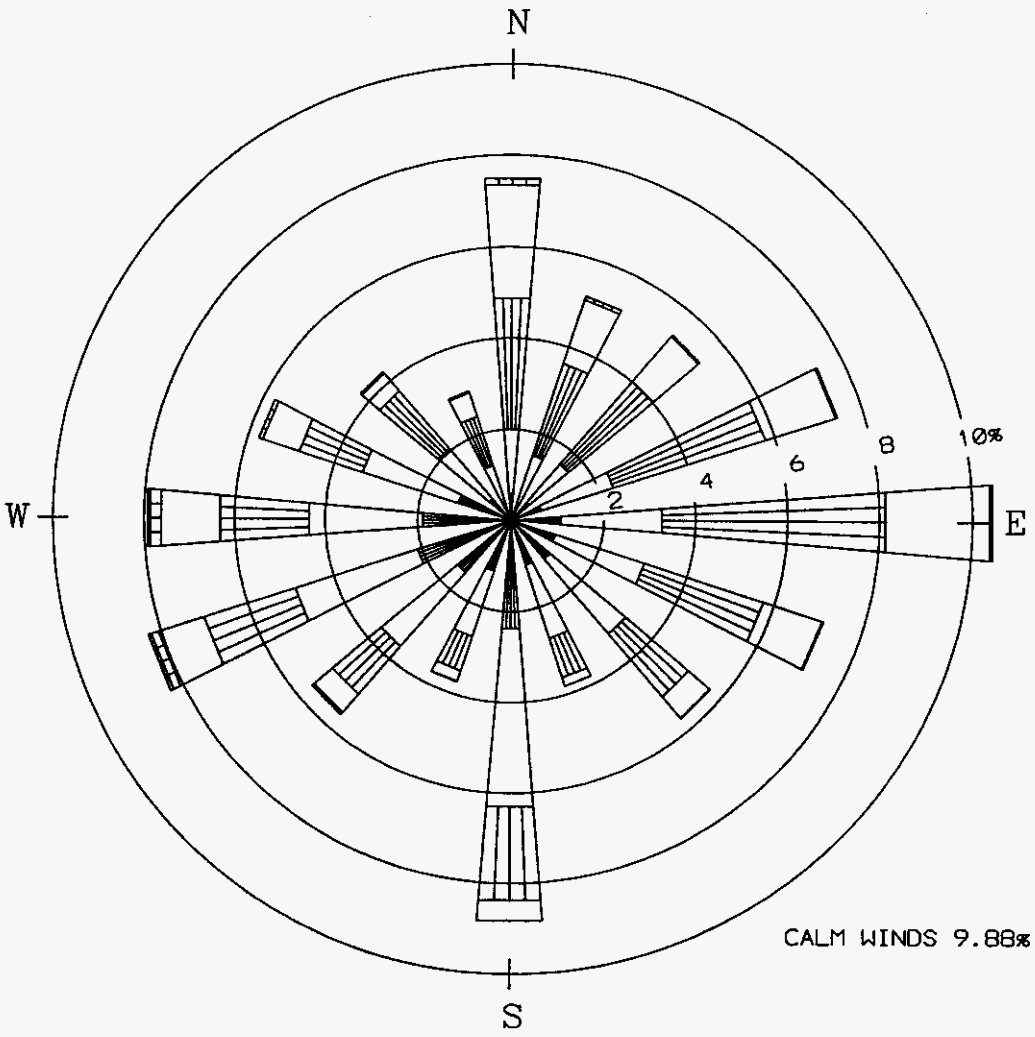
Review of agency records and ecological surveys of the site found no sensitive ecological features. No listed wildlife species were found onsite, and only two listed plant species, cinnamon fern and royal fern, were found. Both plant species are regionally common in Florida and have been listed by Florida Department of Agriculture and Consumer Services (FDACS) only for their protection from overcollecting.

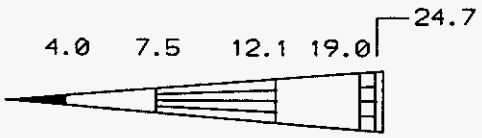
Wetlands onsite were surveyed. Jurisdictional limits were established and regulatory agencies have approved these limits. Appropriate mitigation will be provided for those wetlands impacted by plant construction. As currently proposed, only 0.7 acre of wetland impacts will occur due to project development. Existing stresses to the ecological resources of the site include the existing development (transmission right-of-way, substation, access road, SR 44, and I-95), as well as the ongoing construction of the WWTP.

2.8 AIR RESOURCES AND NOISE FEATURES

Climatological features for the site can be characterized as subtropical with maritime influences. Summers are hot and humid, while winters are mild and usually dry. Based on nearby meteorological data, January is the coldest month and July the warmest. Annual rainfall averages 48 inches, with September being the wettest month. March is the windiest month, and August is the calmest. Prevailing winds are from the east, although south, southwest, and westerly winds are also common. Figure 2-5 presents the wind rose for the area, based on data from Daytona Beach.

Thunderstorms are common weather events. Tornadoes and hurricanes are possible for the area, although their probability at the site is low.





WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

NOTES:
DIAGRAM OF THE FREQUENCY OF OCCURRENCE FOR EACH WIND DIRECTION. WIND DIRECTION IS THE DIRECTION FROM WHICH THE WIND IS BLOWING. EXAMPLE - WIND IS BLOWING FROM THE NORTH 7.5 PERCENT OF THE TIME.

WINDROSE

STATION NO. 12834
Daytona Beach, FL
PERIOD: 1987-1991

FIGURE 2-5.

5-YEAR ANNUAL WIND ROSE FOR DAYTONA BEACH MUNICIPAL AIRPORT (1987 - 1991)

Source: NCDC, 1998; ECT, 1998

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The area around the Project site has been classified by the Florida Department of Environmental Protection (FDEP) as attainment for all criteria air pollutants, based on data from the area's ambient air monitoring stations, whose locations are given in Table 2-1 and shown in Figure 2-6. This means air quality meets all State and Federal ambient air quality standards. Air quality is generally attributable to lack of major emission sources in the region. The only other major power plants in Volusia County are near Lake Monroe, approximately 20 miles southwest of the Project site, as shown in Figure 2-7.

Ambient noise in the site vicinity is generally low due to the relatively rural nature and vegetation buffering effects found there. No residences are located within 3,000 ft of the site. Manmade noise sources currently include traffic on SR 44 and I-95, farm equipment, and infrequent aircraft overhead. Natural noises come from wind, rain, insects, or birds.

Ambient noise monitoring was performed for a 24-hour period and included two monitoring stations, representative of the nearest noise receptors. Ambient noise at the receptor nearest SR 44 was the highest. Volusia County has a noise ordinance that limits noise produced in certain use occupancy categories. In both cases, the ambient noise measured at the site vicinity was below the County's limit.

Table 2-1. Ambient Air Quality Monitoring Stations Closest to the New Smyrna Beach Project Site

Pollutant	FDEP Station No.	Station Location		Relative to Project Site (km)
		County	City	
PM_{10}	0920 002 G01	Volusia	Daytona Beach	22 N
	0920 002 G09	Volusia	Daytona Beach	22 N
	0920 003 G01	Volusia	Daytona Beach	22 N
	1820 001 G01	Volusia	Holly	25 N
SO_2	4900 002 G01	Orange	Winter Park	55 SW
NO_2	4900 002 G01	Orange	Winter Park	55 SW
CO	3280 005 G01	Orange	Orlando	60 SW
	4900 002 G01	Orange	Winter Park	55 SW
Ozone	0920 002 G01	Volusia	Daytona Beach	22 N
	3730 001 G01	Volusia	Port Orange	14 N
Lead	1960 032 H01	Duval	Jacksonville	160 NNW
	1960 084 H01	Duval	Jacksonville	160 NNW

Sources: FDEP, 1997 and 1998.
ECT, 1998.

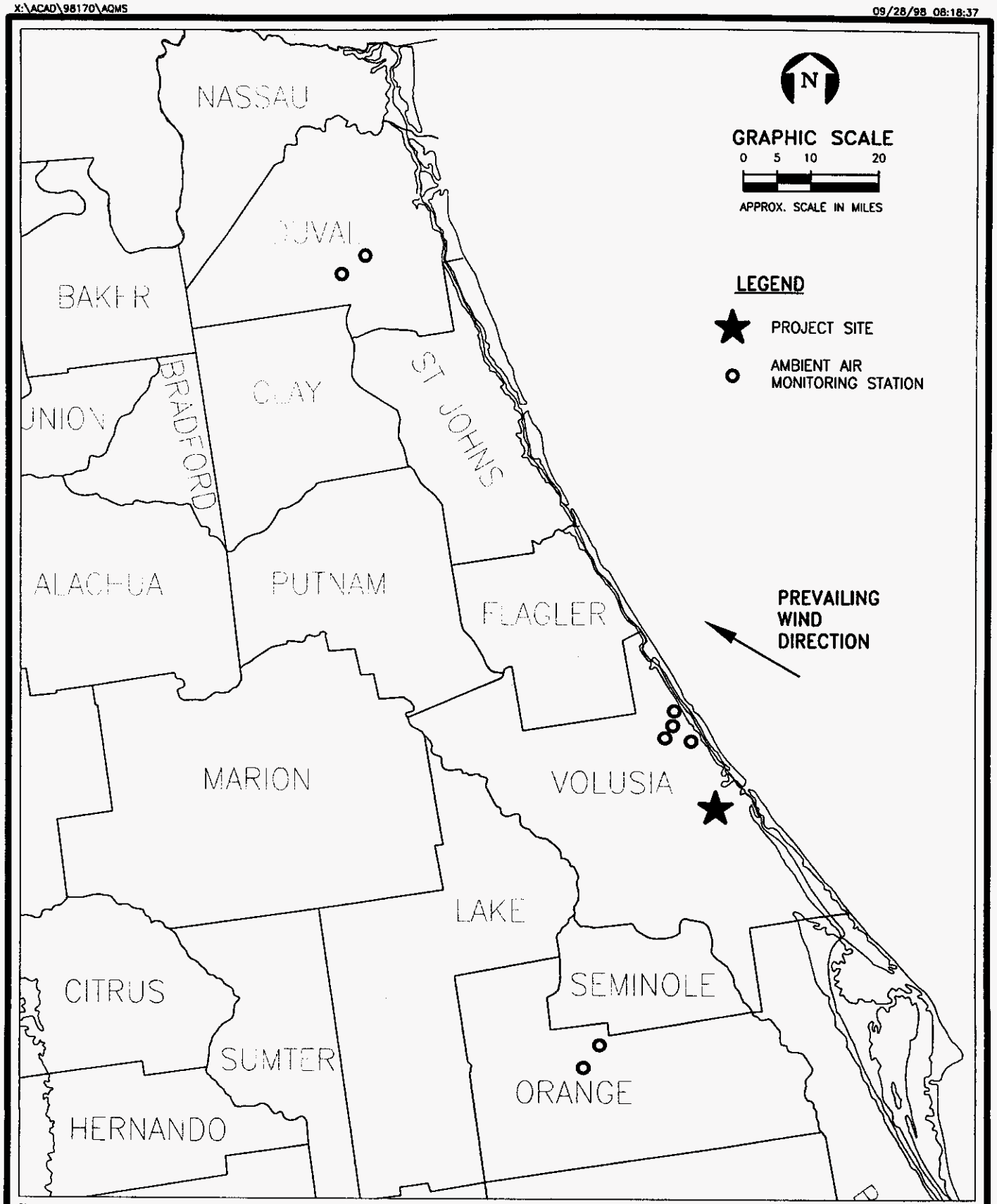

FIGURE 2-6.

LOCATIONS OF CLOSEST FDEP AMBIENT AIR QUALITY MONITORING STATIONS

Source: ECT, 1998.

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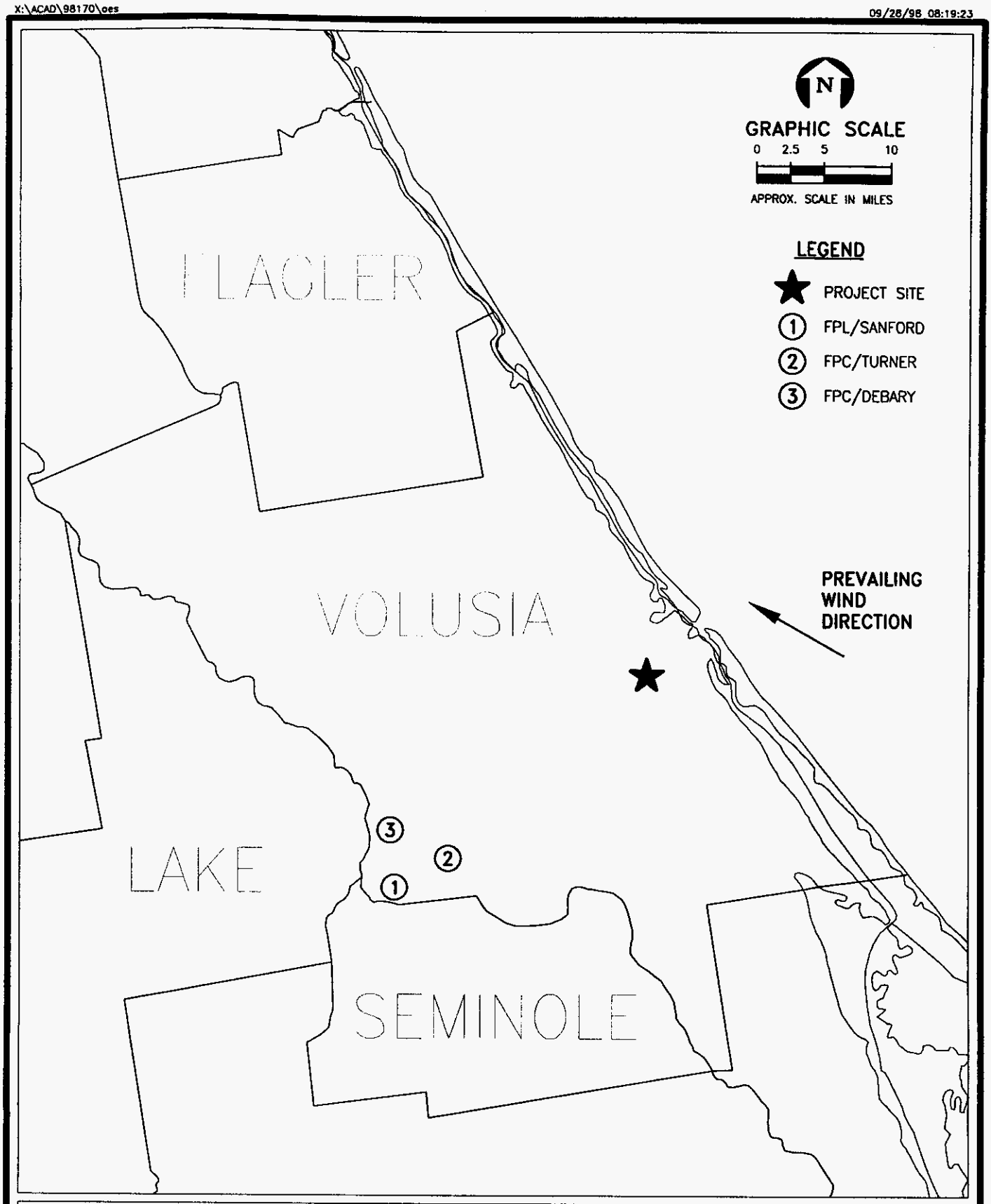

FIGURE 2-7.

OTHER LARGE AIR EMISSION SOURCES IN VOLUSIA COUNTY

Source: ECT, 1998.

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3.0 GENERAL PROJECT DESCRIPTION

The New Smyrna Beach Power Project will utilize state-of-the-art combined cycle (CC) design concepts and equipment to achieve a high level of efficiency in electrical power production. Figure 3-1 presents a simplified flow diagram of a CC unit. Figure 3-2 shows the layout of the plant, while Figure 3-3 provides a rendering of the plant. One of the distinguishing features of the facility will be its use of treated effluent from the adjacent WWTP for plant water makeup. The plant will use the maximum amount of treated effluent currently available to minimize the need for ground water.

In general, a CC electric generating unit consists of combustion turbine generator (CTG) units and a heat recovery steam generator (HRSG), as well as steam turbine facilities. The efficiency of electric generation is improved when CTG units are combined in a CC unit arrangement compared to CTG units operated in simple cycle mode. When CTG units are used in simple cycle, the hot combustion gases are released to the atmosphere after passing through the turbine. In a CC unit, the hot combustion gases from the CTG flow into an HRSG, where water in boiler tubes is heated to produce steam. The steam is then used to drive a steam turbine generator to produce additional electricity. Therefore, by reusing the waste heat from the CTG units, additional electricity is efficiently produced by the steam turbine generator without additional fuel input. The New Smyrna Beach Power Project will include two CTG/HRSG units.

The proposed CC power plant will be capable of continuous operation at base load for up to 8,760 hours per year (hr/yr), except for those years during which a major overhaul of the engine is required. Average availability for the Project is planned to be 96 percent (8,410 hr/yr) during non-overhaul years and 88 percent (7,700 hr/yr) during overhaul years. The two CTGs will be equipped with dry low-nitrogen oxides (NO_x) combustors. The CTGs may normally operate between 50- and 100-percent load, with commensurate steam turbine load. Table 3-1 summarizes maximum projected annual emissions of air pollutants for the facility, using worst-case operating assumptions. Neither CTG will be designed to

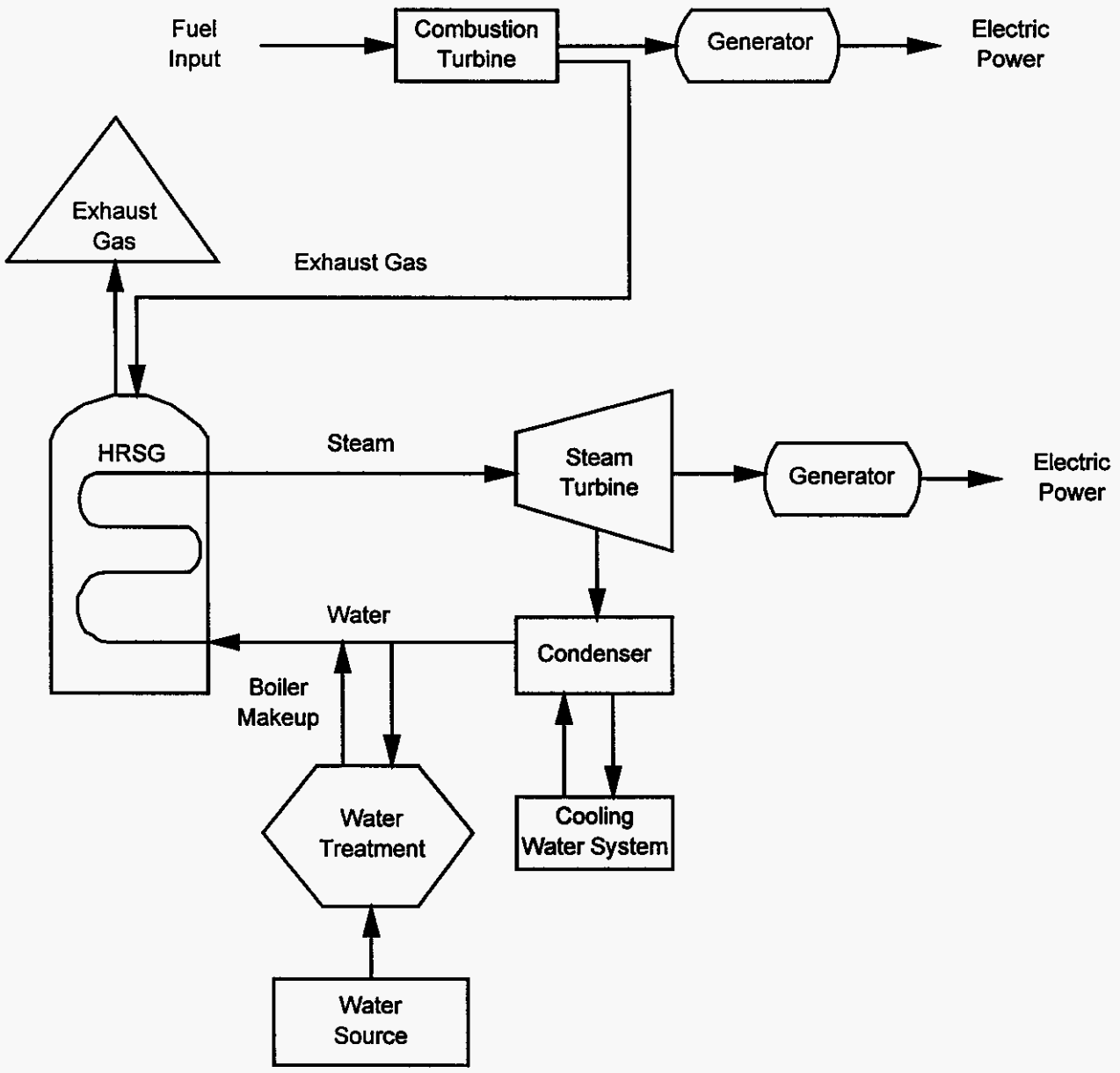

FIGURE 3-1.

SIMPLIFIED FLOW DIAGRAM OF CC POWER SYSTEM

Source: ECT, 1998.

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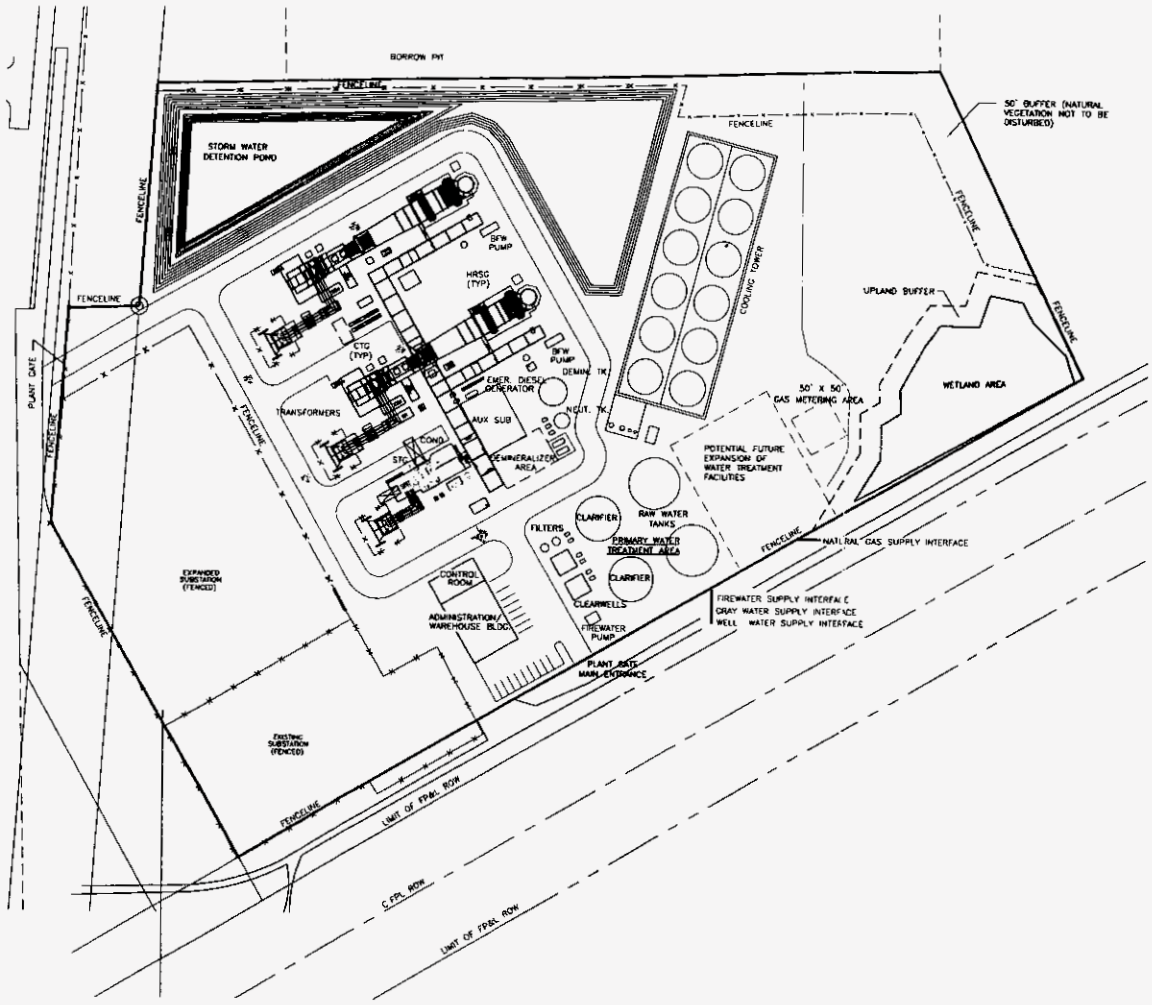

FIGURE 3-2.

PROPOSED PLANT LAYOUT

Source: Fluor Daniel, 1998

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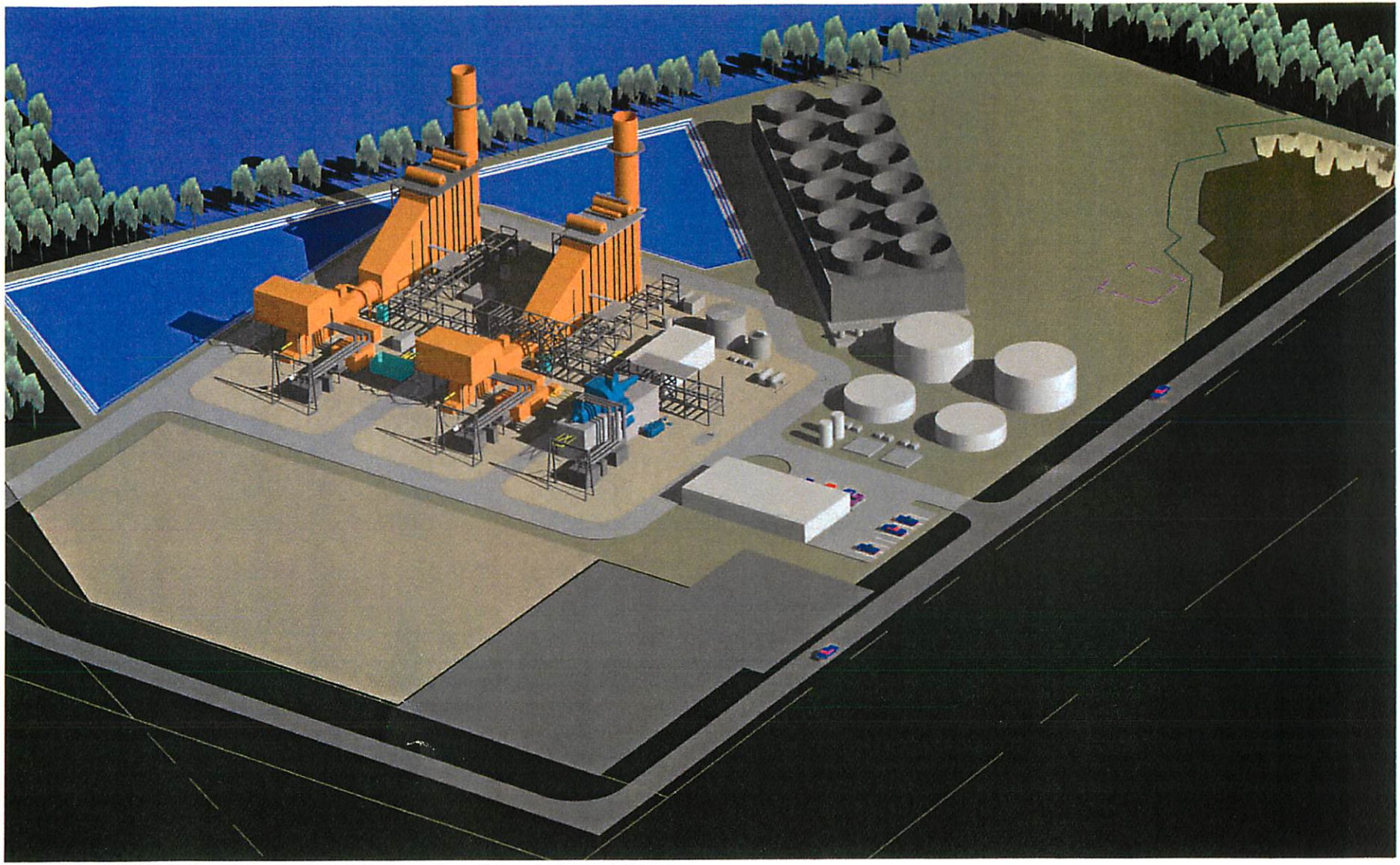

FIGURE 3-3.

ARTIST'S RENDERING

Source: D/FD, 1998.

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Table 3-1. Maximum Annualized Emission Rates for the New Smyrna Beach Power Project

Pollutant	Annualized Emission Rate (tpy)				
	CTG/HRSG Units	Emergency Generator	Emergency Firewater Pump	Cooling Tower	Facility Totals
NO_x	674.5	3.5	1.3	N/A	679.3
CO	339.0	0.1	0.3	N/A	339.4
PM/PM_{10}[1]	78.8	0.2	0.04	26.4	105.4
SO_2	87.7	0.08	0.03	N/A	87.8
VOC	24.7	0.07	0.07	N/A	24.8
H_2SO_4	10.1	0.01	0.003	N/A	10.1

Note: N/A = not applicable.

[1]Excludes H_2SO_4.

Sources: GE, 1998.
D/FD, 1998.
ECT, 1998.

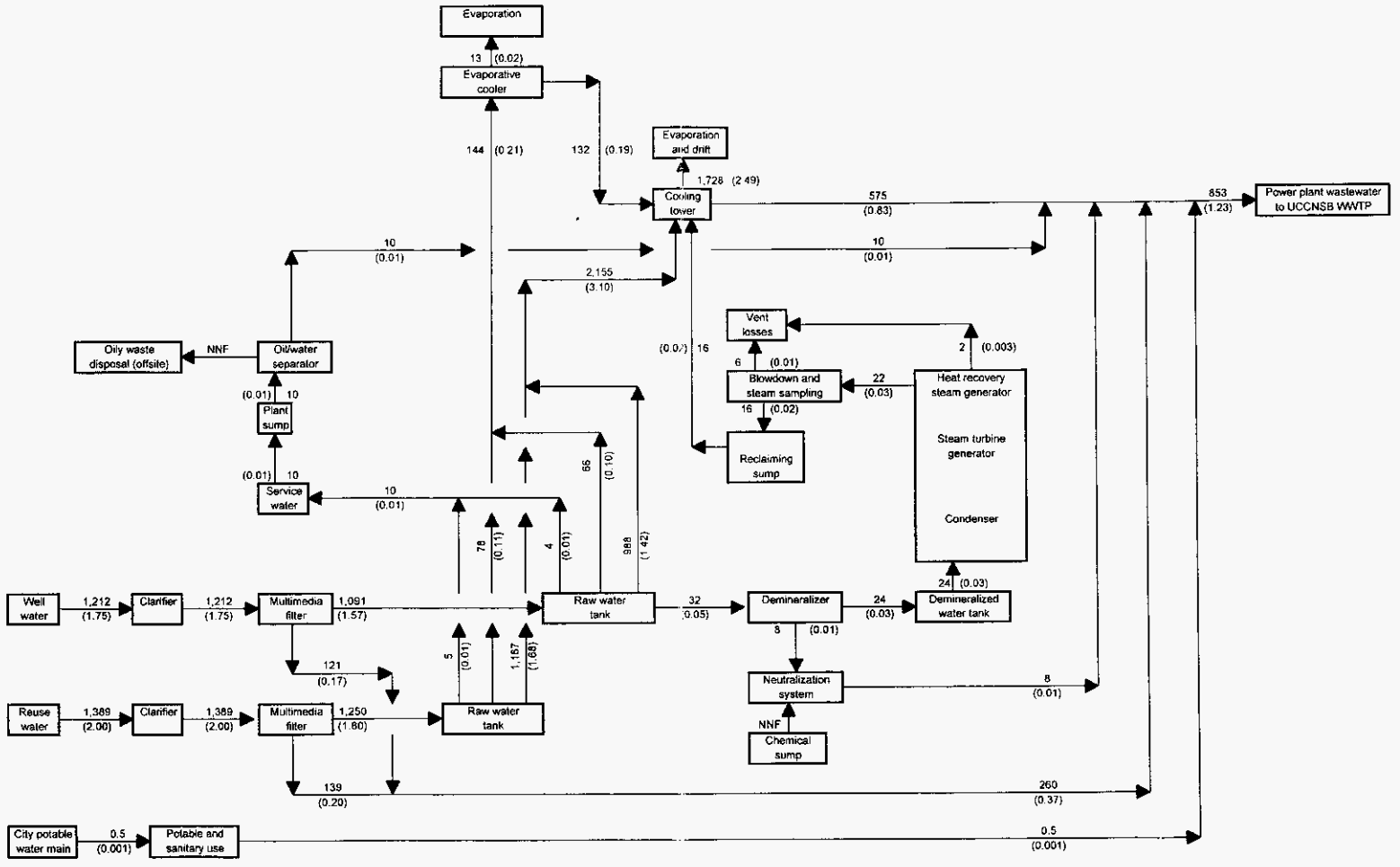
operate in simple cycle mode (i.e., by-passing the HRSG). The HRSG will be of an unfired design (i.e., no supplemental firing).

A cooling water system will provide cooling for condensing the steam turbine exhaust and supplying cooling water to other plant equipment. The cooling system's key component will be a multiple-cell cooling tower.

The Project's overall water requirement, most of which is needed for cooling tower makeup, will be met with water from three sources: treated effluent, ground water, and potable water from the municipal system, as shown in Figure 3-4. Maximum reuse will be made of treated effluent. Up to approximately 2.6 MGD of treated effluent will be available to the Project, with an annual average of approximately 2.0 MGD initially available; these quantities represent the differences between the WWTP's expected output and existing demands and obligations (golf courses, etc.). As the WWTP's throughput increases over time due to population growth in the area, it is possible that a larger amount of reuse water will be available to the power plant. Additional water not supplied from the UCCNSB reuse system will be supplied from a new onsite wellfield and raw water supplied by UCCNSB. As an additional back-up to the water supply system, the Project's full requirements could be met on a short-term basis by the UCCNSB potable water system, although, under normal circumstances, this source will be used only for the Project's small potable water needs.

Both reuse water and ground water will require treatment before being used in the power plant. The WWTP effluent will flow through a filtration and treatment system, then to the raw water storage tank. This tank will directly supply makeup water to the cooling tower. Ground water will be filtered, then will flow to the same raw water storage tank. This tank will supply makeup water to the steam system via the demineralization system.

Demineralized water will be needed as makeup to the steam cycle to replace HRSG blowdown and steam losses. Raw water will feed the demineralizer, which will reduce



NOTES:

1) Flows are in shown in gallons per minute and in (million gallons per day [MGD]).
2) Cooling tower blowdown is based on four cycles of concentration.
3) NNF - normally no flow.

FIGURE 3-4.

WATER BALANCE DIAGRAM—ANNUAL AVERAGE

Source: D/FD, 1998.

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dissolved solids to required levels. A demineralized water storage tank will be sized to provide 7 days of storage at normal usage rates.

The principal wastewater streams will be cooling tower blowdown, backwashes from the water filtration and treatment system, HRSG blowdown, and wastewaters from a neutralization system and an oil/water separator. A waste neutralization system will receive regeneration wastes from the demineralized waste system and the chemical waste sump. This system will agitate the regeneration wastes and inject acid or caustic to adjust the pH of the wastes to desired levels. Process wastewater containing oils will be segregated from other wastewater. This wastewater will be collected in the oily wastewater sump, where an oil/water separator will remove the oil. All treated wastewater and blowdown from the cooling tower will be discharged to the adjacent WWTP. A sanitary lift station will pump domestic wastewater to the adjacent WWTP. Storm water will be routed via sheet flow to culverts and directed to an onsite detention area.

The existing 115-kV substation will be expanded to provide a breaker-and-a-half configuration, into which the Project will be connected. Eight new breakers will be added to the existing substation to accommodate this reconfiguration. Within the substation, repositioning of three existing 115-kV transmission lines will be necessary.

Natural gas will be delivered to the site by a new pipeline from a connection to the FGT system. The interconnection will occur at Mount Plymouth, located in Lake County between Sanford and Mount Dora. Licensing of this pipeline will be the responsibility of FGT, not Duke/UCCNSB, and the license will, therefore, be applied for separately.

The conceptual design of the New Smyrna Beach Power Project just described was reached only after the consideration of various site and design alternatives. Throughout the conceptual design process, Duke/UCCNSB have held environmental protection as a primary goal. First, the Project site itself was selected to offer immediate access to the existing Smyrna Substation and the new WWTP being built adjacent to the site. With any

other site in New Smyrna Beach, new transmission lines and/or water pipelines would have to be constructed, with their associated environmental and other impacts. The chosen site is also already impacted by other construction and development (e.g., the WWTP) and is well buffered from residential areas. Immediate access to the new WWTP gives rise to two of the Project's key environmental mitigation features:

- Maximum use of treated WWTP effluent for cooling and other process needs, thereby both reducing the Project's reliance on ground water and helping significantly reduce the WWTP's amount of discharge to the Indian River.
- Discharge of all wastewater back to the WWTP, thereby eliminating any direct discharge of thermal or other pollutants to the environment.

Second, the proposed site layout has been designed to minimize wetland impacts. A significant portion of the site is wetlands. Duke/UCCNSB have selected the alternative of locating the physical plant to avoid impacting all but two isolated wetlands, which total less than an acre.

Finally, Duke/UCCNSB considered a number of possible technologies and designs for the Project, including alternative generation technologies and fuels (e.g., pulverized coal), air emission controls, cooling systems and sources of water, and wastewater treatment and discharge alternatives. The selection of natural gas-fired CC technology was relatively straightforward given the advantages this technology has over the alternatives. These advantages include higher efficiency, lower construction cost and shorter construction schedule, much lower air emissions, and lower operation and maintenance costs. With the selected technology, the New Smyrna Beach Power Project will be one of the least polluting, most efficient electrical power generating plants in Florida, and will be an industrial asset to the community.

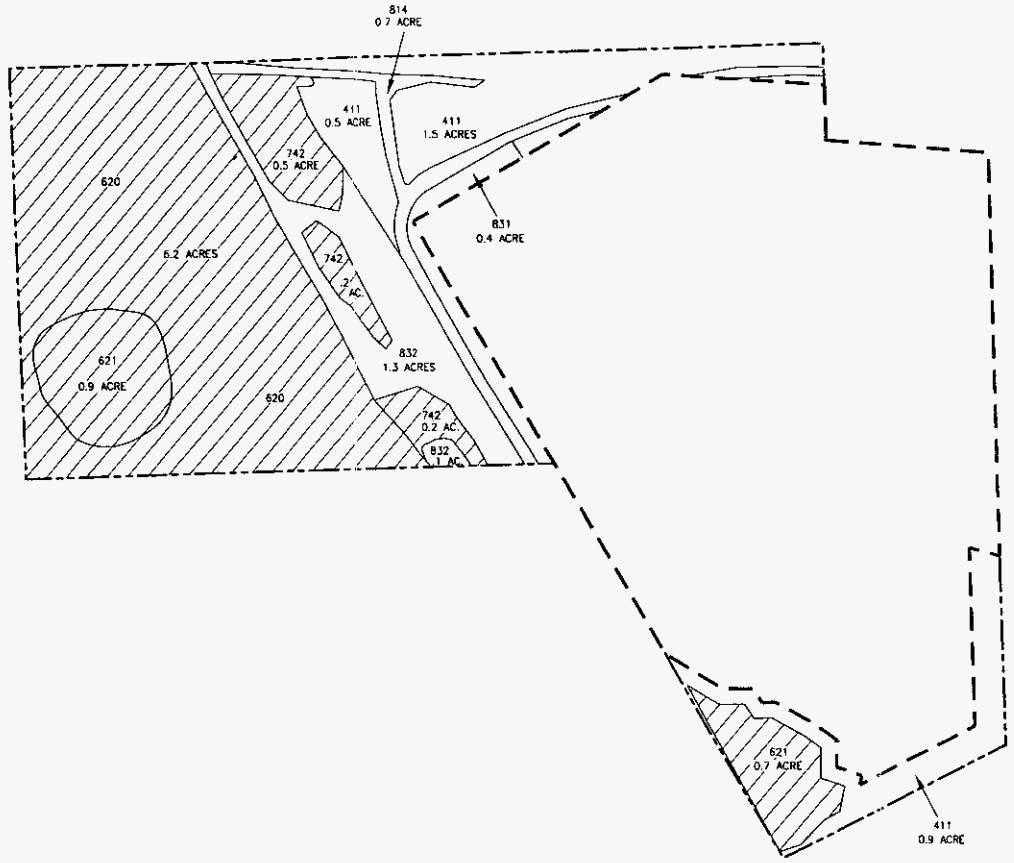
4.0 IMPACTS OF PROJECT CONSTRUCTION

The proposed New Smyrna Beach Power Project will be located on a 30.5-acre parcel, but the Project will only require development of 17 acres of that parcel, as illustrated in Figure 4-1. Land impacts, therefore, will be minimal due to construction of the facility. Construction activities will include site drainage and storm water basins, dewatering of low areas (if required), clearing, grading, final storm water management, power plant erection, and final grading and landscaping.

No explosives will be used in any aspect of construction. Construction impacts will be further minimized due to use of a construction access road already in place for the WWTP construction and possible use of adjacent UCCNSB property for the construction laydown area. Trash and construction debris will be removed or recycled by a licensed waste handling contractor.

Since the site is relatively flat, drainage patterns after construction will be designed to closely match preconstruction drainage. Use of temporary and permanent storm water basins, as well as erosion control measures, will minimize offsite runoff and sedimentation. The only surface water features potentially impacted by construction include the adjacent borrow pit and a few onsite wetlands. Use of best management practices (BMPs) will minimize offsite erosion/sedimentation. Construction will require the loss of less than 1 acre of onsite wetlands, but the loss will be mitigated by preservation of other onsite wetlands.

Construction impacts on ground water resources are expected to be short-term and minimal. Dewatering activities for construction will follow an approved dewatering plan, which will include a construction storm water and sedimentation pond to collect and settle surface water runoff before discharge. Dewatering impacts to the surficial aquifer will be offset by increased infiltration and recharge to the system and by the decreased



LEGEND

- PROPERTY BOUNDARY
- CLASSIFICATION BOUNDARY
- WETLAND
- SITE DEVELOPMENT AREA

Land Use Codes	Land Use Type	Acres
	Site Development Area	16.3
411	Pine Flatwoods	2.9
620	Wetland Coniferous Forest	6.2
621	Cypress	1.6
742	Borrow Areas-Scraped Areas	0.9
814	Dirt Trail	0.7
831	Electrical Power Facilities	0.4
832	Transmission Lines	1.5

N

GRAPHIC SCALE
0 50 100 200
SCALE IN FEET

FIGURE 4-1.

PROJECT AREA--LAND USE AND VEGETATION CONSTRUCTION IMPACTS

Source: ECT, 1998.

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evapotranspiration that accompanies a lowered water table. No impacts will occur to drinking water supplies or other uses of the Upper Floridan aquifer.

Impacts to ecological resources are anticipated to be minimal. No surface waters are found onsite, so no net loss of such resources will occur. Use of BMPs during construction will minimize any potential impacts to offsite aquatic resources.

The site is vegetated with commonly occurring shrub and forested areas occurring in east-central Florida. The site is already impacted due to adjacent clearing and development of the existing substation, electric transmission line right-of-way, and WWTP. Less than 17 acres will be disturbed out of the 30.5-acre parcel. Less than 1 acre of wetlands will be impacted, and their loss will be compensated.

The site contains no unique ecological features or sensitive habitats. No state or federally listed wildlife species were found onsite, nor are any suspected of depending on the site's resources for their uses. Two fairly common fern species are found onsite and are listed by FDACS due to their commercial exploitation, not because of any endangerment. Construction of the project will, therefore, have minimal impacts to the local ecological resources and virtually no impacts to regional plant and animal populations.

Construction impacts on air resources may occur in three forms: clearing of the site resulting in fugitive dust, open burning of cleared debris, and construction vehicle emissions. All of these potential emissions will be low and short-termed in nature. Mitigation methods will include dust suppressant activities during clearing and grading, use of paved roads for access to the site, and controlling any open burning within applicable state and local guidelines.

Although construction of this facility represents a change in land use of the site, the change is compatible with existing City of New Smyrna Beach land use and zoning regulations. New Smyrna Beach has annexed the site into the City. Currently, Volusia

County's land use plan governs the site until the City has a chance to amend their land use plan.

Socioeconomic impacts of the project are largely beneficial, although short-term during construction. An approximate peak workforce of 320 people will be required with an approximate average of 200 persons working on the site during the 21-month construction period. Many of these workers will be local and will generate a $31.5 million construction payroll. Additionally, the Project is expected to generate over $113,000,000 in indirect local economic benefits (e.g., related goods sold and services generated locally). Much of that money will be spent locally on goods and services. The out-of-county workforce (70 percent) will largely use rental properties in Volusia County during construction providing further economic benefits. Available rental housing should be able to adequately provide for this workforce. No significant impacts to housing demand are anticipated due to the relatively short construction period.

Similarly, essential services (police, fire, emergency medical, and schools) are currently adequate to meet any short-term demands the construction workforce will generate. Although construction will generate additional traffic on local roadways, this increase will be short-term. Volusia County does not regard this increase as significant. Additionally, SR 44 is being widened, which will further minimize traffic impacts.

Project construction will have no impacts on any of the County's landmarks, natural resource areas, parks, or cultural resources.

Noise generated during construction will be generated by heavy equipment at the site and, to a lesser degree, by construction traffic going to and from the site. With the possible exception of temporary pile-driving activities, noise at the nearest receptor (service station at the I-95 and SR 44 intersection) will be at or below ambient noise levels already occurring along SR 44. Pile driving activities will be heard at this receptor, but the noise is of short duration.

5.0 OPERATION IMPACTS

Overall, the proposed facility will be a highly efficient and environmentally clean operation. Key features helping to minimize the operational impacts include modern clean burning equipment, small site size, use of clean natural gas fuel, reuse of treated wastewater for much of the plant's needs, and compatibility with adjacent land uses and existing utility facilities.

The plant will discharge all its wastewater to the neighboring WWTP, and water quality limits of the discharge will meet operational limits of the WWTP for proper treatment. Since there will be no discharges to surface waters, surface waters in the region will not be affected by any thermal or chemical effects of the power plant's discharges.

Since water use is primarily wastewater reuse from the WWTP and ground water from onsite wells, no surface waters will be diverted or consumptively used for plant operations. Based on ground water modeling for the proposed ground water usage at the plant, the amount of water withdrawn will not adversely affect the surficial or Upper Floridan aquifer, nor will any existing municipal wells, residential wells, or wetlands be adversely affected.

Drinking water at the plant will be supplied from the municipal system and amounts will be minimal given the small operational workforce. No discharges will occur to any drinking water source.

As with construction, use of BMPs and implementation of the storm water management plan will also help protect adjacent water resources during plant operation from any potential sedimentation and leachates. Solid wastes generated will be disposed offsite by a licensed contractor at a landfill permitted to receive such wastes. No hazardous wastes will be routinely generated at the facility. Specialty contractors involved in cleaning plant

components may generate such wastes, but will be responsible for proper handling, removal, and disposal of them.

The New Smyrna Beach Power Project is considered a major stationary source for air pollutants, meaning it has the potential to emit 100 tons per year (tpy) of any pollutant regulated under the federal Clean Air Act. As such, the facility is required to undergo prevention of significant deterioration (PSD) review to determine whether significant air quality deterioration will result from operation. As part of PSD review, a best available control technology (BACT) analysis was performed for control technologies applicable to each pollutant. Given the fuel type and control technologies proposed, modeling indicates that maximum impacts caused by combustion emissions will be less than regulated significance levels for all averaging times for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), particulate matter nominally 10 microns and less (PM_{10}), and carbon monoxide (CO). This means operation of the Project will produce low impacts on air quality in the region. Emissions of PM_{10} from the cooling tower are conservatively predicted to have impacts above the significance level in the immediate plant vicinity (i.e., within several hundred yards of the plant site). However, overall impacts in this very localized area will be below all applicable air quality standards.

It is probable that the New Smyrna Beach Power Project will have a net *positive* impact on air quality in Florida. This is due to the fact that the Project's generation may, at least to some extent, displace that of older, less efficient facilities whose emissions are significantly greater per unit of electrical output. An analysis of this issue is provided in the Appendix to this report. A summary of the essential findings is as follows:

- Due to the Project's greater efficiency and use of clean natural gas, its emissions per unit of electricity produced will be much less than those from most existing facilities.
- Based on a model forecast of the Project's output of electricity in 2002, if the Project's generation were to completely offset generation from existing steam-

electric facilities burning a 50/50 mix of fuel oil and natural gas, air pollutant emissions in Florida would be decreased by the following amounts:

- NO_x—8,430 tpy
- CO—3,135 tpy
- SO_2—13,048 tpy
- PM—848 tpy

The Project's secondary air impacts, such as visibility impairment or deposition impacts on soils and vegetation, are expected to be negligible. Opacity from the plant's exhaust stack will be near zero. In addition, the visual character of the site is influenced by the WWTP and electric transmission structures so visual quality of the vicinity will not be affected significantly. The type of pollutants emitted and their low levels will not be sufficient to cause damage to soils, vegetation, or wildlife from deposition.

Noise generated by plant operation was modeled based on ambient noise levels for the site and estimated equipment noise levels during operation as provided by the vendors. Results show that noise levels will comply with Volusia County's ordinance at the plant border. Noise impacts to any residential areas are not anticipated due to their distance from the facility and attenuation effects of vegetation found around the site.

No ecological impacts are anticipated due to plant operation. Additional noise and human presence already exists at the site due to WWTP construction. Since air emissions are not significant and no discharges to surface waters will occur, no impacts to vegetation communities or listed plant and animal species are expected from plant operation.

Similarly, traffic generated by the operational workforce will be minimal compared to existing and soon-to-be-added capacity of SR 44. The operational workforce will most likely reside in the Volusia County area, but impacts to housing, educational facilities, and essential services will be negligible due to these few individual workers.

Socioeconomic benefits are positive and significant. Besides providing additional inexpensive and reliable electricity to rate payers in Florida, the Project will generate revenues for Volusia County and New Smyrna Beach. The plant and its capital assets will yield approximately $750,000 per year in ad valorem taxes to the local community. Additionally, the facility will pay fees to UCCNSB for water, reuse water, and wastewater treatment. The modest plant staff will generate a $1 million annual payroll, much of which will be spent on local goods and services. Various local contractors and vendors will also service the plant, providing additional revenues to the community.

In all, the Project will affect the following irreversible and irretrievable commitments of resources:

- Use of Land—The site is to be developed on approximately 17 acres of a 30.5-acre parcel. This relatively small acreage will represent an irreversible conversion of natural lands.
- Natural Gas—This fossil fuel is one of the cleanest, most efficient fuels available for this large capacity of generation. Nevertheless, the gas consumed will be an irreversible and irretrievable loss of this energy resource.
- Water—Evaporation of water in the plant's cooling process will represent a consumptive use of water. However, the plant will greatly reduce its water resource needs by extensive use of treated wastewater for plant operations. Given the use of treated effluent, which otherwise could be discharged to the Indian River, the overall impact on the region's water quality will be positive.
- Air—There will be a slight increment of air quality consumed by the Project. The emissions, however, will have no significant impacts on regional air quality, nor will they impede development of other industry in the area. In fact, it is reasonable to expect that, because of displacement of less efficient, more pollution-intensive electrical generation sources, the Project's overall impact on regional air quality will be positive.

6.0 CONCLUSIONS

In summary, the New Smyrna Beach Power Project will provide an efficient source of needed electrical power to UCCNSB and Florida, while minimizing the potential environmental impacts of power generation. In fact, the Project will have two important and *positive* environmental benefits:

1. Use of treated effluent from the UCCNSB WWTP, reducing—or even eliminating—the WWTP's discharges of effluent to the Indian River.
2. Significantly lower emissions of air pollutants compared to other electrical generation units whose production would be partially offset by the Project, resulting in a net positive impact on regional air quality.

Additionally, the Project will have positive socioeconomic impacts on the New Smyrna Beach area, due to jobs created, taxes and fees paid, and reduced costs of power to the City's residents.

APPENDIX

APPENDIX

Comparison of Air Emissions: New Smyrna Beach Power Project Relative to Existing Facilities

Air pollutant emissions from the New Smyrna Beach Power Project are compared here to those from existing Florida power generation facilities. The Project's emissions are based on the specific vendor performance information for the combustion turbines, as represented in the site certification application. For the existing facilities, available information from the Florida Department of Environmental Protection and the U.S. Environmental Protection Agency has been employed to develop characteristic emissions from *proxy* units. The proxy units are oil- and natural gas-fired steam-electric generation units that are representative of existing facilities in Florida.

The accompanying figure compares the Project's emission rates for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM) with those of the proxy units. The emission rates for each pollutant are presented in terms of pounds of pollutant per megawatt-hour (lbs/mwh). As shown, the Project's emission rates are less than—in some cases *significantly* less than—those of the proxy units. The Project's greater mechanical efficiency and clean fuel result in lower emissions per megawatt of electricity produced.

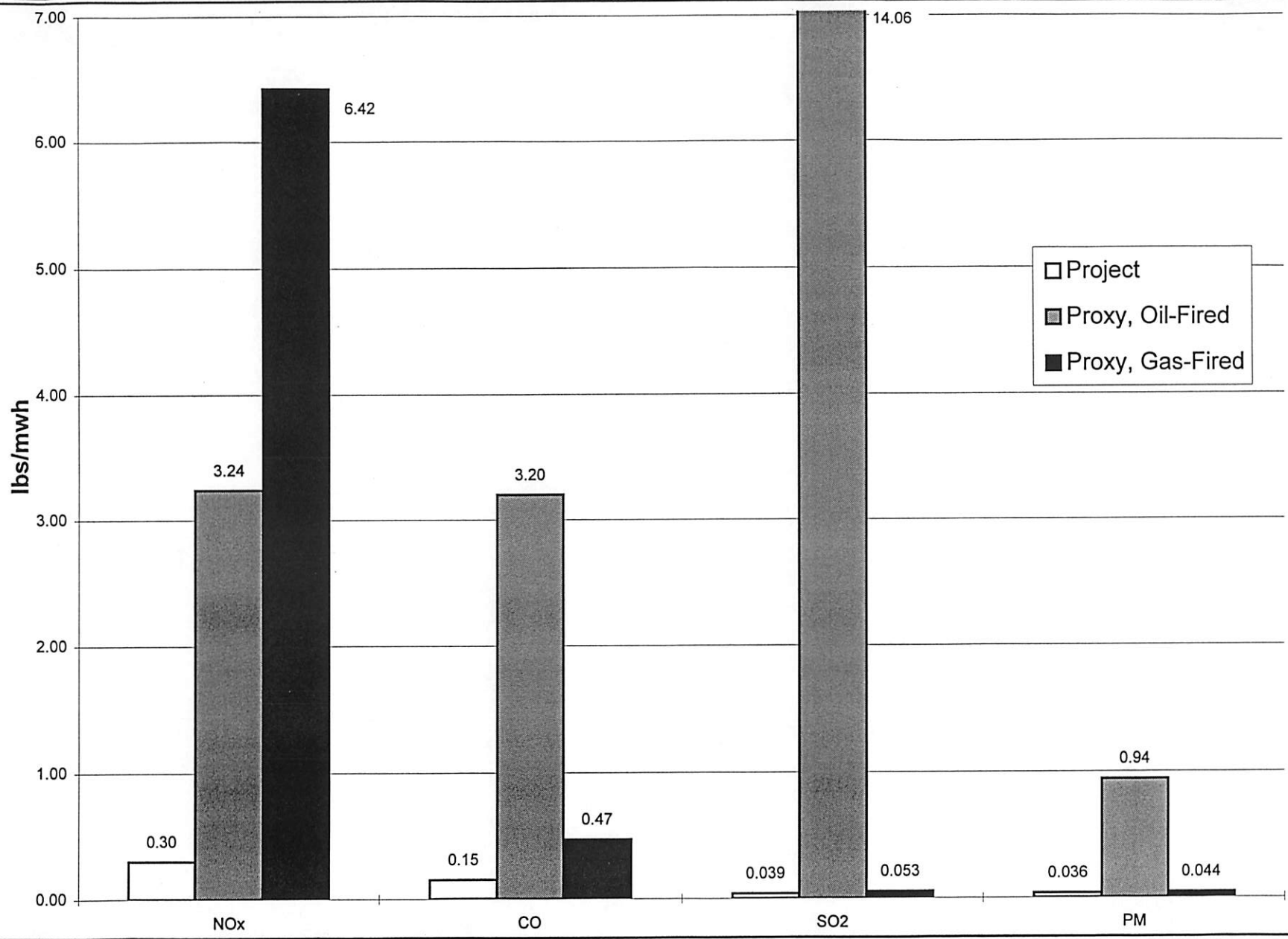
These emission rates can be used to estimate the reductions in total emissions that would occur if the Project's electrical generation offsets or displaces the operation of existing facilities. Based on an economic dispatch model, the Project is estimated to generate 3,719,550 mwh of electricity in 2002. The following table compares the resulting emissions under various scenarios:

	Annual Emissions (tons per year [tpy])			
	NO_x	CO	SO_2	PM
Project	558	279	73	67
Proxy, oil-fired	6,029	5,958	26,142	1,747
Proxy, gas-fired	11,947	869	99	82
Proxy, 50/50 mix	8,988	3,414	13,121	915

From these estimates, the emissions reductions that could result from the Project can be calculated as follows:

	Annual Emissions Reductions Due to the Project (tpy)			
	NO_x	CO	SO_2	PM
Project offsetting Proxy, oil-fired	5,471	5,679	26,069	1,680
Project offsetting Proxy, gas-fired	11,389	590	26	15
Project offsetting Proxy, 50/50 mix	8,430	3,135	13,048	848

These comparisons show that, if the Project's generation offsets that of existing facilities, the reductions in emissions will be significant.



COMPARISON OF EMISSION RATES

Source: ECT, 1998.

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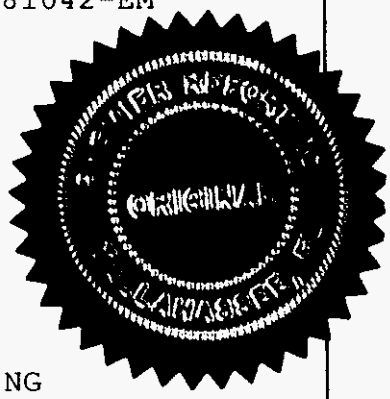
1 J. Butler

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Joint petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	DOCKET NO. 981042-EM



THE DEPOSITION OF:	JEFFREY L. MELING
TAKEN AT THE INSTANCE OF:	Florida Power & Light
DATE:	November 12, 1998
TIME:	Commenced: 1:30 p.m. Concluded: 5:30 p.m.
LOCATION:	Steel, Hector & Davis 215 South Monroe Street Suite 601 Tallahassee, Florida
REPORTED BY:	Debra R. Krick Court Reporter and Notary Public in and for State of Florida at Large

PREMIER REPORTING
6753 THOMASVILLE ROAD
TALLAHASSEE, FL 32312
(850) 894-0828

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 27
COMPANY/ WITNESS: FPL/ Meling
DATE: 12-2-98

APPEARANCES OF COUNSEL:

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On behalf of Florida Power & Light:

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DEPOSITION

Whereupon,

JEFFREY L. MELING

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MR. BUTLER:

Q Would you state your name for the record, please?

A Jeffrey L. Meling, spelled M-e-l-i-n-g.

Q Okay. And by whom are you employed?

A Environmental Consulting and Technology, Incorporated.

Q Are you the Jeffrey L. Meling who has had filed on your behalf testimony in the current proceeding that -- by New Smyrna Beach on a need determination proceeding?

A Yes.

Q I have a copy of what I believe is your direct testimony, which consists of 15 pages of text testimony and then an attached exhibit, JLM 1.

Do you have any changes or corrections to make to either of those presently?

A No, sir.

Q Okay. Do those reflect what you intend your direct testimony to be in this proceeding?

A Yes.

Q Okay. Were you involved in the preparation of the needs determination petition that was filed in this proceeding?

A Yes.

Q Tell me what involvement you had in its preparation.

A My involvement was with two graphics that were included in the petition, and I will find those for you here. On page 39, Figure 15; and on pages 40 through 42, Table 3.

Q Figure 15 is this licensing schedule for the project; is that right?

A Yes.

Q Okay. I am sorry, you said 40 through 42?

A Yes, I did.

Q Okay. I thought that you answered an interrogatory about this Table 3 to the effect that this is a list of essentially, potentially applicable regulations, but has not been used directly in the processing of the application for this project?

A I think that's a fair characterization, yes.

Q Do you have a list of the environmental

regulations that you believe actually will be applicable to the review of this project for citing purposes?

A No, sir, I don't.

Q Could you go through what is on -- in Table 3, and identify any of these regulations that you do not think will end up having an affect on the review of the application or the projects certification?

A I am not sure I understand what you mean by saying, an effect on the review.

Q Well, that will play a role in the review, I guess.

A Do you want me to include those that would play a fairly minor role, but be applicable? I am not sure I understand your question exactly.

Q I am just trying to understand, given the answer to the first question in this line of questions about the fact that these are not necessarily all the regulations that would be involved in, you know, review and approval of the site certification for the project, if you could help me sort of edit it to understand what really is and isn't involved.

A Okay. I understand.

So, again, to restate, what you would like me to do is go through this list and identify those that I don't think will either apply or play a significant role?

Q That's right.

A Okay. We'll start with the federal rules. They are listed one through nine.

Q Okay.

A And each of those really applies, other than number nine. Number nine, which is need by National Environmental Policy Act, may not apply.

Numbers seven and eight technically apply, but they have fairly little consequence for the project.

Same could be stated actually for number six.

I will move down to the state listing. Item two, the Transmission Line Siting Act does not apply.

I will note that item three, permits, is really a fairly inconsequential rule, in that it really provides nothing of substance for this proceeding.

Item six does not apply. We did not -- we were not required to conduct sampling analysis or -- and/or analysis that triggered any quality assurance requirements.

I quite honestly don't recall on number ten, surface water discharge. If that applies to stormwater, then it has some implication. But if it applies only to process wastewater discharges, then that would not be applicable. I don't recall precisely.

Same comment applies to number 17.

I don't recall, for example, on number 19, the extent to which that may or may not apply. If it does apply, it would be fairly limited in its consequence for the project.

I think the same could be said for item 21. Item 22 will definitely not apply. There are no plans for any underground storage tank systems for this project. Aboveground storage tanks systems, I don't recall if that applies in any limited fashion to small storage tanks. If it did apply, it would be fairly limited and minor in its nature.

Item 24 does not apply.

Item 25, I do not believe that applies.

I will move on to page 41.

I would characterize all of the following, 27 through 31, as having limited, if any, real impact on the licensing of the project.

I will move on to the regional rules.

I don't believe item four applies.

I will move on to local.

I don't think item eight has any particular -- I am not sure about item eight, whether that applies to any aspect of the project or not. Again, it would be fairly limited in its impact.

That takes us through the list. The last page

is just footnotes.

Q Why do you conclude that NEPA doesn't apply?

A Because this project is not involved in any federal action that would trigger NEPA.

Q Do you know what the concern over potential federal action was that warranted its inclusion in Table 3 in the first place?

A Say that one more time, please.

Q Do you know what potential federal action was envisioned that warranted inclusion of NEPA in Table 3 in the first place?

A There really was none. It was included, again, in keeping with the general purpose of the table, which was to identify potentially applicable rules and requirements. And for another project, NEPA might apply; but for this one, it does not.

Q So this is just kind of a generic list of the things that could apply to any power plant projects; is that right?

A I think that's a good characterization, yes.

Q Okay. Why do you conclude that the Transmission Line Siting Act does not apply?

A Because the project that is being proposed for licensing does not include any transmission line facilities that would trigger applicability of the act.

Q Does the project envision the construction or modification of any transmission line facilities that would trigger the application of the Transmission Line Siting Act?

A I believe it is accurate to state that the need petition does identify possible transmission related improvements that may be made. I have not conducted any analysis to determine whether those would trigger the Transmission Line Siting Act.

Q Have you had any discussions with the Florida Department of Environmental Protection, which I will call DEP, about whether or not the -- whether or not those improvements to transmission line components will require Transmission Line Citing Act approval?

A No, I have not.

Q Okay. So you haven't been told one way or the other whether that approval would be required?

A That's correct.

Q Okay. I have sort of a similar question about number 24 in the state potential regulatory systems, the Natural Gas Transmission Pipeline Citing Act revisions.

Why have you concluded that those are not applicable to this project?

A This project that is -- what is proposed for licensing by Duke and the Utilities Commission does not

include a natural gas pipeline. That pipeline will be built by others, and others will have control over what licensing process is used to obtain the necessary approvals to construct that pipeline.

Q Have you had any discussions with the DEP about the appropriateness of leaving the siting for the natural gas transmission pipeline to others, with respect to this project?

A I don't recall if it came up in any discussions that we have had with them or not, at times when I was involved in those discussions; I don't recall.

Q Has the site certification application for this project been filed with DEP yet?

A Yes, it has.

Q When did that occur?

A October 5th.

Q Have you had any communications from DEP staff, written or oral, as to the sufficiency of the application?

A No.

Q When do you expect that that will occur?

A I don't have a precise date to give. It's -- of course, the schedule for DEP providing to us the sufficiency request, is addressed in the statute. I don't recall exactly what the statute says.

Q On your figure 15 -- on figure 15 that you said you assisted in preparing, page 39 in the exhibits to the need petition, there is a triangle for completeness determination. It looks like it is mid-October 1998; is that correct?

A Yes.

Q What does that refer to?

A That refers to a milestone that is reached when DEP provides a response to our initial submittal that the site certification application is complete or incomplete.

Q Have you received that communication yet from DEP?

A Yes, sir, we have.

Q Okay. And I assume that you were told it is complete?

A That's correct.

Q Okay. But you have not yet had a first round of sufficiency on that; is that correct?

A That's correct.

Q Have you participated in a site certification application for any electric power plant facilities in Florida previously?

A Yes.

Q Can you tell me which ones?

A By participation in the proceeding, you mean

some involvement with the preparation or review of the site certification application?

Q Yeah, that's fair. Let me define it better for you.

Let me start with the question, have you ever been the project manager for the preparation and submission of a site certification application, for an electric power plant facility in Florida before?

A No, sir.

Q Okay. Have you ever participated as a staff member providing input to such a project before?

A Yes, sir, I have.

Q Tell me about where you have served as a staff member providing input.

A As I indicated in my written direct testimony, I was the manager of the air quality tasks for Tampa Electric Companies, Polk Power Station in Polk County, Florida. I also participated in -- to a lesser degree, in the Hardee Power Station site certification application.

Q What was your participation on the Hardee Power Plant?

A Essentially, review capacity for Tampa Electric Company, which got involved in the application process after it had already proceeded along a fairly substantial

part of the preparation process. And I was involved as an -- a consultant to Tampa Electric Company after they got involved in the application.

Q Would you turn to page 15 of your testimony, please?

A Yes, sir.

Q If you have never previously been a project manager for a site certification application, what experience is it that you base your conclusion upon, that the project can be licensed and approved within the times provided in the licensing schedule on page 15, lines 13 to 18 of your testimony?

A So you are asking what is my experience base to make that statement?

Q Yeah. You have reviewed the application and helped prepare it in some respect, correct?

A Yes.

Q And I assume, based on that review and your analysis of it, you're concluding that the project can be licensed within the allotted licensing schedule as proposed, correct?

A Yes.

Q I am asking you, what experience do you have to allow you to reach that conclusion?

A I understand.

I would say that my response has two components to it. First is my experience in power plant permitting and licensing generally, both here in Florida and elsewhere, which has been described in some detail in my pre-filed testimony. And what I mean by that is I have been involved in many projects that involved permitting for licensing of power plant facilities, power generation facilities. And so that experience is the first component of the two components that I described.

Secondly, that experience is based on what has occurred to date in this particular project; the work that we have done to prepare the site certification application, our knowledge of the site, its features, and the impacts that the proposed project would have in the context of the rules and regulations that apply; also supported by what the statutes and rules say with respect to schedules of site certification applications, and that the issues that we are dealing with in this application, in my opinion, lend themselves to being resolved, if not quickly, certainly within the time frames that we have planned.

Q I guess what I am trying to get at, though, is, given what you have seen about the project and what you have analyzed concerning it and your review of the statutes, what, in your experience, puts you in a

position to give an opinion on how the DEP is likely to come out on this particular application?

A They --

MS. KAUFMAN: I am just going to interpose an objection. I think he has asked and answered that. But if you want him to answer it again, he can do that.

MR. BUTLER: Well, he gave an answer, but it didn't seem to be to my question. That's why I am reposing it.

MS. KAUFMAN: You can go ahead and answer.

BY MR. BUTLER:

Q I mean -- let me rephrase it so that, to the extent possible, it addresses Ms. Kaufman's objection and also clarifies for you.

I don't doubt that you are familiar with the applicable rules. I don't doubt that you are familiar with this project. But what I am asking separate from that is -- there is going to be a decision made by a particular body, DEP, with respect to a particular application in the site certification application.

What is it that you have in your experience that gives you a basis to have an opinion on whether DEP is going to say, yes, or no, to that application?

A Now, you seem to be asking a different question,

however, whether they are going to say yes or no, as opposed to whether it will be done within a particular schedule, so --

Q Well, my earlier question had been, whether it would be approved within a particular schedule period. If that's a compound question, I apologize for it.

You know, the first half of it is, will it be approved, period. Then we will get to the schedule part of it.

Let's start with the, will it be approved, period.

MS. KAUFMAN: So now you are asking him, in his opinion, will it be approved?

MR. BUTLER: No. I am asking him -- just read the question back.

(Whereupon, the court reporter read the pending question.)

THE WITNESS: My opinion is that it will be approved, yes.

BY MR. BUTLER:

Q Okay. And the question I want to ask you, then, given that, is what is your basis for forming that conclusion?

A I understand. At the risk of repeating myself, I will, as part of my answer, repeat that that opinion is

based at least partly on the particulars of this project and the, let me call it, feedback that we have received from DEP and other agencies.

Secondly, it would be based on my experience with previous projects, including Tampa Electric, Polk Power Station and Hardee Power Station.

And third, it would be based on my knowledge of other projects that I wasn't necessarily involved with, personally. And the nature of those projects, their design, their impacts and their either similarity, or lack thereof, to this project as it supports that statement. In other words, that other projects of a very similar nature have been approved, and I don't see any reason -- knowing what I know about this project and the feedback we received from agencies -- that there is any reason why this project would also not be approved.

Q You mentioned a TECO, Polk County and the Hardee projects. And then you said, among others.

Are there any other projects in which you have been involved where application has been made for site certification under the Florida Electrical Power Plant Siting Act?

A No. As I indicated before, I have not been personally involved in any others besides those two.

Q What feedback have you received from DEP or

other agencies that forms part of the basis for your conclusion?

A Our project team, myself included, has met with DEP on several occasions to introduce the project and to describe our plans for the data collection efforts and impact analysis studies, that would be done to support its licensing. And during those meetings, there has certainly not been any negative feedback as to, for example, the identification of some issue by DEP that either they intended or we would otherwise interpret as being something that would preclude the permitting and licensing of this project. And to the extent that there were comments provided by DEP staff on the project, they were actually quite positive.

Q Will you tell me who at DEP made positive comments to you about the project?

A I don't recall names at this point.

Q Do you recall what they said?

A To paraphrase at least one comment that sticks in my mind -- and it sticks in my mind because it was obviously something that we appreciated hearing -- was -- again, paraphrasing -- this is a great project, let's get going, what's the problem; something to that effect.

Q You don't recall who made that statement?

A I don't recall the name.

Q Do you recall the position of the person who made it?

A I believe it was someone from DEP's Orlando office. Again, I just -- I apologize for not recalling the name.

Q Any other positive comments?

A I don't recall any others in particular.

Q Have you ever been involved in a site certification application for a project that was denied?

A No.

Q Have you reviewed the site certification applications for any projects that have been denied?

A If by, review, you mean at least look at, then I would say yes.

Q And which would those be?

A The only one that I know of that's been denied is FPL's orimulsion project, and I have, I'm pretty sure, seen or at least glanced at documents associated with that project.

Q Your testimony states, page five, lines 14 to 16, that you have previously testified before regulatory authorities or courts. Would you tell me where and when?

A It's going to be tough for me to be real specific or precise about dates. I testified on a number of occasions, in contested permit hearings in the state

of Texas, which would have occurred during the years 1984 to 1987.

Q What were the -- what permits were being contested?

A Oh, boy. In two occasions that I can recall, they had to do with permits for industrial facilities. I believe they were concrete batch plants.

Q Were they air emission permits or what type of permits?

A Yes, sir, air permits.

Subsequent to leaving Texas, I testified on a number of occasions in the state of Maryland. As I described, I think elsewhere in my testimony -- let me find it -- on page four, during the period 1992 through I think approximately 1996, on a number of occasions related to the Panda Energy Corporation, Brandy-Wine Cogeneration facility, that involved the licensing process very similar to the one we use here in Florida. It's not called the same thing. But it essentially operated in a very similar manner.

And more recently, I testified under a deposition earlier in this project.

Q You will have to forgive me. I am sort of newly involved with this project. Who -- to whom did you give that deposition?

A I don't recall the names of the attorneys or their firm. Is that what you are asking?

Q Do you remember which party they represented?

A Yes. They represented the Sax family.

Q What was the subject of your deposition in that context, in that case?

A The subject of the deposition was environmental matters associated with this project.

Q Was it in an administrative proceeding or in a court litigation; do you recall?

A The latter.

Q Okay. Do you know any of the details of why the Sax family was involved in litigation of the project?

A Yes, to a limited extent.

Q Just give me a general idea of what the involvement was.

A Essentially, it could be described as a condemnation proceeding.

Q Did the Sax family own land that was being condemned for the project?

A Yes.

Q Okay. Have you ever testified before the Florida Public Service Commission?

A No, sir, I have not.

Q Other than in this proceeding, have you ever

participated in the preparation of a petition for determination of the need for an electrical power plant, before the Florida Public Service Commission?

A No, not that I can recall.

Q Did you participate in the preparation of any portions of the site certification application?

A For this project you mean?

Q Yes, for this project.

A Yes, sir, I did.

Q And what portions were those?

A Well, as project manager, I was involved really in the entire application.

Q Okay. Did you directly prepare any portions of the site certification application for this project?

A What do you mean by, directly?

Q As opposed to overseeing someone else who would have prepared the section, and, you know, you would have reviewed and approved it.

A Yes.

Q And what sections -- section or sections did you directly prepare?

A Again, I will interpret when you say, directly prepared, to mean that I was the lead author.

Q Yes, that's fine.

A That would include the applicant information

page, the project fact sheet; the introduction to Chapter 2, Section 2.1; the introduction to Section 2.3, Section 2.3.9; the introduction to Chapter 3 and Section 3.1, Section 3.2.

Although, let me point out that in some cases there are graphics included in these sections that were provided by others. I did not prepare those graphics.

Section 3.3. Section 3.4, I co-authored.

Q With whom?

A With another member of my project team.

Q Which was who?

A Tom Davis. Some portions of Section 3.5, I authored.

Section 4.5 -- let me back up for a second. Probably also the introduction to Chapter 4.

The introduction to Chapter 5.

Section 5.2, Section 5.5, Section 5.6, which was, again, co-authored with Tom Davis; Sections 5.11 and 5.12.

Chapter 6, relying heavily on information provided by FGT.

Chapter 8, relying heavily on information provided by Duke and/or Duke/Fluor Daniel, I believe.

The introduction to Chapter 9.

I co-authored portions of Appendix 10.1.3. I

prepared Appendix 10.1.7. And I prepared most of the introductory text to Appendix 10.5.

Q Have you prepared any estimates of the cost to the project of the environmental compliance connection, with either the site certification application or the need petition?

A I don't believe so, no.

Q Has anybody on your staff done that?

A My staff, meaning ECT staff, you mean?

Q Yeah. The people you supervise as project manager for the work ECT did in connection with the New Smyrna project?

A The only case where you would find that addressed at all would be in the PSD permit application; more precisely, the best available control technology or BACT portion of that application, which addressed -- addresses costs of various potentially applicable air pollution control devices. That's the only place I can think of.

Q Did you prepare that analysis?

A No, sir.

Q Who did?

A Tom Davis.

Q Did you review the analysis?

A Yes, sir.

Q And did you concur with its results?
A I did.
Q By the way, I forgot to mention at the outset, whenever you want to take a break, you know, just let me know. I will be happy to accommodate you.
A I will.
Q I am going to show you an excerpt from the document that was referred to as Chapter 5 of the PSD permit application, which is contained in Section 10.1.1 of the site certification application. That description of it is in a pleading entitled, Duke Energy New Smyrna Beach Power Company, Limited LLP, supplemental response to SAP's first sets of interrogatories. Are you familiar with this Section 5 of the PSD permit application --
A Yes.
Q -- referred to there?
A Yes, I am.
Q Okay.
MR. BUTLER: Vicki, are we doing this Exhibit 1 for this deposition, or is there a series of consecutive exhibit numbers for --
MS. KAUFMAN: As far as I know, we should start with Exhibit 1 in this deposition.
(Whereupon, Exhibit No. 1 was marked for identification.)

BY MR. BUTLER:

Q Let me ask you first to turn to pages 70, 71 and 72 in Exhibit 1. Does -- this is Table 5-15, 5-16 and 5-17 in this Chapter 5 of the PSD permit application. Do these reflect ECT's best estimate of the costs for adding a selective catalytic reduction system to the Duke New Smyrna project, these three tables?

A Yes, sir.

Q And how were these cost estimates developed?

A The procedure that was used is a commonly used procedure -- commonly used procedure by air pollution environmental engineers.

The procedure was developed by EPA, and it's outlined in detail in guidance documents that EPA has published in the past. So using that procedure, it's really just a matter of plugging in various numbers into the required blanks for various cost components. And then those numbers are processed using the EPA procedure to arrive at a total annualized cost.

Q Where do you get the numbers that you plug into the spots in the procedure?

A As you will notice, for example, on all three tables, the sources of these tables include Duke/Fluor Daniel; Duke/Fluor Daniel being the engineering contractor for the project.

Some of these numbers that constitute the inputs to these tables were provided by Duke/Fluor Daniel. I believe there may have been a number or two that were also provided by Duke Energy.

Q It also identifies ECT 1998 as a source, correct?

A Yes, sir.

Q And that would be your company, correct?

A Yes, sir.

Q Which of these numbers did ECT provide?

A Well, it might be simpler for me to identify those that we didn't supply.

Q That's fine.

A We did not supply the purchased equipment cost in Table 5-15. We did not supply the operator, labor and materials cost number, nor did we supply the --

Q I am sorry, are you now on 5-16?

A I am sorry. I am now on 5-16, I apologize. I was just about to say we also did not supply the labor, maintenance, direct cost in Table 5-16.

I don't believe we supplied any of the costs associated with catalysts or other raw materials that you can find in the middle of Table 5-16. The costs associated with energy penalties were calculated by us, using information provided by others.

Q Who were the others?

A Duke/Fluor Daniel and/or Duke. And I think the same would be said for the Capitol recovery cost listed under indirect costs.

Table 5-17, I don't recall who provided which numbers on Table 5-17.

Q Go back to Table 5-15, please.

How did you develop the -- you, ECT, develop the amounts that appear in here for the various installation costs?

A Well, as you will notice in the table, on the far right column, it has the heading, OAQPS factor; so that's essentially the EPA factor. So that all the installation-related costs that you see there are simply multiples of the purchased equipment cost.

Q Okay. So in other words, you received from Duke/Fluor Daniel or Duke, this purchased equipment cost which is the $1,183,101. And then EPA has a -- an estimating system that takes a percentage of that for each of these other elements. Just multiply it times that total; is that right?

A That's correct.

Q Okay. And did ECT make any adjustments to those, either to the percentages that EPA recommended using, or to the result of multiplying a percentage times

the purchased equipment cost?

A I don't believe so, no.

Q Okay. I think I understand, then, what you have done here. The only thing I have to ask you, though, if you will notice on the indirect costs -- oh, I am sorry, never mind, I see. I have got you.

Do you believe that $2,034,933, which appears as the total capital investment on Table 5-15, is a reasonable estimate of the capital investment costs for a selective catalytic reduction system for the Duke New Smyrna project?

A Do I believe that that's reasonable?

Q Yes.

A Yes, I do.

Q And the same question about the total annual cost of $1,548,144 that appears on Table 5-16, do you believe that's a reasonable annual operating cost for adding -- can I call it an SCR system?

A Certainly. That's what we refer to, commonly.

Q SCR system for this project?

A Yes, sir.

Q Okay. I ask you to turn to the last page in Composite Exhibit 1. It's Table 5-20, Proposed NOX BACT Emissions Limits. Am I correct that the part per million emission limit that you're proposing in the site

certification application is 12 parts per million?

A That's correct.

Q Okay. Would you turn back one page to Table 5-19? If you will look at the last project, the natural gas-fired CTGs that appears here, it's city of Lakeland, McIntosh Unit 5, that was permitted July 10, 1998, correct?

A Yes, sir.

Q Okay. And you will note that it has an NOX emission limit of nine p.p.m., does that -- does that mean that the NOX emission limit that was permitted for the city of Lakeland, McIntosh Unit 5 on that date is nine p.p.m.; is that what this chart shows?

A No, it doesn't.

Q Tell me what it shows, then. What is the significance of the nine p.p.m. that appears as the -- within the last row on this Table 5-19?

A Well, what it shows and where I take issue with your previous question is that the initial limit that was permitted for McIntosh Unit 5 is actually five p.p.m.; actually 25 p.p.m., not nine.

Q Does this indicate, then, that the nine p.p.m. is to become effective on May 1, 2002?

A I believe that's correct. Yes.

Q Would you expect DEP to require the Duke New

Smyrna project to meet that same nine p.p.m. emission limit by that same time period; i.e., 2000 -- the year 2002?

A I don't know at this point.

Q Can you think of any reason why DEP would not require the Duke New Smyrna project to meet a nine p.p.m. NOX emission limit by the year 2002?

A Can I think of any reason why DEP would not require the New Smyrna project to meet nine by 2002?

Q Yes. In view of the fact that it has required the city of Lakeland, McIntosh Unit 5 to meet that emission limit as of May 1, 2002?

A The answer to your question is yes.

Q What would those reasons be?

A First, it needs to be recognized that the determination of emission limits through the permitting process, specifically through the best available control technology -- or BACT process that we have discussed before -- is by EPA policy and guidance, a case-by-case assessment. Each project is evaluated totally separately as to its merits. And --

Q Let me stop you.

A I was not finished with my answer.

Q Go ahead.

A In that respect, there may very well be reasons

why the Duke New Smyrna Beach project -- arguably, as we have proposed in our application -- should have a 12 p.p.m. limit, as opposed to a nine p.p.m. limit. That assessment by DEP hasn't been carried out yet, so I really can't say too much more as to what EPA -- excuse me, DEP will ultimately determine.

I would also point out another reason why 12 p.p.m. for the Duke New Smyrna project might in actuality be better from a bare emissions standpoint. The nine p.p.m. from McIntosh Unit 5 is that you will notice in the last line of Table 5-19, that the city of Lakeland may -- if the Unit 5 turbine is not able to achieve nine p.p.m. using dry technology, the unit may have to install an SCR system.

And with SCR systems, there is a corollary emission of ammonia, which is another form of nitrogen that's emitted to the atmosphere, that would need to be added to the NOX represented by the nine parts per million in the permit limit.

So the bottom line of this is that nine p.p.m. of NOX emitted from unit, McIntosh Unit 5 with an SCR system, could very well result in more nitrogen being emitted to the atmosphere than a 12 p.p.m. NOX emission from the Duke New Smyrna Beach project.

So for all of those reasons, I feel that there

is an argument to be made that 12 p.p.m. is a reasonable limit for the Duke New Smyrna Beach combustion turbines, which is the limit that we have proposed in the application.

Q But wouldn't DEP presumably have taken the down side of the SCR technology into account, in its limit conditions for city of Lakeland, McIntosh Unit 5?

A I have no personal knowledge of what they did or did not consider in that matter.

Q Do you have any personal knowledge of any distinctions between that project and the Duke New Smyrna project, that would justify not applying a nine p.p.m. NOX limitation to the Duke New Smyrna project?

A You're -- I got confused on your question.

Q I am asking you if you are aware of any specific differences between the projects that would justify in your mind DEP making a distinction between applying nine p.p.m. NOX emission limit on city of Lakeland, McIntosh Unit 5, but not requiring that on the Duke New Smyrna project?

A I am not aware of any distinctions one way or the other, no.

Q What is your best engineering judgment as to what would need to be done at the Duke New Smyrna project if DEP imposed a nine p.p.m. emission limit?

A I am not certain if anything would need to be done; I really don't know.

Q When you say nothing would need to be -- or nothing would need to be done, do you think that the Duke New Smyrna project is capable of meeting a nine p.p.m. emission limit, using just the dry low NOX combustor technology that is proposed as its BACT?

A It may indeed be capable of achieving that limit, but that's not the limit that we have requested.

Q What information do you have to suggest that the project would be capable of achieving a nine p.p.m. NOX emission limit, using only the control technology that you proposed for it?

A Well; first, I am involved in other projects using the same equipment, that have been imposed upon them, nine parts per million limitation. So I am assuming that those limitations can be met and based on information that I have reviewed, provided by General Electric. Those representations would indicate that nine parts per million could be met.

Q And what projects would those be?

A Two projects in the state of Texas. One in the City of Paris, Texas; and another in Guadalupe, spelled G-a-u-d-a-l-u-p-e County, Guadalupe County, Texas.

Q Did those involve the same type of GE combustion

turbines as are planned for the Duke New Smyrna project?

A Yes, sir.

Q Okay. Were there any other projects besides those two Texas projects you just mentioned?

A That I have personally been involved in?

Q Yes.

A I think those are the only other two that I am currently involved in, involving the same technology.

Q If the GE combustion turbine equipment is capable of limiting emissions to nine p.p.m. of NOX, why isn't Duke New Smyrna proposing to limit its emissions to that level, in order to help protect Florida's air quality?

A The simple answer to that is that I believe Duke New Smyrna has concerns that over a period of time, as equipment ages, if you will, that the ability of the equipment to meet nine parts per million --

Q So they want a safety margin; is that right?

A That's a safe characterization, yes.

Q I think I know the answer to this, but I just want to confirm. If it turned out that DEP didn't agree to that approach, and instead insisted on some emission limit -- whatever it would be -- that would require the addition of SCR technology to the Duke New Smyrna project, is it your best estimate that the cost to the

project of doing so are the capital and operating costs reflected in Table 5-16 -- I mean, 5-15, 5-16 and 5-17?

A Those costs, what? I didn't follow your question.

MR. BUTLER: Could you read that back?

(Whereupon, the court reporter read the pending question.)

THE WITNESS: I misunderstood. I didn't catch the verb in there. So you are asking me, if we had to do this, if the cost we presented here would be my expectation of what that cost would truly be --

MR. BUTLER: That's right.

THE WITNESS: The answer to that is yes.

BY MR. BUTLER:

Q Okay. Sitting here today, do you have a position on whether or not SCR technology would need to be added to the Duke New Smyrna project, if DEP imposed a nine p.p.m. NOX emission limit?

A My expectation is that SCR would not need to be applied.

Q How low an emission limit do you think that the project could meet without having to add SCR equipment?

A I don't know. That would be a question better posed to General Electric.

Q What would you do if the DEP demanded an

emission, NOX emission limit of, say, seven p.p.m.; what process would you go through to determine the most appropriate way of meeting that limitation?

A First, let me say that it wouldn't be my decision as to whether to accept or reject that limit, to the extent that, let's say, if that limit were perceived by the project team, including Duke New Smyrna, of course, as being excessively low. Then I believe that our next step would be to present data and arguments that that number was, indeed, too low.

Q But for the sake of my hypothetical, assume that your arguments are unsuccessful, the choice is to accept this seven p.p.m. limit or not proceed with the project, technically. What would you recommend be done to try to meet that limit?

A I really have no way of answering that because, first of all, I am not certain as to what the turbine can achieve without SCR. And second, I am not -- it is not my role to determine whether or not -- or would not be my role to determine whether or not the costs and other impacts of having to install SCR would be acceptable for the project or not.

Q Would you turn to the first page of Exhibit 1, please, that's page 68, about four lines, three and four lines into the economic impact section.

It says, baseline technology is expected to achieve a NOX exhaust concentration of 12 p.p.m. V.D. at 15 percent 02. Do you see that?

A Yes, sir.

Q From what you have been saying, would I be correct to understand that what you really mean is that you're expected to achieve at least that level of emission control?

A When you say, at least, I assume, then, that you mean 12 p.p.m. or less, not 12 p.p.m. or more.

Q That's right.

A Correct.

Q Okay. But you don't know how low the equipment is capable of going?

A No, sir.

Q Would you like to take a short break?

A I don't need one.

MS. KAUFMAN: Do you want one, John?

MR. BUTLER: I am fine.

MS. KAUFMAN: Okay.

BY MR. BUTLER:

Q I am going to have marked as Exhibit 2 a copy of the appendix to your exhibit, an appendix to your exhibit, JLM 1?

(Whereupon, Exhibit No. 2 was marked for

identification.)

MS. KAUFMAN: Can we go off the record for a second?

(Discussion off the record.)

BY MR. BUTLER:

Q Do you recognize what's been marked as Exhibit 2, Mr. Meling?

A Yes, sir.

Q Okay. Did you prepare this comparison of air emissions?

A Yes, I did.

Q Okay. Am I correct that the emissions from oil-fired and gas-fired power plants that appear on the second page of Exhibit 2 are not for any particular Florida generating unit or units, but rather for some proxy that you have developed for those units?

A I guess that's not correct entirely to the extent that existing units in the state of Florida were used to develop these proxies.

Q But the proxy values -- for example, let's just refer to the NOX annual emissions for the proxy oil-fired units of 6,029 tons per year. Is that the annual emission for any particular Florida generating plant?

A No, sir.

Q How did you develop that figure?

A As described on the previous page, which is page one of Exhibit No. 2, that particular number was developed using existing public information for existing -- in this case -- oil-fired units in the state of Florida to develop an emission rate for the proxy oil-fired unit in terms of pounds per megawatt hour. And then that pounds per megawatt hour emission rate was multiplied by 3,719,550 megawatt hours, as indicated on the bottom of page one previously. And then the units were converted to units per year.

Q For what unit or units did you use information on the tons per megawatt hour, to get the sort of proxy unit information that is one of the two inputs to that calculation you just described?

A I don't recall offhand exactly which units they were.

Q Do you recall how you chose the units that you chose?

A Actually, I did not make that selection, I used information that was provided to me, that was developed from original sources. So I had secondary sources of this information.

Q Okay. What was your source of the information, who gave it to you?

A Richard Shine.

Q Who is he?

A He is a clerk at Landers and Parsons.

Q And where did he get the information; do you know?

A He got the information, as I indicated earlier, from original sources, which included emissions data -- emissions inventory data from Florida DEP and FERC information, F-E-R-C, for units in Florida. And that FERC information referred to or provided information or data as to the megawatt hours generated by particular units.

Q Did you review those FDEP and FERC data that Mr. Shine relied upon?

A I did not review the original sources, no.

Q Did you check his calculations against the original sources?

A I did not have the original sources, so I was unable to do that.

Q Do you have any independent knowledge that his calculations are correct?

A I have no reason to believe they are not correct.

Q But that wasn't my question.

Do you have any independent knowledge confirming that they are correct?

A I was able to verify certain numbers in what was provided to me. And to that extent -- to the extent that that's independent verification, I am not sure.

Q What numbers did you verify that were provided to you?

A Well, along with the information that I was provided, were comparable emissions data for the proposed Duke New Smyrna project; as the means to comparison, which is what we are doing here, which is comparing the Duke New Smyrna project to other existing units.

Q So in other words, you confirmed that he calculated the emissions for the Duke New Smyrna units correctly?

A Yes.

Q But because you didn't see the original sources of the information for the proxy units, you didn't confirm that the calculation of the emissions for the proxy units were correct?

A Let me correct myself to the extent that I believe, in the information I was provided, there were some original data sheets appended. And I don't recall if that was some of the FERC information or some of the DEP information or if it was both.

Q Did you go back to it and make any independent calculations to confirm the information that he provided

to you, about the proxy units?

A Let me say that the information that was provided to me, I checked to a level to be confident about its accuracy.

Q How?

A To the extent that I could.

Q How did you check it if you didn't review the sources from which it came?

A Well, as I just said, I believe that some of the original data -- again, my recollection is that some of the original data was appended to the information that was provided to me.

Q And it's your testimony today that you looked at that data and reproduced Mr. Shine's calculations to verify that he had done them accurately?

A I believe in several instances, enough to be comfortable with the numbers, yes, I did.

Q Can I ask you what refreshed your recollection, such that you are now saying that you saw the sheets and that you verified the calculations when -- or in contrast you were, when I first asked you the question, you didn't believe that you had even seen the original data?

A Well, when I said -- I gave my original answer, I had not seen the original, for example, book or report that the data came from. As I was continuing to answer

your questions, however, the mental picture of the form that the information was provided to me became more clearer. And I recalled, as I said, I believe that some of the actual data sheets from those reports that I referred to, I believe was appended to the information. And I neglected to remember that in my initial answer.

Q Did you review the appropriateness of the units that Mr. Shine selected for making his calculations to the proxy units emissions?

A I don't really know what you mean by, appropriateness.

Q Well, is it correct that Mr. Shine selected some number of Florida generating units and the emissions from those units to calculate a proxy for the oil-fired and the gas-fired emissions, that appear on the chart on the second page of what's been marked as Exhibit 2?

A I got lost in your question. I believe you are asking me, did Richard Shine select various units?

Q Yes.

A Yes, he did.

Q Okay. Do you know what criteria he used to select those units?

A Other than the fuel that they burned, I don't know.

Q Did he select all units that were oil-fired in

order to develop the proxy for oil-fired units?

A Yes.

Q How do you know that that is the case?

A First of all, I have, again, no reason to believe that he would have provided me information on oil-fired units, that wasn't an oil-fired unit.

Second, to the extent that I am familiar with other units here in the state of Florida, the information that he provided to me appeared to be accurate.

Q Do you mean that it appeared to be in the sort of range of emission levels that you would have expected to see for such units?

A I would agree with that, but that was not the original intent of my answer. The original intent of my answer was that, again, my familiarity with units here in Florida is such that if he said facility X was oil-fired -- being familiar with at least, again, to some extent that unit -- that sounded right to me.

I did not necessarily go back to other independent sources and verify that indeed it was an oil-fired unit, but I had no reason to doubt it. And my familiarity led me to, again, have no reason to doubt what units he had selected for which fuel.

Q Did he tell you what units he selected?

A Yes.

Q Did he tell you all the units he selected?
A Yes.
Q How did he provide that information to you?
A It was provided in hard copy.
Q Do you have a copy of that list of the units, that you can provide to me?
A Not with me.
Q Why not?
A I didn't bring it.
Q You were asked to please bring with you documents relied upon in the preparation of your testimony.

You don't consider that a document you relied on in the preparation of your testimony?

A I would have to agree with you that it was a document that I relied upon, and I did not bring it.
Q I would ask that you provide a copy, as soon as possible, of that.

MR. BUTLER: Whatever documentation Mr. Meling received from Mr. Shine supporting his calculation of the proxy oil-fired and gas-fired unit emissions that appear in Exhibit 2, as marked for the deposition.

MS. KAUFMAN: We will provide it.

BY MR. BUTLER:
Q Is Mr. Shine an engineer?

A I couldn't honestly say what his educational and/or job experience is, other than his current employment.

Q Which is as a clerk at a law firm; is that correct?

A Correct.

Q Okay. Is it your usual engineering practice to rely on clerks in law firms to make calculations for you that you use in forming engineering judgments?

A I am not certain that that has ever happened before in my career.

But I would add to that answer that, again, I verified enough of the information to be comfortable with what I was provided. I verified enough of the calculations to be comfortable with it. And quite honestly, the results of those calculations certainly appeared to be reasonable to me based on my experience with these types of facilities and fuels.

So I am perfectly comfortable to support everything that's in this exhibit, as to its conclusions.

Q Do you know what the range of emissions were for the oil-fired units that are included as -- or were included in the calculation of the proxy oil-fired emission levels in Exhibit 2? In other words, just using the NOX, again, as an example, we have got a value of

6,029 tons per year here.

Do you know what the range in tons per year from the lease emitting to most heavily emitting of the oil-fired units that were used in the proxy calculation was?

A I don't recall, no.

Q Do you know if the range was less than 10 percent?

A I don't recall.

Q Do you know if it was more than 50 percent?

A I don't recall.

Q Without knowing which unit would be displaced, how can you know that using the average NOX emission of 6,029, is appropriate for measuring the displaced emissions from proxy oil-fired units?

A I don't think that the form of your question is consistent with how I have represented this at all.

First of all, let me point out that my exhibit is clear to state that these numbers would be accurate only to the extent that the proposed unit would displace other units. I have no personal knowledge, nor would I be comfortable posing guesses, as to whether or not the proposed unit would, indeed --

Q And it would be accurate only to the extent it displaced either ones that were -- had emissions right at

this average for the proxy units or, you know, it displaced power that worked out mathematically to be equivalent to an average of that emission rate, correct?

A Yes. And that's exactly how I presented this information.

Q Well, if you look on page two of Exhibit 2, the sentence after the tables says, these comparisons show that if the project's generation offsets that of existing facilities, the reductions in emissions will be significant.

I gather from what you had just stated that to the extent of the offset, will depend on the extent to which, one, there actually is a displacement of generation; and also the extent to which the generation displaced displays the average emission characteristics that are used as the proxies here; is that correct?

A I would agree with that, yes.

Q And you have just done the calculation. You don't have independent knowledge of whether, one, it will displace them; or two, whether it will displace the units that have this average characterization emission; is that correct?

A That's correct.

Q This may be somewhat afield from your area of expertise and testimony, but I just want to see if you

have an opinion on it.

If the PSC were to approve the need for projects based on their economics and on, as you show here, the reduction in air emissions, do you have an opinion on who should pay for the capacity of plants that are -- you know, the higher emission plants that are idoled by running these lower emissioned plants?

A I have no opinion on that.

MS. KAUFMAN: I just -- okay.

BY MR. BUTLER:

Q Okay. Do you have any -- do you have any information on whether the operation of the Duke New Smyrna plant on natural gas, will have any impact on the availability of natural gas to fire other plants in peninsular Florida?

A I don't have any personal knowledge of that, no.

Q If it reduced -- if the operation of the Duke New Smyrna plant reduced the gas available to fire other plants in peninsular Florida that were dual fuel -- capable of burning natural gas or oil -- and those plants, instead, burned oil to make up for the reduced natural gas available to them; do you believe that that would offset, in part, the air emission reductions that you have calculated in what we have marked as Exhibit 2?

A If the premise of your question is -- or turned

out to be accurate, then I would say that that could happen, yes.

Q Okay.

A Although, if I could add to that just a little bit, I would point out that my proxies included both gas and oil-fired and a mix. I am not sure if that helps clarify or not.

Q But you would agree that if a plant capable of burning both fuels has to burn more oil than it otherwise would, that it is likely to increase the emissions from that plant compared to burning gas in that plant?

A I would agree -- repeat my previous answer then, yes, I would agree with you.

Q Okay. You haven't taken that possible offset effect into account in calculating the emission reductions in Exhibit 2, have you?

A Not directly, no.

Q Have you done so indirectly?

A No, sir.

Q Okay. I had one question I wanted to follow up on Exhibit 1. I am sorry, you will have to get it back from the court reporter here.

A That's all right.

Q You calculate on Table 5-17 $1 per ton, what you call cost-effectiveness of the SCR technology of $6,534

per ton. Do you see that?

A Uh-huh.

Q And am I correct that at least part of your recommendation that SCR technology not be required for the Duke New Smyrna plant, is that $6,534 per ton is too much to pay for that NOX reduction?

A That's correct.

Q What is the guideline or the threshold at which the price becomes too high?

A There is no regulatory number that's in any regulation or rule that I am aware of.

Q So what if this number were $3,000 per ton, would that be too high?

MS. KAUFMAN: Let me just object. And ask you too high for what?

BY MR. BUTLER:

Q If that would be so high as to recommend that SCR technology not be required as an additional form of air emission control for NOX on the Duke New Smyrna plant?

A You are asking me if, in my opinion, $3,000 per ton would be excessive?

Q Right.

A Probably yes.

Q What about $2,000 a ton?

A Probably yes, but with less certainty or emphasis than $3,000 per ton.

Q What about $500 a ton?

A My experience is that something like that would probably be acceptable.

Q What is the difference between $500 a ton and $3,000 a ton, other than that 3,000 is six times as big? I mean, is there some threshold that's been crossed; some, you know, perceived value of the emission reduction that makes 500 a ton seem possibly reasonable and 3,000 probably excessive?

A With -- you are asking for my personal opinion, which is what I am giving you. And I would point out that if you asked this to other engineers in my same profession, you might get a different answer.

But I would say that my own personal threshold probably is somewhere in the $1,000 to $2,000 range.

Q And that is based on what?

A Just my experience.

Q But what sort of experience informs that judgment?

A Other experience where BACT determinations have been made.

Q So in other words, am I correct in understanding you to say that it's your experience in what regulators

will accept?

A I think that's fair, yeah.

Q Okay. Do you have any experience as to what sort of cost per ton for NOX emission reductions Florida DEP regulators will accept?

A Again, I don't want to put words in anyone's mouth, but I would say that their threshold probably falls fairly close to mine in the $1,000 to $2,000 range. But, again, that's going to depend on who precisely you would ask that question.

Q If it -- just hypothetically, if the DEP's sort of threshold of tolerance for additional expenditures on NOX reduction were instead $4,000 a ton, are there any additional emission control technologies that would be appropriate for this plant, that should be included and are not proposed to be included?

A I am not sure I followed your question. You are saying that if the threshold of reasonableness is $4,000 per ton?

Q That's right. If it's $4,000 a ton, we will call it your term, threshold of reasonableness, are you aware of any emission control technology that would have a cost-effectiveness in that range that should be considered for inclusion on the New Smyrna, Duke New Smyrna project?

A No, sir.

Q So basically, there is sort of nothing between zero and the $6500 per ton SCR technology that you have considered, at least as far as you are aware of?

A That would be correct, yes.

MR. BUTLER: Okay. You know, now I do want to take a break?

THE WITNESS: I am ready for one.

(Brief recess.)

MR. BUTLER: Let me mark as Exhibit 3 table 3.5.1-1 from the site certification application.

(Whereupon, Exhibit No. 3 was marked for identification.)

BY MR. BUTLER:

Q Are you familiar with this table, Mr. Meling?

A Yes, I am.

Q It says that it is the estimated quality of treated effluent from the UCC NSB WWDB, which we will call the treatment plant. Why is it the estimated quality instead of the actual quality? Have there not been any measurements of the actual effluent quality from the treatment plant?

A It's estimated simply because the plant is still under construction.

Q Has the plant operated at all yet?

A No.

Q No? Okay. What are these estimates based on; do you know?

A They are based on another facility of either a very similar or almost identical design, as the one being built.

Q Which is located where?

A I don't recall. I believe it's here in Florida, but I don't remember specifically.

Q Okay. Do you know if the inflow to that treatment plant is substantially the same as the inflow to the New Smyrna treatment plant that's under construction?

A I don't know in detail. It is my understanding that it is another system that has a comparable mix of sources, meaning primarily domestic waste. That is my understanding.

Q What is your understanding based on?

A Information picked up at various points through the project. I don't recall.

Q Did anybody perform any sort of assessment of the comparability of the input stream, inlet stream into the treatment plant that was used for comparison purposes?

A I don't recall. I don't know. I have no

personal knowledge of such a study.

Q Okay. Does the quality of the influent have an impact on the quality of the treated effluent from a treatment plant?

A It could under certain circumstances, I suppose.

Q And what would those circumstances be?

A I can give you an example, if that would help.

Q Okay.

A An example of that would be if there was, say, a particular type of industry that had a particular type of effluent with very particular types of characteristics that was or was not present, and that could have a difference, yes. Could have an impact, excuse me, to be more precise.

Q If you had a radiology services outlet mall located there where everybody provided that, you would see a lot more of these various radioactive inlights, perhaps, show up in the effluent, because you would have more of them in the influent, right?

A I don't know. But I would hope that that effluent was handled in a somewhat different manner.

Q All right. Do you know if the New Smyrna Beach treatment plant -- well, strike that. Let me rephrase it.

Do you know if the level of fecal coliform and

fecal streptococcus bacteria present in the effluent from the New Smyrna Beach treatment plant, would be affected by the levels of those bacteria in the influent to the plant?

A I don't know.

Q I am going to ask you a couple of questions about the proposed cooling for the plant, the cooling towers that are proposed for it.

In recommending the use of cooling towers, and recognizing that in using those cooling towers the water going into them is going to be substantially reuse water, did ECT consider the potential for spreading infectious bacteria in the drift -- or in the drift from the towers?

A Yes.

Q Okay. What assessment did you perform of that potential?

A I would characterize it as being very limited, because no more than a limited assessment was really necessary. And that is due to the fact that treated effluent is being used more and more commonly in -- for just this same purpose. And the technology and the treatment chemicals, et cetera, are readily available to provide more than adequate insurance -- let me say, assurance, that such an issue would not be a problem.

Q Do you know whether the DEP is conducting any

rule-making proceedings considering the question of the appropriateness of reuse water for cooling tower applications?

A I am only vaguely aware that there is something along those lines going on. But I don't have any particular knowledge of the details.

Q Do you know if anyone at ECT participates in any sort of task force or other group that is involved in that rule-making?

A I am not aware that we have anybody involved, no.

Q Did anyone at ECT discuss -- or has anyone at ECT discussed the potential concerns over spreading infectious agents through the use of reuse water in the cooling towers with personnel at DEP?

A Yes. I recall myself participating in one of our preliminary meetings with DEP at which there was a staff person from DEP, whose name escapes me, that brought this up as a potential issue. And the discussion ended with, I believe -- my recollection is that an understanding that, yes, indeed there was adequate means available to Duke New Smyrna, such that this issue would not be a problem.

Q And what were those adequate means?

A The use of chemical treatments in the cooling

tower water.

Q What sort of treatments would you use to control the infectious agents?

A Well, I think I just answered that. It's really just chemical treatments, and I am not sure what specific chemicals are involved.

Q I don't think you did answer it, because I asked what chemicals do you use.

A I just said I don't know.

Q Now you have said you don't know.

Do you have any idea what it would cost to install a system for controlling infectious agents in the cooling tower reuse water?

A I do not know. I have no idea.

Q Did you perform the -- I think it's the acronym that's SACTI, modeling of the vapor plume from the cooling towers that -- or that might be emitted from the cooling towers?

A It was done under my supervision, yes.

Q Okay. Who performed that modeling?

A By performing the modeling, I will interpret that as meaning actually sitting at a computer entering data into the computer model and running the model. And if that's indeed what you mean, then the person's name who performed that function is Theresa Barnard.

Q And she did that at your direction?
A Yes, sir.
Q Was anybody else involved in assessing the lightly spread of a vapor or plume from the cooling towers?
A Yes. There was one other person.
Q And who was that?
A His name is Al Trbovich, spelled T-r-b-o-v-i-c-h.
Q Rather than take time to try to find the reference to it, will you accept that the site certification application states that SACTI model predicts a plume height of 50 meters aboveground at I-95 and 60 meters aboveground at State Road 44?
A Subject to confirmation in the document, would you like me to confirm that?
Q Let's see, I may be able to do it. Oh, gosh, it is here. It's page 5-35 in Chapter 5.
You want to just look at it; maybe that will be helpful.
A You are correct, I believe.
Q Do you know if those are minimum plume heights that are predicted by the model?
A I don't recall offhand. I would have to go back to the model guidance manual to verify what exactly the

significance of those numbers is.

Q Do you know what the minimum plume height is at I-95 or State Road 44 predicted by the model?

A No, sir, not offhand.

Q Do you know whether it's greater than zero meters?

A I don't know.

Q I would ask you to assume for the purpose of a hypothetical, that a vapor or plume developed from the cooling towers at the New Smyrna project that descended low enough with sufficient regularity that DEP or somebody insisted that steps be taken to prevent that from occurring.

What would you recommend be done to the plant design or operation in order to address such a problem?

A I don't know if I can really answer that, because I really have a very hard time accepting the premise of the question, because I just don't think that it will occur.

Q You don't even know what the minimum height predicted by your model is, as you sit here, right?

A I don't recall, correct.

Q So why is it so hard to accept the premise to my question? I mean, all I am positing is that perhaps because of the -- you know, it is modeled to or actually

the plume ends up descending to road level with enough frequency that it turns out to be a safety concern; and that as a result, DEP or another agency requires that steps be taken to prevent that from occurring. That's all the hypothetical is.

And I am just asking you what, in your engineering judgment, would be the appropriate response to such a requirement?

A I don't have a recommendation.

Q So if Duke or New Smyrna came to ECT with that problem, you would just have to send them to Dames and Moore or somebody else?

A I don't know what my response would be, but, again, I state, again, based on my own experience with cooling towers, that in this particular instance, this particular project, this particular location, it is my opinion that this cooling tower will cause no problems at either I-95 or State Road 44.

Q And what is your opinion based on?

A It's based in part on these modeling results, and in part on my own observations of cooling towers in operation, under various circumstances.

Q Where have you observed them in operation?

A I have observed them in operation at a number of power plants on many occasions.

Q And where are those power plants located?
A All over the United States.
Q How many of them are located in Florida?
A I don't know if I could give you a count.
Q Are any of them located in Florida?
A Yes.
Q Where in Florida?
A Gainesville for one, Tampa for another.
Q All right. Do you know if your computer modeling, the SACTI modeling, calculates a minimum plume height over the period of time in which the model is run?
A I am not certain exactly what you mean by your question, but I will point you to the third paragraph on page 535 that deals with ground level fogging, which you could possibly characterize as a minimum elevation.
Q Well, I am not going to characterize it one way or the other. I mean, is that what the model predicts as the minimum elevation?
A I believe so, yes. You can't get a whole lot lower than zero.
Q Under those circumstances -- let me put it this way; are those the only circumstances in which the model proposes a minimum elevation of zero?
A I believe that's correct, yes.
Q Do you know if it's correct?

A Again, I would have to refer back to the user's manual for the model.

Q Do you have output from the SACTI model that shows under the various conditions that were modeled in that model at various points in time, what the plume height is for the vapor plume from the cooling towers?

A I believe so, yes.

MR. BUTLER: Ms. Kaufman, I ask that you provide us a copy of that output, if it indeed exists.

MS. KAUFMAN: Well, I will have to discuss it with Mr. Meling. I mean, I will be happy to answer you one way or the other as to whether it does.

MR. BUTLER: Well, if it exists, I want it. If it doesn't exist, I am not asking you to create it. But if it exists -- he doesn't know what it says. And I think it's -- he hasn't brought it with him.

BY MR. BUTLER:

Q Right? Do you have that with you?

A No, I don't.

MR. BUTLER: Again, another instance of not having brought materials that his -- he relied on in forming his opinions in his testimony. And I would like to see what the results of that modeling show.

MR. DEE: With all due respect, that modeling information was included in the SCA, which is not

part of his pre-filed testimony.

MS. KAUFMAN: I was going to say that, and I was also --

MR. BUTLER: I think, though, that his testimony has --

MR. DEE: Maybe we can cut this short. I don't know any reason why you couldn't have that computer output. Does that solve your problem?

MR. BUTLER: It solves it, sure. That wasn't the response I was getting, but that's great.

MS. KAUFMAN: Well, I just need to check and be sure that there is nothing confidential, proprietary about the model or any of the inputs. That's something we haven't been able to discuss with the deponent.

MR. BUTLER: Well, we will make any reasonable arrangements necessary to preserve its confidentiality.

MS. KAUFMAN: And Mr. Butler, I will discuss it, and I will let you know.

MR. BUTLER: I would like to mark as Exhibit 4 a composite exhibit consisting of Figures 4-1 through 4-4, and Table 4-1, from the water supply alternative analysis to the site certification application.

(Whereupon, Exhibit No. 4 was marked for

identification.)

BY MR. BUTLER:

Q Mr. Meling, did you prepare the water supply alternative analysis that was attached to the site certification application?

A I was one of the authors, yes.

Q Were you involved in preparing the figures that I have excerpted and marked as Exhibit 4?

A Yes, sir.

Q Okay. The copy we have of Figures 4-1 and 4-4 isn't real good as to this WWTP effluent projected line. But can you see it well enough to identify it on the exhibit?

A Yes, sir.

Q Okay. Can you explain to me what the -- on Figure 4-1, what the upper graph represents -- the upper line on the graph represents, the one defined by the little square boxes?

A From -- for the years 1992 through 1997, it represents actual effluent data from the performance of the existing wastewater treatment plant. So in other words, this provides the actual effluent from the Utilities Commission's wastewater treatment system for those years.

Q Okay. Now let me ask you something to be sure I

just understand where this project stands. When we were talking about what we marked as Exhibit 3 a few minutes ago, which is the estimated quality of treated effluents, I thought I understood that the reason why this is estimated effluent quality, is that the facility isn't operating yet; and so one has to go on expected performance and, you know, similar facilities to estimate what the treatment, the treated effluent quality would be, correct?

A Correct.

Q Okay. What does the 1992 through 1997 actual effluent output of about two-and-a-half million gallons per day on here represent?

A The existing system.

Q Is that system being enlarged?

A No, sir.

Q There is, then, what, a new treatment facility that is being built at the same location as the existing one?

A That's not correct, no.

Q No? Okay. So then this -- well, where does the effluent that reflects the two-and-a-half million gallons on here, where does that come from?

A As I said, the existing system.

Q Where is it being treated now?

A At the existing plant.

Q Where is the existing plant?

A Somewhere in downtown New Smyrna Beach, I believe.

Q Is there a plan to pump that effluent or not that effluent, but pump the influent that now goes into that treatment plant out to this new plant that is being constructed near the New Smyrna power project?

A Yes, that's precisely the plan.

Q Okay. When is that supposed to start happening?

A My understanding, that that will be next July. Could I verify that?

Q Sure.

A To expedite our proceeding here, I would -- the date that that new facility is expected to come on line is somewhere in the SCA. I can't really put my finger on it right this minute. But I believe it's next summer.

Q Okay. On Figure 4-1, there is a trend over the periods from 1995 to 1997 of declining effluent. That is then projected to turn around to a trend of increasing effluent quantity; is that correct?

A Yes.

Q Why is there a projection that the quantity of effluent will start increasing instead of continuing to decrease?

A As these data were provided to me by the Utilities Commission, I don't know if I could give you a precise answer. I believe it would be due to growth in the area.

Q Did you do any verification of the reasonableness of these estimates of the effluent quantity?

A No, sir.

Q What impact would it have on the design of this facility if the effluent quantity continued to decline or stayed flat over the period from 1997 to 2020, rather than increasing, as projected in the data that was supplied to you?

A It would have little, if any, impact.

Q Would it require additional nonreuse water as a source of input water to the plant operations?

A By, additional, you mean beyond what we have already proposed?

Q Beyond what you have proposed, correct, sir.

A No, sir.

Q Why is that? How would you find enough reuse water to meet your projections of the reuse water quantity, if the actual output of treatment plant effluent continued to decline instead of turning around and increasing?

A Because the current design of the plant and plants for its operation assume no increase, at least as of the initial operation of the plant.

Q Well, would you look at Figure 4-4, please? Starting in year 2001, there is a series of vertical lines connecting the lower line, defined by the round dots with the upper line defined by the first squares and then little Xs, right?

A Correct.

Q So the difference between those two graphs is the water available, reuse water available to the power plant, correct?

A Correct.

Q Well, if the treatment plant effluent projected, continued to decline instead of increasing starting at about the year 2000, wouldn't the length of those lines connecting the two graphs be shorter, and therefore reflect less reuse water available?

A For the out years, that would be correct.

Q Well, look at 2001. 2001 isn't an out year, is it, in your opinion?

A No. That's meant to -- that year is included because that's the first year that the New Smyrna Beach Power Project is expected to be operational.

Q Which means it would not be an out year, would

it?

A Correct. That's not what I meant by the term out year.

Q Now, if you look at year 2000, you will see that the treatment plant effluent projected is -- it is hard to put units on this, but it looks like probably somewhere on the order of a one million gallon per day difference, between the projected effluent available and the other reuses for the effluent, correct?

A You are referring to the year 2000?

Q Yes.

A That's correct.

Q Okay. Then in 2001, which is the first year the plant's going to operate, it jumps up -- the projection of treatment plant effluent jumps up, such that there is now a two and a quarter million gallon per day difference between projected effluent available, and the other uses for it, correct?

A Correct.

Q Okay. And my question was, if you didn't see that increase in the projected effluent, instead it remained flat or continued to decline, wouldn't that reduce the size of these vertical lines? In other words, the amount of reuse water available to the power plant starting in the very first year of its operation, which

is 2001?

A That's not a correct statement.

Q I am sorry. I have got to ask you to explain that. If the treatment plant effluent projected -- let's just say it doesn't go down; let's just say it stays constant. In 2,000, it's 2.69 million gallons per day, right?

A Correct.

Q Okay. Say it stays constant, which means it would be 2.69 million gallons per day in 2001, okay? That would be staying at a constant level, correct?

A With or without the power plant? Your question needs to accommodate the power plant.

Q I am just talking about the projected effluent. I am just talking about the top line.

I mean, the way this is set up -- tell me if I am wrong. The way this is set up is, you have got the top line, is the projected effluent output from the plant available, and then you have got -- below, you have got the increased usage, right?

A Correct.

Q All right. The other use is contractual commitments. What I am asking is simply, in 2001, if the output of the effluent plant remained constant at 2.69 million gallons per day, instead of jumping up to 4.05

million gallons per day, wouldn't that cut substantially the amount available as reuse water for the power plant?

A No, because the premise of your question does not assume the existence of the power plant, I think.

Q I am not assuming it's existence or not assuming it's existence. I am simply saying, if the treated effluent, the dashed or light line on here, remained flat instead of jumping up in the year 2001, wouldn't that substantially reduce the amount of reuse water available to the power plant?

MR. DEE: Counselor, the question has been asked and answered several times. If you would like to ask him to explain it, maybe he could do that for you.

BY MR. BUTLER:

Q Well, let's try that, can you explain it?

A I certainly can. The point you're missing is the presence of the power plant. The power plant, itself, will contribute much of that increase from the year 2000 to the year 2001 of the throughput; i.e., the effluent from the wastewater treatment plant.

Q But the power plant only puts back some portion of water that it has already received as reuse water, isn't it? I mean, it's sort of recirculating the reuse water. Does it increase the net volume of reuse water?

A Yes.

Q And why is that?

A Because it has other sources of water in addition to the reuse water.

Q Which are?

A As we have indicated in the application, the plan is for some of that water to be provided from an on-site wellfield, and some of that additional water to be provided from an off-site source.

Q Okay. So that is, then, what is responsible for the roughly 1.3 million gallons per day jump from 2000 to the year 2001; is the treatment of the additional, essentially, new water that's being put into the treatment plant as effluent from the power plant operation and then comes back out as reuse water?

A That's correct.

Q Okay. What is responsible for the increase between 2001 and 2005 from 4.05 million gallons per day to 4.35 million gallons per day?

A The same factors that are responsible for the comparable increase in Figure 4-1.

Q In other words, the estimates of the effluent that you were provided by the city of New Smyrna Beach, is that right? I mean, when we were discussing Figure 4-1, you told me you didn't generate these estimates of the effluent projections that are without the New Smyrna

Beach power project, right?

A Correct.

Q So whatever the factors are you are suggesting that result in this increase in the trend there, are what you were provided by the city of New Smyrna Beach, right?

A That is a true statement.

Q Okay. Did you have any discussions with the city of New Smyrna Beach officials who provided you these reuse water figures about whether it was reasonable to expect the trend to reverse from declining effluent to increasing effluent over the next 25 years or so?

A Did I have any discussions as to whether that was reasonable?

Q Yes.

A No, I did not.

Q Okay. Are you personally aware of any reasons that would explain a reversal of the trend from one of decreasing effluent to increasing effluent over the next 25 years?

A I don't particularly accept the premise of the question that there is a trend in place that shows a decrease. If you are just looking at three years of data, to me, that does not constitute sufficient data to project a trend. And I would leave it to the experts, in this case, the Utilities Commission, who has the

responsibility of planning for their system and its operation, that whatever information they use to project that, certainly I would expect to be reliable.

Q Why?

A Because that's their job.

Q So your experience, everybody who has a job does it reliably?

A I wouldn't say that that's true, no.

Q Who provided you the data?

A As it indicates here as a source, the Utilities Commission on the city of New Smyrna Beach.

Q I was thinking of a person.

A Pete Korelich, K-o-r-e-l-i-c-h.

Q Speaking of trends, you don't agree that there is a trend of declining treatment plant effluent, because it's only three years of that. I note here that the level of treatment plant effluent in 1992 is 2.44 million gallons per day, and then it is 2.46 million gallons a day in 1997, a period of six reported years. Would that be enough to show you a trend of flat, relatively flat effluent output?

A Not necessarily.

Q How many years would it take before you started seeing a trend?

A I really don't know. Again, that's not my job

to project these trends. I don't have an opinion on that.

Q Do you have a copy of the water supply alternatives analysis?

A I do.

Q Would you look at it, please? I have got to find mine here.

I don't think we will need to mark an exhibit for this.

Would you go to page 28, please?

A All right.

Q Under 4.1.2.2, Other Sources, am I correct that ECT considered two other possible sources of reuse water, the city of Edgewater and the city of Port Orange?

A It would be more precise and accurate to say that the project considered those two sources, yes.

Q Is that because ECT didn't undertake that consideration? Was this information provided to you by the city of New Smyrna Beach?

A It was provided by the Utilities Commission, yes.

Q Okay. Is that Pete Korelich again?

A Correct.

Q Okay. Do you know if he contacted any cities or other municipalities besides Edgewater or Port Orange?

A I don't have any personal knowledge that he did or did not.

Q Do you have any reason to know whether there would be any other municipalities in a feasible radius, to pump the water that might supply the reuse water to the project?

A My understanding is that there would be no other cities that could reasonably and economically be considered as possible candidates.

Q And what is that understanding based on?

A Distance and cost.

Q How far is it to the next city that is north of the City of Port Orange?

A I don't know, offhand.

Q Okay. How far is it to the next city that is south of the city of Edgewater?

A I do not have -- I don't know, offhand.

Q How can you conclude, then, whether or not it is too expensive to pump water from whatever municipalities those might be?

A Because I believe the project team collectively concluded that there was no other city, or more accurately, treatment system that was close enough to warrant any further consideration.

Q Did you ever ask Pete Korelich or anybody else

on the project team how they reached that conclusion?

A Well, as I said, it was a collective decision.

Q But you are the project manager, right?

A I am the project manager of ECT's team. I am not the project manager of the entire project. If by project, you mean the entire development effort for this project.

Q But you either prepared or at least oversaw preparation of this water supply alternatives analysis, correct?

A Yes, I did.

Q Don't you feel you have some obligation to know whether the information that goes into it, even if it comes from another source, is reasonable, and the basis for the conclusion, that the information is reasonable?

A Yes. And I feel that we have arrived at reasonable conclusions.

Q Well, I am asking you now about one of the conclusions reflected in here, which is apparently according to you, that no cities other than the city of Port Orange or the city of Edgewater would be economically viable sources of reuse water. I am asking you what you understand the basis for that conclusion to be and --

A And I've indicated distance and cost.

Q But you don't know how far it is to the next cities, correct?

A That was my statement, yes.

Q Did you calculate how much it would cost to get water from the next cities to the north or south?

A No, I did not.

Q Did you talk to anybody about their calculations of that cost?

A Not in a specific manner, no.

Q Okay. Is it true that in both the cases of the cities -- city of Edgewater and the city of Port Orange, their Utilities Commission, or its equivalent, concluded that there was more demand for their reuse water than they were projecting, to generate in reuse water?

A I think that's what it states here, yes.

Q Do you know why it is, then, that New Smyrna Beach, in between those two cities projects -- let me go back to Exhibit 4 here -- even without this project, a gap now that will ever widen between their treated effluent and the projected demand for that treatment effluent from sources other than this power project?

A Do I know the reason for that gap?

Q Yes.

A No, I do not.

Q Did you ask anybody?

A No.

Q Is it anticipated that the Duke New Smyrna project will have to pay the New Smyrna Beach Utilities Commission for reuse water?

A It is my understanding that there will be a fee associated with the power plant using the reuse water, yes.

Q Okay. Do you know if that is comparable to the charge that the city of New Smyrna Beach charges the other reuse water customers that it has?

A It is my understanding that at least some of the other reuse customers don't pay anything. But that's the extent of my knowledge on that.

Q Do you know if whatever it is estimated the project has to pay the New Smyrna Beach Utilities Commission for the reuse water, has been included as an operating cost for the plant in the economics of the project that are reflected in the needs determination petition?

A I don't know that. No.

MR. BUTLER: I am going to mark as Exhibit 5, a pair of tables from the water supply alternatives analysis, Table 6-1 and 6-2.

(Whereupon, Exhibit No. 5 was marked for identification.)

BY MR. BUTLER:

Q Are you familiar with these tables, Mr. Meling?

A Yes, sir.

Q Okay. Would you turn to the second one, please, Table 6-2?

My question on this is sort of similar to the question I was asking you earlier about the BACT cost analysis that we had marked as a prior exhibit.

Does this table reflect ECT's best engineering judgment as to the capital and operating costs associated with the various water supply alternatives that were considered in your water supply analysis?

A No.

Q Okay. What do these costs reflect?

A They reflect Duke's and Duke/Fluor Daniel's best estimates.

Q Have you reviewed them and reached any independent conclusions on whether they are reasonable cost estimates?

A No, sir. Let me add to that just to the extent that these -- again, these data were provided by Duke and/or Duke floor Daniel, and I undertook no independent assessment.

Q Who provided them to you; do you know?

A Again, you are asking for an individual?

Q Individual, yes, I am sorry.

A I believe Dan Springer with Duke floor Daniel. And I believe also Cathy Ayan, A-y-a-n, with Duke provided a few of the numbers. I don't recall specifically who provided what.

Q Let me see if I understand this. The water supply alternatives analysis, in its totality as a package, is a document that you prepared, correct?

A I didn't prepare it alone.

Q I am sorry, that ECT prepared; is that correct?

A That's not entirely correct, no.

Q I guess what I am wanting to try to get at is, are you the right person or is it somebody else, to ask about the conclusions in it, about the most appropriate water supply alternative for this project?

A Am I the most appropriate person?

Q Well, are you -- no. Are you the person to ask about the conclusions in here concerning what is the most appropriate water supply alternative?

A You certainly may pose those questions to me, and I will do the best I can to answer them.

Q Well, but who would you suggest that I ask. I mean, I am just trying to find out -- it would seem at some point somebody has got to own up to know the conclusions as to a particular alternative being the most

appropriate. And who would that person be?

A As I just said --

MS. KAUFMAN: Excuse me, Mr. Butler, I think you are going to have to be more specific. You just referenced -- there is a lot of conclusions in this report.

MR. BUTLER: Well, I think there is only one conclusion in this water supply alternatives analysis as to what the most appropriate alternative is, isn't there? You recommend alternative two is clearly the best and most feasible option when considering all three perspectives shown in Table 6-1, that's on page 69 of the water supply alternatives analysis.

BY MR. BUTLER:

Q Is that your conclusion, or is that somebody else's conclusion?

A It's the project team's conclusion.

Q Nobody speaks for the project team?

A I said I will be glad to try. I am certainly willing to entertain any question you may want to ask about this report.

Q Well, turn to the first page of Exhibit 5, Table 6-1, Summary Comparison of Alternatives Overall Feasibility.

One of the three criteria that go into overall

feasibility is relative cost, right?

A Yes, sir.

Q Okay. Is that one of the three perspectives that this statement I read a moment ago on page 69 is referring to? Alternative two is clearly the best and most feasible option when considering all three perspectives shown in Table 6-1?

A Yes. Cost is one of those three perspectives, yes.

Q Okay. If you are not prepared to say that the cost estimates on Table 6-2 are reasonable, then how did you feel comfortable taking them into account in looking at the relative cost, as one of the three perspectives on Table 6-1?

A I didn't say that those cost estimates were unreasonable.

Q Are they reasonable?

A I have no reason to think that they are not.

Q Do you have a reason to think that they are?

A Yes. Because --

Q What is that reason?

A -- they were provided by Duke floor Daniel who has expertise in this area and whose expertise I would be very pleased to trust in developing these sorts of cost estimates. That's what they do for a living.

Q Well, get back to where I started with, then. Are these figures, the cost figures on Table 6-2, ECT's best engineering judgment as to what the cost of the alternative water supply options would be?

A If by ECT's, you mean, we developed them, the answer is no.

Q No. I don't mean you developed them.

A Okay.

Q I don't care how they are developed. It's just, is this your best engineering judgment as to what those costs would be?

A If you are asking me whether I feel that these numbers are appropriate for use in this analysis the way that they were used, the answer would be yes.

Q Okay. Do you think they reasonably reflect what the costs actually would be if one or the other of these alternatives were implemented as the form of it -- water supply for the Duke New Smyrna project?

A Again, my best answer to that is, I have no reason to think otherwise.

Q And is your answer again to the question of, do you have a reason to think that they are, that you trust Duke floor Daniel?

A Yes.

Q On what is your trust of Duke floor Daniel

based?

MS. KAUFMAN: I think that's been asked and answered, but I am glad to let him answer it again.

MR. BUTLER: No, I don't think it was.

MS. KAUFMAN: Yes.

THE WITNESS: It's based on the fact that they are an engineering firm of good reputation and longstanding; and based on the performance of the people from Duke floor Daniel with whom I had contact on this project, I would have every reason to be willing to accept information that they provided me for this project.

BY MR. BUTLER:

Q Alternative nine shown on Table 6-2 is the use of an air-cooled condenser, correct?

A Yes, sir.

Q Which basically doesn't involve a loss of water to evaporation or misting or drift, as do the other cooling tower options that are considered here, correct?

A Yes, sir.

Q And would I be correct in concluding that the incremental capital cost of using that alternative, versus alternative two -- which is the one that you recommend -- is that 29.54 million minus 19.11 million, which is $10.43 million?

A Could you say that again?

Q I am trying to get the sort of incremental capital cost for the air-cooled condenser, versus what you recommend. And this shows the delta to the base case, but you are not recommending the base case, right? You're recommending alternative two.

A That's correct.

Q So I am looking for the delta in capital cost to alternative two. I am just wanting to confirm that it would be essentially the difference between 29.54 million and $19.11 million.

A That is a correct statement.

Q Okay. And then similarly, it would be annual O & M of the difference between 2.47 million and .9 million, correct?

A Correct, yes.

Q Okay. Do you know if the O & M costs associated with the air-cooled condenser option here include the impact of reduced plant output that are discussed in your water supply alternatives calculation or -- I am sorry, analysis?

A As stated on pages 67 and 68 of the water supply alternatives analysis, I will just quote from page 68. It indicates that the loss of revenue due to a significant reduction in power output was considered as a

factor, yes.

Q I am sorry, where are you, on page 67?

A Sixty-eight, I am sorry.

Q Sixty-eight?

A The third bullet.

Q But then, if you look at the last sentence on page 68, that's actually where my question had come from; O & M costs for alternative nine would be driven primarily by power consumption. And they are estimated to be 2.5 million per year.

I mean, I know that one of the other impacts of the air-cooled condenser that you discuss in here is that it takes a lot of electricity to run the blowers to force all of that air through there, which is I think what that's referring to, the power consumption requirement, right?

A (Witness nods head in the affirmative.)

Q And I just want to be sure that I understand whether this 2.5 million a year or 2.47 million a year actually includes sort of the reduced -- the impact of the reduced power output from the unit, because you don't have as good -- you don't have as good a vacuum in the condenser, or if it's only looking at the sort of positive power consumption, you know, that is required to drive the big fans?

A To me, those are one and the same.

Q No, I don't think those are the same. Let me be sure you understand my question for this.

If I understand this correctly, one of the assumed adverse impacts of an air-cooled condenser is that it doesn't condense the steam as quickly or to as low a temperature. And as a consequence, you have a higher back pressure on the low pressure side of the turbine; and that that is -- that lowers, I am sorry, increases the heat rate, and basically, you get a lower fueled power conversion efficiency, et cetera.

Then there is the problem that you have to run these larger fans to move enough air across the condensing surfaces to remove enough heat. And I see clearly the reference in the $2.5 million to the second of those, to the increased power consumption. What's not clear to me is whether the reduced thermal efficiency of the unit is taken into account as an O & M cost in the number that's included on Table 6-2.

A And the answer to that is that I -- it is my understanding that that is included; and I point to page 67, middle of the page, start of the paragraph that says, and additional loss of plant output would result from the power consumed by the condenser air fans, period, which indicates to me that that was considered.

Q I am sorry, where is that again?
A The middle of page 67, first sentence of that large paragraph.
Q But that has to do, again, with the power consumed by the air fans, not the loss of efficiency of the unit because of the higher condensate temperature enhanced greater back pressure, lower vacuum in the condenser side of the steam turbine?
A Well, I think that point is addressed in the previous paragraph.
Q I am just wanting to be sure whether it is in the 2.47 million. Your testimony is that it is.
A It is my understanding that it is, yes.
Q Okay. Did you review the calculation of O & M costs for alternative nine?
A No, I did not.
Q Okay. Do you know who provided that? Would that, again, be Cathy Ayan or Dan Springer --
A Correct.
Q -- of Duke?
A Yes.
Q Okay. All right.
Once the plant is constructed, where is it proposed that stormwater from the plant site will go?
A That stormwater will go to an on-site detention

pond.

Q Does it stay there until it evaporates or soaks into the ground, or does it spill out of the retention pond and go someplace else?

A First, I would correct you that it's a detention pond with a D, not a retention pond with an R. And answer to that question would be dependent on the meteorological conditions at the time.

Q Where does it go if it spills out of the detention pond --

A I believe --

Q -- because of meteorological conditions?

A I believe that under those circumstances where water could go off-site, our analysis is that it would be discharged to nearby wetlands.

Q Do you know where those wetlands are?

A Yes. Those wetlands are nearby the plant site and generally to the north.

Q Have you done any attempts at modeling or otherwise assessing what the water quality of stormwater that might be discharged from the plant site to some off-site location would be?

A No.

Q Have you reached any conclusions about whether that stormwater that is discharged would meet applicable

stormwater quality standards?

A I am sure it's stated in the SCA that any stormwater that was released would meet applicable standards.

Q How do you know that that will be the case if you haven't modeled or otherwise assessed the stormwater quality?

A Because other members of the project team, primarily from Duke floor Daniel's engineering side of the project team, have provided in the SCA detailed calculations supporting the design of the detention pond. Those calculations are supportive of the fact that any stormwater releases from the project site, would be consistent with applicable rules and requirements.

Q They did analysis of the water quality of the stormwater discharges or only of quantity?

A I wouldn't want to say absolutely that stormwater quality was not considered, but I don't see a reference to it. I see references to stormwater quantity and design criteria for the detention basin.

Q What sort of control technology would you recommend that the Duke New Smyrna project use if the stormwater quality was not acceptable to meet regulatory standards?

A I wouldn't want to provide an opinion on that.

That would be better posed to some of the engineers on the project from Duke floor Daniel.

Q Who would they be?

A Primarily, Harry Lancaster, L-a-n-c-a-s-t-e-r.

Q I would like to ask you, please, to, unless you can confirm from your own knowledge here today, that the impact of reduced thermal efficiency from the use of an air-cooled condenser rather than water cooling tower as the cooling technology for the New Smyrna plant, is included in the two-and-a-half million dollars O & M cost reflected on Figure 6-5 that's in Exhibit 5 we have identified; that you confirm whether that is or isn't the case. And if it is not, to provide me with what the economic impact of that reduced thermal efficiency would be?

MR. DEE: You're giving him a homework assignment? I don't think so, counsel.

MR. BUTLER: Well, I would at least like confirmation of whether or not it is, in fact, included in the calculation. I think that's certainly fair. And he has got a number in there that is the cost impact of the different alternatives.

And unless he now is sure, I don't think that he has personal knowledge of what that includes. And I

would at least like to have confirmation of whether it does or doesn't include the effect of the reduced thermal efficiency.

MS. KAUFMAN: Mr. Butler, I think that he answered to the best of his ability several times. Your question, he referred you to pages in the document that address the question. And I think that that's all that he's required to do.

MR. BUTLER: Well, let me just confirm --

BY MR. BUTLER:

Q Do you or don't you know from personal knowledge whether the reduced thermal efficiency, all the stuff I just said in my request a moment ago, is or is not reflected in the $2.47 million O & M cost that is calculated on Figure 6-5 for -- I think -- is it 6-5? I am sorry, Table 6-2 for the air-cooled condenser?

A It is my understanding, based on a rereading of the text that supports these tables, that it was considered, but I cannot say that with absolute certainty, because I did not calculate that number myself.

Q And Cathy Ayan or Dan Springer would be the appropriate people at Duke floor Daniel to ask that question?

A Yes, sir.

MR. BUTLER: Okay. I tell you what, I probably don't have more than a few more questions. But it will go faster if I have a few minutes to go through here.

MS. KAUFMAN: That's great. I would like to check with my office.

MR. BUTLER: Okay. Five or ten minutes?

MS. KAUFMAN: Sure.

(Brief recess.)

BY MR. BUTLER:

Q Have you prepared any -- or have you prepared responses to any of the interrogatories in this proceeding?

A I believe I did, yes.

Q Do you remember which ones?

A Well, the ones that have Meling in parentheses after them.

Q Okay. So if it doesn't have Meling in parentheses after it, you didn't prepare it?

A Correct.

Q Okay. Going back briefly to this question of the cost-effectiveness of emission reductions in the BACT analysis, do you know if the DEP ever looks at the cost-effectiveness from the perspective of the average cost for reduction of a particular pollutant for all of

the control technologies that are employed instead of incrementally, you know, at the cost of each sort of individual additional control technology?

MS. KAUFMAN: I'm going to object. I didn't understand that question.

MR. DEE: Me, either.

MS. KAUFMAN: But if you understand it, you can answer it. If you don't, restate it.

THE WITNESS: I will answer by saying I don't have any personal knowledge of exactly how DEP does their analysis.

BY MR. BUTLER:

Q Have you ever looked at the cost-effectiveness of emission control for a facility on the basis of the sort of overall average cost for a unit of pollutant on eliminated, as opposed to incrementally for each element of control technology that is applied?

A The only way I can answer that question is to say that the only way I have ever done it is to evaluate the cost relative to the base case. And it depends, then, on what the definition of the base case would be, I guess.

Q And in your particular analysis, the base case includes the -- both the cost and the environmental benefits of the dry low NOX combustor, correct?

A That's true.

Q Have you ever looked at the cost-effectiveness, again, the cost per unit of NOX reduction for a base case that would start without the use of that dry low NOX combustor technology, and would assess the cost-effectiveness of using both it and SCR technology instead of starting with the dry low NOX combustor as the base case?

A The answer to that is probably yes. Although, that would have been years ago.

Q Why would it have been years ago?

A Because the dry low NOX technology is relatively recent.

Q Do you have any idea what the cost per -- cost per ton -- right, that's the unit?

A Dollars per ton, yes.

Q Dollars per ton. What the dollars per ton of NOX reduction would be if you used a base case that did not include the dry low NOX combustor, and then compared that to both the application of that dry low NOX combustor technology and the SCR technology?

A Could I do it, yes. It would depend, however, on what the new definition of the base case happened to be.

Q Well, I thought from what you were saying and

what I was trying to follow up to your way of characterizing it, is that the base case would be the combustion turbine that does not have the dry low NOX combustor and does not have the SCR equipment?

A I suppose you could concoct some sort of new baseline that did that. It wouldn't be appropriate.

Q Why would it not be appropriate?

A Because it's my understanding that GE isn't even selling the old types of combusters anymore.

Q So in your opinion, the base case starts with the dry low NOX combustor, because that's essentially standard equipment in the GE combustion turbines that one would be looking at --

A Yes, sir.

Q -- in this analysis, right?

A Yes, sir.

Q Okay. Do you have any idea what the cost per ton would be on a NOX reduction, if one looked at such a comparison?

A Again, you would have to -- I can't answer a question phrased that way. You would have to provide more details.

Q And what details would I have to provide you?

A The emission rate for the base case, at least.

Q You are not familiar, from your past work, with

what that emission rate would be?

A As I responded earlier to another question, every BACT analysis is specific, a project specific; and unless you gave me project specifics, it would be difficult to do that.

Q There would not be a general expectation of the NOX emission rate for a GE combustion turbine without dry low NOX combustor technology?

A If you want to give me a number, I will do my best to calculate a new cost-effectiveness. But I am not sure what you are asking here at all.

Q Well, at the moment, I am just asking whether there, at least in the -- if it's true that one no longer one can readily buy emission turbines without that low NOX combustor technology, fine. But at the time when one could, I am asking whether there was sort of a common expectation on what the emission rate would be from a GE combustion turbine, without that low NOX combustor technology incorporated?

A Well, it's changed overtime. There was a time not that long ago when a gas-fired combustion turbine emitted 42 parts per million of NOX, as opposed to the current nine.

Q And what changed between -- technologically changed between the time when sort of a common emission

rate would be 42 parts per million and now the expectation of nine parts per million?

A The technology has improved.

Q Can you summarize what has changed about the technology?

A Very generally, it has to do with combustor design. But you are getting into a field that a question like this should be answered by one of the Ph.D.s at General Electric, not me.

Q Is it more than the sort of addition or change to incorporate the dry low NOX combustor design?

A I don't know.

Q Would you look again at the Table 6-2 in Exhibit 5, please?

In assessing the appropriateness of the various alternatives that are shown here, did you have any sort of cost per million gallons a day of fresh water left in the upper Floridan aquifer that, you know, forms sort of a threshold for assessing the cost-effectiveness of these improvements, comparable to what we were talking about as the cost-effectiveness threshold for your BACT analysis?

A I have absolutely no idea what you just asked me, I am sorry.

Q Well, is it correct that at least one of the purposes of running through these alternatives is to try

to determine if there are sort of feasible and cost-effective alternatives that will reduce the amount of fresh water, fresh, you know, potential drinking water that is going to be consumed by this plant?

A Is that one of the purposes of this analysis?

Q Yes.

A Yes.

Q Okay. And one of the factors that you looked at in assessing the appropriateness of the alternatives was the cost of the alternative, correct?

A That is true.

Q The incremental cost of that over the base case, right?

A That is true.

Q Okay. And what I am asking is, whether you had any threshold in mind of a cost for an alternative that would be an acceptable cost for, you know, moving to that alternative, and thereby reducing the use of fresh water or, instead, rejecting the alternative as being too expensive and not worth it for that particular alternative?

A Did I have a threshold in mind?

Q Yes.

A No.

Q Do you know if anybody who participated in the

preparation of the water supply alternatives analysis did?

A Not to my knowledge.

Q Do you know if DEP does?

A No.

Q Have you ever had any discussions with DEP about what they considered to be an acceptable level of expenditures to avoid consumption of, you know, some particular unit of fresh water?

A No.

Q Okay. How, then, is one to assess whether the increased costs shown on Table 6-2 would be worthwhile to incur or not?

MS. KAUFMAN: When you say, worthwhile, to whom are you speaking; the project, DEP, the State?

BY MR. BUTLER:

Q Worthwhile as a basis to select that alternative versus another alternative.

A Well, again, cost was only one of the factors that was considered. And I would point out the use of the word relative in Table 6-1.

Each of these nine alternatives was evaluated relative to the others. And taking all three factors into account, an overall feasibility was assigned, recognizing that that's somewhat subjective. And one

alternative in this case, alternative two, stood out as being the most appropriate.

Q Well, let's look at your relative cost column, then. Maybe that's a way of at least trying to understand what I am asking you.

Alternative two is identified as low cost, correct?

A Yes.

Q Okay. And it has a cost of $19.11 million capital and 900,000 a year operating, right?

A That's correct.

Q Okay. Now, alternative three is medium cost, correct?

A That's the way it is presented in Table 6-1, correct.

Q You don't disagree with that, do you?

A No.

Q On Table 6-2, the capital cost is 23.86 million, about four-and-a-half million more, and 950,000, so about 50,000 more on O & M cost.

Where was the threshold dividing low from medium cost in your Table 6-1?

A Clearly somewhere between 19.13 million and 23.86 million.

Q Based on what?

A The relative comparison of the various alternatives.

Q I mean, did you have anything in mind that distinguished 19.11 million from 23.86 million, as one being low cost and the other being medium cost?

A Again, just the relative, the relative cost of one alternative to another, that's it.

Q Okay. If the new Duke New Smyrna project were to select alternative nine instead of alternative two, the result would be leaving something like about 1.3 million gallons a day of fresh water in the upper Floridan aquifer; is that right?

A I think that's generally correct, yes.

Q Okay. How did you conclude that the value of leaving 1.3 million gallons a day of fresh water in the upper Floridan aquifer, was not worth the additional expenditures reflected by the difference between the capital cost and the annual O & M cost for those two alternatives shown on Table 6-2?

A The direct answer to your question is, we did no such analysis. However, we did perform, as is described here, analyses as to whether or not the effects or impacts associated with withdrawing various amounts of water from the upper Floridan aquifer would be acceptable or not. And it was our conclusion that the withdrawal of

those quantities of water are acceptable.

Q Acceptable, meaning what?

A Acceptable in terms of impacts to other users of water, other wells, wetlands, springs, streams --

Q Will the plant's withdrawal of 1.3 million gallons a day of water from the upper Floridan affect water available to meet future needs, drinking water needs of people in the vicinity of New Smyrna Beach?

A Our assessment is that it will not have a detrimental impact.

Q And what is that conclusion based on?

A The answer to that question is the same one I just gave, with respect to the analysis that we did, again, looking at other wells, et cetera.

Q If the Duke New Smyrna project did not need to be sited near New Smyrna to provide power to New Smyrna, would you otherwise consider its location to be an appropriate one from the perspective of statewide environmental concerns?

A Yes.

Q And why is that?

A Well, the real answer to that question is our entire site certification application, which addresses every environmental feature of the area and our proposed project's impacts on those features, which we have

concluded are very much acceptable.

Q But my question isn't really whether -- given where it's going to be -- the impacts are acceptable, but rather whether if it didn't have to be where it is, would there be a better location?

A I have no way to answer that question.

Q Do you think that there would be more or less overall environmental impacts of the project, if it were built essentially in the vicinity of the connection point for the natural gas pipeline spur that is proposed to get gas to the plant from the FGT pipeline?

MS. KAUFMAN: Do you want to define what you mean by, in the vicinity of?

BY MR. BUTLER:

Q Say, within five miles.

A Within five miles of what again?

Q The connection point to the FGT natural gas pipeline.

A Having never been there, I have no ability to answer that question. I have never studied that area specifically. I have never evaluated it for its appropriateness as a power plant site. I have no idea.

Q Okay. But --

MR. BUTLER: Okay. Thank you very much, Mr. Meling.

THE WITNESS: You're welcome.

(Whereupon, the deposition was concluded at 5:30 p.m., and reading and signing by the witness was not waived.)

TRANSCRIPT CERTIFICATE

STATE OF FLORIDA)

COUNTY OF LEON)

I, DEBRA R. KRICK, Court Reporter, hereby certify that the foregoing transcript was taken down as stated in the caption, and the questions and answers thereto were reduced to typewriting under my direction;

That the foregoing pages 4 through 110 represent a true, correct, and complete transcript of the evidence given upon said hearing;

And I further certify that I am not of kin or counsel to the parties in the case; am not in the regular employ of counsel for any of said parties; nor am I in anywise interested in the result of said case.

Dated this 20th day of November, 1998.

DEBRA R. KRICK
Court Reporter and Notary Public
State of Florida at Large

CORRECTIONS

Corrections to the deposition of JEFFREY L. MELING, taken in the case of City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P., Docket No. 981042-EM, taken on November 12th, 1998.

Page-Line	Correction

Date Signature

AS TO SIGNATURE ONLY

IN WITNESS WHEREOF, I have set my hand and affixed my seal this _____ day of _____, 1998; said instrument was acknowledged before me by _____ who is personally known or identified himself to me.

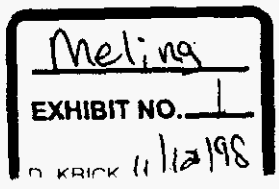
Notary Public

leases of NH_3 during upsets or malfunctions have the potential to cause ambient odor problems. NH_3 also acts as an irritant to human tissue. Depending on the concentration and duration of exposure, NH_3 can cause eye, skin, and mucous membrane irritation. These effects can vary from minor irritation to severe damage. Contact of the skin or mucosa with liquid NH_3 or a high vapor concentration can result in burns or obstructed breathing.

- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of NH_3 with SO_3 present in the exhaust gases; total particulate matter emissions would increase by approximately 50 percent.
- A public risk due to potential leaks from the storage of large quantities of NH_3; NH_3 has been designated a "Extraordinarily Hazardous Substance" under the federal Superfund Amendment and Reauthorization Title III regulations.
- Disposal of spent catalyst which may be considered hazardous due to heavy metal contamination; vanadium pentoxide is an active component of a typical SCR catalyst and is listed as a hazardous chemical waste under Resource Conservation and Recovery Act Regulations 40 CFR 261.30. As a potential hazardous waste, spent catalyst may have to be transported and disposed in a hazardous waste landfill. In addition, facility workers could be exposed to high levels of vanadium pentoxide particulates during catalyst handling.

5.5.3 ECONOMIC IMPACTS

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced dry low-NO_x combustor technology and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve a NO_x exhaust concentration of 12 ppmvd at 15 percent O_2. SCR technology was premised to achieve NO_x concentrations of 3.5 ppmvd at 15 percent O_2 for natural gas -firing. The NO_x concentration of 3.5 ppmvd is representative of recent LAER determinations made in California for natural gas-fired CTGs equipped with dry low-NO_x combustor technology and SCR controls. SCR control costs were based on the reduction of NO_x concentrations from 12 to



3.5 ppmvd. As supplied by GE, the PG7241 (FA) unit is equipped with dry low-NO_x combustors. GE does not offer any other option with respect to combustor type or design.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Table 5-1 and project-specific economic factors provided in Table 5-7. Emission reductions were calculated assuming base load operation for 8,688 hr/yr at an annual average ambient temperature of 59°F. Specific capital and annual operating costs for the SCR control system are summarized in Tables 5-15 and 5-16, respectively.

Cost effectiveness for the application of SCR technology to the New Smyrna Beach Power Project CTGs was determined to be $6,534 per ton of NO_x removed. This control cost is considered to be economically unreasonable. Results of the NO_x BACT analysis are summarized in Table 5-17.

5.5.4 PROPOSED BACT EMISSION LIMITATIONS

BACT NO_x limits obtained from the RBLC database for natural gas-fired CTGs are provided in Table 5-18. FDEP natural gas-fired CTG NO_x BACT determinations for the past 5 years range from 12 to 25 ppmvd at 15 percent O_2 with an average CO limit of 15 ppmvd at 15 percent O_2. Of the 10 most recent FDEP NO_x BACT determinations for CTGs, seven determinations established a limit of 15 ppmvd or higher. A summary of FDEP NO_x BACT determinations for natural gas-fired CTGs for the previous 5 years is provided in Table 5-19.

NO_x BACT emission limits proposed for the New Smyrna Beach Power Project CTGs, based on the application of dry low-NO_x combustors, are 12 ppm and 83 lb/hr, and are summarized in Table 5-20. NO_x emission rates proposed as BACT for the Project CTGs are consistent with prior FDEP BACT determinations as shown in Table 5-19. An additional NO_x BACT consideration pertinent to the Project is the exclusive use of natural gas (CTGs typically achieve 42 ppmvd NO_x during oil-firing).

Table 5-15. Capital Costs for SCR System

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	1,183,101 (A)	
Sales tax	70,986	0.06 x A
Freight	59,155	0.05 x A
Subtotal Purchase Equipment	**1,313,242**	
Installation		
Foundations and supports	94,648	0.08 x A
Handling and erection	165,634	0.14 x A
Electrical	47,324	0.04 x A
Piping	23,662	0.02 x A
Insulation for ductwork	11,831	0.01 x A
Painting	11,831	0.01 x A
Subtotal Installation Cost	**354,930**	
Subtotal Direct Costs	**1,668,172**	
Indirect Costs		
Engineering	118,310	0.10 x A
Construction and field expenses	59,155	0.05 x A
Contractor fees	118,310	0.10 x A
Startup	23,662	0.02 x A
Performance test	11,831	0.01 x A
Contingency	35,493	0.15 x A
Subtotal Indirect Costs	**366,761**	
TOTAL CAPITAL INVESTMENT	**2,034,933** (TCI)	

Sources: D/FD, 1998.
ECT, 1998.

Table 5-16. Annual Operating Costs for SCR System

Item	Dollars		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	19,955	(A)	
Supervisor	2,993		0.15 x A
Maintenance			
Labor	13,304	(B)	
Materials	13,304		1.00 x B
Subtotal Labor, Material, and Maintenance Costs	**49,556**	(C)	
Catalyst costs			
Replacement (materials and labor)	905,407		
Annualized Catalyst Costs	**364,078**		
Raw materials and Utilities			
Electricity	19,073		
Aqueous ammonia	144,473		
Subtotal Raw Materials and Utilities	**163,546**		
Energy Penalties			
Unforced Outages	415,800		
Turbine backpressure	250,866		
Subtotal Direct Costs	**1,243,845**	(TDC)	
Indirect Costs			
Overhead	29,733		0.60 x C
Administrative charges	40,699		0.02 x TCI
Property taxes	20,349		0.01 x TCI
Insurance	20,349		0.01 x TCI
Capital recovery	193,168		
Subtotal Indirect Costs	**304,299**		
TOTAL ANNUAL COST	**1,548,144**		

Sources: D/FD, 1998.
ECT, 1998.

Table 5-17. Summary of NO_x BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Envir. Impact (Y/N)
SCR	45.0	195.1	473.9	4,069,866	3,096,288	6,534	129,986	Y	Y
Baseline	154.0	669.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) CTGs, 100-percent load, 59°F ambient temperature, 8,760 hr/yr gas-fired.

Sources: D/FD, 1998.
ECT, 1998.

Table 5-19. Florida BACT NO_X Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	NO_X Emission Limit (ppmvd)	Control Technology
08/17/92	Orlando Cogeneration, L.P.	79	15	Dry low-NO_X combustors
08/17/92	Florida Power Corp. University of Florida	43	25	Steam injection
12/17/92	Auburndale Power Partners	104	25	Steam injection
			15	Steam injection
04/09/93	Kissimmee Utility Authority	40	25	Water injection
			15	Dry low-NO_X combustors
04/09/93	Kissimmee Utility Authority	80	25	Water injection
			15	Dry low-NO_X combustors
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	25	Dry low-NO_X combustors
		184	15	Dry low-NO_X combustors
02/21/94	Polk Power Partners	84	25	Dry low-NO_X combustors
			15	Dry low-NO_X combustors
02/24/94	Tampa Electric Company Polk Power Station	260	25	Nitrogen diluent injection
02/25/94	Florida Power Corp. Polk County Site	235	12	Dry low-NO_X combustors
07/20/94	Pasco Cogen, Limited	42	25	Wet injection
03/07/95	Orange Cogeneration, L.P.	39	25	Dry low-NO_X combustors
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	15	Dry low-NO_X combustors
06/01/95	Panda-Kathleen	75	15	Dry low-NO_X combustors
09/28/95	City of Key West (relocated unit)	23	75	Water injection
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	15	Dry low-NO_X combustors
05/98	City of Tallahassee Purdom Unit 8	160	12	Dry low-NO_X combustors
07/10/98	City of Lakeland McIntosh Unit 5	250	25	Dry low-NO_X combustors
07/10/98	City of Lakeland McIntosh Unit 5	250	9	Dry low-NO_X combustors or SCR (effective 05/01/2002)

Source: FDEP, 1998.

Table 5-20. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits*†	
	lb/hr	ppmvd**
GE PG 241 (FA) CTG (Per CTG)	83.0	12

* Maximum rates for all operating scenarios
† 24-hour block average.
**Corrected to 15 percent O_2.

Sources: GE, 1998.
D/FD, 1998.
ECT, 1998.

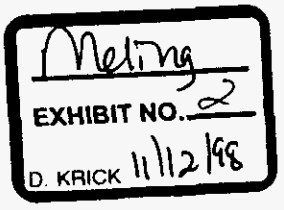
APPENDIX

Comparison of Air Emissions: New Smyrna Beach Power Project Relative to Existing Facilities

Air pollutant emissions from the New Smyrna Beach Power Project are compared here to those from existing Florida power generation facilities. The Project's emissions are based on the specific vendor performance information for the combustion turbines, as represented in the site certification application. For the existing facilities, available information from the Florida Department of Environmental Protection and the U.S. Environmental Protection Agency has been employed to develop characteristic emissions from *proxy* units. The proxy units are oil- and natural gas-fired steam-electric generation units that are representative of existing facilities in Florida.

The accompanying figure compares the Project's emission rates for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM) with those of the proxy units. The emission rates for each pollutant are presented in terms of pounds of pollutant per megawatt-hour (lbs/mwh). As shown, the Project's emission rates are less than—in some cases *significantly* less than—those of the proxy units. The Project's greater mechanical efficiency and clean fuel result in lower emissions per megawatt of electricity produced.

These emission rates can be used to estimate the reductions in total emissions that would occur if the Project's electrical generation offsets or displaces the operation of existing facilities. Based on an economic dispatch model, the Project is estimated to generate 3,719,550 mwh of electricity in 2002. The following table compares the resulting emissions under various scenarios:

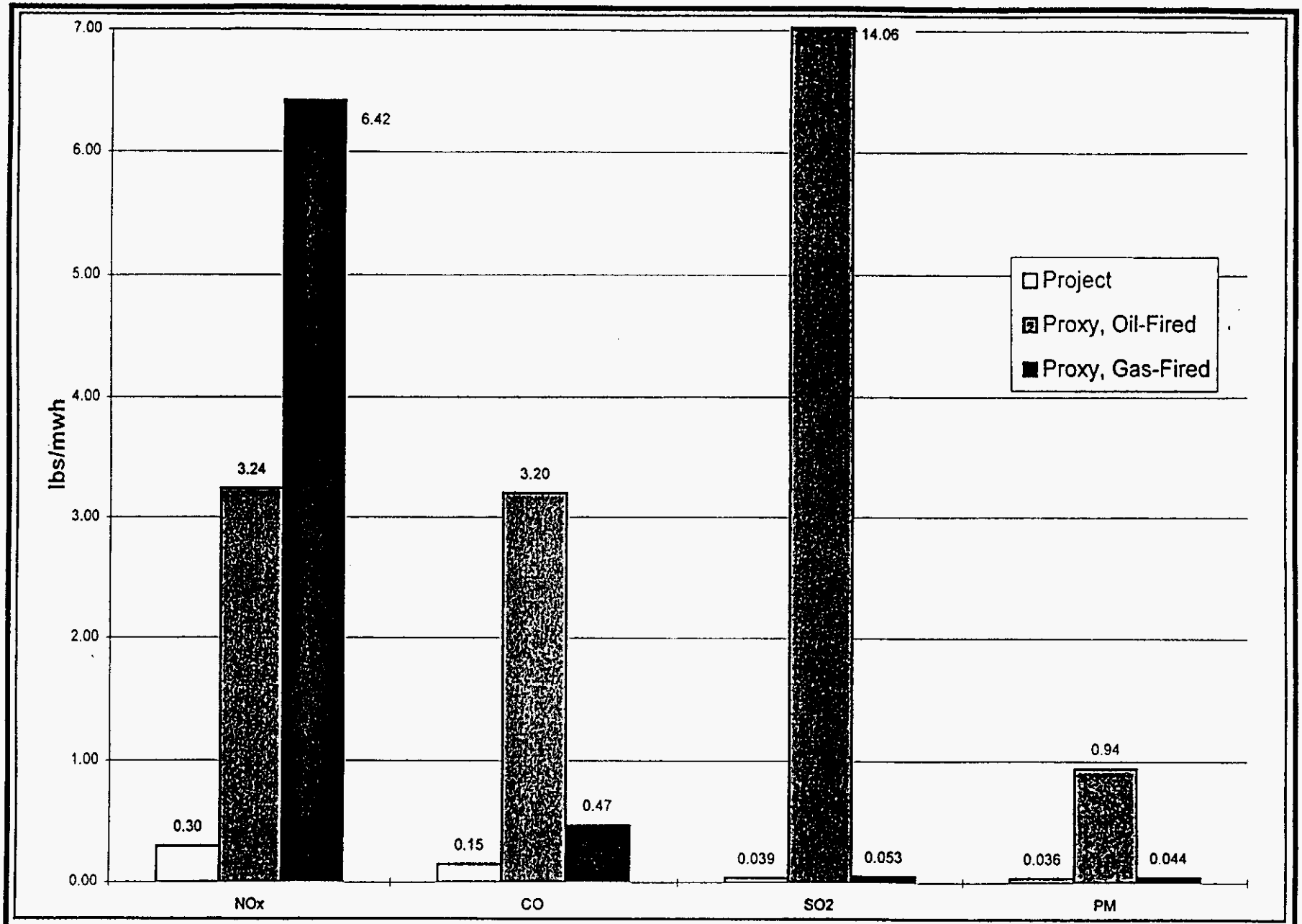


	Annual Emissions (tons per year [tpy])			
	NO_x	CO	SO_2	PM
Project	558	279	73	67
Proxy, oil-fired	6,029	5,958	26,142	1,747
Proxy, gas-fired	11,947	869	99	82
Proxy, 50/50 mix	8,988	3,414	13,121	915

From these estimates, the emissions reductions that could result from the Project can be calculated as follows:

	Annual Emissions Reductions Due to the Project (tpy)			
	NO_x	CO	SO_2	PM
Project offsetting Proxy, oil-fired	5,471	5,679	26,069	1,680
Project offsetting Proxy, gas-fired	11,389	590	26	15
Project offsetting Proxy, 50/50 mix	8,430	3,135	13,048	848

These comparisons show that, if the Project's generation offsets that of existing facilities, the reductions in emissions will be significant.



COMPARISON OF EMISSION RATES

Source: ECT, 1998.

ECT
Environmental Consulting & Technology, Inc.

Table 3.5.1-1. Estimated Quality of Treated Effluent From the UCCNSB WWTP

Analyte	Result	Unit	Reporting Limit
Fecal coliform (MF)	1	#/100 mL	1
Fecal streptococcus (MF)	<1	#/100 mL	1
Specific conductance	546	umho/cm	5.0
Total hardness as $CaCO_3$	140	mg/L	1.2
pH	7.01	UNIT	N/A
Total dissolved solids (TDS)	400	mg/L	5.0
Total suspended solids (TSS)	<1.0	mg/L	1.0
Turbidity	0.45	NTU	0.10
Suspended solids <0.062 mm diameter	<0.50	%	0.50
Total Kjeldahl nitrogen	1.2	mg/L	0.50
Dissolved oxygen	5.4	mg/L	1.0
Total phosphorus	0.10	mg/L	0.025
Dissolved oxygen (% saturation)	59	%	10
Gross alpha—total suspended	<1.8+/-1.3	pCi/L	
Gross beta—total suspended as Cs-137	<2.2+/-1.3	pCi/L	
Gross beta—total suspended as Sr/Y-90	<2.0+/-1.2	pCi/L	
Nitrogen—NO_3/NO_2 (NO_x)	<0.10	mg/L	0.10
TDS—sum of constituents	370	mg/L	5.0
Bicarbonate alk. as $CaCO_3$	120	mg/L	5.0
Carbonate alk. as $CaCO_3$	<1.0	mg/L	1.0
Total alkalinity as $CaCO_3$	120	mg/L	5.0
Total phosphorus	0.10	mg/L	0.025
Dissolved silica	20*	mg/L	5.0
Nitrogen—ammonia	0.11	mg/L	0.050
Nitrogen—ammonia, ionized (NH_4+)	0.11	mg/L	0.050
Gross alpha	<1.6+/-0.7	pCi/L	
Radium 226	0.8+/-0.3	pCi/L	
Uranium	<0.6+/-0.3	pCi/L	
Gross beta as CS-137	<1.9+/-1.2	pCi/L	
Gross beta as Sr/Y-90	<2.4+/-1.5	pCi/L	
Chloride	100	mg/L	0.50
Fluoride	0.13	mg/L	0.050
Nitrate nitrogen	<0.10	mg/L	0.10
Nitrogen—NO_3/NO_2 (NO_x)	<0.10	mg/L	0.10
Orthophosphate—P	<0.10	mg/L	0.10
Sulfate	27	mg/L	0.50
Cobalt (total)	<0.010	mg/L	0.010
Lithium (total)	<0.01	mg/L	0.01
Potassium (total)	9.5	mg/L	0.50
Strontium (total)	<0.10	mg/L	0.10
Aluminum (total)	<0.10	mg/L	0.10

Melving
EXHIBIT NO.
D. KRICK 11/16/98

Table 3.5.1-1. Estimated Quality of Treated Effluent From the UCCNSB WWTP (Continued, Page 2 of 2)

Analyte	Result	Unit	Reporting Limit
Barium (total)	<0.010	mg/L	0.010
Cadmium (total)	<0.0010	mg/L	0.0010
Calcium (total)	45	mg/L	0.50
Copper (total)	<0.010	mg/L	0.010
Iron (total)	0.036	mg/L	0.025
Lead (total)	<0.0050	mg/L	0.0050
Magnesium (total)	6.6	mg/L	0.50
Manganese (total)	0.018	mg/L	0.0050
Molybdenum (total)	<0.010	mg/L	0.010
Nickel (total)	<0.010	mg/L	0.010
Selenium (total)	<0.0050	mg/L	0.0050
Silver (total)	<0.010	mg/L	0.010
Sodium (total)	78	mg/L	0.50
Vanadium (total)	<0.010	mg/L	0.010
Zinc (total)	0.060	mg/L	0.025

Note: All data results from testing of sample collected April 6, 1998.
NTU = nephelometric turbidity units.
pCi/L = picoCurie per liter.
umho/cm = micromho per centimeter.

* Sample was diluted due to the concentration of analyte exceeding calibration range or the presence of interference. Result and detection limit were corrected with dilution factor.

Sources: Envirolab, 1998.
UCCNSB, 1998.

KEY:

■ = WWTP effluent (*actual*)
= WWTP effluent (*projected*)

▲ = Reuse (*actual*)
● = Reuse (*projected*; existing contractual commitments only)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2005	2010	2015	2020
WWTP effluent (*actual*)	2.44	2.62	2.67	2.88	2.78	2.46								
WWTP effluent (*projected*)							2.53	2.61	2.69	2.8	3.1	3.5	4.0	4.5
Reuse (*actual*)	0.00	0.09	0.15	0.40	0.57	0.94								
Reuse (*projected*; existing contractual commitments only)							1.20	1.46	1.69	1.8	1.8	1.8	1.8	1.8

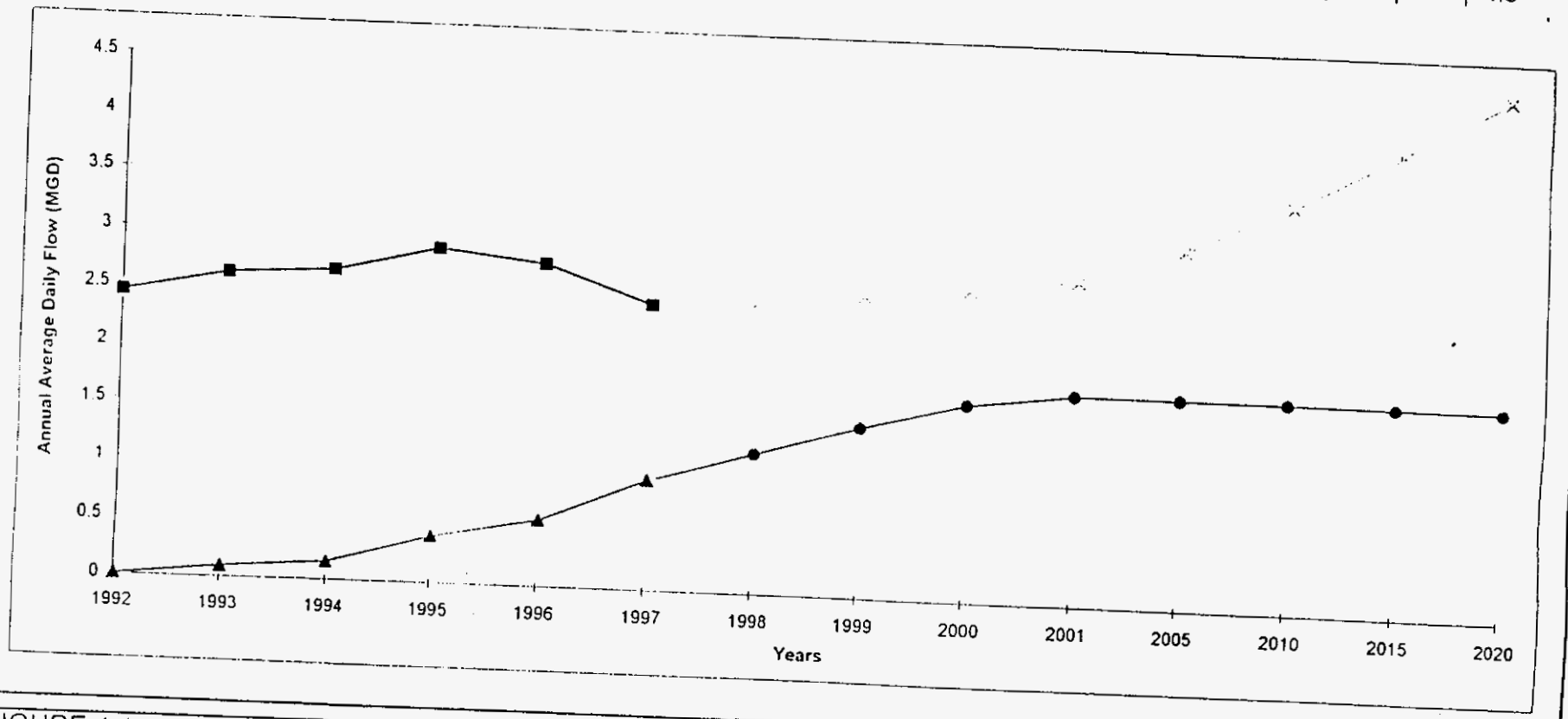


FIGURE 4-1.

WWTP EFFLUENT AND REUSE FLOWS WITHOUT NEW SMYRNA BEACH POWER PROJECT

Sources: UCCNSB, 1998. ECT, 1998.

ECT
Environmental Consulting & Technology, Inc.

EXHIBIT NO. 4
D. KRICK 11/12/98

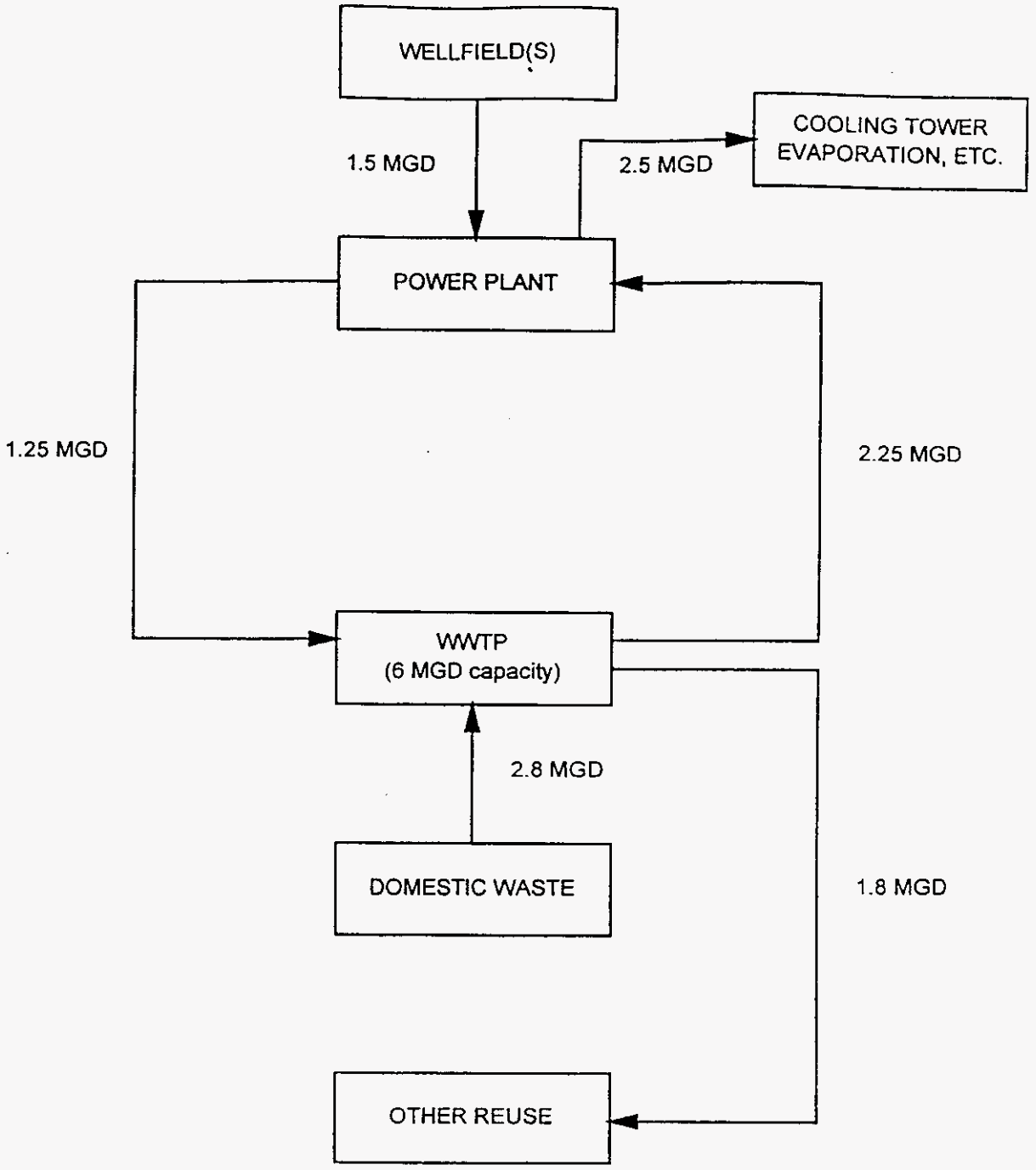


FIGURE 4-2.
EXPECTED EFFECT OF NEW SMYRNA BEACH POWER PROJECT ON WWTP EFFLUENT/REUSE BALANCE, YEAR 2001

Sources: UCCNSB, 1998. ECT, 1998.

ECT
Environmental Consulting & Technology, Inc.

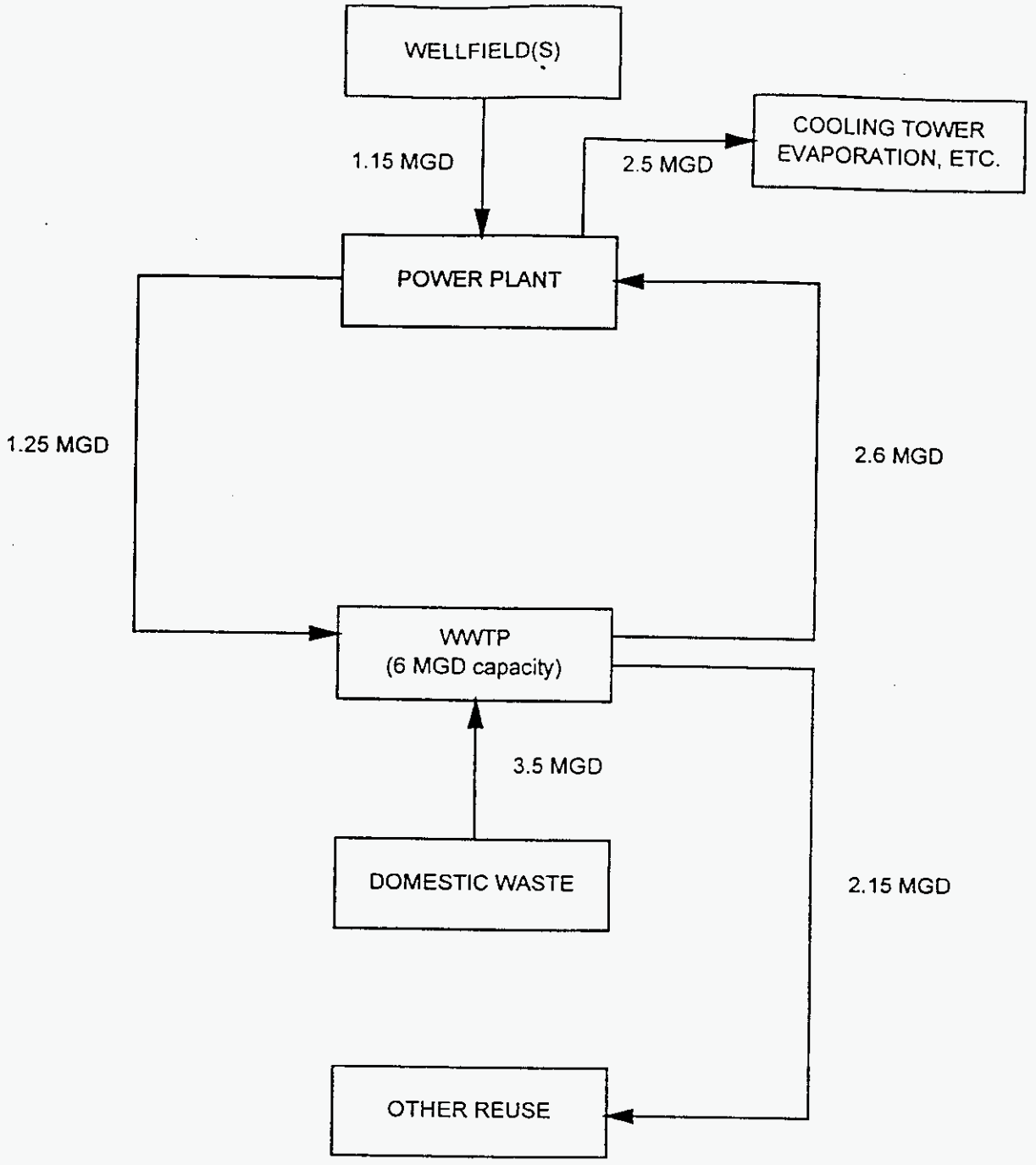


FIGURE 4-3.
EXPECTED EFFECT OF NEW SMYRNA BEACH POWER PROJECT ON WWTP EFFLUENT/REUSE BALANCE, YEAR 2010

Sources: UCCNSB, 1998, ECT, 1998

ECT
Environmental Consulting & Technology, Inc.

KEY:

- = WWTP effluent (*actual*)
- = WWTP effluent (*projected*)
- = Reuse (*actual*)
- = Reuse (*projected*, other; existing contractual commitments plus 50% of projected increases)
- = Reuse water available to power plant

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2005	2010	2015	2020
WWTP effluent (*actual*)	2.44	2.62	2.67	2.88	2.78	2.46								
WWTP effluent (*projected*)							2.53	2.61	2.69	4.05	4.35	4.75	5.25	5.75
Reuse (*actual*)	0.00	0.09	0.15	0.40	0.57	0.94								
Reuse (*projected*, other; existing contractual commitments plus 50% of projected increases)							1.20	1.46	1.69	1.8	1.95	2.15	2.4	2.65
Reuse water available to power plant										2.25	2.4	2.6	2.85	3.1

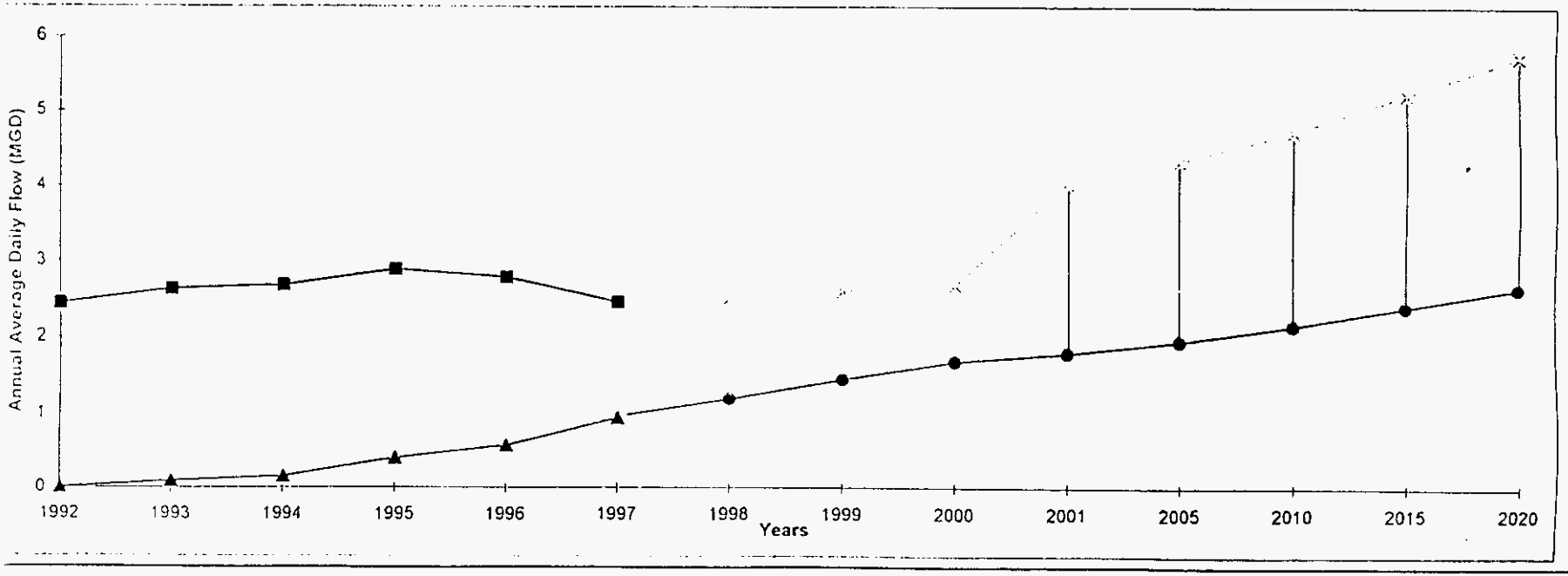


FIGURE 4-4.

WWTP EFFLUENT AND REUSE FLOWS WITH NEW SMYRNA BEACH POWER PROJECT

Sources: UCCNSB, 1998. ECT, 1998.

ECT
Environmental Consulting & Technology, Inc.

Table 4-1. Monthly WWTP Effluent and Reuse Statistics, 1997

Month	WWTP Effluent		Reuse				
	Total Volume (MG)	MADF (MGD)	Total Volume (MG)	MADF (MGD)	MMDF (MGD)	MMDF/ MADF	Total Rainfall (inches)
January	74.20	2.39	17.16	0.550	1.170	2.127	2.22
February	68.28	2.44	13.63	0.490	1.420	2.898	0.50
March	79.30	2.56	36.40	1.170	2.470	2.111	2.78
April	72.63	2.42	43.74	1.460	1.850	1.267	3.52
May	73.49	2.37	42.87	1.380	2.110	1.529	3.06
June	80.02	2.67	35.90	1.200	2.280	1.900	6.66
July	80.33	2.59	31.27	1.010	1.890	1.871	6.77
August	77.16	2.49	27.09	0.870	1.740	2.000	6.45
September	64.83	2.16	35.87	1.200	1.850	1.542	2.94
October	67.64	2.18	30.75	0.992	1.540	1.552	5.48
November	64.15	2.14	32.22	1.074	1.700	1.583	2.50
December	73.66	2.38	17.44	0.563	1.600	2.842	8.34
	Average	**2.40**	**30.36**	**0.997**	**1.802**	**1.808**	
	Standard Deviation	**0.17**		**0.322**			
						Total	**51.22**

Note: MADF = monthly average daily flow. MG = million gallons. MMDF = monthly maximum daily flow.

Source: UCCNSB, 1998.

Table 6-1. Summary Comparison of Alternatives: Overall Feasibility

Alternative	Description	Relative Technical Difficulty			Relative Likely Permitting Difficulty			Relative Cost			Overall Feasibility		
		High	Medium	Low	High	Medium	Low	High	Medium	Low	Poor	Average	Good
Base Case	Fresh ground water from onsite wells, fresh water cooling tower			✔	✔					✔	✔		
1	Reuse water supplemented by fresh ground water from onsite wells, fresh water cooling tower			✔		✔				✔		✔	
2	Reuse water supplemented by fresh ground water from onsite wells and public raw water supply, fresh water cooling tower			✔			✔			✔			✔
3	Reuse water supplemented by fresh ground water from new offsite wells, fresh water cooling tower			✔		✔			✔			✔	
4	Reuse water supplemented by brackish water from Indian River, fresh water cooling tower	✔			✔			✔			✔		
5	Reuse water supplemented by brackish water from St. Johns River, fresh water cooling tower	✔			✔			✔			✔		
6	Reuse water supplemented by brackish ground water from onsite wells (Lower Floridan), fresh water cooling tower	✔				✔			✔			✔	
7	Brackish water cooling tower using Indian River for makeup	✔				✔			✔			✔	
8	Once-through cooling with Indian River as source		✔			✔		✔			✔		
9	Air-cooled condenser			✔	✔			✔			✔		

Sources: D/FD, 1998; ECT, 1998.

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EXHIBIT NO. 5
D. KRICK 11/12/98

Table 6-2. Summary Comparison of Alternatives: Incremental Costs

Alternative	Description	Capital Cost ($ millions)	Δ Capital Cost ($ millions)	Annual O&M ($ millions)	Δ Annual O&M ($ millions)	Cost of Water* ($/1,000 gal)	Δ Cost of Water ($/1,000 gal)
Base Case	Fresh ground water from onsite wells, fresh water cooling tower	17.67	—	0.95	—	2.23	—
1	Reuse water supplemented by fresh ground water from onsite wells, fresh water cooling tower	19.13	1.46	0.90	-0.05	2.30	0.07
2	Reuse water supplemented by fresh ground water from onsite wells and public raw water supply, fresh water cooling water	19.11	1.44	0.90	-0.05	2.30	0.07
3	Reuse water supplemented by fresh ground water from new offsite wells, fresh water cooling tower	23.86	6.19	0.95	-0.01	2.71	0.47
4	Reuse water supplemented by brackish water from Indian River, fresh water cooling tower	34.21	16.54	1.60	0.65	4.11	1.87
5	Reuse water supplemented by brackish water from St. Johns River, fresh water cooling tower	47.96	30.29	1.73	0.78	5.29	3.06
6	Reuse water supplemented by brackish ground water from onsite wells (Lower Floridan), fresh water cooling tower	25.35	7.68	1.58	0.63	3.40	1.17
7	Brackish water cooling tower using Indian River for makeup	27.68	10.01	8.07	7.12	9.48	7.24
8	Once-through cooling with Indian River as source	78.02	60.35	7.42	6.47	12.79	10.56
9	Air-cooled condenser†	29.54	11.87	2.47	1.51	4.53	2.30

*$ per thousand gallons calculated assuming hypothetical 10-percent discount rate, 2.5-percent inflation rate, and 30-year life.
†Cost of water based on water use for equivalent fresh water cooling tower load.

Sources: D/FD, 1998.
ECT, 1998.
Duke Energy Power Services, 1998.

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STEEL HECTOR & DAVIS

REGISTERED LIMITED LIABILITY PARTNERSHIP

Steel Hector & Davis LLP
215 South Monroe, Suite 601
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850.222.2300
850.222.8410 Fax
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November 19, 1998

Charles A. Guyton
850.222.3423

Robert Scheffel Wright, Esquire
Landers & Parson
310 West College Avenue
Tallahassee, Florida 32301

Via Hand Delivery

In re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.
Docket No. 981042-EM

Dear Mr. Wright:

Enclosed please find Florida Power & Light Company's Answers to Petitioners' First Set of Interrogatories (Nos.1-14) to Florida Power & Light Company in Docket No. 981042-EM.

Very truly yours,

Charles A Guyton

Charles A. Guyton

Enc.
cc: Parties of Record

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 28
COMPANY/ WITNESS: Duke Energy
DATE: 12-2-98

TAL/26565-1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	**DOCKET NO. 981042-EM** **DATE: November 19, 1998**

FLORIDA POWER & LIGHT COMPANY'S
ANSWERS TO PETITIONERS' FIRST SET OF INTERROGATORIES (NOS. 1-14)

Florida Power & Light Company ("FPL"), pursuant to Uniform Rule 28-106.206, Florida Administrative Code, hereby answers Petitioners' First Set of Interrogatories (Nos. 1-14). Affidavits identifying the individuals who assisted in preparation of the answers are attached to this response and incorporated within.

Respectfully submitted,

STEEL HECTOR & DAVIS LLP
215 South Monroe Street
Suite 601
Tallahassee, FL 32301
(850) 222-2300

Attorneys for Florida Power
& Light Company

By: Charles A. Guyton
Charles A. Guyton

1. If FPL believes that the Commission does not have sufficient information to assess the need for the New Smyrna Beach Power Project under the criteria set forth in Section 403.519, F.S., please state with particularity what additional information FPL alleges must be provided to the Commission by the Petitioners.

   The Petitioners have not supplied utility specific information addressing the specific utility's' need for this project, how the project meets that utility's reliability criteria, whether it will produce electricity at reasonable cost, whether there are conservation measures which might mitigate the need for the project, and whether the proposed project is the most cost effective alternative available to that specific utility.

   Conspicuously absent are: the identity of the entities purchasing the output of the facility; their load forecast, resource projections, reliability criteria; the other options considered to meet need; comparisons of options; details on cost; terms and conditions of purchase that would affect reliability; terms and conditions of purchase that would affect cost effectiveness; details on unit performance and engineering. (Mario Villar)

2. If FPL believes that the Commission does not have sufficient information on the site, design and engineering characteristics for the New Smyrna Beach Power Project to evaluate the project, please state with particularity what additional information FPL alleges must be provided to the Commission by the Petitioners.

   The Petitioners have not disclosed any detailed information regarding the unit's projected operation. The Petitioners need to provide the Commission with sufficient detailed information to allow it to assess the unit's performance. (Mario Villar)

3. Has FPL ever obtained a determination of need from the Commission in which some portion of the capacity of the subject power plant was not committed? If the answer is yes, please identify the following:

   a. the facility;
   b. the amount of excess capacity; and
   c. the Commission docket in which the determination of need was granted.

   No. (Mario Villar)

4. In paragraph 18 of FPL's Petition for Leave to Intervene, FPL alleges that the Petitioners' proposal will "result in the uneconomic duplication of generating facilities." Please state with particularity the basis for this allegation and identify all analyses and models that support this allegation.

The Petitioners' premise their need on the Peninsular Florida, a planning convention which is an aggregation of individual utilities. The "Peninsular Florida" utilities have plans in place to meet their needs based on their own reliability criteria. As none of those utilities have a final purchased power contract in place with the project, the project will result in the uneconomic duplication of facilities. FPL did not perform any analyses to make this allegation. (Mario Villar)

5. In paragraph 18 of FPL's Petition for Leave to Intervene, FPL alleges that the Petitioners' proposal will "tie up transmission facilities which will adversely affect the ability of FPL and other utilities to meet their service obligations." Please state with particularity the basis for the allegation, identify which transmission facility or facilities will be "tied up," and identify all analyses and models that support the allegation.

The allegation in the petition to intervene was not based upon an analysis or model. It was based on the knowledge that the allegation in the Joint Petition that the power from the Project would flow over the FPL and FPC systems. Any use of FPL's system ties up FPL transmission facilities which would otherwise be available to meet FPL service obligations. (Juan Villar)

6. In paragraph 33 of FPL's Petition for Leave to Intervene, FPL alleges that the relief sought in this proceeding "would adversely affect FPL by displacing oil-fired and gas-fired generation on the FPL system." Please identify the "oil-fired and gas-fired generation on the FPL system" that will be displaced and please identify all analyses and models that support this allegation.

FPL's allegation was based on the Petitioners' representations in their Joint Petition for Determination of Need. The Petitioners' represented that the New Smyrna Beach Power Project would replace oil and gas-fired generation in Peninsular Florida. FPL has over 45% of all Peninsular Florida's oil and gas-fired generation; therefore, the potential is that it would affect FPL's oil and gas fired generation. FPL has not performed any analyses in this regard. (Mario Villar)

7. If purchases of firm capacity and energy from the New Smyrna Beach Power Project are available to FPL at favorable prices (i.e., prices that are cost-effective to FPL), and on terms and conditions comparable to those applicable to power purchases from other utilities and wholesale suppliers, will FPL purchase such capacity and energy?

Without a contract and other relevant facts, FPL cannot reasonably speculate as to whether it would make this hypothetical purchase. (Mario Villar)

8. If purchases of energy from the New Smyrna Beach Power Project are available to FPL at favorable, i.e., cost-effective, prices, and on terms and conditions comparable to those

applicable to power purchases from other utilities and wholesale suppliers, will FPL purchase such energy?

Without a contract and other relevant facts, FPL cannot reasonably speculate as to whether it would make this hypothetical purchase. (Mario Villar)

9. In 1998, did FPL sell any energy generated at plants within Florida to an out-of-state utility? If yes, please identify:

   a. the date or dates the energy was sold out of state;
   b. the utility to which FPL sold the energy;
   c. the amount of energy sold out-of-state; and
   d. the price FPL was paid for the energy.

Yes. Enclosed as Attachment A is a copy of FPL's filings with the Florida Public Service Commission regarding such sales. (Joe Stepenovitch)

10. Does FPL contend that the construction and operation of the New Smyrna Beach Power Project will lead to the existence of stranded costs for FPL? (For purposes of this interrogatory, stranded costs mean an investment with a cost recovery schedule that was initially approved by regulatory action that subsequent regulatory action or market forces has rendered not practically recoverable. Costs that electric utilities are currently permitted to recover through their rates but whose recovery may be impeded or prevented by the advent of competition in the industry.) If yes, please quantify those stranded costs and identify all analyses or models that FPL used to calculate such costs.

FPL has not made that contention. FPL does not have sufficient information to ascertain, and will not speculate on, whether this project will create stranded costs in FPL's or any other utility's system. (Mario Villar)

11. Does FPL or any of its affiliates or parent entities own any interest in any existing or proposed "qualifying facilities" ("QF") within the meaning of the Public Utility Regulatory Policies Act, or in "exempt wholesale generators," ("EWG") within the meaning of the Energy Policy Act of 1992 and the Public Utility Holding Company Act of 1935, in Florida or in any other states other than Florida? If yes, please identify:

   a. the name of the QF or EWG;
   b. the location of the QF or EWG;
   c. the capacity of the facility; and
   d. the in-service date for the facility

FPL does not own any interest in any Qualifying Facility or Exempt Wholesale Generator. FPL has previously objected that FPL's affiliates or parent entities ownership in any QFs or EWGs is irrelevant and immaterial and not reasonably calculated to lead to admissible evidence. (Mario Villar)

12. Does FPL contend that the Commission's granting the determination of need requested by the Joint Petitioners will create a risk that either (a) past and future investments made by FPL, or by any other electric utility in Florida, would not be recovered, or (b) that such non-recovery would result in increased costs of providing electric service or in increased costs of maintaining future service reliability? If the answer to either component of this question is yes, please explain how such results would occur.

Yes. The petitioners sponsor testimony that the project will displace generation from existing generating units and that some such units should be retired. If the project led to such unit retirement, then there is a risk that the cost of such a retired unit would not be recovered. A risk of non-recovery would increase FPL's cost of capital, increasing its cost of producing service and its costs of maintaining future service reliability. (Mario Villar)

13. Does FPL contend that the Commission's granting the determination of need for the New Smyrna Beach Power Project as requested by the Petitioners would result in increased costs of providing electric service or in increased costs of maintaining service reliability being incurred by FPL or by any other electric utility in Florida? If the answer to this question is yes, please: (a) state with particularity the projected impact on FPL or on such other utility and (b) identify all analyses, studies, or reports that purport to show that such results would occur.

FPL has not made this contention. FPL and the Commission do not have sufficient information to ascertain, and FPL will not speculate on, whether the Project would increase FPL's or other utilities costs of providing electric service or maintaining system reliability. (Mario Villar)

14. Does FPL contend that the Commission's granting the determination of need for the New Smyrna Beach Power Project as requested by the Petitioners would result in FPL's past or future investments, or in the past or future investments of any other electric utility in Florida not being recovered? If the answer to this question is yes, please: (a) state with particularity the projected impact on FPL or on such other utility and (b) identify all analyses, studies, or reports that purport to show that such results would occur.

No, FPL has not made such a contention. Neither FPL nor the Commission have sufficient information to determine whether granting a determination of need will result in past or

future investments not being recovered. The petitioners' position and testimony suggest that the unit may displace existing generation, but that cannot be determined absent the identity of the purchasers and the terms and conditions of purchase. Even with that information one would only be able to conclude as to whether there was risk of non recovery. (Mario Villar)

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI-DADE)

BEFORE ME, the undersigned authority, personally appeared Mario Villar, who being first duly sworn deposes and says:

That he occupies the position of Manager Resource Planning, in the Resource Assessment and Planning Department of Florida Power & Light Company, 9250 W. Flagler Street, Miami, Florida and is the person who is sponsoring the answers to the Petitioners' First Set of Interrogatories, Interrogatory Nos. 1-4, 6-8 and 10-14, Docket No. 981042-EM, and further says that said answers are true and correct to the best of his knowledge and belief.

I hereby certify that on this 16 day of NOVEMBER, 1998, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Mario Villar who is personally known to me, and he acknowledged before me that he executed this certification of signature as his free act and deed.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16 day of NOVEMBER 1998.

Tina Schlamkowitz
Notary Public, State of Florida
My comm. expires June 16, 2000
No. CC561498

Notary Public
State of Florida
My Commission Expires: JUNE 16, 2000

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

BEFORE ME, the undersigned authority, personally appeared Joseph P. Stepenovitch, who being first duly sworn deposes and says:

That he occupies the position of Director, Energy Marketing and Trading Division, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida and is the person who is sponsoring the answer to the Petitioners' First Set of Interrogatories, Interrogatory No. 9, Docket No. 981042-EM, and further says that said answer is true and correct to the best of his knowledge and belief.

Joseph P. Stepenovitch

I hereby certify that on this 16th day of NOV, 1998, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Joseph P. Stepenovitch who is personally known to me, and he acknowledged before me that he executed this certification of signature as his free act and deed.

In Witness whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of NOV, 1998.

Diane S. Munroe

Notary Public
State of Florida
My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA
DIANE S. MUNROE
MY COMMISSION # CC 692809
EXPIRES: October 30, 2001
1-800-3-NOTARY Fla. Notary Service & Bonding Co.

AFFIDAVIT

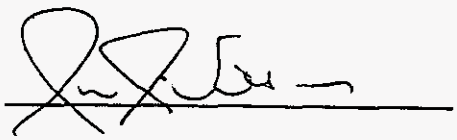
AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI-DADE)

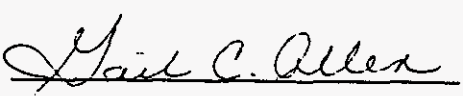
BEFORE ME, the undersigned authority, personally appeared Juan R. Villar, who being first duly sworn deposes and says:

That he occupies the position of Supervisor Technical Policy and Analysis, System Planning, in the Power Delivery Business Unit of Florida Power & Light Company, 4200 W. Flagler Street, Miami, Florida and is the person who is sponsoring the answer to the Petitioners' First Set of Interrogatories, Interrogatory No. 5, Docket No. 981042-EM, and further says that said answer is true and correct to the best of his knowledge and belief.



I hereby certify that on this 17th day of November 1998, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan R. Villar who is personally known to me, and he acknowledged before me that he executed this certification of signature as his free act and deed.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 17th day of November 1998.



Notary Public
State of Florida
My Commission Expires: 5/12/02

OFFICIAL NOTARY SEAL
GAIL C ALLEN
NOTARY PUBLIC STATE OF FLORIDA
COMMISSION NO. CC734624
MY COMMISSION EXP. MAY 12,2002

SCHEDULE A8

POWER SOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF JANUARY 1998

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					cents/KWH			
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	(a) FUEL COST	(b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (5) x (6)(a)	TOTAL COST $ (5) X (6)(b)
ESTIMATED:								
	C	40,817	0	40,817	2.695	3.282	1,100,016	1,339,611
	OS	31,383	0	31,383	2.695	3.282	845,774	1,029,993
	S	0	0	0	0.000	0.000	0	0
		44,914	0	44,914	0.389	0.389	174,530	174,530
							191,676	
ST. LUCIE RELIABILITY								
80% OF GAIN ON ECONOMY SALES								
TOTAL		117,114	0	117,114	1.810	2.172	2,311,996	2,544,134 *
ACTUAL:								
ECONOMY		5,333	0	5,333	2.447	3.243	130,487	172,937
FMPA (SL 1)		15,899	0	15,899	0.602	0.602	95,714	95,714
OUC (SL 1)		10,995	0	10,995	0.602	0.602	66,186	66,186
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		1,163	0	1,163	1.873	2.154	21,781	25,048
FLORIDA KEYS ELECTRIC COOPERATIVE (Prior Mo. Adj.)		(956)	0	(956)	58.555	58.555	(559,783)	(559,783)
ENRON	OS	17,477	0	17,477	1.735	2.381	303,188	416,124
FLORIDA POWER CORPORATION	OS	112	0	112	2.839	1.660	3,180	1,859
CITY OF GAINESVILLE (Prior Month Adjustment)	OS	0	0	0	0.000	0.000	303	0
CITY OF HOMESTEAD	OS	37	0	37	2.092	2.481	774	918
JACKSONVILLE ELECTRIC AUTHORITY (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	63	0
UTILITY BOARD OF THE CITY OF KEY WEST	OS	4,986	0	4,986	1.979	2.786	98,696	138,916
CITY OF LAKE WORTH UTILITIES	OS	450	0	450	1.883	2.688	8,473	12,098
LOUISVILLE G & E POWER MARKETING	OS	9,218	0	9,218	1.477	1.568	136,172	144,574
UTIL COMM, CITY OF NEW SMYRNA BEACH	OS	1,692	0	1,692	1.980	3.717	33,501	62,900
OGLETHORPE POWER CORPORATION	OS	200	0	200	2.124	2.859	4,248	5,717
ORLANDO UTILITIES COMMISSION (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	169	0
SEMINOLE ELECTRIC COOPERATIVE, INC. (Prior Mo. Adj.)	OS	0	0	0	0.000	0.000	103	0
SOUTHERN COMPANIES	OS	14,099	0	14,099	1.890	2.584	266,465	364,272
CITY OF TALLAHASSEE	OS	829	0	829	1.475	1.655	12,230	13,724
THE ENERGY ALTERNATIVE	OS	2,639	0	2,639	1.654	1.865	43,659	49,219
TAMPA ELECTRIC COMPANY (Prior Mo. Adj.)	OS	(6)	0	(6)	(1.867)	3.450	112	(207)
ECONOMY SUB-TOTAL		5,333	0	5,333	2.447	3.243	130,487	172,937
ST. LUCIE PARTICIPATION SUB-TOTAL		26,894	0	26,894	0.602	0.602	161,902	161,902
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		51,940	0	51,940	0.719	1.300	373,334	675,379
80% OF GAIN ON ECONOMY SALES (SEE SCHED A6a)							33,960	
TOTAL		84,167	0	84,167	0.791	1.200	699,683	1,010,218 *
CURRENT MONTH:								
DIFFERENCE		(32,947)	0	(32,947)	(1.020)	(0.972)	(1,612,313)	(1,533,916)
DIFFERENCE (%)		(28.1)	0.0	(28.1)	(56.3)	(44.7)	(69.7)	(60.3)
PERIOD TO DATE:								
ACTUAL		333,502	0	333,502	1.856	2.731	8,390,224	9,107,691
ESTIMATED		404,402	0	404,402	3.501	3.032	10,300,330	12,260,222
DIFFERENCE		(70,900)	0	(70,900)	(1.645)	(0.301)	(3,910,106)	(3,152,331)
DIFFERENCE (%)		(17.5)	0.0	(17.5)	(47.0)	(9.9)	(37.9)	(25.7)

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.

POWER SOLD
COMPANY FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF FEBRUARY 1998

SCHEDULE A6

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					cents/KWH			
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	(a) FUEL COST	(b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (5) x (6)(a)	TOTAL COST $ (5) X (6)(b)
ESTIMATED:								
	C	45,853	0	45,853	2.518	3.160	1,154,591	1,448,970
	OS	8,047	0	8,047	2.518	3.160	202,611	254,270
	S	0	0	0	0.000	0.000	0	0
ST. LUCIE RELIABILITY		40,594	0	40,594	0.389	0.389	157,870	157,870
80% OF GAIN ON ECONOMY SALES							235,503	
TOTAL		94,494	0	94,494	1.603	1.970	1,750,575	1,861,110 *
ACTUAL:								
ECONOMY **		9,904	0	9,904	2.288	2.620	226,633	259,532
FMPA (SL 1)		23,808	0	23,808	0.551	0.551	131,133	131,133
OUC (SL 1)		16,463	0	16,463	0.403	0.403	66,353	66,353
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		420	0	420	0.656	0.754	2,754	3,167
FLORIDA KEYS ELECTRIC COOPERATIVE (Prior Mo. Adj.)		(7)	0	(7)	3.771	3.771	(264)	(264)
ELECTRIC CLEARINGHOUSE	OS	809	0	809	2.016	2.867	16,308	23,197
ENRON	OS	15,786	0	15,786	1.792	2.244	282,920	354,237
FLORIDA POWER CORPORATION	OS	100	0	100	1.641	2.350	1,641	2,350
CITY OF GAINESVILLE	OS	1,787	0	1,787	1.676	2.530	29,957	45,211
CITY OF HOMESTEAD	OS	358	0	358	1.866	2.689	6,689	9,627
UTILITY BOARD OF THE CITY OF KEY WEST	OS	7,297	0	7,297	1.983	2.837	144,686	207,022
KOCH POWER	OS	1,600	0	1,600	1.843	2.400	29,488	38,400
LOUISVILLE G & E POWER MARKETING	OS	11,441	0	11,441	1.597	1.970	182,691	225,335
NP ENERGY	OS	123	0	123	1.285	1.625	1,581	1,999
UTIL COMM, CITY OF NEW SMYRNA BEACH	OS	485	0	485	2.113	3.258	10,249	15,803
OGLETHORPE POWER CORPORATION	OS	4,974	0	4,974	1.816	2.357	90,333	117,252
ORLANDO UTILITIES COMMISSION	OS	275	0	275	2.156	2.800	5,930	7,700
SEMINOLE ELECTRIC COOPERATIVE, INC.	OS	125	0	125	1.699	2.560	2,124	3,200
SOUTHERN COMPANIES	OS	28,528	0	28,528	1.905	2.521	543,458	719,219
SOUTH CAROLINA	OS	1,300	0	1,300	2.035	2.960	26,455	38,475
CITY OF TALLAHASSEE (Prior Month Adjustment)	OS	(328)	0	(328)	2.888	1.840	(9,472)	(6,034)
THE ENERGY ALTERNATIVE	OS	5,662	0	5,662	1.685	2.102	95,419	119,005
TAMPA ELECTRIC COMPANY	OS	4,803	0	4,803	2.007	3.274	96,420	157,273
ECONOMY SUB-TOTAL		9,904	0	9,904	2.288	2.620	226,633	259,532
ST. LUCIE PARTICIPATION SUB-TOTAL		40,271	0	40,271	0.490	0.490	197,486	197,486
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		85,538	0	85,538	1.824	2.434	1,560,162	2,082,174
80% OF GAIN ON ECONOMY SALES (SEE SCHED A6a)							26,319	
TOTAL		135,713	0	135,713	1.462	1.871	2,010,600	2,539,192 *
CURRENT MONTH:								
DIFFERENCE		41,219	0	41,219	(0.141)	(0.099)	260,025	678,082
DIFFERENCE (%)		43.6	0.0	43.6	(8.8)	(5.0)	14.9	30.4
PERIOD TO DATE:								
ACTUAL		469,215	0	469,215	1.742	2.482	8,406,824	11,647,083
ESTIMATED		498,896	0	498,896	3.141	2.831	12,056,905	14,121,332
DIFFERENCE		(29,681)	0	(29,681)	(1.399)	(0.348)	(3,650,081)	(2,474,249)
DIFFERENCE (%)		(5.9)	0.0	(5.9)	(44.5)	(12.3)	(30.3)	(17.5)

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.
** C-SCHEDULE TRANSMISSION INCLUDED = 30,821

POWER SOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF MARCH 1998

SCHEDULE A6

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					cents/KWH			
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	(a) FUEL COST	(b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (5)x(6)(a)	TOTAL COST $ (5)X(6)(b)
ESTIMATED:								
	C	12,504	0	12,504	2.432	3.100	304,102	387,630
	OS	10,196	0	10,196	2.432	3.100	247,962	316,070
	S	0	0	0	0.000	0.000	0	0
ST. LUCIE RELIABILITY		44,914	0	44,914	0.389	0.389	174,820	174,820
80% OF GAIN ON ECONOMY SALES							66,822	
TOTAL		67,614	0	67,614	1.075	1.299	793,706	878,520 *
ACTUAL:								
ECONOMY **		19,969	0	19,969	2.158	2.459	430,885	491,119
FMPA (SL 1)		21,518	0	21,518	0.552	0.552	118,872	118,872
OUC (SL 1)		14,880	0	14,880	0.420	0.420	62,496	62,496
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		352	0	352	1.518	1.745	$,342	6,143
FLORIDA KEYS ELECTRIC COOPERATIVE (Prior Mo. Adj.)		142	0	142	2.396	2.396	3,403	3,403
AMERICAN ELECTRIC POWER	OS	19,902	0	19,902	1.821	3.363	362,361	669,247
AQUILA	OS	2,546	0	2,546	1.817	2.412	46,258	61,408
CP&L	OS	642	0	642	2.154	3.450	13,828	22,149
DUKE POWER	OS	1,456	0	1,456	1.646	2.390	23,960	34,802
ELECTRIC CLEARINGHOUSE	OS	4,960	0	4,960	1.869	2.800	92,679	138,880
ENRON	OS	41,560	0	41,560	1.857	1.924	771,962	799,786
ENTERGY	OS	250	0	250	1.697	3.800	4,243	9,500
FLORIDA POWER CORPORATION (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	10	0
CITY OF GAINESVILLE	OS	55,800	0	55,800	1.712	2.530	955,191	1,411,740
CITY OF HOMESTEAD (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	16	0
JACKSONVILLE ELECTRIC AUTHORITY (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	24	0
UTILITY BOARD OF THE CITY OF KEY WEST	OS	10,645	0	10,645	1.916	3.212	203,950	341,940
KOCH POWER	OS	1,664	0	1,664	1.883	3.200	31,341	53,248
LOUISVILLE G & E POWER MARKETING	OS	17,507	0	17,507	1.665	2.275	291,433	398,211
NP ENERGY (Prior Month Adjustment)	OS	(3)	0	(3)	1.267	1.633	(38)	(49)
UTIL COMM, CITY OF NEW SMYRNA BEACH	OS	567	0	567	1.940	3.952	10,999	22,406
OGLETHORPE POWER CORPORATION	OS	14,496	0	14,496	2.249	3.020	326,043	437,828
ORLANDO UTILITIES COMMISSION	OS	76	0	76	1.863	3.763	1,416	2,860
REEDY CREEK IMPROVEMENT DISTRICT	OS	4,960	0	4,960	1.869	2.800	92,679	138,880
SEMINOLE ELECTRIC COOPERATIVE, INC.	OS	63,812	0	63,812	1.542	2.005	984,022	1,279,659
SOUTHERN COMPANIES	OS	49,093	0	49,093	2.393	3.572	1,174,982	1,753,724
CITY OF TALLAHASSEE	OS	402	0	402	76.530	6.042	307,650	24,288
TAMPA ELECTRIC COMPANY	OS	11,389	0	11,389	1.878	3.293	213,890	375,092
THE ENERGY AUTHORITY	OS	8,189	0	8,189	1.481	3.002	121,294	245,835
TVA	OS	44,361	0	44,361	1.833	3.391	813,245	1,504,423
ECONOMY SUB-TOTAL		19,969	0	19,969	2.158	2.459	430,885	491,119
ST. LUCIE PARTICIPATION SUB-TOTAL		36,398	0	36,398	0.498	0.498	181,368	181,368
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		354,768	0	354,768	1.931	2.744	6,852,183	9,735,403
80% OF GAIN ON ECONOMY SALES (SEE SCHED A6a)							48,187	
TOTAL		411,135	0	411,135	1.816	2.532	7,512,623	10,407,890 *
CURRENT MONTH:								
DIFFERENCE		343,521	0	343,521	0.741	1.232	6,718,916	9,529,370
DIFFERENCE (%)		506.1	0.0	506.1	68.9	94.8	846.5	1,084.7
PERIOD TO DATE:								
ACTUAL		880,350	0	880,350	1.776	2.506	15,919,447	22,054,973
ESTIMATED		566,510	0	566,510	2.895	2.648	12,850,612	14,999,852
DIFFERENCE		313,840	0	313,840	(1.118)	(0.143)	3,068,835	7,055,121
DIFFERENCE (%)		55.4	0.0	55.4	(38.6)	(5.4)	23.9	47.0

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.
** C-SCHEDULE TRANSMISSION INCLUDED = 61,136

POWER SOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTHS OF OCTOBER 1997 THROUGH MARCH 1998

SCHEDULE A6

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	cents/KWH (a) FUEL COST	cents/KWH (b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (5) x (6)(a)	TOTAL COST $ (5) X (6)(b)
ACTUAL:								
ECONOMY **		93,946	0	93,946	2.306	2.891	2,166,524	2,716,296
FMPA (SL 1)		79,865	0	79,865	0.567	0.567	452,952	452,952
OUC (SL 1)		55,227	0	55,227	0.481	0.481	265,871	265,871
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		4,070	0	4,070	2.266	2.606	92,216	106,047
FLORIDA KEYS ELECTRIC COOPERATIVE (Includes Prior Adj.)		2,756	0	2,756	(25.358)	(25.358)	(698,868)	(698,868)
AMERICAN ELECTRIC POWER SERVICES CORP.	OS	19,902	0	19,902	1.821	3.363	362,361	669,247
AQUILA POWER CORP.(Includes Prior Adj.)	OS	5,026	0	5,026	2.321	(4.736)	116,640	(238,016)
CORAL POWER	OS	842	0	842	2.326	3.913	19,582	32,949
DUKE POWER	OS	2,256	0	2,256	1.790	2.784	40,376	62,802
ELECTRIC CLEARINGHOUSE INC.	OS	6,369	0	6,369	2.007	3.736	127,833	237,945
ENRON POWER MARKETING	OS	76,586	0	76,586	1.828	2.142	1,399,843	1,640,637
ENTERGY SERVICES INC.	OS	4,740	0	4,740	2.969	6.768	140,734	320,780
FLORIDA POWER CORPORATION	OS	15,336	0	15,336	2.269	3.405	348,042	522,116
FT. PIERCE UTILITIES AUTHORITY	OS	68	0	68	2.835	3.662	1,928	2,490
CITY OF GAINESVILLE	OS	57,587	0	57,587	1.714	2.530	986,796	1,456,951
CITY OF HOMESTEAD	OS	792	0	792	2.130	2.822	16,872	22,348
ILLINOIS POWER COMPANY	OS	3,200	0	3,200	2.225	3.850	71,200	123,200
JACKSONVILLE ELECTRIC AUTHORITY (Includes Prior Adj.)	OS	0	0	0	0.000	0.000	2,253	0
UTILITY BOARD OF THE CITY OF KEY WEST	OS	23,320	0	23,320	1.964	3.001	458,045	699,832
KOCH POWER	OS	3,884	0	3,884	2.010	3.086	78,077	119,858
LOUISVILLE G&E POWER MARKETING	OS	38,957	0	38,957	1.566	1.985	609,944	773,364
CITY OF LAKE WORTH UTILITIES	OS	550	0	550	2.085	2.875	11,466	15,810
MORGAN STANLEY CAPITAL GROUP	OS	928	0	928	2.798	3.800	25,967	35,264
UTIL COMM., CITY OF NEW SYMRNA BEACH	OS	5,359	0	5,359	2.103	3.567	112,709	191,153
NP ENERGY INC.	OS	120	0	120	1.286	1.625	1,543	1,950
OGLETHORPE POWER CORPORATION	OS	29,458	0	29,458	2.333	3.284	687,190	967,254
ORLANDO UTILITIES COMMISSION	OS	2,139	0	2,139	2.552	3.659	54,577	78,266
REEDY CREEK IMPROVEMENT DISTRICT	OS	4,960	0	4,960	1.869	2.800	92,679	138,880
SEMINOLE ELECTRIC COOPERATIVE INC.	OS	65,515	0	65,515	1.561	2.043	1,022,620	1,338,668
SONAT	OS	206	0	206	2.095	3.600	4,316	7,416
SOUTH CAROLINA ELECTRIC & GAS	OS	1,300	0	1,300	2.035	2.960	26,455	38,475
SOUTHERN COMPANIES	OS	162,573	0	162,573	2.339	3.487	3,802,869	5,669,051
CITY OF STARKE	OS	8	0	8	2.738	4.500	219	360
CITY OF TALLAHASSEE	OS	903	0	903	34.375	3.541	310,408	31,978
TAMPA ELECTRIC COMPANY	OS	22,542	0	22,542	2.185	3.496	492,487	787,976
THE ENERGY AUTHORITY	OS	18,755	0	18,755	1.724	2.822	323,327	529,229
TENNESSEE VALLEY AUTHORITY	OS	70,305	0	70,305	2.289	4.174	1,609,622	2,934,442
ECONOMY SUB-TOTAL		93,946	0	93,946	2.306	2.891	2,166,524	2,716,296
ST. LUCIE PARTICIPATION SUB-TOTAL		135,092	0	135,092	0.532	0.532	718,823	718,823
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		651,312	0	651,312	1.958	2.859	12,752,328	18,619,854
80% OF GAIN ON ECONOMY SALES (SEE SCHED A6a)							281,771	
TOTAL		880,350	0	880,350	1.776	2.505	15,919,447 *	22,054,973

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.
** EFFECTIVE JANUARY 1998, C-SCHEDULE TRANSMISSION INCLUDED = $120,786

POWER SOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF APRIL 1998

SCHEDULE A6

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		cents/KWH			
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	(a) FUEL COST	(b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (5) X (6)(a)	TOTAL COST $ (5) X (6)(b)
ESTIMATED:								
	C	47,555	0	47,555	2.087	2.774	992,482	1,319,187
	OS	19,245	0	19,245	2.087	2.774	401,634	533,845
	S	0	0	0	0.000	0.000	0	0
ST. LUCIE RELIABILITY		42,741	0	42,741	0.388	0.388	165,630	165,630
80% OF GAIN ON ECONOMY SALES							261,364	
TOTAL		109,541	0	109,541	1.424	1.843	1,821,110	2,018,662 *
ACTUAL:								
ECONOMY		7,917	0	7,917	2.221	2.530	175,832	200,282
FMPA (SL 1)		28,234	0	28,234	0.548	0.548	154,629	154,629
OUC (SL 1)		19,524	0	19,524	0.440	0.440	85,921	85,921
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		1,513	0	1,513	1.783	2.050	26,971	31,017
FLORIDA KEYS ELECTRIC COOPERATIVE (Prior Mo. Adj.)		(68)	0	(68)	2.376	2.376	(1,616)	(1,616)
AMERICAN ELECTRIC POWER	OS	1,941	0	1,941	2.361	2.994	45,821	58,118
CORAL POWER & LIGHT	OS	76	0	76	1.797	2.595	1,366	1,972
DUKE POWER (Prior Month Adjustment)	OS	(56)	0	(56)	(3.596)	2.414	2,014	(1,352)
ELECTRIC CLEARINGHOUSE (Prior Month Adj.)	OS	0	0	0	0.000	0.000	0	42,512
ENRON (Prior Month Adjustment)	OS	(10,405)	0	(10,405)	0.707	0.337	(73,536)	(35,091)
ENTERGY (Prior Month Adjustment)	OS	(10)	0	(10)	(35.950)	3.800	3,595	(380)
FLORIDA MUNICIPAL POWER AGENCY	OS	936	0	936	2.324	2.700	21,753	25,272
CITY OF GAINESVILLE (Prior Month Adjustment)	OS	14,574	0	14,574	2.053	2.644	299,174	385,346
CITY OF HOMESTEAD	OS	24	0	24	2.075	2.646	498	635
JACKSONVILLE ELECTRIC AUTHORITY (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	335	0
UTILITY BOARD OF THE CITY OF KEY WEST (Prior Mo. Adj.)	OS	0	0	0	0.000	0.000	939	0
CITY OF LAKE WORTH UTILITIES	OS	420	0	420	2.378	2.940	9,986	12,346
LOUISVILLE G & E POWER MARKETING	OS	1,059	0	1,059	2.265	2.255	23,987	23,876
UTIL COMM, CITY OF NEW SMYRNA BEACH	OS	174	0	174	2.479	3.833	4,314	6,669
OGLETHORPE POWER CORPORATION (Prior Mo. Adj.)	OS	1,820	0	1,820	(1.549)	2.770	(28,191)	50,413
ORLANDO UTILITIES COMMISSION	OS	100	0	100	2.104	3.500	2,104	3,500
REEDY CREEK IMPROVEMENT DISTRICT (Prior Mo. Adj.)	OS	(4,960)	0	(4,960)	1.869	2.800	(92,679)	(138,880)
SEMINOLE ELECTRIC COOPERATIVE, INC.	OS	36,862	0	36,862	2.529	2.951	932,277	1,087,836
SOUTHERN COMPANIES	OS	13,336	0	13,336	0.338	2.755	45,036	367,391
CITY OF TALLAHASSEE (Prior Month Adjustment)	OS	(117)	0	(117)	258.870	15.700	(302,878)	(18,369)
TAMPA ELECTRIC COMPANY	OS	4,976	0	4,976	2.377	3.729	118,260	185,551
THE ENERGY AUTHORITY (Prior Month Adjustment)	OS	(348)	0	(348)	(7.061)	(8.923)	24,571	31,051
TENNESSEE VALLEY AUTHORITY (Prior Mo. Adj.)	OS	(20,420)	0	(20,420)	1.813	3.460	(370,263)	(706,579)
CITY OF TALLAHASSEE	AF	117	0	117	2.590	15.700	3,030	18,369
ECONOMY SUB-TOTAL		7,917	0	7,917	2.221	2.530	175,832	200,282
ST. LUCIE PARTICIPATION SUB-TOTAL		47,758	0	47,758	0.504	0.504	240,550	240,550
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		41,544	0	41,544	1.677	3.441	696,868	1,429,607
80% OF GAIN ON ECONOMY SALES (SEE SCHED A8a)							19,560	
TOTAL		97,219	0	97,219	1.145	1.924	1,132,810	1,870,439 *
CURRENT MONTH:								
DIFFERENCE		(12,322)	0	(12,322)	(0.279)	0.081	(688,300)	(148,223)
DIFFERENCE (%)		(11.2)	0.0	(11.2)	(19.6)	4.4	(37.8)	(7.3)
PERIOD TO DATE:								
ACTUAL		97,219	0	97,219	1.145	1.924	1,132,810	1,870,439
ESTIMATED		109,541	0	109,541	1.424	1.843	1,821,110	2,018,662
DIFFERENCE		(12,322)	0	(12,322)	(0.279)	0.081	(688,300)	(148,223)
DIFFERENCE (%)		(11.2)	0.0	(11.2)	(19.6)	4.4	(37.8)	(7.3)

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.

POWER SOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF MAY 1998

SCHEDULE A6

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					cents/KWH			
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	(a) FUEL COST	(b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (5) x (6)(a)	TOTAL COST $ (5) X (6)(b)
ESTIMATED:								
	C	11,015	0	11,015	1.863	2.664	205,212	293,443
	OS	18,185	0	18,185	1.863	2.664	338,784	484,445
	S	0	0	0	0.000	0.000	0	0
ST. LUCIE RELIABILITY		44,177	0	44,177	0.389	0.389	171,670	171,670
80% OF GAIN ON ECONOMY SALES							70,585	
TOTAL		73,377	0	73,377	0.975	1.294	786,251	949,558 *
ACTUAL:								
ECONOMY **		10,583	0	10,583	2.766	3.148	292,704	333,203
FMPA (SL 1)		27,230	0	27,230	0.538	0.538	146,523	146,523
OUC (SL 1)		18,831	0	18,831	0.438	0.438	82,387	82,387
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		826	0	826	2.157	2.481	17,817	20,490
FLORIDA KEYS ELECTRIC COOPERATIVE		586	0	586	2.647	2.647	15,509	15,509
AMERICAN ELECTRIC POWER	OS	24,973	0	24,973	2.361	8.470	589,693	2,115,328
AQUILA	OS	107	0	107	2.898	20.000	3,101	21,400
AVISTA ENERGY, INC.	OS	728	0	728	2.849	40.000	20,741	291,200
CP&L	OS	2,000	0	2,000	2.242	4.500	44,840	90,000
COMMONWEALTH EDISON	OS	4,800	0	4,800	2.228	8.100	106,960	388,800
ELECTRIC CLEARINGHOUSE	OS	25	0	25	2.412	7.800	603	1,950
ENRON	OS	75,948	0	75,948	1.855	2.213	1,408,800	1,680,744
ENTERGY	OS	44,676	0	44,676	2.333	7.726	1,042,419	3,451,812
FLORIDA POWER CORPORATION	OS	100	0	100	2.301	4.340	2,301	4,340
CITY OF GAINESVILLE	OS	135	0	135	2.589	2.948	3,495	3,980
CITY OF HOMESTEAD	OS	4,501	0	4,501	2.126	2.901	95,681	130,581
JACKSONVILLE ELECTRIC AUTHORITY (Prior Mo. Adj.)	OS	0	0	0	0.000	0.000	17	0
UTILITY BOARD OF THE CITY OF KEY WEST (Prior Mo. Adj.)	OS	0	0	0	0.000	0.000	(8)	0
KOCH POWER	OS	4,000	0	4,000	2.300	7.940	92,000	317,600
CITY OF LAKE WORTH UTILITIES	OS	7	0	7	1.786	2.457	125	172
LOUISVILLE G & E POWER MARKETING	OS	14,873	0	14,873	2.149	3.880	319,581	577,019
UTIL COMM, CITY OF NEW SMYRNA BEACH	OS	2,992	0	2,992	2.473	3.900	73,988	116,688
NORAM ENERGY SERVICES	OS	208	0	208	1.651	1.950	3,434	4,056
OGLETHORPE POWER CORPORATION	OS	31,954	0	31,954	2.286	5.005	730,545	1,599,240
ORLANDO UTILITIES COMMISSION (Prior Mo. Adj.)	OS	0	0	0	0.000	0.000	11	0
SEMINOLE ELECTRIC COOPERATIVE, INC.	OS	7,961	0	7,961	1.918	2.571	152,680	204,667
SOUTHERN COMPANIES	OS	92,721	0	92,721	2.291	5.714	2,124,060	5,298,166
SOUTH CAROLINA	OS	2,338	0	2,338	2.268	4.833	53,037	113,000
TAMPA ELECTRIC COMPANY	OS	9,227	0	9,227	7.704	15.339	710,888	1,415,289
TEA	OS	1,805	0	1,805	2.238	2.863	40,396	51,681
TVA	OS	9,361	0	9,361	2.338	16.345	218,859	1,530,032
ECONOMY SUB-TOTAL		10,583	0	10,583	2.766	3.148	292,704	333,203
ST. LUCIE PARTICIPATION SUB-TOTAL		46,061	0	46,061	0.497	0.497	228,910	228,910
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		336,852	0	336,852	2.337	5.772	7,871,573	19,443,744
80% OF GAIN ON ECONOMY SALES (SEE SCHED A6a)							32,399	
TOTAL		393,496	0	393,496	2.133	5.084	8,425,586	20,005,857 *
CURRENT MONTH:								
DIFFERENCE		320,119	0	320,119	1.158	3.790	7,639,335	19,056,299
DIFFERENCE (%)		436.3	0.0	436.3	118.7	292.9	971.6	2,006.9
PERIOD TO DATE:								
ACTUAL		490,715	0	490,715	1.937	4.458	9,558,396	21,876,296
ESTIMATED		182,918	0	182,918	1.244	1.623	2,607,361	2,968,220
DIFFERENCE		307,797	0	307,797	0.693	2.835	6,951,035	18,908,076
DIFFERENCE (%)		168.3	0.0	168.3	55.7	174.7	266.6	637.0

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.
** C-SCHEDULE TRANSMISSION INCLUDED = 34,656

POWER SOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF JUNE 1998

SCHEDULE A6

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					cents/KWH			
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	(a) FUEL COST	(b) TOTAL COST	TOTAL $ FOR FUEL ADJ. (5) x (6)(a)	TOTAL COST $ (5) X (6)(b)
ESTIMATED:								
	C	42,176	0	42,176	2.298	3.081	969,214	1,299,456
	OS	88,824	0	88,824	2.298	3.081	2,041,166	2,736,654
	S	0	0	0	0.000	0.000	0	0
ST. LUCIE RELIABILITY		42,740	0	42,740	0.389	0.389	166,220	166,220
80% OF GAIN ON ECONOMY SALES							264,194	
TOTAL		173,740	0	173,740	1.826	2.419	3,440,794	4,202,330 *
ACTUAL:								
ECONOMY **		31,896	0	31,896	3.627	4.387	1,156,852	1,399,360
FMPA (SL 1)		25,339	0	25,339	0.522	0.522	132,298	132,298
OUC (SL 1)		17,246	0	17,246	0.438	0.438	75,465	75,465
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		110	0	110	2.006	2.307	2,207	2,538
FLORIDA KEYS ELECTRIC COOPERATIVE		4,324	0	4,324	3.246	3.246	140,371	140,371
AMERICAN ELECTRIC POWER	OS	325	0	325	2.433	2.125	7,908	6,906
CP&L	OS	214	0	214	3.881	350.000	8,305	749,000
ENRON	OS	50,004	0	50,004	2.858	3.182	1,429,082	1,590,894
ENTERGY	OS	21,625	0	21,625	2.551	7.765	551,596	1,679,091
FLORIDA POWER CORPORATION	OS	6,636	0	6,636	2.774	7.008	184,098	465,072
CITY OF GAINESVILLE	OS	64	0	64	2.450	2.681	1,568	1,716
CITY OF HOMESTEAD	OS	5,707	0	5,707	2.421	3.292	138,190	187,889
KOCH POWER	OS	1,632	0	1,632	2.474	6.690	40,374	109,184
CITY OF LAKELAND	OS	100	0	100	3.295	12.000	3,295	12,000
CITY OF LAKE WORTH UTILITIES (Prior Month Adj.)	OS	0	0	0	0.000	0.000	1	0
LOUISVILLE G & E POWER MARKETING	OS	48,850	0	48,850	2.527	35.478	1,234,679	17,330,992
MORGAN	OS	416	0	416	2.763	280.000	11,494	1,164,800
UTIL COMM, CITY OF NEW SMYRNA BEACH	OS	300	0	300	2.654	6.500	7,961	19,500
OGLETHORPE POWER CORPORATION	OS	95,485	0	95,485	2.436	4.047	2,326,286	3,864,288
ORLANDO UTILITIES COMMISSION	OS	100	0	100	3.295	12.000	3,295	12,000
SEMINOLE ELECTRIC COOPERATIVE, INC. (Prior Month Adj.)	OS	0	0	0	0.000	0.000	20	0
SOUTHERN COMPANIES	OS	42,064	0	42,064	2.689	5.913	1,131,305	2,487,247
THE ENERGY ALTERNATIVE	OS	20,656	0	20,658	2.094	3.472	432,480	717,265
TAMPA ELECTRIC COMPANY	OS	22,844	0	22,844	0.280	0.727	63,890	165,973
TENNESSEE VALLEY AUTHORITY (Prior Month Adj.)	OS	(1)	0	(1)	2.500	88.900	(25)	(889)
TRACTEBEL	OS	8,512	0	8,512	2.374	10.603	202,081	902,544
WILLIAMS	OS	52	0	52	2.202	5.500	1,145	2,860
ECONOMY SUB-TOTAL		31,896	0	31,896	3.627	4.387	1,156,852	1,399,360
ST. LUCIE PARTICIPATION SUB-TOTAL		42,585	0	42,585	0.488	0.488	207,763	207,763
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		330,021	0	330,021	2.400	9.579	7,921,600	31,611,241
80% OF GAIN ON ECONOMY SALES (SEE SCHED A6a)							194,006	
TOTAL		404,502	0	404,502	2.296	8.212	9,480,221	33,218,364 *
CURRENT MONTH:								
DIFFERENCE		230,762	0	230,762	0.467	5.793	6,039,427	29,016,034
DIFFERENCE (%)		132.8	0.0	132.8	25.6	239.5	175.5	690.5
PERIOD TO DATE:								
ACTUAL		895,217	0	895,217	2.099	6.154	19,038,617	55,094,660
ESTIMATED		664,455	0	664,455	0.821	3.925	12,999,190	26,078,626
DIFFERENCE		230,762	0	230,762	1.279	2.230	6,039,427	29,016,034
DIFFERENCE (%)		34.7	0.0	34.7	155.8	56.8	46.5	111.3

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.
** C-SCHEDULE TRANSMISSION INCLUDED = 146,974

POWER BOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF JULY 1998

SCHEDULE A6

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL KWH SOLD (000)	(4) KWH WHEELED FROM OTHER SYSTEMS (000)	(5) KWH FROM OWN GENERATION (000)	(6) cents/KWH (a) FUEL COST	(6) cents/KWH (b) TOTAL COST	(7) TOTAL $ FOR FUEL ADJ. (5) x (6)(a)	(8) TOTAL COST $ (5) X (6)(b)
ESTIMATED:								
	C	81,467	0	81,467	2.753	3.551	1,892,188	2,162,885
	OS	245,433	0	245,433	2.753	3.551	6,756,769	8,715,324
	S	0	0	0	0.000	0.000	0	0
ST. LUCIE RELIABILITY		44,177	0	44,177	0.383	0.383	169,210	169,210
80% OF GAIN ON ECONOMY SALES							392,406	
TOTAL		351,077	0	351,077	2.455	3.152	9,010,373	11,067,229
ACTUAL:								
ECONOMY **		17,130	0	17,130	3.110	3.636	532,667	622,787
FMPA (SL 1)		28,807	0	28,807	0.527	0.527	151,728	151,728
OUC (SL 1)		19,920	0	19,920	0.462	0.462	92,014	92,014
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		928	0	928	1.810	2.082	16,801	19,321
FLORIDA KEYS ELECTRIC COOPERATIVE (Prior Mo. Adj.)		11,069	0	11,069	4.496	4.496	497,717	497,717
AMERICAN ELECTRIC POWER SERICE CORP.	OS	2,481	0	2,481	2.667	58.694	66,164	1,456,200
AQUILA POWER CORPORATION	OS	11,175	0	11,175	2.565	5.000	286,690	558,750
CME	OS	1,204	0	1,204	2.896	73.272	34,890	882,200
CAROLINA POWER & LIGHT	OS	5,217	0	5,217	6.495	34.406	338,848	1,794,962
DUKE POWER	OS	243	0	243	2.314	4.233	5,623	10,287
EWS	OS	1,432	0	1,432	2.574	78.627	36,865	1,126,600
ENRON	OS	42,253	0	42,253	1.778	1.982	750,470	837,378
ENTERGY	OS	15,666	0	15,666	2.831	8.201	443,559	1,284,786
FLORIDA POWER CORPORATION (Prior Mo. Adj.)	OS	0	0	0	0.000	0.000	731	332,340
CITY OF GAINESVILLE	OS	50	0	50	2.298	2.900	1,148	1,450
CITY OF HOMESTEAD	OS	85	0	85	2.432	2.925	2,067	2,486
JACKSONVILLE ELECTRIC AUTHORITY (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	14	0
KOCH POWER SERVICES, INC.	OS	4,396	0	4,396	2.654	47.065	116,716	2,070,760
LOUISVILLE G & E POWER MARKETING	OS	12,220	0	12,220	2.519	6.218	307,818	759,849
MORGAN STANLEY CAPITAL GROUP INC.	OS	152	0	152	3.388	276.053	5,150	419,600
NORAM ENERGY SERVICES, INC.	OS	428	0	428	2.646	46.250	11,325	197,950
OGLETHORPE POWER CORPORATION (Prior Mo. Adj.)	OS	(45,136)	0	(45,136)	2.419	4.041	(1,091,674)	(1,823,849)
ORLANDO UTILITIES COMMISSION (Prior Mo. Adjustment)	OS	(62)	0	(62)	3.256	(56.774)	(2,020)	35,200
PUBLIC SERVICE ELECTRIC & GAS	OS	368	0	368	3.103	29.224	11,416	107,545
UTILITY BOARD CITY NEW SMYRNA BEACH (Prior Mo. Adj.)	OS	0	0	0	0.000	0.000	44	0
SOUTHERN COMPANIES	OS	41,153	0	41,153	2.728	8.140	1,122,607	3,350,011
SOUTH CAROLINA	OS	850	0	850	2.277	4.847	19,352	42,050
CITY OF TALLAHASSEE	OS	60	0	60	3.447	6.500	2,066	3,900
THE ENERGY ALTERNATIVE	OS	4,095	0	4,095	2.233	3.778	91,450	154,783
TAMPA ELECTRIC COMPANY	OS	11,373	0	11,373	2.702	5.392	307,245	613,275
TRACTEBEL	OS	3,000	0	3,000	3.471	53.551	104,137	1,606,525
TENNESSEE VALLEY AUTHORITY	OS	12,497	0	12,497	2.618	10.501	327,357	1,312,280
WILLIAMS	OS	240	0	240	3.558	325.000	8,542	780,000
FLORIDA POWER CORPORATION (Prior Mo. Adj.)	DF	44,301	0	44,301	7.006	9.617	3,103,881	4,260,504
CITY OF HOMESTEAD (Prior Mo. Adj.)	AF	20	0	20	5.160	31.160	1,032	6,232
ECONOMY SUB-TOTAL		17,130	0	17,130	3.110	3.636	532,667	622,787
ST. LUCIE PARTICIPATION SUB-TOTAL		48,727	0	48,727	0.500	0.500	243,740	243,740
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		181,780	0	181,780	3.612	12.481	6,928,512	22,703,292
80% OF GAIN ON ECONOMY SALES (SEE SCHED A8a)							72,060	
TOTAL		247,617	0	247,617	3.112	9.519	7,776,999	23,569,799
CURRENT MONTH:								
DIFFERENCE		(103,460)	0	(103,460)	0.657	6.366	(1,233,574)	12,502,570
DIFFERENCE (%)		(29.5)	0.0	(29.5)	26.8	202.0	(13.7)	113.0
PERIOD TO DATE:								
ACTUAL		1,142,834	0	1,142,834	2.319	6.863	26,815,616	78,664,459
ESTIMATED		1,015,532	0	1,015,532	1.365	3.858	22,009,762	37,145,855
DIFFERENCE		127,302	0	127,302	0.933	3.228	4,805,854	41,518,604
DIFFERENCE (%)		12.5	0.0	12.5	67.3	68.2	21.8	111.8

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.
** C-SCHEDULE TRANSMISSION INCLUDED = 867,364

POWER SOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF AUGUST 1998

SCHEDULE A6

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL KWH SOLD (000)	(4) KWH WHEELED FROM OTHER SYSTEMS (000)	(5) KWH FROM OWN GENERATION (000)	(6) cents/KWH (a) FUEL COST	(6) cents/KWH (b) TOTAL COST	(7) TOTAL $ FOR FUEL ADJ. (5)x(6)(a)	(8) TOTAL COST $ (5)X(6)(b)
ESTIMATED:								
	C	48,746	0	48,746	2.706	3.365	1,319,065	1,640,301
	OS	149,454	0	149,454	2.706	3.365	4,044,227	5,029,129
ST. LUCIE RELIABILITY	S	0	0	0	0.000	0.000	0	0
80% OF GAIN ON ECONOMY SALES		44,177	0	44,177	0.383	0.383	169,300	169,300
TOTAL		242,377	0	242,377	2.283	2.822	256,989 5,789,581	6,838,730
ACTUAL:								
ECONOMY **		21,284	0	21,284	2.259	2.651	480,775	564,288
FMPA (SL 1)		27,967	0	27,967	0.519	0.519	145,205	145,205
OUC (SL 1)		19,340	0	19,340	0.440	0.440	85,167	85,167
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		164	0	164	2.837	3.262	4,652	5,349
FLORIDA KEYS ELECTRIC COOPERATIVE (Prior Mo. Adj.)		2,775	0	2,775	4.444	4.444	123,328	123,328
AMERICAN ELECTRIC POWER SERVICES CORP.	OS	1,780	0	1,780	2.846	25.315	50,659	450,600
AQUILA POWER CORPORATION	OS	3,950	0	3,950	2.517	5.000	99,423	197,500
CP&L	OS	1,600	0	1,600	2.323	10.000	37,168	160,000
COMMONWEALTH EDISON (Prior Mo. Adjustment)	OS	(104)	0	(104)	2.894	74.231	(3,010)	(77,200)
DUKE POWER (Prior Mo. Adjustment)	OS	(9)	0	(9)	2.311	4.233	(208)	(381)
ENRON	OS	50,429	0	50,429	2.666	2.886	1,344,539	1,455,466
ENTERGY	OS	1,869	0	1,869	2.682	6.147	50,119	114,895
FLORIDA POWER CORPORATION	OS	17,241	0	17,241	2.832	11.536	488,312	1,988,979
CITY OF GAINESVILLE (Prior Month Adjustment)	OS	0	0	0	0.000	0.000	51	0
CITY OF HOMESTEAD	OS	445	0	445	1.865	2.678	8,300	11,919
JACKSONVILLE ELECTRIC AUTHORITY (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	58	0
KOCH POWER	OS	802	0	802	2.329	3.349	18,675	26,859
CITY OF LAKE WORTH UTILITIES	OS	15	0	15	2.380	5.500	357	825
LOUISVILLE G & E POWER MARKETING	OS	15,714	0	15,714	2.322	4.878	364,869	766,569
MORGAN	OS	2,840	0	2,840	2.346	4.758	66,631	135,140
UTIL COMM. CITY OF NEW SMYRNA BEACH	OS	54	0	54	2.878	5.200	1,554	2,808
OGLETHORPE POWER CORPORATION	OS	45,003	0	45,003	2.522	5.576	1,135,177	2,509,454
ORLANDO UTILITIES COMMISSION (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	1	0
PUBLIC SERVICE ELECTRIC & GAS	OS	95	0	95	2.736	7.447	2,601	7,075
SEMINOLE ELECTRIC COOPERATIVE, INC.	OS	125	0	125	1.736	2.679	2,170	3,349
SOUTHERN COMPANY SERVICES	OS	62,221	0	62,221	2.310	4.642	1,437,025	2,888,210
SOUTH CAROLINA	OS	600	0	600	1.792	3.308	10,752	19,850
THE ENERGY AUTHORITY	OS	12,230	0	12,230	2.191	3.609	267,948	441,329
TAMPA ELECTRIC COMPANY	OS	15,659	0	15,659	2.477	4.504	387,884	705,333
TENNESSEE VALLEY AUTHORITY	OS	5,176	0	5,176	2.310	6.356	119,553	328,980
TRACTEBEL (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	0	5,100
ECONOMY SUB-TOTAL		21,284	0	21,284	2.259	2.651	480,775	564,288
ST. LUCIE PARTICIPATION SUB-TOTAL		47,307	0	47,307	0.487	0.487	230,372	230,372
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		240,674	0	240,674	2.501	5.099	6,018,568	12,271,336
80% OF GAIN ON ECONOMY SALES (SEE SCHED A6a)							66,810	
TOTAL		309,265	0	309,265	2.176	4.225	6,796,545	13,065,996
CURRENT MONTH:								
DIFFERENCE		66,888	0	66,888	(0.107)	1.403	1,006,964	6,227,266
DIFFERENCE (%)		27.6	0.0	27.6	(4.7)	49.7	17.4	91.1
PERIOD TO DATE:								
ACTUAL		1,452,099	0	1,452,099	2.288	6.317	33,612,161	91,730,455
ESTIMATED		1,257,909	0	1,257,909	1.558	3.497	27,799,343	43,964,585
DIFFERENCE		194,190	0	194,190	0.730	2.820	5,812,818	47,745,870
DIFFERENCE (%)		15.4	0.0	15.4	46.8	80.7	20.9	108.6

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.
** C-SCHEDULE TRANSMISSION INCLUDED = $12,069

POWER SOLD
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTH OF SEPTEMBER 1998

SCHEDULE A6

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL KWH SOLD (000)	(4) KWH WHEELED FROM OTHER SYSTEMS (000)	(5) KWH FROM OWN GENERATION (000)	(6) cents/KWH (a) FUEL COST	(6) cents/KWH (b) TOTAL COST	(7) TOTAL $ FOR FUEL ADJ. (5) x (6)(a)	(8) TOTAL COST $ (5) X (6)(b)
ESTIMATED:								
	C	12,659	0	12,659	2.113	2.844	267,494	360,034
	OS	54,493	0	54,493	2.113	2.844	1,151,426	1,549,769
	S	0	0	0	0.000	0.000	0	0
ST. LUCIE RELIABILITY		45,057	0	45,057	0.384	0.384	172,810	172,810
80% OF GAIN ON ECONOMY SALES							74,032	
TOTAL		112,209	0	112,209	1.419	1.858	1,665,764	2,082,613
ACTUAL:								
ECONOMY		12,517	0	12,517	2.798	3.010	350,261	376,788
FMPA (SL 1)		27,869	0	27,869	0.501	0.501	139,591	139,591
OUC (SL 1)		19,272	0	19,272	0.425	0.425	81,903	81,903
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		678	0	678	1.635	1.880	11,088	12,749
FLORIDA KEYS ELECTRIC COOPERATIVE (Prior Mo. Adj.)		5,474	0	5,474	3.489	3.489	191,006	191,006
AMERICAN ELECTRIC POWER SERVICE CORP.	OS	875	0	875	1.913	13.029	16,742	114,000
DUKE POWER	OS	104	0	104	2.382	5.825	2,477	6,058
ENRON	OS	38,740	0	38,740	1.696	1.778	657,114	688,376
ENTERGY	OS	17,758	0	17,758	2.681	6.058	476,033	1,075,496
FLORIDA POWER CORPORATION (Prior Month Adjustment)	OS	100	0	100	4.749	351.114	4,749	351,114
CITY OF GAINESVILLE (Prior Month Adjustment)	OS	0	0	0	0.000	0.000	53	0
CITY OF HOMESTEAD	OS	399	0	399	2.132	2.612	8,506	10,420
JACKSONVILLE ELECTRIC AUTHORITY (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	13	0
KOCH POWER SERVICES INC.	OS	1,726	0	1,726	2.695	5.895	46,511	103,481
CITY OF LAKE WORTH UTILITIES (Prior Mo. Adjustment)	OS	0	0	0	0.000	0.000	2	0
LOUISVILLE G & E POWER MARKETING	OS	14,268	0	14,268	2.170	3.587	309,650	511,781
MORGAN	OS	5,880	0	5,880	2.209	3.255	129,883	191,420
MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA	OS	30	0	30	2.377	4.700	713	1,410
UTIL COMM, CITY OF NEW SMYRNA BEACH (Prior Mo. Adj.)	OS	0	0	0	0.000	0.000	11	0
OGLETHORPE POWER CORPORATION	OS	15,248	0	15,248	2.308	3.789	351,986	577,784
ORLANDO UTILITIES COMMISSION	OS	425	0	425	1.763	2.400	7,493	10,200
SEMINOLE ELECTRIC COOPERATIVE, INC.	OS	1,300	0	1,300	2.175	3.500	28,275	45,500
SOUTHERN COMPANY SERVICES INC.	OS	74,410	0	74,410	2.353	5.284	1,750,589	3,931,759
TAMPA ELECTRIC COMPANY	OS	4,944	0	4,944	2.307	3.888	114,058	192,242
TENNESSEE VALLEY AUTHORITY	OS	32,419	0	32,419	2.120	5.850	687,272	1,831,596
THE ENERGY AUTHORITY	OS	15,343	0	15,343	2.192	3.852	336,284	591,048
VIRGINIA POWER	OS	1,100	0	1,100	2.116	4.500	23,276	49,500
ECONOMY SUB-TOTAL		12,517	0	12,517	2.798	3.010	350,261	376,788
ST. LUCIE PARTICIPATION SUB-TOTAL		47,141	0	47,141	0.470	0.470	221,484	221,484
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		231,221	0	231,221	2.229	4.536	5,153,762	10,487,940
80% OF GAIN ON ECONOMY SALES (SEE SCHED A8a)							21,222	
TOTAL		290,879	0	290,879	1.968	3.811	5,746,739	11,086,222
CURRENT MONTH:								
DIFFERENCE		178,670	0	178,670	0.550	1.955	4,080,975	9,003,609
DIFFERENCE (%)		159.2	0.0	159.2	38.8	105.3	245.0	432.3
PERIOD TO DATE:								
ACTUAL		1,742,978	0	1,742,978	2.235	5.899	38,958,900	102,816,677
ESTIMATED		1,370,118	0	1,370,118	1.647	3.362	29,485,107	46,067,198
DIFFERENCE		372,860	0	372,860	0.588	2.537	9,893,793	56,749,479
DIFFERENCE (%)		27.2	0.0	27.2	44.5	75.4	33.6	123.2

* ONLY TOTAL $ INCLUDES 80% OF GAIN ON ECONOMY SALES.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's Answers Petitioners' First Set of Interrogatories (Nos. 1-14) in Docket No. 981042-EM was served by Hand Delivery (when indicated with an *) or mailed this 19th day of November, 1998 to the following:

Leslie J. Paugh, Esq.*
Legal Division
Florida Public Service Commission
2540 Shumard Oak Boulevard
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Ausley & McMullen
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Florida Power Corp.
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St. Petersburg, FL 33733

Robert Scheffel Wright, Esq. *
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William Willingham, Esq.
Michelle Hershel, Esq.
FECA
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Utilities Director
Utilities Commission
City of New Smyrna Beach
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New Smyrna Beach, FL 32170-0100

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Structured Transactions
Duke Energy Power Services LLC
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Moyle Flanigan, et al.
210 South Monroe Street
Tallahassee, FL 32301

By: Charles A. Guyton
Charles A. Guyton

29

STEEL HECTOR & DAVIS

REGISTERED LIMITED LIABILITY PARTNERSHIP

Steel Hector & Davis LLP
215 South Monroe, Suite 601
Tallahassee, Florida 32301-1804
850.222.2300
850.222.8410 Fax
www.steelhector.com

November 19, 1998

Charles A. Guyton
850.222.3423

Robert Scheffel Wright, Esquire
Landers & Parson
310 West College Avenue
Tallahassee, Florida 32301

Via Hand Delivery

In re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.
Docket No. 981042-EM

Dear Mr. Wright:

Enclosed please find Florida Power & Light Company's Responses to Petitioners' First Request for Production of Documents (Nos.1-9) to Florida Power & Light Company in Docket No. 981042-EM.

Very truly yours,

Charles A. Guyton

Charles A. Guyton

Enc.
cc: Parties of Record

TAL/26570-1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 29
COMPANY/
WITNESS: Duke Energy
DATE 12-2-98

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	)))))	**DOCKET NO. 981042-EM** **DATE: November 19, 1998**

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO PETITIONERS' FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-9)

Florida Power & Light Company ("FPL"), pursuant to Uniform Rule 28-106.206, Florida Administrative Code, hereby responds to Petitioners' First Request for Production of Documents (Nos. 1-9).

Respectfully submitted,

STEEL HECTOR & DAVIS LLP
215 South Monroe Street
Suite 601
Tallahassee, FL 32301
(850) 222-2300

Attorneys for Florida Power & Light Company

By: Charles A. Guyton
Charles A. Guyton

1. Please provide all document relied on by Mr. Steinmeier in making his statement at page 21, lines 17-18 of his direct testimony that "[g] ranting the Joint Petition in this case would create the risk that past and future utility investments made to provide service may not be recovered."

No documents.

2. Please provide all documents relied on by Mr. Steinmeier in making his statement at page 18, lines 11-13 of his direct testimony that a positive need determination in this case "could adversely affect FPL's and other Peninsular Florida utilities' ability to meet their service obligations."

No documents.

3. Please provide all documents relied on by Mr. Steinmeier in making his statement at page 18, lines 14-15 that a positive need determination in this case could affect FPL's ability to plan for and meet system need.

No documents.

4. Please provide all documents relied on by Mr. Steinmeier in making his statement at page 18, lines 16-17 that a positive need determination in this case could "lead to uneconomic duplication of facilities to meet need."

No documents.

5. Please provide all documents relied on by Mr. Steinmeier in making his statement at page 18, line 17 that a positive need determination in this case could "adversely affect the customers of Florida utilities."

No documents.

6. Please provide all documents identified in FPL's responses to Interrogatories Nos. 4, 5, 6, 13, and 14.

No documents.

7. Please provide all documents relating to any communication between FPL and the System Council U-4, IBEW concerning the New Smyrna Beach Power Project.

No documents.

8. Please provide any and all gas supply and gas transportation contracts for FPL's proposed Ft. Myers repowering project.

FPL has objected to this request.

9. Please provide any and all gas supply and gas transportation contracts for FPL's proposed Sanford repowering project.

FPL has objected to this request.

By: Charles A. Guyton
Charles A. Guyton

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's Responses to Petitioners' First Request for Production of Documents (Nos. 1-9) in Docket No. 981042-EM was served by Hand Delivery (when indicated with an *) or mailed this 19th day of November, 1998 to the following:

Leslie J. Paugh, Esq.*
Legal Division
Florida Public Service Commission
2540 Shumard Oak Boulevard
Room 370
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Ausley & McMullen
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Tallahassee, FL 32302

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Florida Power Corp.
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St. Petersburg, FL 33733

Robert Scheffel Wright, Esq. *
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Utilities Director
Utilities Commission
City of New Smyrna Beach
Post Office Box 100
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P.O. Box 2861
St. Petersburg, FL 33733

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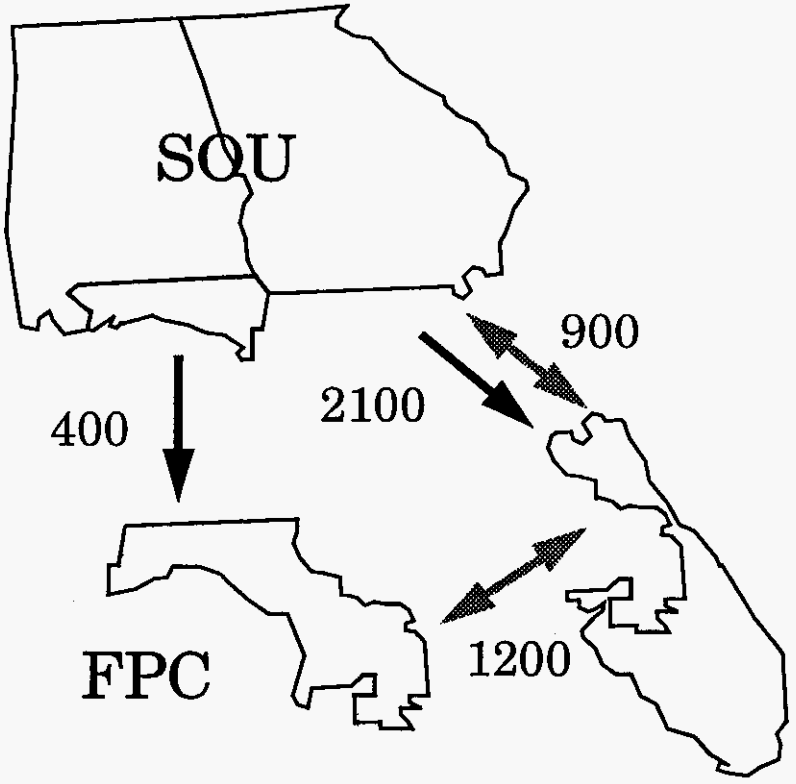
Moyle Flanigan, et al.
210 South Monroe Street
Tallahassee, FL 32301

By: Charles A. Guyton
Charles A. Guyton

TAL/26582-1

Assistance Area Model for TIGER



Tie Capacity Committed By Interchange Contracts

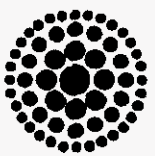
Tie Capacity Available for Economy/Emergency Interchange

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 30
COMPANY/ WITNESS: Duke
DATE: 12-2-98

FLORIDA POWER CORPORATION'S PRESENTATION ON THE APPLICATION OF PLANNING MODELS

TO THE FLORIDA PUBLIC SERVICE COMMISSION

FEBRUARY 25, 1993



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Florida Power
CORPORATION

JAMES A. McC
SENIOR COUN

July 9, 1998

Mr. Tom Ballinger
Division of Electric & Gas
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

RECEIVED
JUL 13 1998
ELECTRIC

Dear Mr. Ballinger:

Enclosed is Florida Power's response to Staff's data request regarding the implementation of our non-firm tariffs on June 2 and 3, 1998. I have also enclosed is a diskette containing the response in WordPerfect format.

Please let me know if you have any questions or require any additional information regarding this matter.

Very truly yours,

James A. McGee

JAM/kma
Enclosures

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 31
COMPANY/ WITNESS: Duke Energy
DATE: 12-2-98

EXHIBIT
7
Dolan 11-16-98

FLORIDA POWER CORPORATION'S RESPONSE TO FPSC STAFF DATA REQUEST REGARDING FPC'S IMPLEMENTATION OF LOAD MANAGEMENT, INTERRUPTIBLE AND CURTAILABLE TARIFFS ON JUNE 2-3, 1998.

1. What provision(s) of FPC's tariff(s) was (were) relied upon when implementing load management and interruptible/curtailable tariffs on the days in question?

Response

Residential/Commercial Load Management Tariffs (June 2nd and 3rd): For interruptions of Air Conditioning load under Rate Schedules RSL-1 and GSLM-1 during the designated Peak Period (1:00 to 10:00 p.m.), FPC relied on and adhered to the tariffs' Interruption Schedules A and B (Pool Pumps are not subject to interruption schedule limitations during the Peak Period). For interruptions of Water Heating load during the Peak Period longer than specified in Interruption Schedule C, and for interruptions of any load outside of the Peak Period, FPC relied on the language in Special Provisions 5 and 7 in RSL-1 and GSLM-1, respectively, which states: "The limitation on Interruptible Schedules shall not apply during critical capacity conditions on the Company's system; ... ."

Interruptible/Curtailable Tariffs (June 2nd only): For interruptions/curtailments under Rate Schedules IS-1, IS-2, CS-1 and CS-2, FPC relied on the language in the "Limitation of Service" section which states: "[Interruptible/Curtailable] service under this rate schedule is subject to [interruption/curtailment] during any time that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments ... ."

2. What was the total number of customers affected by this implementation? List by rate schedule. For residential load management, show number by load management option.

Response

	Customers
June 2nd and 3rd	
Residential Load Management (RSL-1)	523,346
Air Conditioning	462,216
Water Heater	477,127
Pool Pump	56,501
Commercial Load Management (GSLM-1)	450
Standby Generation (GSLM-2)	62
June 2nd	
Interruptible (IS-1, IS-2)	134
Curtailable (CS-1, CS-2)	7
Total	523,999

3. What was the longest period of time any customer was interrupted? The shortest period of time? The average length of time? Provide data by rate schedule.

Response

	Longest Interruption/ Curtailment	Shortest Interruption/ Curtailment	Average Interruption/ Curtailment
June 2nd			
Load Management			
Air Conditioning*	6 hrs., 32 min.	5 hrs., 39 min.	N/A
Water Heating	7 hrs., 45 min.	7 hrs., 5 min.	7 hrs., 20 min.
Pool Pumps	6 hrs., 4 min.	6 hrs., 4 min.	6 hrs., 4 min.
Interruptible/Curtailable	3 hrs., 40 min.	3 hrs., 40 min.	3 hrs., 40 min.
June 3rd			
Load Management			
Air Conditioning*	6 hrs., 54 min.	5 hrs., 8 min.	N/A
Water Heating	9 hrs., 9 min.	7 hrs., 55 min.	8 hrs., 32 min.
Pool Pumps	8 hrs., 12 min.	8 hrs., 12 min.	8 hrs., 12 min.
Interruptible/Curtailable	No interruptions or curtailments.		

* Time periods listed represent the total overall length of time Air Conditioning was subject to interruption. The longest continuous period of interruption was 10 minutes for customers on Schedule A and 16.5 minutes for customers on Schedule B.

4. How many customers experienced the longest period of interruption? Provide data by rate schedule.

Response

	Number of Customers	
Load Management (June 2nd and 3rd)		
Air Conditioning	452,971	(all Schedule B customers)
Water Heating	53,000	(approximate)
Pool Pumps	56,501	
Interruptible (June 2nd only)	134	
Curtailable (June 2nd only)	7	

5. How many KW of load reduction in total were realized through residential load management? Give both coincident and noncoincident numbers.

Response

The maximum load reduction (non-coincident) from residential load management was approximately 714 MW on June 2nd and 673 MW on June 3rd. Coincident load reduction is not meaningful because the time of the system peak was distorted by the "pay back" effect when the use of load management was ramped downed.

6. How many KW of load reduction in total were realized through non-residential load management (including interruptible and curtailable load)? Give both coincident and non-coincident numbers.

Response

The maximum load reduction from non-residential load management cannot be determined until metering data from the individual interruptible and curtailable customers becomes available at the end of July.

7. How many residential customers asked to be taken off load management as a result of the latest heat wave?

Response

During the month of June, 39,737 customers have asked to be partially or completely removed from the residential load management program. In most cases, the "partial removals" involved a request to disconnect air conditioning from the load control device, with other equipment (central heating, water heaters and/or pool pumps) remaining subject to load control.

8. Give the details of the capacity situation that caused FPC to implement load management and/or interruptible tariffs.

Response

The situation that lead to the implementation of load management and interruptible/curtailable tariffs on June 2nd and 3rd was caused by a combination of (1) continuous, near-record high temperatures with no significant precipitation or cloud cover to dissipate the heat, (2) the unavailability or limited availability of purchased power because of similar weather conditions experienced by other utilities throughout the Southeast, and (3) an unscheduled outage at Crystal River 2 (500 MW) and several peaking units (180 MW on June 2nd and 210 MW on June 3rd).

9. On average, over the past year, how many residential load management customers are added monthly? On average, over the past year, how many ask to be removed per month?

Response

For the 12 months ending May 1998, an average of 1,654 load management customers were added each month. Over the same period, an average of 922 customers were partially (528) or completely (394) removed from the program each month.

10. Was the buy-through provision for interruptible customers exercised during these two days? Provide megawatts, megawatt-hours, and hours buy-through was exercised. Also, what was the average price for the buy-through?

Response

Interruptible/curtailable buy-through power was purchased for two hours on June 3rd at an average price of approximately $100 per MWH. The amount used (MWs and MWHs) by these customers cannot be determined until metering data from the individual interruptible and curtailable customers becomes available at the end of July.

11. What has been the average response time to remove a residential customer from load management after a request has been made? What is the procedure for being removed and what physically must be done to remove the customer from load management?

Response

The average response time to remove a customer from the residential load management program is approximately two weeks.

The procedure utilized to accomplish this removal is as follows:

1. The customer contacts FPC.
2. FPC initiates a service order.
3. The service order is assigned to a contractor.
4. The contractor contacts the customer to set up a home appointment.
5. The contractor disables the device. (The device is physically removed only when requested by the home owner.)
6. The contractor returns the completed service order to FPC.
7. FPC updates its customer service system and the customer is returned to the standard residential rate schedule, RS-1 (rate code 01).

12. Is there a disproportionate number of customers who ask to be taken off load management in the Orlando/Orange County area?

Response

No. The percentage of total load management customers in Orange County who asked to be partially or completely removed from the program in the month of June is approximately the same as the overall FPC system.

13. How many days and how many hours per day did FPC plan to exercise load management, by load management option, for 1998?

Response

For operational purposes, FPC plans to have load management available for use during peak conditions on any given day and hour of the year. For planning purposes, FPC projected that Water Heaters and Pool Pumps would be interrupted on 64 days in 1998 for an average duration of 4.8 hours per day, and that Central Heating and Air Conditioning would be interrupted 11 times for an average duration of 3.7 hours per day. (From the customers' perspective, their heating and air conditioning would be subject to interruption for only 20 or 33 minutes during each of these hours, depending on their selection of Interruption Schedule A or B.)

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Florida Power
CORPORATION

PUBLIC AFFAIRS

106 E. College Avenue
Suite 770, HighPoint Center
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FAX NO.: (850) 222-9768
PHONE: (850)222-8738
INTEROFFICE: 231-5095

TO: Tom Ballinger

DATE: 7-23-98

FAX: 413-6681

FROM: GARY ROBERTS ☐ PAUL LEWIS ☐

SUE NOYES ☐ JIM STANFIELD ☑

OTHER: _____

NUMBER OF PAGES TO FOLLOW: 1

SUBJECT: Inquiry on Purchased Power

COMMENTS: The data is being assembled for the next FA. These should be accurate — in any event not far off.

Jim

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 32
COMPANY/ WITNESS: Duke Energy
DATE: 12-2-98

EXHIBIT
8
Doulon 11-16-98

Florida Power Corporation

RE: Inquiry on Purchased Power

Questions posed by Tom Ballinger:

1. For the June and July time period:

   a. What was the highest price per MWH FPC paid? How long?

   * Answer: Through July 20, FPC paid $126/MWH for 2 hrs for straight energy and $376/MWH for capacity and energy for 3 hrs.

2. What was the highest price per MWH FPC sold?

   * Answer: Through July 20, FPC sold capacity and energy in state for $225/MWH for 3 hrs. FPC sold out-of-state for $3,250/MWH for 2 hrs.

*Please note these answers are preliminary and subject to audit.

mwb98.doc

EXHIBIT NO. _____

DOCKET NO: 981042-EM

WITNESS: Michael D. Rib

PARTY: Florida Power Corporation

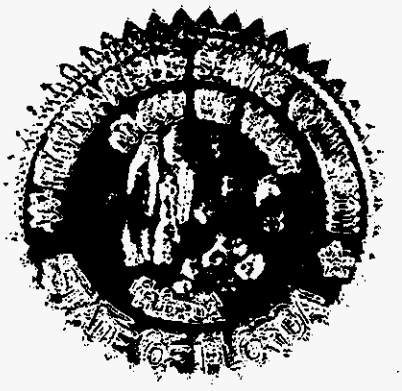
DESCRIPTION: Transcript of the Deposition of Michael D. Rib, Taken at the Instance of the Staff of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 33
COMPANY/ WITNESS: Staff
DATE: 12-2-98

PROFFERING PARTY: STAFF

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of: Joint petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	DOCKET NO. 981042-EM



DEPOSITION OF: **MICHAEL D. RIB**

TAKEN AT THE INSTANCE OF: The Staff of the Florida Public Service Commission

PLACE: Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Room 362
Tallahassee, Florida

TIME: Commenced at 9:00 a.m.

DATE: Thursday, November 12, 1998

REPORTED BY: H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter

APPEARANCES:

ROBERT SCHEFFEL WRIGHT, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302, appearing on behalf of **Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.**

JAMES A. McGEE, Florida Power Corporation, P. O. Box 14042, St. Petersburg, Florida 33733-4042, and **GARY L. SASSO**, Carlton, Fields, Ward, Emmanuel, Smith & Cutler, P.A., Post Office Box 2861, St. Petersburg, Florida 33731, appearing on behalf of **Florida Power Corporation.**

JAMES D. BEASLEY, Ausley & McMullen, 227 South Calhoun Street, Tallahassee, Florida 32302, appearing on behalf of **Tampa Electric Company.**

JON C. MOYLE, JR., Moyle, Flanigan, Katz, Kolins, Raymond & Sheehan, 210 South Monroe Street, Tallahassee, Florida 32301, appearing on behalf of **U. S. Generating Company.**

LESLIE J. PAUGH, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the **Commission Staff.**

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S T I P U L A T I O N

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

MICHAEL D. RIB

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

EXAMINATION

BY MS. PAUGH:

Q Good morning, Mr. Rib, and thank you for coming to Tallahassee for this deposition. We very much appreciate that.

Please state your name for the record.

A Michael Rib.

Q And by whom are you employed?

A Florida Power Corporation.

Q How long have you been employed by Florida Power Corporation?

A Roughly 16 years.

Q What are your duties at Florida Power Corporation?

A Currently I'm the director of resource planning. I'm responsible for determining the company's needs for energy and providing for reliability and cost-effectiveness for the customers.

Q As director of resource planning, could you please describe things that you handle on a day-to-day basis? I'd like to have a fuller description of your job.

A Okay. I'm responsible for preparing 10-year site plans that are submitted to the Commission for review.

Behind those plans is an evaluation of the requirements of our customers; their energy requirements and the demand and the -- as well as looking at the cost, the cost and relative quality of technology, fuel options, and dealing with, you know, the course of fleet management -- we'll call it -- issues regarding the fleet we have; issues regarding any new additions we may be pursuing, and looking for ultimately reliable plans for cost-effective service to our customers, which is the type of thing that we would submit in our 10-year site plans to the Commission for review and comment.

Q When you say fleet management, what do you mean by fleet?

A Fleet, being the fleet of assets that we have to serve. Assets, being power plants, power purchase contracts, fuel contracts; the firm commitments that we depend on.

Q When you discuss new additions, does that relate to generation?

A Yes. Also responsible for assisting in the evaluation of power purchases and fuel options as

well. It's pretty broadly across the mix of energy requirements that we provide to our customers.

Q Is there anything else? He's thinking isn't that enough. (Laughter.)

A I mean, certainly from day to day there are other things, but ultimately that's what I'm responsible for.

Q Okay. Have you filed direct testimony in this docket, Docket 981042?

A Yes.

Q Could you please summarize your direct testimony? And I'd like as much detail as possible, please.

A Well, in the testimony that I provided I attempted to offer a viewpoint of how prospects such as merchant plants affect what I understand to be the planning process and kind of the framework of planning under the regulations in Florida. And, you know, I've been working in that framework for a few years, and I, in essence, am trying to provide a viewpoint of how we plan in that environment. And then to examine not only the general concept of how merchant plants might or might not fit in that environment, but also discussing in some more detail some of the comments put forward in testimony of some of Duke's witnesses,

like Mr. Nesbitt and Ms. Hesse.

Generally I'd say that it's -- my belief, as put forward in this testimony, is that the merchant plants do not fit within the current framework and the planning environment in Florida at this time, and that it's my observation that Florida Power Corporation and other utilities in the state who are charged with planning for the requirements and who do from time to time have a need for resources are doing -- working within the framework to accomplish that, to accomplish what I believe is the requirements outlined in the framework we have.

So, in summary, I guess that would imply that the utilities are currently meeting their obligations as outlined in that I don't envision or don't perceive the type of need that's reported by the petitioners. In other words, I don't believe what the petitioners are proposing is a need, as I understand it, within Florida regulation. So I think that's what I've examined.

Q When you talk about the planning process or the planning framework, what are the elements of that framework, please?

A Well, in a sense, that -- I think that question would be best answered looking at what we do

at Florida Power. I can't answer for what other utilities might do, but as I understand it --

Q And we don't expect you to either.

A As I understand it in discharging our duties, we're looking at the requirements of the customers who we've made commitments to and examining what their forecasted needs are going to be, and we work closely with the customers that we're responsible for to accomplish that, and look at the resources, both the resources that we have currently available and any -- and look at opportunities for resources that we may have available to us in the future and examine the mix of resources that will provide a cost-effective supply of power to meet those responsibilities.

So we -- you know, I think if you look in the framework of the 10-year site plan, you can see the fundamental questions being asked. The question is "What are you anticipating fuel costs to be generally?" And we weigh in on that, what do we believe our needs would be. We weigh in on that. "What do you think our resource requirements will be going forward?" We weigh in on that. And we -- you know, I understand that framework to be fairly complete if you look at the 10-year site plan process

that we participate in.

If -- I think that's it.

Q Thank you. You've discussed the 10-year site plan process. Did you also discuss planning under FEECA in your direct testimony?

A Yes, I did. Help me with your page number so I can follow you.

Q Page 8.

A It's my understanding that -- and I guess this would be helpful in thinking of the framework of planning beyond what I've discussed -- is that the 10-year site planning process, as I understand it, is an opportunity to convey information to parties beyond just the Public Service Commission on what might be coming in the future; and this has broad statewide planning implications to prepare for the growth of the state and the needs.

So FEECA helps address in a broad systematic way how different measures for the energy needs of growing Florida are met, and FEECA helps examine demand-side options, supply-side options, and in that framework is looking towards a balance, ultimate balance, of resources to match the needs of the state, and it helps encompass by communicating the way we do in advance of our plans, it helps with the review

process from the consumer affairs group of the Department of Environmental Regulation. It brings in to a broad -- a broad spectrum of interested and concerned parties to examine in advance what -- how these needs may be met and anticipate them and participate in the process.

So I think, as I understand the regulatory framework under FEECA, of which the site planning and site certification is a part of the process as well as the 10-year site plan and the forward-looking portion of it all, I think it's all encompassing in helping parties in the state anticipate the needs and participate in that dialogue.

And I think it's -- you know, when I think about the 10-year site plans that we submit, you know, each year we're trying to convey in advance information to the best of our knowledge what we may be doing to meet the needs, the growth needs, of the state; and it gives people time to react. It gives people time to understand how we plan to proceed. I think that is an important element, and it is relevant, I think, in what we're examining here.

Q What is an important element? FEECA or time to react? That was within the same sentence.

A Well, I think both. I think FEECA is the --

encompasses the reliability issues, the economics issues and the environmental issues. I think it really encompasses all of those, but it also, by having an advanced planning process or a coordinated planning process, to some extent it provides interested parties beyond just the utilities themselves or beyond the people that are just dealing with direct supply of electric power, it invites participation by others in advance to help them react. So I think it's both.

Q In your direct testimony, did you also discuss need proceedings and generation planning?

A Yes.

Q Could you please describe that for us in detail?

A I think what I -- in the testimony what I'm attempting to convey is how all of these pieces, the planning process, the 10-year site plans and FEECA, are all part of the framework we discussed.

It's my understanding in looking at a need proceeding as being part and parcel to this planning process that I've described. It also, in essence, is a means by which the utilities in the state who are responsible for carrying out the supply of energy to retail customers means by which they convey their

plans to do so.

I think the -- at least it's my understanding of the regulations as they're written that the obligation to serve is a part of the framework, and we're discharging our responsibilities under this regulatory framework to examine and disclose our expectations and plans for any needs that we as a utility might have.

I don't think of a need as a general amorphous issue. It's very specific to utilities who have an obligation to serve and who are serving the customers of the state on a retail level. At least that's my understanding of how it's defined in the framework that we exist in today.

Q Okay. Thank you. Does your direct testimony also discuss uneconomic duplication of resources? I refer you to Page 29.

A Yes, I do get into that.

Q Could you please describe your testimony relative to uneconomic duplication, please?

A What I've outlined in my testimony is a question that does speak to the proposal made by the petitioners that there is an opportunity in Florida, and -- which I haven't really confused with what I understand the definition of a need to be -- but they

do purport that there is an opportunity in Florida. And the way that they've described it pretty clearly in some of their witness testimony is that opportunity is an opportunity, in essence, to displace existing generation; and it's -- you know, it's made quite clear.

It's not -- certainly not a -- it's not a hidden agenda. I think they've come out very clearly and say that they believe that a plant of nature -- some nature "X" has the ability to displace existing generation in Florida, which I think of as uneconomic duplication in the current regulatory framework.

They're proposing, in essence, to capture an economic opportunity that I think the -- I guess in the utility planning process that, in essence, is accounted for in the way we plan. I mean, they're not proposing anything dramatically different than the type of facilities that we might offer to improve our mix, so to speak. But I think what their testimony leads me to believe is, number one, this is again an opportunity versus what I think of as a need; and, number two, it's hard for me to think of this in -- it's hard for me to think of this on its own, to think that a precedent that could be set for one merchant plant might not lead to further and further potential

merchant generation.

And I guess I don't -- in general, I don't feel like we've examined that in any detail, nor is it proposed to be examined in the proceeding so far, and it's a pretty important issue. And I think of that as uneconomic duplication by the potential for significant proliferation, not necessarily on its face just this first plan, but those that might follow, searching again the economic opportunity rather than what we think of in the regulatory framework as a need.

Q Is it your testimony that uneconomic duplication relates more to the precedential value of this proposed plant than the plant itself?

A I'm not sure I'd characterize it that way. I think they're both important issues. I think that I've tended more to focus on the testimony as it relates to this particular plant.

I've provided some indications here, if you go back into Pages 30, 31, examining Mr. Nesbitt's work that he's proposing -- in his examination he's seeing an economic opportunity for what he calls profitable new additions of up to 6,000 megawatts, and he premises his assumptions on the fact that the information he had available to him projected

installed capacities of less than half of that when, in fact, at the time it was proposed, that at least 4,000 megawatts were to be added by the utilities; and then the most recent plan submitted by the Florida Reliability Council, it's over 8,000 megawatts. And I don't know how that's been accounted for.

I did not do his analysis. I don't necessarily believe that I can critique the details of his analysis. It just seems on its face certainly conflicting conclusions. So it leaves me with some doubt that this plant or others will fit, and the framework is as -- by which the utilities currently plan and have proposed their additions and have satisfied whatever -- potentially whatever needs they as utilities have identified, they've proposed plants to accomplish that.

So I guess there's a purpose here, a proposed purpose, that this plant is needed; and when I think about it in the framework of how we plan in Florida, I don't see that.

Q Okay. Thank you. Based on your last answer, is it a fair statement that the site certification process should only be utilized to address reliability needs or -- and not solely economic needs? Is that your position?

A Well, no; that wouldn't be my position.

Q What is your position?

A I think that -- and, again, here I'm speaking for responsibilities that I carry out. I'm looking at reliability and economics, and all the planning work we do encounters and encompasses both.

So I guess my position would be better described as planning for needs as described by utilities that serve retail customers in Florida. Those are the people who, it's my understanding -- and I don't profess to be a legal expert on this issue; I'm just conveying my understanding -- that the needs are not general in nature. They are specific to the utilities.

All of the regulatory framework surrounding them addresses specific utility needs. You know, what is your demand and energy requirements, the economics of your system, every -- all the questions you answer in a need determination or a site certification process are very specific to the needs of the utility that's coming forward.

They are not general in nature, nor are they statewide in nature. And upon examining that, we are held to a standard to demonstrate a broad range of considerations; you know, a lot of technology options,

different growth scenarios, different fuel scenarios as well as demand-side measures versus supply-side measures.

It's a very broad area of information requirements in pursuing a need determination. And all of those take reliability and economics into account. I think to my mind there is -- it isn't one or the other; you're always addressing both reliability and economics in concert.

Q I'm going to next ask you a series of questions regarding the regulatory framework. We've discussed it in general terms prior to this, and we're looking for some additional clarification on your understanding.

It is not my intent to request legal opinions. I understand you are not an attorney, but your testimony addresses regulatory framework, which is necessarily a creature of rule and statute. So for every question, please assume that I'm not asking a legal opinion; I'm asking your understanding as in your position at Florida Power Corporation and how it applies.

A Okay.

Q To your knowledge, has the Public Service Commission promulgated rules relative to the 10-year

site plan process?

A To my knowledge, they have. I think when that came over from consumer affairs, rules were promulgated to that effect.

Q We have just handed you a packet of copies of various statutes and rules to refresh your memory, if that's necessary.

A Thank you.

Q Would you agree that the Public Service Commission has jurisdiction to require the filing of 10-year site plans subject to the statute?

A That's my understanding.

Q Are you aware whether the Commission has promulgated rules relative to the Power Plant Siting Act? The Power Plant Siting Act may be defined as Florida Statutes 403.501 through .518.

A Yes, they have.

Q And would you agree that the Commission has jurisdiction to determine need for new generation under the Power Plant Siting Act?

A Certainly they do. I think that's made quite clear that the Commission is the sole determination. It is charged with the responsibility of determining need before the environmental impacts are fully considered. So, yes, they're empowered.

Q Thank you. Are you aware whether the Commission has promulgated rules relative to supply-side alternatives? By that, I'm referring to bidding.

A Yes, I'm familiar with those.

Q In your opinion, does the Commission have jurisdiction to require investor-owned electric utilities to solicit and evaluate proposals for supply-side alternatives?

A Yes. As outlined in the rules, yes, they do.

Q Do you know whether the Commission has promulgated rules relative to conservation?

A Certainly they have.

Q In your -- I'm sorry. Go ahead.

A That would be the framework for the DSM goals dockets that are currently active in other, you know, other related activities.

Q My other favorite dockets. (Laughter)

Would you agree that the Commission has jurisdiction to establish conservation goals for utilities pursuant to the Florida Energy Efficiency and Conservation Act, known as FEECA?

A That's my understanding, and I think -- I view that as a cooperative process by which with help

of both the Commission and the utilities you determine the best path forward for opportunities on the conservation side.

Q Okay. Thank you. Is it your opinion that these four areas of regulatory framework constitute the framework for new electric generation in Florida?

A As it relates to the Commission, I think the answer is yes. I think that the remainder, or the rest of the framework, is in the environmental certification and licensing process that occurs under the jurisdiction of the DEP. So I think that's also part and parcel of the process.

Q Okay.

A That it's all-inclusive.

Q I believe you've testified that you're familiar with the 10-year site plan process; is that correct?

A Yes.

Q Is the 10-year site plan submitted by Florida Power Corporation every year a final, permanent plan, or is it a tentative plan?

A Well, I'd characterize them as tentative plans. I think in the planning process we recognize that as we move along in our plans, things change. It is clear, however, that at certain points in time you

make decisions based on the best available information. So often those decisions come out of the information that's put forward in these 10-year site plans.

One example would be the construction of Hines Power Plant -- Power Block I, which is in its final stages of construction and start-up. That was -- been in our plan for many years and is well-known to all. At some point a decision was made that we would go forward with that plan as it had been reported, and now that plant will come on line.

So, I mean, that's consistent with the planning process, but at the same time there's -- you know, the planning process looks out over a horizon of time. Things change. You also need to ensure that you can react appropriately as things change in the planning process.

Q Did Florida Power Corporation change their 10-year site plan filing after April 1st, 1998?

A Technically we did not. We are coming forward with heading towards a need determination. We filed a bid waiver to pursue an additional expansion at our Hines Energy Complex, but we did not formally amend the 10-year site plan since that -- the 10-year site plan was submitted in April based on

information -- the best information available at that time.

Q Is it possible for a utility's plan as presented in the 10-year site plan to change from the date of filing then before the next filing?

A I think it's possible. I think we've seen others, other utilities, file changes or amendments to their plans. I don't think it's required or necessary to that. I think there are different ways to convey the information, that that might be one way of conveying information --

Q I'm not talking about the actual filings; I'm talking about the substance of the plans. The plans change; is that correct? Like with the Hines unit.

A Certainly. Okay. In essence, we're charged with a continuous review of circumstances and exam -- I think we've examined some phenomenon this past summer that certainly caused us to rethink some aspects of our planning. So that's an example that was prompted by events where a thought process is changed, and we're adapting our plan to that.

Q Would it then be appropriate to characterize the 10-year site plans as truly planning documents, not as an etched in stone course of action for a

utility subject to that process?

A Well, that's how I'd characterize it. I think -- I probably won't put my finger directly on it, but somewhere in these rules you find the words that the plans are tentative and not binding in nature, and I think the language is pretty specific that -- you know, that they are plans; they are not etched in stone. I'm sorry. I can't point out exactly where those --

Q That's fine. Again, we're looking for your understanding of the regulatory framework here.

Do Florida's investor-owned electric utilities have an obligation to seek out the lowest cost source of power even if that means changing the generation source identified in a 10-year site plan?

A I would address that in -- in general I'd say yes; it's my understanding that's what we're searching for. I'd say that we're examining -- lowest cost implies economics only. Reliability considerations may cause changes as well. So timing, growth rates, and there are other things besides economics that drive you to an outcome, but we're searching for what, in essence, is a cost-effective solution.

Sometimes the -- you might imply least cost

with parentheses around it would imply something to the decimal point beyond the uncertainty of the planning process. So it's certainly a challenge to demonstrate exclusively and without a doubt that you have a, quote, least cost plan.

I think cost-effective and a low cost are more -- better characterize the process within the bounds of uncertainty that we're dealing with.

Q Okay. Thank you. Do you recall in your testimony discussing the fact that the petitioner in the instant docket does not file pursuant to the 10-year site plan process?

A Yes, I do. The essence of that is that the parties who have continuing -- there is a continuum of planning process, and the utilities in Florida provide information on an annual basis.

It's actually my understanding that the plans are only required every other year, but I think utilities have participated in and submitted these plans annually to keep all parties, not just the Commission, but all of the interested stakeholders in the state, abreast of developments and changes and reactions in the planning process that may be of interest to them.

So that information is shared, provided and

shared with others. And when something pops up that hasn't really been discussed or isn't part of this continuum in the planning process, it raises -- I guess it raises some concerns that the key stakeholders and the interested parties haven't had an opportunity to examine it in the full context of what other utilities -- or what the utilities, as I think of them, in the state are doing.

So the planning process is supposed to help anticipate and help people who do other types of planning in the state other than energy planning to do their work as well.

So this might come as a, quote, surprise if somebody declares an intent to do something and simply puts that forward and says, here's what I want to do; it's not part of the continuum. And so people have to react to it without necessarily understanding its place in the continuum.

Q Would it alleviate some of your concerns regarding the type of petition we have before us if the petitioner in this instance were a member of the FRCC and required to file a 10-year site plan? Would that eliminate the element of surprise that you've discussed?

A A couple of issues there. Number one, I

think the petitioner and others can be a member of the FRCC. There's nothing that prevents that. I don't think that membership in the FRCC requires 10-year site plans. For example, Enron is a member of the FRCC, but they don't file 10-year site plans, to my knowledge; at least not in the context we're discussing.

I guess it doesn't increase my comfort that somebody who wants to propose a plant could agree to participate in the planning process, because I'm not certain that it provides the type of useful information we're talking about. In other words, the entity of this petitioner may file a 10-year site plan from here to eternity that simply states that they have their plan, and that's it. They may not disclose any other plans that they may have in that document.

You know, others who are interested in this process may choose, I suppose, plant by plant to offer a proposal to build, in this case, a merchant plant and simply have a series of reports coming out that in perpetuity describe the plant they built one by one by one; not a systematic approach, but potentially just a singular approach that doesn't provide near the useful information that the utilities provide when they're reporting on their systems.

Q What kind of additional useful information would assist you? You're describing what you called, I believe, a linear approach, just one by one adding plants, but they don't provide the additional information to assist the utilities.

What type of information would you be looking for that would assist you?

A Well, when I think about my responsibilities at Florida Power, I guess I don't think I'd be looking at those type of plans for assistance. The Commission might, if that were to eventually happen. The FRCC might in some way, if that were to eventually happen.

But as a utility planner, I would be more focused on our emerging needs and how to satisfy those. So I would -- I might note that somebody who's out there might -- might be an opportunity to help satisfy our needs in the future through a -- some solicitation process perhaps. But by focussing on my needs, it's only -- since it's -- on the one hand, it's relevant to me that there is an option or an opportunity that may be out there, but at the same time it may not be the best choice for us.

So I would just look at it from -- at least in the framework we're in today, as I understand it, look at it in terms of the needs of our particular

utility. And, you know, I guess the useful information -- I don't know that there would be much useful information. They would tell me that there's a plant there. They would tell me approximately what its capability is, and that's not terribly useful information.

What's useful to me is at a time that I'm trying to anticipate a need and look at opportunities or options that we have, at that point it becomes of interest. Does that make any sense?

Q Not yet, but let me ask another question and maybe we can. I'm hearing conflicting testimony. I'm hearing that there's nothing a plant like the proposed plant could file that would be useful to you, and then I'm hearing that there is some information that could be useful in terms of planning and your needs; and I'm not understanding this conflict. Could you help me with that?

A Okay. Well, that's part of the frustration. And I guess that -- you're asking me a question as a utility planner for a specific utility, okay, at the outset. And in simplistic terms, if we identify a need, then we would look at resources available to potentially serve that need. So that's a pretty straightforward utility perspective.

I wouldn't necessarily look to a 10-year site plan that they might file for that type of information. I guess where I was trying to refer to is the information that we're talking about might be more useful to the Commission or to statewide planners and so forth than it would be to me directly.

Q I'm still confused. I'm sorry. Let's try this one more time.

A Okay.

Q In your direct testimony, with respect to the 10-year site plan process in a plant of the nature that's the subject of this petition, one of your concerns is that it is not a part of the 10-year site plan process; is that correct?

A That's true.

Q And then my question was, if they became a part of the 10-year site planning process, would that be of -- would that alleviate some of your concerns about them not being a part of the process?

A Well, I think in a general sense, the answer is yes. But what I think you're talking about is having part of the planning process being -- having merchant plants or merchant developers filing 10-year site plans, and I don't really see them as part of the framework to begin with, so that's what confounds me.

I guess what I'm trying to convey is that when I'm planning for the needs of our particular utility, I'm looking at resource options available to that utility, so when that -- when those resource options become relevant in the planning process, then they're available to consider.

But, for example, if I was interested in options from developers to satisfy a need in the future, I can write them a letter or issue a solicitation and get information about what they might be able to do to satisfy my needs.

I think the concern about them not being involved in the site planning process more relates to all the other stakeholders in general who are not getting information and being able to see how that fits into the bigger picture.

Q Who would the other stakeholders be?

A Consumer affairs, environmental protection, the localities that may be -- localities that might be affected by development of plants, et cetera, et cetera. I mean, all those who participate in the site planning process, the need determination, and site certification process; a very broad group of players.

I feel like the 10-year site planning

continuum helps provide those people with information based on the best of our knowledge in advance to examine what might be going on.

I guess the context that I find frustrating is more to the overall planning process; if the group of stakeholders does not have that information until a developer of a merchant plant who is not attached to a need announces that they'd like to pursue an economic opportunity, and, you know, here I come, boom, I'm in, they have them in part of the overall process.

Q Okay. Mr. Rib, are you familiar with the Commission's bidding rule? It's Florida Administrative Code 25-22.082.

A Yes. Take it out. (Pause) Okay.

Q In your opinion, does the Commission's bidding rule require investor-owned utilities to purchase from plants similar to the type of plant that is the subject of the instant petition? Are you required to purchase from them?

A To my knowledge, no. I suppose if a plant like what the petitioners offer is built, in the context of this rule if I were soliciting proposals as outlined in the request for proposals, I would have no idea whether they'd even bid on it.

I mean, to me a merchant plant may be -- I

think of them potentially as more interested in trading and short-term opportunity. They may not even be interested. I have no idea if they'd even answer a request.

Q That's a fair response.

A But I don't believe in any way I'm required to buy anything from them.

Q You indicated that you are familiar with the bidding rule. Could you please elucidate your understanding of the bidding rule for us?

A I guess in general terms it offers that for investor-owned utilities -- although I think it's been more broadly accepted -- but at least for investor-owned utilities, that when supply-side options seem to be the best option going forward, then the company would request proposals for the supply-side options and examine them as compared, for example, with the self-build if the utility is interested. If they're a utility that doesn't build their own generation, they might simply be evaluating proposals from others, and in reviewing that and providing a selection from that process for examination by the Commission to see as a part of the need determination process, demonstrating the cost-effective alternatives that have been examined

and chosen.

Certainly I think there is some latitude the Commission has also in this process to waive the bidding requirements, which certainly are a current issue also, and that's clearly within the rules as they're written, so -- but it does outline a pretty specific process.

Q Is it your testimony, then, that the bidding rule only requires the utilities to solicit and evaluate bids pursuant to the Power Plant Siting Act, but it does not require the utilities to accept any of the bids? You mentioned self-generation.

A I think it, to my knowledge, does not require the utility to accept any of the bids. Tallahassee recently went through an RFP process. KUA recently went through an RFP process. Both of those utilities at the end of the day chose the self-build option which they felt was most cost-effective and which was reviewed by the Commission in their site certification proceedings as a part of or as the need portion of their examination. So that would characterize how utilities might employ that process.

Q What is your understanding of how the bidding rule relates to the Power Plant Siting Act?

A Well, it's clearly a part of the Siting Act.

Again, I think this is part of the Commission discharging its responsibilities to determine the need; quote, need in the framework that we've described for generating capacity. And I think the Commission is choosing this method to examine the alternatives on the supply side.

I think there's also an expectation expressed in the statute to look at demand-side alternatives as well. It's all framed around a retail utility having various options for supply or offsets in conservation encompassing all of those options and providing the best, most appropriate, balanced plan from all those options. This is just a part of that.

Q Mr. Rib, I will ask you to take a look at Section 1, sub (a) of Rule 25-22.082. It starts "Next plan generating unit." That's a definition. Would you please read that definition into the record?

A "1(a) Next plan generation. Generating unit. The next generating unit addition planned for construction by an investor-owned utility that will require certification pursuant to Section 403.519, Florida Statutes."

Q How do you interpret this section as it relates to the need section, .519?

A .519, in my understanding, simply places the

Commission in the primary responsible or sole primary responsible role for determination of need in light of the impacts, all the other impacts, that a plant, a new plant, may have on the community; the environment, et cetera.

This is specific to investor-owned utilities, although I've seen it more broadly applied. And it simply defines, in my mind, something very specific to what the next unit addition that a particular utility is planning.

Q The point of my question is essentially that not all generation is created the same. There's generation, and there's generation. Subsection 1(a) specifically refers to 403.519; is that correct?

A Yes, it does.

Q Is it a fair statement to say that the type of generation that is subject to .519 is the type of generation that is the subject to the bidding rule?

MR. SASSO: I'm going to object to that question. I don't understand it, and I'm a lawyer.

WITNESS RIB: Can you help me a little bit more than that?

MR. SASSO: And we're really kind of getting far afield from the testimony that Mr. Rib has filed in this case.

WITNESS RIB: I can attempt to offer my opinion that --

MR. SASSO: Do you want to re-ask the question, or do you want him to try to answer what you've proposed?

MS. PAUGH: I'll re-ask the question. Let's go off the record for a minute.

(Discussion off the record.)

MS. PAUGH: We'll go back on the record.

Q **(By Ms. Paugh)** Are there types of plants which are exempt from the Power Plant Siting Act?

A My understanding, there are. There are -- it's specific to types of plants, types of fuel, steam megawatts capability and so forth. So simple cycle combustion turbines, for example, would be exempt, and companies like Florida Power and others have built combustion turbine peaking facilities without going through the site certification process.

Q All right. Let's use combustion turbine, CT, plants. If Florida Power Corporation were proposing to build a CT, would they be required to go through the bidding rule?

A Not as I understand it, no.

Q Excellent. Thank you.

Mr. Rib, would you agree that the bidding

rule allows investor-owned electric utilities the final decision on how it, the utility, will meet its needs?

A That's my belief, subject to Commission review. In other words, I believe that the final determination is made by the utility, and then it's offered for consideration for Commission review.

I suppose if there was a flaw or a concern that surfaced, then maybe I'd say that the Commission had the final say in that process.

Q We'd like to think so. (Laughter)

Would you agree that the bidding rule allows investor-owned electric utilities to petition for waiver of requirements of that rule?

A In simple terms, yes, I do.

Q Has Florida Power Corporation ever petitioned for waiver of that rule?

A Well, we have recently petitioned for a waiver of that rule. Within my time frame I don't know that we have -- I'm not familiar with a time in the past where we have, but specific to that, certainly very recently.

Q Are you familiar with your current petition for waiver of the bidding rule?

A Generally familiar, yes.

Q What is your understanding of the request in that petition?

MR. SASSO: I have some concern about our getting into a different issue, a different docket, in this case. This really is outside the scope of his testimony.

MS. PAUGH: But it is intricately related to the regulatory framework, which is his testimony; and I'm not again asking for a legal opinion on the petition. The petition is a matter of public record.

MR. SASSO: I'm just not sure how this relates to the petition filed by Duke and New Smyrna Utilities Commission in this case.

MS. PAUGH: Well, we have a series of questions coming up regarding the Power Plant Siting Act. I think it will be become clear at that point.

MR. SASSO: Okay.

WITNESS RIB: Could you repeat the question for me?

Q **(By Ms. Paugh)** Are you familiar with the petition for waiver of the bidding rule?

A Right. I said I was generally familiar with the petition we had filed. I don't have it with me, but I'm generally familiar with it.

Q That's fine. What is your understanding of

the purpose, or the request I should say, of that petition, just briefly?

A My understanding in general terms is that we have provided, in essence, a proposal of a combination of many different things that we've evaluated and discovered and put forward in that petition that we feel provide compelling reasons to waive the request for proposal phase of the need determination process.

The essence, I think, is that what we're proposing to offer is not simply a generating option, although the generating option is high technology, superefficient and meets, I think, all of the expectations that our customers would have as being an appropriate choice of resources to better our cost-effective position on their behalf, but also proposing specific rate treatments that provide even more compelling evidence, or at least more compelling opportunity for our customers.

So perhaps one way to characterize it is that if you would take two -- think of it strictly in generation options, you'd take two options which are very similar, providing much the same product, in essence; and it seems that what we're offering in that waiver in terms of the total -- the total package, we'll call it, is certainly to the benefit of the

customers beyond what -- the way that we would approach purchased power alternatives, which is what we would solicit through the bidding process. I think it's pretty compelling.

Q Thank you.

A I'd guess I'd like to add, given the opportunity, that I feel like we are following the guidelines and the rules as written. In other words, we're not attempting to subvert or circumvent or in any way work around the rules. We're working within the framework, within the rules and the guidelines established in what we believe the most benefit to our customers would be.

Q Okay. Thank you. Are you familiar with the DSM goals setting process at the Commission?

A I'm generally familiar with it. I haven't had the pleasure of direct participation.

Q Well, you must come join us.

A Thank you for the invitation. (Laughter)

Q You may or may not know the answer to this question. If you don't, just say so. The DSM goals process is essentially where a utility proposes future kilowatt and kilowatt hour savings, goals for savings; is that correct?

A That's my understanding.

Q And these savings are achieved through DSM measures. That means demand-side management measures. Is that correct?

A Again, that's my understanding of it, yes.

Q That's fair.

After a utility has set a goal for kilowatt and kilowatt hour savings, it then proposes specific programs to meet those goals; is that correct?

A Again, yes, that's my understanding.

Q Is it the purpose of setting the DSM goals in the programs that become the framework of the goals to avoid the addition of future generation? Is that your understanding?

A I suppose that would be considered the ultimate outcome, is to either defer and/or avoid in some manner.

Q Thank you. That's a fuller statement than mine. I appreciate that.

Is it fair to assume, based on the DSM goals and programs process, that by the time a utility comes to the Commission for a need determination, they have or will be able to show the Commission that they've exhausted their -- what am I looking for -- whatever resources they have for DSM to minimize their generation needs? Is that part of this regulatory

framework?

A That's my understanding. I think the -- that would be in the context of what we might consider integrated resource planning; that the utilities come forward and examine all of their options, supply-side and demand-side, to find the best end result. And I think that the ultimate stated purpose for FEECA was to accomplish those goals of deferring and/or avoiding generation, if it's possible.

Q Let's discuss the Power Plant Siting Act for a few minutes. Are you familiar with the Power Plant Siting Act?

A Reasonably familiar, yes.

Q What is your understanding of the Power Plant Siting Act?

A I understand it to be a framework for which the need for the resources proposed are examined and determined and then followed by a fairly exhaustive review of all other impacts, environmental, economic, and otherwise, of the proposed resource, to search for the most acceptable way of imposing a new factory, if you will, in the state.

And -- you know, so there's a lot of elements of it. It's not just the need determination we're talking about, but it's pretty broad reaching, I

think. You know, having assisted in some manner in the development of the Hines Complex or the Polk Site, as it was called, it's a very exhaustive process to try to examine the needs of the stakeholders and work with them to, in essence, come up with a balance, a balance like we have in that process.

Q Is it your testimony, then, that the Power Plant Siting Act balances environmental impact with the need for generation, in essence?

A I don't think I would characterize it that way. I think the environmental community looks to the Commission. This is how I feel.

Q And that's why we're here.

A I think the environmental community looks to the Commission to determine if we actually need to do something. Is this necessary, you know. In other words, following through -- you know, let us not examine the environmental impacts in exhaustive detail unless we first determine that this step is necessary to impose on the state.

If you, the Commission, have determined that this step is necessary, and it's been demonstrated as such, then we examine how it will fit in the environmental framework of the state. So that's maybe a little different characterization.

Q Thank you. Is it fair to characterize the Power Plant Siting Act as providing a control on new construction of generation?

A Well, I think it does to some extent. I think -- and I don't pretend to know all the intricate and personal thoughts of the people who drafted it, but certainly it allowed for certain types of generation to be built without going through the certification process.

So for what I consider the larger facilities that would potentially have more of an impact long term, I think what they were attempting to do is set a hurdle above which plants that would start to have a more significant impact would be examined through this process. But there again, as we discussed before, some plants are exempted for the reasons determined by the -- by those who crafted the language.

Q What types of plants, based on your understanding of the PPSA, are exempted from that act? What types of generation, I should say.

A Well, without getting too exhaustive, it's specific to steam, steam megawatts. So plants that involve a steam cycle of 75 megawatts or greater are required to participate in the site certification process. Plants that do not have the steam cycle for

power generation would not.

So that could lead us in two directions. One direction would be supposing -- I mean, a simple cycle combustion turbine does not have a steam cycle, so it's not required to go through the process. I suppose it could, if the owners or petitioners chose to for some reason, but it's not required.

Then you could carry that a step further and say, suppose you had a small combined cycle plant that had less than a 75-megawatt steam cycle. In theory, that could go through without -- as exempt to the process, not required to participate in site certification. So there's an example of a combined cycle power plant that could be exempt.

The other side of this that we've seen is that as it applies to existing facilities, the option for repowering. An existing facility that does not increase the steam cycle is also, at least in my current understanding, exempt from the site certification process.

Q Thank you. Based on the list of exemptions that you've just given us, would it be correct to state that there are plants that have been built in Florida that have not gone through the Power Plant Siting Act?

A Yes. Certainly the answer would be yes.

Q Okay. Thank you.

MS. PAUGH: We'll go off the record at this point.

(Brief recess.)

Q **(By Ms. Paugh)** Mr. Rib, is it your opinion as a planner for Florida Power Corporation, that the petitioner's plant requires certification under the Power Plant Siting Act?

A Yes, it's my understanding by nature of the fact it's of a certain size, roughly 500 megawatts, with a steam cycle of greater than 75 megawatts, that they are not exempt and, therefore, do need to go through the certification process.

Q Could someone build a plant with less than 75 megawatts of steam and not be required to seek certification under the PPSA?

A My understanding is that yes, they could. I think that some of the documents that Duke has filed, they initially proposed a 240-megawatt plant and later increased the proposed size of the plant to 500.

It is possible, although I don't have the details, but it is possible, I suppose, that a 240-megawatt combined cycle might have less than 75 megawatts of steam generation and, therefore,

potentially be exempt from the Act, as an example.

Q Okay. Thank you. I'm going to pose a hypothetical now, and elicit some responses to that, and it relates to the Power Plant Siting Act.

If a power plant owner is a coapplicant with a utility for certification under the Power Plant Siting Act, but the utility only has a five-year contract for purchase of capacity and energy, could the following scenario occur?

Would the plant still be in place and functioning, likely or not likely, after the five-year contract had expired?

A Are we talking this is a hypothetical situation?

Q This is absolutely hypothetical.

A That's not my understanding in this particular petition, but in this hypothetical situation one would presume that the plant would continue to operate.

Q After the five-ear contract had expired?

A I suppose it would. I guess it depends on the circumstances.

Q Certainly. After the five-year contract period had expired, would the plant become in the nature of a merchant plant?

A I suppose that depends on the circumstances; that it could potentially be considered a merchant plant if the owners did not seek to secure contracts with utilities for the period beyond that period.

Q What is your understanding of a merchant plant?

A Well, I guess there's -- there are different definitions of merchant plants. I suppose one definition would be along the lines that the petitioners have submitted, which is a plant that does not have firm contract obligations to serve. It is simply operating under what I'd term economic opportunity.

I suppose that a merchant plant could potentially be built like the one you described, or a plant could be built like the one you described with hopes of continuing long-term contracts versus being expected or dedicated to continuing, you know, short-term opportunistic generation. So this -- maybe there are different flavors.

Q Okay. Thank you. Would a plant consisting only of combustion turbines be subject to the Power Plant Siting Act?

A If it did not have a steam cycle, I think it would be exempt. So I think it would be up -- I

guess, you know, may go beyond my legal understanding, but just general knowledge, I suppose that anybody could apply through the site certification process, if they chose to.

I think the exemptions are there for those who choose not to and can be exempted under the rules. So a combustion turbine owner, I suppose, could petition to certify their site, if they wanted to, but they don't have to.

Q Thank you. Do you have a sense of whether an 80-megawatt steam plant used for self-service would be subject to the Power Plant Siting Act? And by "do you have a sense," in your experience as a planner for FPC.

A Something brand new?

Q Yes, sir.

A A brand new plant? I don't know. I haven't encountered that. I mean, I think it does under the context of the steam cycle requirements, but I'm not sure.

Q If a plant was refurbished and capacity was increased but there was no net increase in steam capacity, would the modification to that plant be subject to the Power Plant Siting Act?

A I don't believe so. I think that comes

along the lines of repowering.

Q Yes, sir.

A Where you stay within the envelope of the -- you stay within the envelope of the steam cycle or the steam capability, I think it is potentially exempt.

I suppose, depending on other factors brought on through the environmental review process, there might be other factors that I'm -- that could trigger that, but I'm not sure.

Q All right. Thank you. In your capacity as a regulatory planner, do you deal with transmission at Florida Power Corporation?

A Not directly. I do assist transmission planners as needed for the corporate planning effort, but I don't do transmission planning myself, if that's what you're asking.

Q Yes, it is. I've got a couple of general questions on transmission. If you don't know the answer and it's outside your expertise, please just say so.

Are you familiar with how short-term transmission access is acquired?

A Short-term transmission access? Could you define short-term for me?

Q That's, I believe, an hour or less.

A My understanding is that's acquired through what I understand as a FERC regulated process of transmission reservations. I guess I'm not familiar with the intricate details of short-term transmission access.

Q Okay. That's fine. Are you aware whether the short-term transmission rates are posted on the Internet?

A I think the availabilities of transmission and the rates are posted on what we call OASIS at this time. So it's a bulletin board system.

Q Do you know if Florida Power Corporation utilizes the OASIS system?

A Certainly. It's required.

Q In your opinion, would a wholesale generator find it necessary to utilize the OASIS system in the same manner that Florida Power Corporation does for short-term transmission access?

A Yes, I believe so. If they were conducting a transaction from a source to utility "X", Florida Power or Power & Light, any of the other utilities, they would have to make transmission arrangements for those transactions through the OASIS system.

Q Okay. Thank you. Mr. Rib, are investor-owned electric utilities, such as Florida

Power Corporation, required to into enter into long-term contracts for purchased power regardless of its source?

A In simple terms, no, I don't believe we're required to enter into long-term contracts. I think it's a balance of risk and economics that we talked about before. Perhaps there might be some element of that question that you're -- that I could provide in more detail.

Q No. Actually I was looking for a simple yes or no answer. Thank you.

Does construction and ownership of new generation typically assume about a 30-year commitment on the part of a utility and its ratepayers?

A In the current framework I think the answer is yes.

Q Is the selection of new generation by utilities driven primarily by fuel price projections?

A Well, a qualified yes. I think fuel price projections are critical, but technology is certainly an issue as well.

The combined cycle plants, for example, that we have available to choose from today didn't exist in their fashion 10 years ago. So the technology improvements have changed the range of choices as well

as the fuel supply.

So really there's -- it's not strictly fuel, but fuel and technology; and I guess I'd characterize it as balanced fuel supply as well. I mean, from a utility planning point of view, we have to balance all those factors in determining what the choice of the next resource should be.

Q Okay. Thank you. Is there a risk associated with fuel price forecasts when you're looking at planning your next generation, type of generation, your type of fuel?

A Certainly there is a risk of sorts in that forecasts change, and there's simply a forecast reality. So yes, there is inherent risk.

Q Who bears the risk associated with fuel forecast prices changing?

A Well, I think within -- if we're talking about within the normal course of business, and we're not talking about extraordinary situations, but in the normal course of business in our regulatory framework the fluctuations in fuel price and the attendant changes from time to time in which generator might be running to accommodate the least cost supply is -- passes through in the fuel clause to the retail customers of our utility.

Q Okay. Thank you. If fuel prices increase, is it your testimony, then, that the retail ratepayers pay for the costs of those increases?

A If you characterize all fuel prices increasing across the board, then those costs, those increased costs, would pass through to the ratepayers.

Q Through the fuel clause?

A Through the fuel clause; that's correct.

Q Do the shareholders of Florida Power Corporation bear any of that risk?

A In the normal course of business, I think the fuel clause protects the shareholders from that risk. I think there can potentially be more extraordinary situations where judgment is -- judgment of the utility and their decisions could be brought to question.

Q Thank you. I'd like you to think back for a moment to the hypothetical we discussed about the five-year contract.

If a utility had a five-year contract for purchased power as opposed to a 30-year commitment based on a certain kind of fuel and a certain kind of plant, is it possible that that may reduce the risk to the ratepayers for increased fuel prices for the short-term contract?

A That's difficult to answer. There's a lot of variables.

Q What type of variables would inform your answer?

A Well, one would want to understand ultimately who that facility might -- that we're talking about might be serving, if it's beyond the five-year contract period.

If the expectation is that facility will provide continuing service under similar contracts, then ultimately I think the same customers will ultimately carry the same type of risk, because I don't think that the, quote, investors who own these plants -- or municipals, for that matter, who might own plants -- are necessarily intending to absorb that risk.

So in the long view of things, I think that the fluctuations in fuel price will ultimately -- the cost of bearing that risk will ultimately be with the consumer. I'm not sure it's dependent on the contract environment.

MS. PAUGH: All right. We have no further questions.

This is probably an appropriate time to discuss while we were off the record Staff handed

Florida Power Corporation a document entitled "Generating Units Built Since the Enactment of the Power Plant Siting Act." Florida Power Corporation has declined to verify this document because they are not certain they have this information available, but -- and correct me if I'm wrong, Gary -- they will take a look at Florida's Power Corporation's information and verify, to the extent they can, what is in the document.

MR. SASSO: Well, what I suggested to you is that Mr. Rib is not in a position to verify this information today. You first presented this to us today.

I would like to take it back and consider both the factual accuracy and the procedural propriety of using this exhibit at this time and let you know what our position is.

We may have the information within the company or it may be accessible to us to verify it factually, and then I'd still want to make a judgment what we do it about procedurally.

MS. PAUGH: I see.

MR. SASSO: But Mr. Rib isn't in a position to help you with it today.

MS. PAUGH: All right.

MR. SASSO: But we'll consider whether we can stipulate to the information. I understand you're going to supplement it because it may not be complete.

MS. PAUGH: That's correct.

MR. SASSO: And if you can do that as soon as you can, we'll try to get you a response as soon as we can.

MS. PAUGH: Okay.

MR. SASSO: Anybody else want to ask questions?

(No response.)

(Deposition recessed at 11:10 a.m.)

ERRATA SHEET

DOCKET NO. 981042-EM
NAME: MICHAEL D. RIB
DATE: November 12, 1998

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AFFIDAVIT OF DEPONENT

This is to certify that I, MICHAEL D. RIB, have read the foregoing transcription of my testimony, Page 1 through 58, given on November 12, 1998, in Docket No. 981042-EM, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the errata sheet attached hereto.

_____
MICHAEL D. RIB

Sworn to and subscribed before me
this_____ day of _____, 19_____

_____
NOTARY PUBLIC

State of _____

Personally known to me ____ or produced identification___.

Type of identification produced_____

F L O R I D A)
:
COUNTY OF LEON)

CERTIFICATE OF OATH

I, the undersigned authority, certify that MICHAEL D. RIB personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 12th day of November, 1998.

H. RUTHE POTAMI
Notary Public - State of Florida

H. Ruthe Potami
MY COMMISSION # CC777298 EXPIRES
September 22, 2002
BONDED THRU TROY FAIN INSURANCE, INC.

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, H. RUTHE POTAMI, Official Commission Reporter,

DO HEREBY CERTIFY that I was authorized to and did stenographically report the foregoing deposition of MICHAEL D. RIB.

I FURTHER CERTIFY that this transcript, consisting of 58 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 13th day of November, 1998.

H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter
Telephone No. (904) 413-6734

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	:	DOCKET NO. 981042-EM
Joint petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	:	

DEPOSITION OF: MICHAEL D. RIB

TAKEN AT THE INSTANCE OF: The Staff of the Florida Public Service Commission

PLACE: Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Room 362
Tallahassee, Florida

TIME: Commenced at 9:00 a.m.

DATE: Thursday, November 12, 1998

REPORTED BY: H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter

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years 5/15, 7/19, 22/8, 53/24

|

| 59/5, 59/6, 59/7, 59/8, 59/9, 59/10, 59/11, 59/12, 59/13, 59/14, 59/15, 59/16, 59/17, 59/18, 59/19, 59/20, 59/21, 59/22, 59/23, 59/24
|Page|Line| 59/4

EXHIBIT NO. _____

DOCKET NO: 981042-EM

WITNESS: Michael D. Rib

PARTY: Florida Power Corporation

DESCRIPTION: 1998 Forecasts of Reserve Margins

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 34
COMPANY/ STF
WITNESS:
DATE: 02-3-98

PROFFERING PARTY: STAFF

Summary Data for Winter 2000/2001			
	Peninsula	FPL	FPC
Total Capacity (MW)	42,740	19,626	9,517
Firm Winter Peak (MW)	37,317	17,054	8,452
Reserve Margin (%)	15%	15%	13%
LM and Int. as % of Reserve Margin	75%	56%	139%

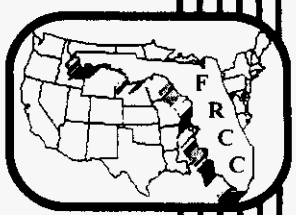
1998

Regional

Load & Resource

Plan

July, 1998



FLORIDA RELIABILITY COORDINATING COUNCIL

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF LOAD MANAGEMENT / INTERRUPTIBLE LOAD - MW

SUMMER

YEAR	FKE	FMPA		FPC		FPL		JEA		KEY	KUA	LAK		NSB	OEU	OUC		SEC		TEC		TOTAL (LM / INT)	
1998	4	5	0	683	272	660	438	0	85	0	12	21	5	6	2	0	1	126	88	151	217	1,670	1,106
1999	4	6	0	708	331	709	458	0	121	0	12	22	5	6	2	0	1	131	93	169	233	1,769	1,242
2000	4	6	0	726	345	752	479	0	121	0	12	22	5	6	2	0	1	136	96	187	230	1,853	1,277
2001	5	7	0	748	350	792	482	0	121	0	12	23	5	6	2	0	1	140	99	206	228	1,941	1,286
2002	5	8	0	762	295	833	485	0	121	0	12	23	5	6	2	0	1	145	102	226	225	2,022	1,234
2003	5	8	0	771	278	873	488	0	121	0	12	24	5	6	3	0	1	149	105	246	222	2,097	1,220
2004	6	9	0	774	271	887	489	0	121	0	13	25	5	6	3	0	1	153	108	266	219	2,142	1,214
2005	6	10	0	776	265	887	489	0	121	0	13	25	5	6	3	0	1	158	111	287	217	2,170	1,209
2006	6	10	0	779	258	887	489	0	121	0	13	26	6	6	3	0	1	162	115	308	215	2,200	1,205
2007	6	11	0	782	256	887	489	0	121	0	13	26	6	6	3	0	1	167	118	330	212	2,231	1,203

WINTER

YEAR	FKE	FMPA		FPC		FPL		JEA		KEY	KUA	LAK		NSB	OEU	OUC		SEC		TEC		TOTAL (LM / INT)	
1998 / 99	0	6	0	1,175	318	866	448	0	108	0	12	51	5	8	3	0	1	185	91	296	211	2,602	1,182
1999 / 00	0	7	0	1,213	340	925	464	0	108	0	12	52	5	8	3	0	1	192	94	317	209	2,729	1,221
2000 / 01	0	7	0	1,251	348	976	464	0	108	0	12	53	5	8	4	0	1	199	96	339	207	2,849	1,229
2001 / 02	0	7	0	1,281	312	1,028	464	0	108	0	12	54	5	8	4	0	1	205	99	361	204	2,960	1,193
2002 / 03	0	8	0	1,306	282	1,079	464	0	108	0	12	55	5	8	4	0	1	212	102	383	203	3,067	1,165
2003 / 04	0	8	0	1,309	275	1,127	464	0	108	0	12	57	5	8	4	0	1	218	105	405	201	3,148	1,159
2004 / 05	0	9	0	1,312	268	1,127	464	0	108	0	13	58	5	8	4	0	1	224	108	428	198	3,183	1,152
2005 / 06	0	9	0	1,315	262	1,127	464	0	108	0	13	59	5	8	4	0	1	231	112	451	196	3,217	1,148
2006 / 07	0	9	0	1,318	255	1,127	464	0	108	0	13	60	5	9	5	0	1	237	115	474	193	3,251	1,141
2007 / 08	0	9	0	1,322	257	1,127	464	0	108	0	13	61	5	9	5	0	1	243	118	482	192	3,270	1,145

NOTE: A SINGLE NUMBER DENOTES LOAD MANAGEMENT.

1998
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
		NET	PROJECTED			RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT.			RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT.	
YEAR	INSTALLED CAPACITY (MW)	CONTRACTED FIRM INTERCHANGE (MW)	FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	(MW)	% OF PEAK	FIRM PEAK DEMAND (MW)	(MW)	% OF PEAK
1998	35485	1412	2220	39117	35633	3484	10%	32857	6260	19%
1999	36112	1702	2220	40034	36628	3406	9%	33617	6417	19%
2000	36356	1852	2220	40428	37410	3018	8%	34280	6148	18%
2001	36866	1766	2295	40927	38220	2707	7%	34993	5934	17%
2002	38406	1704	2286	42396	38844	3552	9%	35588	6808	19%
2003	39430	1623	2286	43339	39395	3944	10%	36078	7261	20%
2004	40500	1633	2286	44419	40227	4192	10%	36871	7548	20%
2005	41325	1644	2276	45245	41112	4133	10%	37733	7512	20%
2006	42042	1630	2143	45815	41998	3817	9%	38593	7222	19%
2007	43096	1755	2143	46994	42885	4109	10%	39451	7543	19%

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
		NET	PROJECTED			RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT.			RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT.	
YEAR	INSTALLED CAPACITY (MW)	CONTRACTED FIRM INTERCHANGE (MW)	FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	(MW)	% OF PEAK	FIRM PEAK DEMAND (MW)	(MW)	% OF PEAK
1998 / 99	38037	1939	2240	42216	39450	2766	7%	35666	6550	18%
1999 / 00	38402	1916	2240	42558	40383	2175	5%	36433	6125	17%
2000 / 01	38809	1691	2240	42740	41395	1345	3%	37317	5423	15%
2001 / 02	40638	1705	2315	44658	42219	2439	6%	38066	6592	17%
2002 / 03	41980	1612	2306	45898	42998	2900	7%	38766	7132	18%
2003 / 04	43073	1623	2306	47002	43925	3077	7%	39618	7384	19%
2004 / 05	44105	1633	2296	48034	44895	3139	7%	40560	7474	18%
2005 / 06	44883	1555	2163	48601	45896	2705	6%	41531	7070	17%
2006 / 07	45916	1630	2163	49709	46879	2830	6%	42487	7222	17%
2007 / 08	46076	1555	2163	49794	47902	1892	4%	43487	6307	15%

NOTE: COLUMN 9: "FIRM PEAK DEMAND" = TOTAL PEAK DEMAND - INTERRUPTIBLE LOAD - LOAD MANAGEMENT.

E-116

FPL

Appendix

to

Ten Year Power Plant
Site Plant

April, 1998

03767

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind Load Management	Comm./Ind Conservation	Net Firm Demand
1987/88	12,372	379	11,993	0	1	38	0	10	12,371
1988/89	12,876	417	12,459	0	9	68	68	17	12,799
1989/90	13,988	648	13,340	0	35	101	94	29	13,859
1990/91	11,868	328	11,540	0	102	135	144	32	11,622
1991/92	13,319	105	13,214	0	174	170	193	38	12,952
1992/93	12,964	102	12,862	0	242	195	275	48	12,447
1993/94	12,594	278	12,316	0	317	231	342	67	11,935
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	18,096	0	459	310	406	143	17,231
1996/97	16,490	119	16,371	0	731	368	418	154	15,341
1997/98	17,755	454	17,300	0	799	41	431	7	16,477
1998/99	17,845	149	17,696	0	866	65	448	13	16,453
1999/00	18,230	173	18,057	0	925	86	464	19	16,736
2000/01	18,622	191	18,431	0	976	104	464	24	17,054
2001/02	19,027	224	18,803	0	1,028	124	464	36	17,375
2002/03	19,426	258	19,168	0	1,079	144	464	47	17,692
2003/04	19,823	292	19,531	0	1,127	163	464	58	18,011
2004/05	20,223	325	19,898	0	1,127	163	464	58	18,411
2005/06	20,630	359	20,271	0	1,127	163	464	58	18,818
2006/07	21,044	394	20,650	0	1,127	163	464	58	19,232

Historical Values (1988 - 1997):

Cols. (2) - (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and MAY incorporate the effects of load control IF load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.

Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes CILC and GS - LC.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (1998-2007):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 1997

Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values in are projected August values and are based on projections with a 1/97 starting point.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: (10) = (2) - (5) - (6) - (7) - (8) - (9).

Schedule 7.2 *

Forecast of Capacity , Demand, and Scheduled

Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)			(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
1997/98	17,257	1,297	0	1,010	19,564	17,755	1,278	16,477	3,087	19	0	3,087	19
1998/99	17,370	1,297	0	1,010	19,677	17,845	1,392	16,453	3,224	20	0	3,224	20
1999/00	17,309	1,297	0	1,010	19,616	18,230	1,494	16,736	2,880	17	0	2,880	17
2000/01	17,319	1,297	0	1,010	19,626	18,622	1,568	17,054	2,572	15	0	2,572	15
2001/02	18,381	1,297	0	1,010	20,688	19,027	1,652	17,375	3,313	19	0	3,313	19
2002/03	18,381	1,297	0	1,001	20,679	19,426	1,734	17,692	2,987	17	0	2,987	17
2003/04	19,457	1,297	0	1,001	21,755	19,823	1,812	18,011	3,744	21	0	3,744	21
2004/05	19,457	1,297	0	991	21,745	20,223	1,812	18,411	3,334	18	0	3,334	18
2005/06	19,905	1,297	0	858	22,060	20,630	1,812	18,818	3,242	17	0	3,242	17
2006/07	20,353	1,297	0	858	22,508	21,044	1,812	19,232	3,276	17	0	3,276	17

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the second year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2)+ Col.(3) - Col.(4)+Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional

5/ Margin (%) Before Maintenance = Col.(8)/Col.(7)

6/ Margin (%) After Maintenance = Col.(11) /Col.(7)

* Schedule 7.2 is similar to Table III.B.3 in the Site Plan document.

Florida Power
CORPORATION

Ten-Year Site Plan

DETAIL AS OF DECEMBER 31, 1997

03763 APR-1 98
FPSC-RECORDS/REPORTING

TABLE 3.3

FLORIDA POWER CORPORATION
TOTAL DEMAND-SIDE MANAGEMENT RESOURCES

SUMMER

YEAR	NON-DISPATCHABLE DSM & SELF-SERVICE COGEN (MW)	INTERRUPTIBLE LOAD (MW)	LOAD MGT., HEATWORKS, & STANDBY GENERATION (MW)	VOLTAGE REDUCTION (MW)	TOTAL (MW)
1998	306	272	586	97	1,261
1999	325	331	606	102	1,364
2000	344	345	625	101	1,415
2001	362	350	644	104	1,460
2002	379	295	662	100	1,436
2003	394	278	677	94	1,443
2004	394	271	677	97	1,439
2005	394	265	677	99	1,435
2006	394	258	677	102	1,431
2007	394	256	677	105	1,432

WINTER

1998/99	350	318	1,063	112	1,843
1999/00	373	340	1,099	114	1,926
2000/01	395	348	1,133	118	1,994
2001/02	415	312	1,167	114	2,008
2002/03	435	282	1,198	108	2,023
2003/04	435	275	1,198	111	2,019
2004/05	435	268	1,198	114	2,015
2005/06	435	262	1,198	117	2,012
2006/07	435	255	1,198	120	2,008
2007/08	435	257	1,198	124	2,014

FLORIDA POWER CORPORATION

SCHEDULE 7.2

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
1998/99	8,234	465	0	831	9,530	8,066	1,464	18%	0	1,464	18%
1999/00	8,261	465	0	831	9,557	8,201	1,356	17%	0	1,356	17%
2000/01	8,146	465	0	906	9,517	8,452	1,065	13%	0	1,065	13%
2001/02	8,146	465	0	906	9,517	8,194	1,323	16%	0	1,323	16%
2002/03	8,146	465	0	906	9,517	7,776	1,741	22%	0	1,741	22%
2003/04	7,980	465	0	906	9,351	8,017	1,334	17%	0	1,334	17%
2004/05	8,385	475	0	906	9,766	8,258	1,508	18%	0	1,508	18%
2005/06	8,385	475	0	906	9,766	8,498	1,268	15%	0	1,268	15%
2006/07	8,890	475	0	906	10,271	8,741	1,530	18%	0	1,530	18%
2007/08	8,890	475	0	906	10,271	8,983	1,288	14%	0	1,288	14%

ORIGINAL

Late-Filed Exhibit 35

Summary of Broker and Off-Broker Savings

Florida Power Corporation

	Purchases			Sales			Total Benefits		
	Broker Savings	Off-Broker Savings	Total Savings	Broker Savings[1]	Off-Broker Savings	Total Savings	Broker Savings	Off-Broker Savings	Total Savings
1994	5,923,583	763,110	6,686,693	1,474,304	387,862	1,862,166	7,397,887	1,150,972	8,548,859
1995	3,627,660	294,967	3,922,627	2,282,194	610,655	2,892,849	5,909,854	905,622	6,815,476
1996	7,057,500	5,695,498	12,752,998	750,716	856,298	1,607,014	7,808,216	6,551,796	14,360,012
1997	3,635,245	5,580,720	9,215,965	444,900	3,526,948	3,971,848	4,080,145	9,107,668	13,187,813
1998	2,003,046	3,713,752	5,716,798	432,977	12,198,867	12,631,844	2,436,023	15,912,619	18,348,642

Broker sales benefit adjustment: ***80%***

5 Year Total Savings: **$ 61,260,802**

Notes:

1. The broker savings for sales have been adjusted to reflect that, per Florida PSC Rules, 80% of the savings are passed back to customers throughout the fuel adjustment clause.

2. The growth in off-broker savings is significant. !00% of these savings are passed back to customers through the fuel adjustment clause.

3. Our cursory evaluation of the broker and off-broker savings for the peninsular Florida IOU's reflects benefits of well over $200 Million over the past 5 years. The growth trend in these benefits could result in substantial benefits to Florida ratepayers in future years.

Total Sales Revenues ($ 000's)	Savings as a % of Total Revenues
2,036,721	0.42%
2,223,400	0.31%
2,328,980	0.62%
2,445,126	0.54%
2,596,022	0.71%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. Late-filed 35
COMPANY/ WITNESS: FPC/ FP&L and TECO
DATE: 12-2-98

DOCUMENT NUMBER-DATE
00515 JAN 14 99
FPSC-RECORDS/REPORTING

Florida Power & Light Company
Docket No. 981042-EM
Late Filed Exhibit _____
Page 1 of 1

Percentage of Revenues From Wholesale Transactions in Relationship To Total Revenues For the Last 5 Years (1994 - 1998)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	TOTAL ELECTRIC REVENUE FROM SALE OF ELECTRICITY	TOTAL OPERATING REVENUE	REVENUES FROM FIRM CONTRACTS (WHOLESALE)	REVENUES FROM NON-BROKER	REVENUES FROM BROKER (C SCHEDULES)	REVENUES FROM (PSL, SEC UNSCH & FKEC ALTERNATE)	(D + E + F + G) FERC FORM 1 TOTAL
SOURCE: FERC FORM 1	PG 300 LN 14 ADJ UNBILLED & DEF.	PG 300 LN 27	PAGES 310s & 311s	PAGES 310s & 311s	PAGES 310s & 311s	PAGES 310s & 311s	PAGES 310s & 311s
YEAR 1994 $	5,258,398,473	5,342,656,459	80,465,091	8,474,544	35,449,231	3,729,325	128,118,191
% OF SALE OF ELECT.			1.53%	0.16%	0.67%	0.07%	2.44%
% OF OPERATING REV.			1.51%	0.16%	0.66%	0.07%	2.40%
YEAR 1995 $	5,447,666,608	5,530,057,167	85,351,068	10,948,142	16,206,099	3,428,778	115,934,087
% OF SALE OF ELECT.			1.57%	0.20%	0.30%	0.06%	2.13%
% OF OPERATING REV.			1.54%	0.20%	0.29%	0.06%	2.10%
YEAR 1996 $	5,895,818,875	5,986,427,727	98,732,185	24,084,697	32,550,206	3,131,700	158,508,788
% OF SALE OF ELECT.			1.67%	0.41%	0.55%	0.05%	2.69%
% OF OPERATING REV.			1.65%	0.40%	0.54%	0.05%	2.65%
YEAR 1997 $	6,035,139,360	6,132,047,181	73,769,813	50,278,909	12,872,351	3,019,261	139,940,334
% OF SALE OF ELECT.			1.22%	0.83%	0.21%	0.05%	2.32%
% OF OPERATING REV.			1.20%	0.82%	0.21%	0.05%	2.28%
YEAR 1998 (as of Sept.) $	4,730,526,557	4,806,569,622	61,884,170	109,904,620	4,420,274	2,449,080	178,658,144
% OF SALE OF ELECT.			1.31%	2.32%	0.09%	0.05%	3.78%
% OF OPERATING REV.			1.29%	2.29%	0.09%	0.05%	3.72%

	GROSS PROFIT NON-BROKER	GROSS PROFIT BROKER (80% GAIN)
SOURCE:	LEDGER ACCT 447.120	A6 PLUS C-TRANS ACCTS.
YEAR		
1994	1,913,692	8,404,009
1995	2,893,978	3,772,262
1996	5,878,104	4,840,224
1997	23,121,373	2,888,771
PERIOD ENDING 9/1998	67,063,531	934,603

TAMPA ELECTRIC COMPANY
Revenues from Off System Sales Transactions Compared to Total Revenue
1994 - 1998

	Total Sales of Electricity* ($000)	Total Operating Revenues* ($000)	Total Revenues Off System Sales* ($000)	Total Revenues from Economy Sales** ($000)
YEAR 1994	1,080,697	1,094,865	70,433	28,017
% of Sales of Electricity			6.52%	2.59%
% of Operating Revenues			6.43%	2.56%
YEAR 1995	1,073,624	1,092,256	79,967	39,219
% of Sales of Electricity			7.45%	3.65%
% of Operating Revenues			7.32%	3.59%
YEAR 1996	1,093,078	1,112,885	93,296	42,488
% of Sales of Electricity			8.54%	3.89%
% of Operating Revenues			8.38%	3.82%
YEAR 1997	1,167,621	1,188,984	94,284	32,903
% of Sales of Electricity			8.07%	2.82%
% of Operating Revenues			7.93%	2.77%
YEAR 1998	1,210,286	1,234,441	89,667	20,232
% of Sales of Electricity			7.41%	1.67%
% of Operating Revenues			7.26%	1.64%

* Data Obtained from Tampa Electric Company Financial Report

** Data obtained from Tampa Electric Company Schedule A6

THE FLORIDA SENATE

COMMITTEE ON REGULATED INDUSTRIES

418 Senate Office Building
Tallahassee, Florida 32399-1100
(904) 487-5957

James A. Scott, *Chairman*
Alberto "Al" Gutman, *Vice Chairman*

John Guthrie, *Staff Director*

December 12, 1997

The Honorable Julia Johnson, Chairman
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 36
COMPANY/
WITNESS: Dolan
DATE: 12-2-98

Dear Chairman Johnson:

My staff has advised me that the Public Service Commission's agenda conference scheduled for December 16, 1997, includes consideration of two petitions for declaratory statements concerning the eligibility of electric companies to seek determinations of need to build large power plants in Florida, even though they would not be regulated by the Public Service Commission pursuant to Chapter 366, F.S.

The complex issues raised by these petitions extend far beyond the interests of the parties involved. In addition to regulatory issues, they raise important statewide policy questions that may affect consumers of electric power throughout the state.

When the Florida Electrical Power Plant Siting Act was enacted during the 1970s, no one contemplated the possibility that it might someday apply to electric companies that do not directly serve retail customers in Florida. Yet that is the interpretation recommended by PSC staff. Without judging the merits of the specific petitions before the Commission, I believe that a policy decision of this magnitude should not be made without a full and complete hearing by the Legislature.

Sincerely,

James A. Scott

James A. Scott, Chairman
Regulated Industries Committee

STATE OF FLORIDA

JULIA L. JOHNSON
CHAIRMAN

CAPITAL CIRCLE OFFICE CENTER
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0854
(850) 413-6044

Public Service Commission

December 19, 1997

The Honorable Jim Scott, Chairman
Senate Regulated Industries Committee
The Florida Senate
Room 308, Senate Office Building
Tallahassee, Florida 32399

Dear Senator Scott:

On behalf of all of the Commissioners, I wanted to respond to your December 12 letter regarding the declaratory statement petitions on merchant plants. We denied those petitions and had concerns that the major policies involved required a more deliberative approach. The orders denying the petitions will be available soon and I will forward them to you.

At the agenda, staff was directed to meet with me to discuss appropriate proceedings to review law and policy related to merchant plants being applicants for certificates of need. I will keep you informed of any decisions we make in this regard. Of course, the Commission recognizes that a company proposing to build a merchant plant may file a petition for rulemaking which is one means for furthering discussion of these issues. We hope that any future work the Commission pursues in this area will provide helpful information to the Legislature in any hearings you may choose to undertake.

I hope to be able to meet with you in early January to discuss these issues.

Sincerely,

Julia L. Johnson
Chairman

JLJ:mw

cc: Commissioner Susan F. Clark
Commissioner J. Terry Deason
Commissioner Joe Garcia
Commissioner Diane K. Kiesling

VMD-2

EXHIBIT NO. _____

DOCKET NO: 981042-EM

WITNESS: William D. Steinmeier

PARTY: Florida Power & Light Company

DESCRIPTION: Transcript of the Deposition of William D. Steinmeier, Taken at the Instance of the Staff of the Florida Public Service Commission, Volume 1, Pages 1-77

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 37
COMPANY/ WITNESS: Steinmeier
DATE: 12-2-98

PROFFERING PARTY: STAFF

STIPULATED DELETIONS FROM THE DEPOSITION OF WILLIAM D. STEINMEIER (EXHIBIT NO. _____)

The Utilities Commission, City of New Smyrna Beach, Florida and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. ("Joint Petitioners"), Florida Power & Light Company and Commission staff hereby stipulate to deletions of the following portions of the deposition of William D. Steinmeier:

Page 8, Line 6 (beginning with the word "And") through Line 17 (ending with the word "unit").

Page 20, Line 17 through Page 21, Line 12.

Page 25, Line 20 through Line 23.

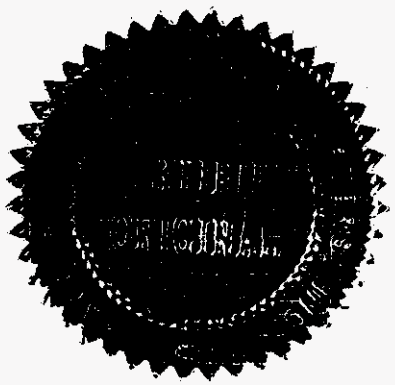
Page 42, Line 10 (beginning with the word "as") though Line 11 (ending with the word "least").

Page 52, Line 12.

Page 58, Line 4 (beginning with the phrase "The purpose" and ending with the word "Act").

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Joint petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	DOCKET NO. 981042-EM



VOLUME 1
Pages 1 - 77

DEPOSITION OF:	WILLIAM D. STEINMEIER
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Gerald L. Gunter Building 2540 Shumard Oak Boulevard Room 362 Tallahassee, Florida
TIME:	Commenced at 1:16 p.m. Concluded at 4:05 p.m.
DATE:	November 17, 1998
REPORTED BY:	MARY ALLEN NEEL, RPR Notary Public, State of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
100 SALEM COURT
TALLAHASSEE, FLORIDA 32301
(850) 878-2221

BUREAU OF REPORTING
RECEIVED 11-20-98

APPEARANCES:

ROBERT SCHEFFEL WRIGHT, Landers & Parsons, P.A., 310 West College Avenue, Tallahassee, Florida 32301, on behalf of Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.

JOHN T. BUTLER, Steel, Hector & Davis, 200 South Biscayne Boulevard, Miami, Florida 33131-2398, on behalf of Florida Power & Light Company.

WILLIAM H. HOLLIMON, Ausley & McMullen, 227 South Calhoun Street, Tallahassee, Florida 32301, on behalf of Tampa Electric Company.

LESLIE J. PAUGH, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-9850, on behalf of the Florida Public Service Commission Staff.

ALSO PRESENT:

MAURA HERNANDEZ, Duke Energy
MARK FUTRELL, FPSC Division of Electric & Gas
SAM WATERS, Duke Energy

I N D E X

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S T I P U L A T I O N S

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

Thereupon,

WILLIAM D. STEINMEIER

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

EXAMINATION

BY MS. PAUGH:

Q Good afternoon, Mr. Steinmeier. My name is Leslie Paugh. I'm an attorney with the Public Service Commission of Florida. We are here in Docket 981042-EM. It is the joint petition of the Utilities Commission of the City of New Smyrna Beach and Duke Power Company. I'm still catching my breath from agenda conference here.

I'm going to ask you a series of questions. If there are any questions that you do not understand my meaning, please just ask me to repeat them or rephrase them and I'll be happy to do so. A number of my questions request a yes or no answer. Please answer yes or no, and then if additional explanation is required, please feel free to do so.

Please state your name for the record.

A William D. Steinmeier.

Q By whom are you employed, Mr. Steinmeier?

A I am employed by William D. Steinmeier, Professional Corporation.

Q Thank you. Have you sponsored testimony in this docket?

A Yes, I have.

Q Do you have any additions or corrections to that testimony?

A Yes.

Q Would you please indicate for the record what that addition or correction is?

A We have previously filed an errata sheet, or Florida Power & Light caused to be filed an errata sheet with four corrections. I would be happy to reflect them if that would be helpful at all.

Q Yes, please.

A There's one very small one that I finally spotted this morning. On page 4, line 3, "What is you understanding," should be, "What is your understanding."

Q Yes, sir.

A Line 21 on page 4, between the words "no" and "contracts," please insert the words "final purchased power."

On page 12, line 16, at the end of the line, "or that there is no" should be "or that there are no."

Page 18, line 9, at the end of the line,

please insert the word "are" between "there" and "a," in the new sentence that begins at the end of line 9.

Page 25 is the one we just distributed that was not part of the errata sheet previously filed. On line 9, delete the words "off system" and replace them with the word "wholesale."

And finally, on page 33, line 1, "the option of the" should be "the question of the," actually pronounced "thee," but the written record will be oblivious to that.

Q Mr. Steinmeier, are you an attorney?

A Yes, I am.

Q Thank you, sir. Now, the direct testimony that you have filed in this docket, upon whose behalf have you filed the testimony?

A On behalf of Florida Power & Light Company.

Q Please summarize, if you will, the major points of your testimony.

A To summarize, it is my opinion that the Public Service Commission should not grant a determination of need in the current docket, primarily for the reason that granting a determination of need in this case would be a substantial departure from the policy underlying need determination grants in the past in Florida. The policy for siting of new

generation plants in Florida is to limit the number of new generating plants that are constructed to balance the need for new generation against broader public interests, particularly land and water use and environmental impacts of siting new generating facilities. And at least since 1989, the application of that policy by the Commission has depended on and required a showing of utility-specific need upon which a need determination would be based, not a more generic statewide need.

So my recommendation to the Commission that the joint petition not be granted in this case is for the reason that in my view, the standards that are set forth as part of the Florida siting policy cannot be met by this application because there is no way to determine a utility-specific need for the proposed unit. This would create inconsistency in the application of Florida's siting policies, depending on the ownership or type of plant that was sought to be sited. I believe that it would increase the complexity of the planning process for Florida utilities which have an obligation to serve, could result in the uneconomic duplication of facilities, and generate other possible negative impacts on customers.

I think that's a reasonable summary of my testimony.

Q Thank you, sir. Mr. Steinmeier, are you familiar with the Florida Public Service Commission's regulatory framework concerning electric generation in Florida?

A Generally, yes.

Q Can you please describe your understanding of the regulatory framework? And by that I mean the specific statutes, how they interact, and that sort of thing.

A The question you asked is the general framework for regulation -- would you ask it again, please? I want to make sure I'm being responsive.

Q I believe it was your testimony that you are familiar with the regulatory framework within which the Public Service Commission works regarding electric generation in Florida.

A Yes.

Q My question is, please describe your understanding of that regulatory framework.

A Okay. In general, the Commission has broad regulatory jurisdiction over electric utilities in Florida. Florida law requires utilities to file ten-year power plant site plans on an annual basis.

Utilities are required to file, to develop and submit to the Commission for review periodically conservation goals. The Power Plant Siting Act requires that before constructing any generating unit of 75 megawatts or more, there needs to be a need determination by the Florida Public Service Commission, as well as review by the Siting Board and approval of the environmental dimensions of the project.

Those are all part of what I understand to be the structure of regulation of electric utilities.

Q Are you familiar with the bidding rule in Florida for electric generation?

A I am aware of it.

Q Can you please describe the difference between familiar and aware?

A I could not off the top of my head recite to you its more fundamental elements or engage in a detailed discussion.

Q All right. Thank you.

A I've read it.

Q Okay. Mr. Steinmeier, are you familiar with the Commission's requirements in the need determination statute, 403.519? And by that I mean, what criteria does the Commission apply?

A Yes.

Q And what are those criteria, sir?

A The Commission is required to evaluate the need for system reliability and integrity, to consider the need for adequate electric capacity at reasonable cost. The statute requires consideration of whether the proposed project is the most cost-effective alternative available, also, what conservation measures have been taken or could be taken by the applicants to mitigate the need for the new generating unit. And the Commission may consider other matters under its jurisdiction which it deems relevant to the inquiry.

Q Are these the criteria the Commission must consider in granting or denying a determination of need?

A That's my understanding of the siting policy of Florida.

Q I would like to talk about the adequate electricity at reasonable cost criteria for a few moments. Does the need determination statute in your opinion require the Commission to take into account the need for adequate electricity at reasonable cost?

A Would you repeat the question, please?

Q Does the need determination statute that

we've just been discussing require the Commission to take into account the need for adequate electricity at reasonable cost as a criteria?

A Yes, it does.

Q What do you believe is required to be shown by the petitioner in a need determination case in order to satisfy that criteria?

A Well, it seems to me that in order to show that there is a need for adequate electricity at a reasonable cost, there has to be a specific showing of need. Again, the purpose of the policy is to balance the need for electric generation against broader public interests and environmental protection and control of land and water use.

The policy seems best applied if applied in a utility-specific determination, because it is utilities which have an obligation to provide service to customers in their service area that are most clearly able to identify what the need is, how need is growing or changing, what conservation measures have been taken to meet the other elements of the inquiry required by the Act.

Q Do you know if state commissions traditionally have to take a look at adequate electricity at reasonable cost, if this is a normal

standard?

A I do not know if that specific phrase appears in other state statutes.

Q Mr. Steinmeier, I would like to talk about the open competitive wholesale market for a few moments here. I assume you're generally familiar with that.

A Generally, yes.

Q How can a utility with the obligation to serve retail customers meet its obligation? And this is in general.

MR. BUTLER: Its obligation to what?

MS. PAUGH: Serve those customers.

THE WITNESS: A utility with an obligation to serve its customers meets that obligation by providing adequate and reliable service to its customers.

BY MS. PAUGH:

Q Can a utility own and operate generation?

A Yes.

Q Can a utility purchase power?

A Yes.

Q Can a utility purchase power on the wholesale market from other utilities?

A It can.

Q Is a utility required to purchase on the wholesale market power from other utilities?

A No.

Q Can a utility on the wholesale market purchase power from nonutility providers?

A I apologize. I was distracted thinking about the previous question. Could we return to it for a moment?

Q Certainly. Would you like the question read back?

A Please.

(Question at line 1 read by the reporter.)

THE WITNESS: Can I elaborate slightly on my answer to that question?

BY MS. PAUGH:

Q Please do.

A The other thought I had in answering the question is -- and not to act too presidential, but what does required mean exactly? And the point I would make is that the Commission Staff, for example -- and I used to be part of one myself -- and the Commission can have opportunities to influence purchasing decisions by a utility. There may be no law that requires a utility to buy power on the wholesale market, but if in a review of the utility's

rates by the Commission, the Commission can identify some places where a company might have reduced costs by buying power from one source that was available to it rather than utilizing the source it chose, there certainly can be influence brought to bear on the purchasing practices of the utility.

So I would add that to my answer to the previous question.

Q Well, I would like to ask a follow-up to that answer. I believe it's your testimony that a commission staff can influence a utility's decision-making whether or not to generate its own power or purchase power; is that correct?

A It can certainly adjust rates if it believes that the company could have made a more cost-effective decision or deployment decision than it made did.

Q By adjusting rates, do you mean within the confines of a rate case?

A Yes.

Q If a commission staff did do that, why would they do that? Why would they influence a utility in that manner?

A Because they believe that the company could have reduced its costs by utilizing an alternative

that was available to it that it did not use.

Q Are you aware of a rate case pending in conjunction with the docket for which you've filed direct testimony?

A No.

Q Is it your testimony that this type of Staff influence could happen within the confines of this docket or as an outcome of that?

A No.

Q Okay. Thank you. It was given as a hypothetical, I take it?

A Well, perhaps I should have asked for more elaboration on your question before I answered it at all, but I was trying to think through the full ramifications of whether a company could be required to buy power on the wholesale market, which I believe was the question.

Q And I understand your answer is, maybe not required, but other things are at work. My question really related to statutory requirements. Could this Commission whack down its gavel and say, "Thou shalt buy wholesale power," in your opinion?

MR. BUTLER: Are you asking him for a legal conclusion about what the Florida Statutes require?

MS. PAUGH: The subject of his direct testimony is a lot of discussion about wholesale power and that sort of thing, and he does a lot of comparison. The nature of my question is directly related to his testimony. Now, I'm aware that there is a motion pending regarding the legal nature or alleged legal nature of his testimony. So my short answer is, my question is related to his testimony. It may be determined at a future time that his testimony itself gave legal conclusions. I'm asking him to expand on his testimony.

MR. BUTLER: I'm going to object to the question to the extent that it requires him to reach any legal conclusions about what the laws of the State of Florida require the Commission to do. Now, if he wants to discuss what he understands the laws of Florida say as sort of background for what his views of the policies here are, fine.

MS. PAUGH: That is the nature of my question.

MR. BUTLER: Okay.

MS. PAUGH: Are you instructing the witness to answer?

MR. BUTLER: I'm not instructing him to answer or not answer. I'm simply -- I posed a potential objection. I think you've addressed the objection by your clarification.

MS. PAUGH: All right. Could you read back my last question, please?

(Preceding question read by the reporter.)

BY MS. PAUGH:

Q As a matter of policy, Mr. Steinmeier, is it your opinion that this Commission could require utilities to purchase power?

A Require a Florida utility company for purposes of meeting the needs of its retail customers?

Q Yes, sir.

A I don't know, but I think not.

Q Do you know if a utility can be required to purchase on the wholesale market power from nonutility providers?

MR. BUTLER: Are you again asking it as his understanding of the statutes in forming his policy testimony?

MS. PAUGH: Yes.

MR. BUTLER: Okay.

THE WITNESS: I'm sorry. Please read it

back.

MR. WRIGHT: Could I ask a clarifying question?

MS. PAUGH: Certainly.

MR. WRIGHT: What do you mean by nonutility providers?

MR. FUTRELL: Everybody that's not a retail provider.

MR. WRIGHT: Retail. Okay. Thanks.

MR. BUTLER: Is that part of the question now?

MS. PAUGH: Only if it needs to be.

Would you please read back the last question?

(Preceding question read by the reporter.)

THE WITNESS: Required to buy power on the wholesale market from nonutility providers. I don't believe so.

BY MS. PAUGH:

Q Okay. Thank you. When a utility agrees to purchase power from either a utility or a nonutility provider, does it, the purchasing utility, pay a price as determined by the seller of the power?

A I'm sorry. I'm still on the last question, but that caused more trouble than it was worth last

time, so I'll move on.

Q Mr. Steinmeier, if you would like to go back, I'll be happy to do that.

A No. Do you need her to read it back, or do you want to just ask me again?

MR. BUTLER: Why don't you read it?

(Preceding question read by the reporter.)

THE WITNESS: It pays a price as determined between the buyer and the seller.

BY MS. PAUGH:

Q So it's a negotiated price?

A It depends on the nature of the transaction. It might be tariffed.

Q In your opinion, would a utility agree to purchase power at a price that is not reasonable?

A No.

Q Why would market price, and that is market price for power, not be considered adequate electricity at reasonable cost?

A The problem I get into there is that to the best of my knowledge, neither the Florida Legislature nor the Public Service Commission has determined that a competitive market should be the model on which utilities in Florida operate. What is in place is a model under which power plant siting is carefully

limited because of the concern that land and water use and environmental quality not be tapped excessively for power plants that are not in fact needed to meet the specific needs for electricity of Floridians.

Within that framework, cost recovery systems are in place. And if in fact what is being sited is electric capacity that is not identifiable as meeting a need for additional electric generating capacity for service to Floridians, it's impossible to -- the price is irrelevant. It's impossible to evaluate the need for power at a price if you can't establish a specific need for the power.

Q I believe it was your testimony a moment ago that utilities can, but are not required to purchase wholesale power; is that correct?

A Correct.

Q And if they did purchase that power, it would be at a negotiated price acceptable to both parties; is that correct?

A Generally.

Q When I asked you the question regarding market price not being considered adequate electricity at reasonable cost, I understood your answer to tie that phrase directly into the regulated model versus the competitive market model. Is that correct?

A My answer is in the record. What are you asking me now?

Q Well, I'm trying to understand, as a general matter, just a utility purchasing wholesale power at a negotiated price, why that would not be considered adequate electricity at a reasonable cost. And I believe your answer dealt more with the competitive model versus the regulated framework. And just the bare question is what I'm trying to understand.

MR. BUTLER: I will object that it has been asked and answered.

MS. PAUGH: It has been asked, but he hasn't answered my question, so I'm trying to rephrase it and focus it.

MR. BUTLER: Well, how you paraphrased it and answered it -- what he said did. That's one of the problems with paraphrasing.

But if you want to try again to clarify it, that's fine.

THE WITNESS: I would love to be as helpful as possible, and it's a fascinating exercise. Part of the joy of this whole process is getting to think about something from a little different direction than you ever had before.

BY MS. PAUGH:

Q Well, welcome to the Florida Public Service Commission.

A I should have stayed on the lawyer's side of the table. That's the lesson.

Okay. I'm really not trying at all to be difficult, but --

Q I don't believe that you are.

A -- I'm having trouble getting my hands around this question adequately.

Q Would you like me to reask it?

A Would you, please?

Q I'll be happy to. Why would a negotiated market price for wholesale power not be considered adequate electricity at a reasonable cost?

A Negotiated by whom, sold by whom to whom?

Q By the buyer and the seller.

A Any buyer, any seller?

Q A utility purchaser and either a utility or nonutility seller.

A Does the buyer have a need for additional capacity that is not being met under its existing set of generating plants and purchased power contracts?

Q Yes, assume that it does.

A So we have a buying utility with an

obligation to serve. And instead of siting a new power plant, they've decided to enter into a purchased power contract?

Q No, sir. I believe my question goes more to short-term power purchases, say less than an hour.

A In terms of opportunity sales or economy sales through the broker system, I'm not sure exactly what the relevance of adequate power is as that term is used in the Siting Act.

Yes, clearly a utility may buy power on the market, on the hourly market, on the opportunity market, for a few days or a few weeks. That's a different question I think than what the Siting Act is asking about.

Q All right. Assume that the purchasing utility needs power for a term of three to five years from a wholesale provider at a negotiated rate. How would your answer change with that change of the facts?

MR. BUTLER: I'm sorry. What is the change in facts?

MS. PAUGH: I had said assume that the power purchase was for an hour, and his answer, very properly, was to discuss the broker system. And I frankly misspoke. What we're looking for

is a longer term, say a three- to five-year contract between a utility or a nonutility provider to a utility with an obligation to serve.

THE WITNESS: And you're asking me now if the utility signs a three- to five-year purchased power contract from a nonutility generator, is that a reasonable thing to do?

BY MS. PAUGH:

Q Essentially. My question is, why would the market price not be considered adequate electricity at a reasonable cost with these parameters that we've just put in place, the three- to five-year contract?

A Signing a three- to five-year contract to purchase power may be a perfectly reasonable thing for a utility to do to help meet its obligation to serve over that next period of time. The thing I continue to struggle with in answering the question is tying that to the statutory language in the Siting Act, which assumes that a new generating facility would have to be built in order to meet whatever increment of need is being identified by this utility that you're speaking of.

Q No, I don't believe my question assumes that a new unit will have to be built by a nonutility

provider. My question assumes any nonutility provider. Perhaps the generation is pre-existing somewhere in the State of Florida. Does that help?

A No, I think I understood your question correctly. The problem I'm having is trying to apply the statutory language of the Siting Act to that circumstance.

Q Is that your answer, Mr. Steinmeier?

A That's my answer.

Q Thank you, sir.

Mr. Steinmeier, I have a series of questions regarding the Commission's bidding rule. My understanding from your prior testimony is that you've read it, but that you're not intimately familiar with it, so you may not be able to answer my questions. If that's so, please just say so. Okay?

A Okay.

Q We'll just see where we can go. We'll provide you with copies of the bidding rule if you would like to refer to that. (Tendering documents.)

Mr. Steinmeier, are you familiar with Florida's bidding rule?

MR. BUTLER: Just for the record, you've handed us 25-22.082. Is that what you're referring to as the bidding rule?

MS. PAUGH: Yes.

MR. BUTLER: Go ahead.

MS. PAUGH: I apologize that. That was an important clarification. How we know it colloquially on campus is a little different than what you would read.

BY MS. PAUGH:

Q Are you familiar with this rule, Mr. Steinmeier?

A I'm aware of it and read it once.

Q What is your understanding of this rule?

A Generally that when a utility determines that it needs additional capacity, generating capacity, it puts that need out for bids.

Q Do you know if the bidding rule requires investor-owned electric utilities to purchase from plants similar to the type of plant in this proceeding?

MR. BUTLER: You mean does the rule say buy from a plant that's a combined cycle natural gas fired plant, or under what circumstances would they have to buy --

MS. PAUGH: That's a fair clarification.

BY MS. PAUGH:

Q Does the bidding rule require

investor-owned utilities to purchase from any plants in Florida?

A I don't know.

Q Do you know if the bidding rule requires investor-owned utilities to purchase power from plants similar to the plant in this petition, the combined cycle plant?

A Requires them to buy what at what point in time?

Q To purchase power from these plants.

A From a plant such as is proposed in this case?

Q Yes, sir.

A Which assumes the plant already exists?

Q Yes, sir.

A That a need determination was already granted and it's constructed?

Q Yes, sir.

A No, I don't.

Q Would you agree that one of the purposes of the bidding rule is to determine reasonable cost of supply-side alternatives along with the utility's proposal?

A Certainly.

Q Thank you. Assuming the plant that's

proposed in this docket is certified and built, if Duke New Smyrna responds to a request for proposals from a utility under this rule and it bids too high and another generating source is selected by the utility going out for RFP, are the utility ratepayers harmed in any way?

MR. BUTLER: Compared to what? Compared to what alternative?

MS. PAUGH: I would like the witness to make those distinctions.

MR. BUTLER: It seems like there's only half a question, unless I'm misunderstanding it. Harm seems to be a comparison between something and something, and I think I've only heard one something in the question.

MS. PAUGH: Well, by harm I mean are they having to pay higher prices for power than they otherwise would have.

MR. BUTLER: Otherwise would have if what? If Duke had bid lower?

MS. PAUGH: If Duke had bid lower, yes.

MR. BUTLER: So you're asking him if the ratepayers would be harmed if Duke had bid higher rather than bidding lower?

MS. PAUGH: Let's go back to my question.

My question is, if a utility under the bidding rule goes out for RFP and Duke bids, but its bid is determined by the utility to be too high, are the ratepayers harmed?

MR. BUTLER: Harmed by what?

MS. PAUGH: By the existence of the Duke plant.

THE WITNESS: Well, that's an interesting question.

BY MS. PAUGH:

Q Thank you, Mr. Steinmeier.

A The Duke plant has already been built under your hypothetical.

Q Yes, sir.

A Therefore, Florida land and water and environmental resources have already been devoted to the construction of that facility.

Q Yes, sir.

A That is a cost to Floridians, not necessarily a direct utility rate cost to the customers you're referring to in your question. The fact that the plant exists means that it has existed for some period of time, which may also mean that power from that plant may have displaced some wholesale sales of existing Florida utilities. It may

have displaced off-system sales by Florida utilities. Since most or all of the revenues from off-system sales flow back to customers through the clauses, there could have been some impact on utility customers of utilities which had such sales displaced from the existence of this plant. In terms of the actual retail rates going forward of the customers of the utility that you're speaking of, there should not be a direct and immediate negative impact on those rates.

Q Thank you, sir. If ratepayers are not harmed under my hypothetical, how is the reasonable cost criteria violated?

A Well, I didn't concede that no ratepayers are harmed. But aside from the issues related to off-system sales and displaced wholesale costs? How did you end your question?

Q How is the reasonable cost criteria violated?

A It's hard for me to see the relevance.

MR. BUTLER: I just want to make sure I understand. I think this relates back to a question where Duke bid too high. Is that right?

MS. PAUGH: That's correct.

MR. BUTLER: Okay. And so you're asking

how is the reasonable cost criteria violated if they bid too high?

MS. PAUGH: Yes.

MR. BUTLER: Okay.

THE WITNESS: First of all, your hypothetical assumes that the Duke plant has already been built, and therefore that there has already been a finding by the Commission of reasonable -- of a need. There has already been a need determination by the PSC which enabled the plant to be built.

The fact scenario that you've just laid out to me raises a serious and interesting question in my mind as to whether, if the Commission decides that it can grant a need determination without making the findings in the statute on a utility-specific basis, might a later determination -- what if Duke always bids too high? What if it can never meet that contract? Hasn't that just proven that there needed to be a utility-specific determination of whether the power that would have been provided by Duke was going to provide adequate electricity at a reasonable cost?

Having already been constructed, I would be

surprised if the Commission required the dismantling of the plant by virtue of Duke's failure to strike a contract. But it raises a very interesting question in my mind as to how we got to that point without first having assessed whether the power from this plant could meet a specific need under the criteria of the Siting Act.

MS. PAUGH: We'll go off the record. We need to take about two minutes, please.

(Short recess.)

BY MS. PAUGH:

Q Okay. Mr. Steinmeier, I'm going to ask you to assume a hypothetical with me, and I will draw our parameters as clearly as possible. Assume that Florida Power & Light Company made all the appropriate inquiries through the bidding rule and did all the appropriate things it was to do to investigate how it can get additional generation. It needs additional generation, say 300 megawatts.

Assume next that through the bidding process, Florida Power & Light Company has discovered that its least cost alternative, least cost supply-side alternative is to purchase that power from a plant that has not been built. Florida Power &

Light then comes to the Commission with a contract in hand with this least cost provider for a need determination. The contract is only for five years. The need determination is granted by the Public Service Commission.

Would the provider of the 300 megawatts be considered adequate electricity at a reasonable cost under my hypothetical?

A Under your hypothetical as you stated it, the PSC apparently has already determined that it's adequate electricity at a reasonable cost in granting the need determination. In my opinion, however, consistent application of a deliberately restrictive siting policy designed to preserve and protect natural resources and restrict the totality of resources that are devoted to generating plants in the state would require applications for a need determination to be based on a contract that reflected the expected useful life of the plant to be constructed, not a five-year contract.

Q Are you aware if that is Commission policy, that the contract be based on the useful life of the plant?

A No. I don't know.

Q Upon what do you base your answer, then,

Mr. Steinmeier?

A That -- well, let me put it this way. Building new plants based on five-year contracts, based on three-year contracts, based on seven-year contracts, based on no contracts, as proposed in this case, is not consistent with restricting the devotion of state land and water and environmental resources to the generation of electricity, to limiting the devotion of resources to those activities.

The way -- the most effective way to assure that a new power plant which is built in Florida gives Floridians the most benefit for the least impact on resources is to tie the contract to the expected useful life of the plant being constructed. Otherwise, you can wind up with many more power plants than are precisely needed to meet the generation needs of Florida.

Q Does the Florida Public Service Commission evaluate the environmental impacts of power plants?

A No, it does not. But its need determination is part and parcel of a process which ties the two together.

Q What does the Florida Public Service Commission analyze in a need determination case pursuant to the statute?

A The factors we discussed before.

Q And those factors are?

MR. BUTLER: Are you just asking what the statute says? Wouldn't it be better to just show him the statute?

MS. PAUGH: He has previously testified to what is in the statute. I think he can testify to it again. I'm trying to tie it to this language. He's welcome to take a look at it.

MR. BUTLER: It just seems like that would be more efficient rather than just trying to remember what it said.

(Document tendered to the witness.)

THE WITNESS: "The Commission shall take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available. The Commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant and other matters within its jurisdiction which it deems relevant."

BY MS. PAUGH:

Q In my hypothetical with this five-year contract, the least cost supply-side alternative that Florida Power & Light has discovered, would the Commission consider the criteria that you have just named?

A Yes, it would.

Q Under this hypothetical, why would this plant not be adequate electricity at reasonable cost?

A I think it would be both reasonable and likely for the Commission in evaluating whether it believed, whether it determined that the power in your hypothetical constituted adequate electricity at a reasonable cost, the duration of the contract and what the potential impacts of this capacity are beyond the terms of the contract, and I can assure you that as a member of the Commission, while my part of the task might be expressly delineated, the fact that it's part of a larger statutory mission is something that I would be mindful of.

Q I'm afraid I don't understand your answer, Mr. Steinmeier. I'm trying. Can you paraphrase your answer for me?

MR. BUTLER: No. If you have another question, ask him, but he gave you his answer.

The question is asked and answered.

BY MS. PAUGH:

Q Okay. Did you answer my question why this plant would not be adequate electricity at reasonable cost?

A I don't have enough information to assess whether even in the hypothetical it constitutes adequate electricity at a reasonable cost, but the length of the contract is something that I think should concern the Commission in making its determination of need.

Q Okay. Thank you. May I have my statute, back?

A Certainly.

Q You should have a copy of this in the packet Staff handed you, or if you don't, you will in a moment.

A Oh, I have a copy of it elsewhere in my notebook, and I summarized it earlier off the top of my head.

Q And did a very good job.

A Thank you.

Q Does Florida's need determination statute require the Commission to determine if the proposed plant, and by that I mean the plant proposed in this

docket, is the most cost-effective alternative available?

A Does the statute require the Commission to consider --

Q Yes, sir.

A -- whether this is the most cost-effective alternative available?

Q Yes.

A Yes, it does.

Q What, in your opinion, is required to be shown by the petitioner in order to satisfy that criteria?

A What alternatives were available to the applicant that it chose among, and why this one is the most cost-effective to meet the specific need of the utility.

Q Mr. Steinmeier, previously I asked you a series of questions regarding a utility such as FPL purchasing power on the wholesale market. Do you recall those questions generally?

A Generally, yes.

Q Would a utility such as FPL agree to purchase power at a price that is not cost-effective, in your opinion?

A No, it would not.

Q If the utility in my prior hypothetical, where you had a purchasing utility and a selling utility that had a negotiated price for wholesale power, had entered into a power purchase agreement and that was a market price, would that be considered a most cost-effective alternative, or could it be considered a most cost-effective alternative?

MR. BUTLER: Which is the question? The could?

MS. PAUGH: Could.

THE WITNESS: Okay. Is somebody building a new power plant here, or are you just asking me whether --

BY MS. PAUGH:

Q This is a long-term purchase arrangement, more than a year. It's at a negotiated price between the buyer and the seller.

A Nobody is building a new power plant to meet the terms of this contract? You're just asking me if it's reasonable to pay a market rate for contract power?

Q Right.

A And to that I would say yes.

Q It is the most cost-effective alternative?

A Well, I don't know what alternatives they

looked at.

Q I understand. Under that hypothetical --

A It's a reasonable approach.

Q Okay. Thank you. Let's go back to the hypothetical where we have a utility that has contracted for a five-year contract for a plant that has to be built, and they have a negotiated price that's established to be the least cost supply-side alternative. In your opinion, would that be considered the most cost-effective alternative?

A (Gesturing.)

THE REPORTER: Do you want it read back?

THE WITNESS: Please.

(Preceding question read by the reporter.)

THE WITNESS: I don't see how I could possibly answer that, based on -- without considerably more information about what other alternatives were evaluated and what the costs are based on in this contract, but I have a fundamental policy problem with building new power plants based on five-year contracts and risking the potential of having substantial excess capacity in the state in the not too distant future from power plants that were built on contracts that only committed the power for

five years.

BY MS. PAUGH:

Q What is the basis of your policy problem, as you put it, with the five-year contracts?

A Well, as I've explained before, the clear public policy in Florida is to devote the fewest natural resources, land, water, and environmental resources to the construction of power plants as is reasonably necessary to meet electricity needs of Floridians. Siting policy as applied in the cases that I've read since 1989, at least, have very carefully tied the construction of any new facilities to utility-specific needs.

If plants are now to be sited with no specific need under contract, or with 30 megawatts under contract for every 514 built, or based on a five-year contract, but a plant that's going to last 20 or 30 or 40 years, then the Commission will have made it impossible to control, to adequately tie the construction of new power plants to the specific and identified need for electricity of Floridians. So when the five years is up, this plant may or may not still be under contract to a Florida utility. Maybe somebody else has built a new power plant under a five-year contract and it displaces some of the

capacity from this power plant. We have the 484 megawatts of excess capacity from the Duke plant that's in the mix, none of which has been tied to specifically identified and quantified growth in electricity demand by Florida retail customers.

So based on that scenario, it seems clearly possible, if not likely, that excess capacity would be the result, and duplicative facilities.

Q Mr. Steinmeier, are you aware if there are any types of plants that are exceptions to the requirements of the need determination statutes, in other words, they don't have to go through the need determination process?

MR. BUTLER: I'm sorry. Do you mean based on who owns them or the mechanical nature of the plant?

MS. PAUGH: Based on the statute, are there exceptions or types of plants.

MR. BUTLER: Types of plants would be the actual mechanical nature of the plant? Is that what you're referring to?

MS. PAUGH: That and size.

THE WITNESS: Waste energy and under 75?

BY MS. PAUGH:

Q Is there anything else you're aware of?

A Not offhand.

Q Do you know if combustion turbine plants are subject to the Act?

A Are combustion turbine plants subject to the Siting Act?

Q Yes, sir.

A Of the sort that Duke proposes here? You're talking about combined cycle combustion turbines?

Q Only combustion turbines, a straight CT plant.

A I would have to check. My understanding -- my assumption was that they're under the Act.

Q Mr. Steinmeier, I would like to get some clarification as to your interpretation of the word "need" as it's used in the need determination statute. Do you interpret that as a reliability standard, or an economic standard, or both, or something different? What do you mean when you use the word "need" as it relates to that statute?

A Fundamentally, a reliability need. I think concerns about whether -- about the cost of available electricity are covered elsewhere in the criteria, the most cost-effective alternative available at a reasonable cost. Need is essentially a reliability

need, the ability of a utility to meet its projected demand and reasonable reserve margins.

Q Mr. Steinmeier, going back to my question about exceptions to the need determination statute, I wonder if, given your answers regarding your policy concerns of duplicative power plants in Florida or the possibility of that and the use of environmental resources, do you -- how can you reconcile exceptions to the need determination statute with your policy concerns, or can you reconcile those?

A The political process is replete with exceptions to rules. From what I understand of the nature of the exceptions, however, they are based on size. In other words, if it's a small enough plant, then the Legislature seems less concerned about whether so many of them could develop that the policies of the Act would be seriously undermined, or are based on the situation of waste energy by a policy determination that that's a technology that should be promoted.

Q Okay. Thank you. Previously I asked you a series of questions regarding the bidding rule, and to the extent that you understand the bidding rule, if you'll go ahead and answer this next series of questions. If you don't understand my question or are

not familiar with the rule, I understand that.

Would you agree that one of the purposes of the bidding rule is to determine the most cost-effective alternative available compared to a utility's proposed generation?

MR. BUTLER: I'm going to object to the question. I think he has already said two or three times that he has read it. I think he said he read it once. And questions going to sort of broad based assessments of what its purpose is, et cetera, clearly go beyond the familiarity of somebody who has just read it. If you want to point out something in it and ask him about it, that's fair, but I think he has already indicated the limitations on his familiarity with it.

MS. PAUGH: I think if I did that, you would object to me requesting a legal opinion. I'm trying to find out what Mr. Steinmeier's understanding is of the regulatory framework in Florida. He has clearly testified to policy in Florida. I would think it's safe to assume that he's familiar with how we apply our rules and statutes in that instance.

MR. BUTLER: With regard to the bidding

rule, I think he has testified more than once that he has had read it, but has no very strong familiarity with it. And I just think it's going to be a lot more productive if you have something specific in there -- you gave him a copy of it. Point him to something and ask him how he thinks that affects his policy positions, if you wish.

BY MS. PAUGH:

Q Let's move away from the bidding rule for a moment. Just as a general matter with the bidding process and the RFP process, would that be geared toward finding the most cost-effective supply-side alternative?

A Generally, certainly.

Q And would that be as it related to a utility's own proposed generation?

MR. BUTLER: I'm sorry. A utility's own generation?

MS. PAUGH: Yes, that was the question.

BY MS. PAUGH:

Q As a general matter, in the bidding process for generation, would the utility compare the cost of it to generate versus other alternatives?

A Generally, yes.

Q Okay. Thank you. Does Florida's need determination statute require the Commission to determine if there are conservation measures taken by or reasonably available to the petitioners which might mitigate the need for this plant?

A Yes, it does.

Q What in your opinion is required to be shown by the petitioner for a determination of need to satisfy this criteria?

A That the petitioners have implemented conservation DSM programs that are reasonably available, that can or will or have deferred or reduced the need for additional generating capacity in order to assure the reliable provision of electricity to the service area, period.

Q Thank you, sir. Are you familiar with the Florida Energy Efficiency and Conservation Act we call FEECA?

A Generally, yes.

Q Would you agree that this Act requires the Commission to establish conservation goals for utilities subject to the Act?

A Yes. I believe I said so early on in my deposition here today.

Q Does the Act give the Commission the

authority to require those utilities to file conservation plans and programs in order to meet their goals?

A I don't recall. I would have to check specifically.

Q We are handing you a copy of FEECA and have indicated a section in the Act. If you would, take a look at it for a moment.

MR. BUTLER: For the record, what you indicated with a little arrow is Section 366.82(3)?

MS. PAUGH: Yes.

THE WITNESS: Your question?

MS. PAUGH: Would you read back my last question, please?

(Question at page 48, line 25, read by the reporter.)

THE WITNESS: Yes.

BY MS. PAUGH:

Q Thank you. Do you know if the Utilities Commission of the City of New Smyrna Beach is subject to FEECA?

MR. BUTLER: Do you mean at all, or do you mean with respect to this requirement to file plans and programs?

MS. PAUGH: Both.

MR. BUTLER: Then I object to it as a compound question.

MS. PAUGH: Your objection is duly noted.

THE WITNESS: I'll give you a real simple answer. I believe I have known the answer to that question within the last two months, but I can't recall it offhand.

BY MS. PAUGH:

Q Is that the answer to the question whether it's subject to FEECA at all or subject to the requirement to file plans and goals? Both? You don't know?

A I don't know.

Q Thank you. Are you familiar with the term or phrase "Peninsular Florida"?

A Yes.

Q What does that phrase refer to?

MR. BUTLER: Excuse me. In what context?

MS. PAUGH: The witness's context, the context of this docket.

MR. BUTLER: Okay. Good.

THE WITNESS: Essentially a planning convention that includes I believe 59 utilities east of the Apalachicola River.

BY MS. PAUGH:

Q Are you familiar with how the statutory criteria on conservation was satisfied in other Florida need determination cases?

A I have read some. I can't recite that to you. I would observe that in this case, whatever the impact on New Smyrna Beach, it only represents 30 of 514 megawatts of capacity. It concerns me that the Commission would consider granting need determinations based on criteria that can only be specifically tied to a utility for about 6% of the proposed capacity to be constructed.

Q Do you know, in the previous need determination cases with which you are familiar, were comparisons made to those petitioner's goals and programs in addressing conservation criteria?

MR. BUTLER: Were comparisons made between what and what?

MS. PAUGH: Those petitioners' goals and programs under FEECA in addressing the conservation criteria.

THE WITNESS: I would have to rereview some orders.

BY MS. PAUGH:

Q Does that mean that you don't know?

A That's correct.

Q Do you know if the statutory criteria on conservation could be satisfied by the FEECA imposed conservation goals and programs on a Peninsular Florida basis?

A You're asking me if the Commission has ever done that or if the Commission routinely does that?

Q My question was, could the statutory criteria on conservation be satisfied by the FEECA imposed conservation goals and programs on a Peninsular Florida basis, in your opinion.

A In my opinion, no.

MR. BUTLER: I'm going to object to that. I'm going to object to that as calling for a legal conclusion. I don't think you're asking what the Commission does. I think you're asking really if he thinks it's a good idea. You're asking, apparently, does the statute allow it; is that right?

MS. PAUGH: No. I'm asking from a policy perspective, which Mr. Steinmeier clearly is testifying to, whether he thinks the criteria could be met on a peninsular basis. If he doesn't know, he doesn't know.

THE WITNESS: I think as a matter of

policy, it cannot be met on a peninsular basis. It needs to be met on a utility-specific basis.

BY MS. PAUGH:

Q Thank you. That was what we were looking for.

With respect to past applications with which you are familiar under the Power Plant Siting Act, do you know if they have been for either utility-owned generation or for a utility with a long-term contract for total plant output?

A I'm sorry. You're asking me if prior need determinations made by the Commission have been for either what or what?

Q Utility-owned generation or a utility with a long-term contract for total plant output.

A Generally, yes.

Q The question was an "or" question.

A Oh, it was?

Q Yes, sir. Would you like me to have the question read back?

A I guess we had better.

MS. PAUGH: Okay. Let's at this point take a brief break. I've been summoned by a Commissioner's aide. I'll be right back.

(Short recess.)

MS. PAUGH: I think we're about to read the question.

MR. BUTLER: Can I shortcut this? I think you're asking two things, have there been proceedings involving utility-built plants and utility-contracted plants, to which the answer could be both, or one or the other, or neither.

MS. PAUGH: Uh-huh.

MR. BUTLER: Okay. That's where I think the confusion came.

THE WITNESS: I was trying to say both.

MR. BUTLER: You asked him about both, but it was maybe not the most easily understood way of saying that.

BY MS. PAUGH:

Q Okay. So is it your testimony, Mr. Steinmeier, that past applications for need determinations with which you are familiar have been for either utility-owned generation or long-term contracts for the plant output?

A Yes.

Q Thank you.

A Isn't that what I said last time?

Q I'm just making sure I understand you.

Would you agree that as a general

principle, utility ownership of new generation approved under the Power Plant Siting Act assumes at least a 30-year obligation on the part of the utility and its ratepayers?

A Yes.

Q Would you agree that nonutility generation with a purchased power agreement approved under the Power Plant Siting Act assumes an obligation on the part of the utility and its ratepayers only for the term of the contract?

A In terms of specific rate obligations of the utility customers, that would be correct. As I indicated in an earlier discussion, there are broader concerns here, including the fact that natural resources would have been devoted to a power plant that may continue to operate beyond the terms of the contract, the potential displacement of both wholesale and off-system sales the power from a plant post contract might have an impact on. But assuming those other concerns that I continue to raise, yes.

Q Okay. Thank you. As a general matter, how are the costs of utility-owned generation recovered by the utility?

A Utility-owned generation costs are recovered through retail rates set by the Commission.

Q And as a general matter, how are the costs of purchased power agreements recovered by the utility purchasing the power?

A Through retail rates.

Q Could they also be recovered through the fuel clauses or other clauses?

A Yes.

Q Are the ratepayers of any utility in the State of Florida apart from the City of New Smyrna Beach obligated to pay for the cost of the plant proposed in this docket?

MR. BUTLER: What do you mean, are? Nobody is obligated at the moment, are they?

MS. PAUGH: I'm asking the witness to answer the question.

BY MS. PAUGH:

Q If the plant was certified and built, would the ratepayers of any utility in the State of Florida besides the City of New Smyrna Beach be obligated to pay for the cost of that plant?

MR. BUTLER: In the absence of any contracts; right?

MS. PAUGH: Yes.

THE WITNESS: As things stand today?

BY MS. PAUGH:

Q Yes.

A Directly through rates or directly through the fuel clause, no. Indirectly through the potential for displaced revenues that could otherwise flow through from off-system sales to utility customers, through the potential displacement of wholesale sales, through the potential duplication of facilities, yes, as well as by the fact that Floridians would have devoted resources to a power plant that Floridians may or may not use or need, the power for which could be sold out of state.

Q I'm sorry. Would you say that again? I didn't get it, your last phrase.

MR. BUTLER: Wait, wait, wait. You can have it read back.

MS. PAUGH: All right. Let's read back just the last part of his answer.

(Requested portion read by the reporter.)

MS. PAUGH: Okay. Thank you.

BY MS. PAUGH:

Q Mr. Steinmeier, would you agree that because no utility's ratepayers are obligated to pay for the proposed plants through their rates as we've discussed, that this distinguishes this proposal from all previous need determinations with which you are

familiar before the Commission?

A No, I would not.

Q Can you please explain your answer?

A The purpose of the Siting Act, the purpose of the State's siting policy is to limit the construction of new generating capacity in the state to the level reasonably necessary to meet the power needs of Floridians. Whether a plant is built as a merchant plant without contracts or with the entire output under contract to a Florida utility, or whether it's built as a QF, or whether it's built by a utility, the purpose of the Siting Act is precisely the same, to assure that power plants are not built unless the power from those plants is needed to meet the electricity needs of Floridians.

Q Okay. Thank you. I will ask you now to turn to pages 22 and 23 of your direct testimony.

Starting on line 18 of page 22, you discuss risk. If you would like to take a moment to refresh your memory on that paragraph leading into page 23, that will be fine.

A Thank you. (Examining document.) Okay.

Q Would you please explain the difference between obligating customers to purchase from a power plant for a short term, say up to five years, versus

obligating customers for 20 to 30 years?

A You're asking me the difference between five years and 20 years? It's 15 years.

Q Is there less risk or more risk to customers with a five-year obligation versus a 20- to 30-year obligation?

A It depends on exactly what risk we're talking about. Again, you keep focusing on the short-term immediate rate impact of customers of the buying utility. The Commission has a responsibility to look at a broader range of issues than that. And in the long term and in the broader scale, the immediate rate impact on that group of customers is not the only part of this puzzle. A new power plant built under a five-year contract is still going to be there and be operational, presumably, after the end of the five-year contract.

The fact that new merchant plants can be built without a utility-specific determination of need will make it much more difficult for existing utilities to plan accurately for their future needs. They will still have an obligation to serve. They still have a responsibility to plan adequately and accurately to provide and to fulfill their obligation to serve their customers.

Then again -- I hate to belabor the point, but again we get into questions about displaced revenues from wholesale sales, displaced off-system sales, the effects that those have on customers, short-term and long-term, and the potential effects on the recoverability of plant by the utility as a result.

So it's not just quite as simple a question as these customers will only be obligated for five years, besides which we don't know what it will cost to provide that power at the end of five years. It may be a short-term saving with a long-term detriment.

Q Why does a plant of this nature make it more difficult for utilities to plan for their obligation to serve their customers?

A It simply adds an additional variable in the equation. In terms of transmission planning, just looking at the proposed Duke plant here, how are surrounding utilities to know and plan for where the power from this plant will move? Which direction, when, on peak, what times of day, what times of year? How do the utilities plan ungrades that may be necessary to assure that power from this plant can get where it needs to go, or do they build in every possible direction to make sure that there can be no

negative impact on reliability? But that approach, of course, has cost consequences. Generation planning, again, it adds an important variable to the equation.

Okay. We've evaluated our load growth. We've evaluated our DSM programs, our efficiency programs. We've evaluated our loss of load probability. We think this is the increment of capacity that we are now going to add to the system in order to make sure we maintain our reserve margin by this date. But what's the impact going to be when we undertake an investment and this Duke plant is built? In fact, if a merchant plant can be built on the basis that Duke proposes in this case, it is likely to be the first of a number of merchant plant applications, which certainly cannot be distinguished from this one by any definitional construct. So the problem of the additional variables to plan around in that planning process continues to grow.

A utility traditionally and at the encouragement of regulators is concerned about fuel diversity and fuel mix. As a regulator, I didn't want my utilities to have all their eggs in one basket. But some generating technologies have higher capacity costs and lower fuel costs. Some have lower capacity costs and higher fuel costs. In order to achieve the

highest level of efficiency of operation of some plants, they need to be run at a certain level, 80%. Suppose new merchant plants displace off-system sales and wholesale sales of the utility, and now we're not able to run the utility. It doesn't have the demand to run that plant at that 80% capacity factor.

I can't tell you exactly how it plays out, but these are the concerns that I have about how it complicates the planning process if we decide to devote resources to the construction of a plant when nobody knows where the power is going to go, at what price, to whom, on what days, what time of day, what time of the year, et cetera.

Q If the Duke plant were certified and built and displaced, as you just testified, some of the output of other units, why would that be so?

A If the Duke plant were built and displaced?

Q Yes. That was your word.

A That was my word? Who's displacing whom? I'm sorry.

Q I believe it was your testimony that the Duke plant may displace some of the output of other plants in Florida. My question is, why would it displace the output of other plants?

A Presumably it would displace the output from other plants if at certain times it could be sold at a lower price than power from those other plants.

Q Mr. Steinmeier, are you familiar with or do you have any knowledge regarding the cogeneration contracts held by Florida Power Corporation?

A No.

Q Okay. Are you familiar with the laws and regulations regarding the transmission of electric energy, particularly with respect to the jurisdiction of FERC?

A Generally.

Q Please turn to page 23 of your direct testimony and read the sentence beginning on line 18 that starts, "The lack of."

MR. BUTLER: Aloud or to himself?

MS. PAUGH: Aloud.

A "The lack of information about whether or when this power will be available and where it will be delivered could also make it more difficult to maintain the reliability of the grid."

Q What do you mean by the sentence?

A Just what I was discussing a few minutes ago about the fact that without contracts, it can't be predicted precisely when this power will move over

what part of the transmission system where, and so if a utility has not planned adequately, has not guessed right about where merchant power is going to move when, transmission constraints could jeopardize system reliability.

Q Is it your testimony that one effect of this plant could be that transmission line planning would be more difficult?

A Yes. And again, the precedential nature of this application I think magnifies that concern.

Q Are you familiar with the OASIS system for postings on transmission?

A Generally.

Q Would you agree that in order for the petitioner to make short-term sales if the plant is built, transmission capacity is acquired by the postings on the OASIS system?

A That's my understanding.

Q Then why would transmission planning be more difficult?

A Capacity has to be there. Access has to be given to the power. You have to plan for the power that could move over your system.

Q Okay. My question related to short-term sales, and you indicated that you're familiar with

OASIS. Are you aware that OASIS is price posting on the Internet?

A Yes.

Q I'll ask my question again, making sure you understand that this is for short-term sales. How would this make transmission planning more difficult if these are prices based on the Internet that are available to everyone?

A Posting prices on the Internet does not create transmission capacity. My point is, what we're talking about here is setting a precedent for the construction of merchant plants in Florida. Merchant plants by definition do not have a predetermined destination point for the power generated in the plant. And transmission systems will have to be developed in a way that accommodates the access of those plants to the transmission system, while not jeopardizing the reliability of those systems for providing needs to native customers.

Q If the petitioner in this docket had built the plant and were to make a long-term sale, would it have to pay for any increase in transmission capacity associated with that sale pursuant to FERC jurisdiction?

THE WITNESS: Would you repeat that,

please?

(Preceding question read by the reporter.)

THE WITNESS: If Duke had entered into a long-term contract?

BY MS. PAUGH:

Q Yes, sir.

A I believe so, but I would have to check.

Q How would that affect long-term planning, in your opinion?

MR. BUTLER: How would what affect it? You mean if they have to pay for transmission capacity?

MS. PAUGH: Yes.

THE WITNESS: Okay. Forgive me. I've now got two versions of this question in my mind.

The fact that we're talking about a long-term contract affects transmission planning, because now the owner of the transmission system knows where that power is going over an explicit period of time. That will facilitate transmission planning. I'm not sure that answers your question.

BY MS. PAUGH:

Q No, I think it does.

A Okay.

Q Please turn to page 24 of your direct testimony. If you would, take a moment, if you need it, to refresh your memory on the question and answer beginning on line 14 of this page.

A Yes.

Q Would you please summarize that question and answer for us?

A Okay, but it's not that long. When a utility makes an off-system sale today, the gain from that sale or the largest part of the gain from that sale flows through to its customers through the clauses. If power from the plant under proposal here displaces those off-system sales, the benefit of those sales do not go to those utilities' customers. The benefit of those sales go to Duke shareholders, and the customers of the utilities that would have made off-system sales no longer have the benefits of the gain on those sales flowing back to them through the clauses.

Q Are you saying that the customers of utilities, ratepayers, I should say, will be harmed because of a loss of off-system sales potentially that Duke would make in lieu of the utility making the sale?

A Utility customers will lose the benefit of

off-system sales.

Q Do you have knowledge of how off-system sales are accounted for by Florida utilities?

A Not in detail.

Q Please tell me what you do know.

A About how they're accounted for?

Q Yes, sir.

A What do you mean by how they're accounted for?

Q How they're handled through the clauses, any splits that are made, whether they go above the line or below the line.

A Basically, it's my understanding that on brokered or Schedule C sales, 80% of the gain flows through to the company's customers, and 20% to the company.

Q To the company shareholders?

A To the company shareholders.

Q Are you familiar with anything else about the accounting of these sales?

A Not really.

Q Okay. Would you agree that the profits, or at least 80% of them -- I'm sorry. Strike that. Would you agree that the profits from off-system sales under one year duration inure to the customers through

the fuel clause?

A Yes.

Q Given the treatment of revenues of off-system sales, should utilities build power plants to serve customers under the current regulatory scheme, or should they in addition build power plants to make off-system sales?

A Build additional capacity to try to promote off-system sales? Is --

Q Yes, sir.

A -- that what you're asking?

Q Yes, sir.

A It doesn't strike me that that's the logical next step. It does strike me that finding additional uses for existing capacity through off-system sales makes sense as an efficiency measure, and obviously the Commission's policy is designed to provide some incentive for those off-system sales by allowing the company to keep some of the gain from those sales, but it's also clearly designed to aid utility customers through the revenues from those sales.

I fail to see why that would mean that utilities should all be encouraged to build new power plants in order to try to sell more power or to

encourage those sales.

Q I'll take that as a no.

Are the profits from these short-term --

MR. BUTLER: Well, you can take it as you wish. The answer is the entire thing that he gave.

MS. PAUGH: I understand that, Counsel.

BY MS. PAUGH:

Q Are the profits from the short-term off-system sales material?

MR. BUTLER: For whom?

MS. PAUGH: Relative to total revenues received from customers of utilities.

MR. BUTLER: For utilities generally, for FPL? What are you asking? Utilities generally?

MS. PAUGH: Utilities generally, FPL specifically, if he knows.

THE WITNESS: Materiality is an opinion that CPAs render, and I'm not a CPA. But I understand FPL had about $37 million in off-system sales. As a percentage of all sales, it may not be huge. As a sum of money, it's significant.

BY MS. PAUGH:

Q Do you know what the percentage of these

profits are relative to total revenues for FPL?

A I do not.

Q If there were increased competition in the wholesale market, isn't it possible that there would be reduced risk from price spikes of the nature that we experienced this summer?

A If there were additional competition in the wholesale market?

Q Yes, sir.

A That's not clear to me.

Q Is that a yes or a no?

MR. BUTLER: It's an answer.

MS. PAUGH: The question asked for a yes or no answer. I'm asking him to answer the question. He says it's not clear to him. I don't know if the question is not clear to him, the answer is not clear to him, or what.

THE WITNESS: Could you ask the question again, please?

BY MS. PAUGH:

Q If there is increased competition in the wholesale market, would that reduce the risk of price spikes?

A Not necessarily.

Q Is it possible that customers of a

purchasing utility would benefit from a situation where -- wait a minute. I'll strike that.

Please turn to page 25 of your direct testimony and read into the record the question and answer beginning on line 3.

A "Why would granting the joint petition affect utility customers?"

Answer: "As just indicated, utility customers could experience direct rate impacts, in addition to long-term concerns about the ability of utilities to plan accurately to meet future needs, increased risk of utility investments, and the potential for uneconomic duplication of facilities. Customers of utilities which lose off-system sales will be harmed, because they will no longer receive the benefits of those sales through the clauses. Reductions in wholesale sales by utilities may also result in changes in wholesale-retail allocations of cost and rate base, resulting in higher rates for the utility's customers."

Q Can you describe the Commission's policy on rate base allocation for off-system sales?

A Rate base allocation for off-system sales?

Q Yes, sir.

A No, I cannot.

Q The last sentence that you just read into the record beginning with, "Reductions in wholesale sales," would you please explain what you mean in this sentence? It's not clear to me.

A Okay. In a nutshell, the Commission bases wholesale-retail allocations in setting retail rates based, as I understand it, on a 12 coincident peak basis. In other words, depending on the relative contribution to peak load in each of the 12 months of the year by residential customers or firm wholesale customers, that determines the amount of plant or the percentage of plant that is included in retail rate base.

If wholesale sales by a utility are reduced or displaced by power from merchant plants, then at some point in time in a rate proceeding, that could affect the retail-wholesale allocation for retail ratemaking purposes. It's possible that some plant that had previously been allocated to the wholesale jurisdiction could be determined now to be part of the retail jurisdiction, or it may fall through a jurisdictional crack, as it were.

MS. PAUGH: Okay. Thank you. We have no further questions.

(Deposition concluded at 4:05 p.m.)

ERRATA SHEET

DOCKET NO.: 981042-EM
NAME: WILLIAM D. STEINMEIER
DATE: November 17, 1998

Page	Line	

CERTIFICATE OF DEPONENT

This is to certify that I, WILLIAM D. STEINMEIER, have read the foregoing transcript of my testimony, pages 1 through 73, given on November 17, 1998, in Docket No. 981042-EM, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the errata sheet attached hereto.

_____
WILLIAM D. STEINMEIER

Sworn to and subscribed before me this

_____ day of _____, 1998.

_____
Notary Public
State of _____

My Commission Expires:

CERTIFICATE OF OATH

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, Notary Public in and for the State of Florida at Large:

DO HEREBY CERTIFY that on November 17, 1998, WILLIAM D. STEINMEIER personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 19th day of November, 1998.

Mary Allen Neel

MARY ALLEN NEEL
Notary Public - State of Florida

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, do hereby certify that I was authorized to and did stenographically report the foregoing deposition of WILLIAM D. STEINMEIER.

I FURTHER CERTIFY that this transcript, consisting of 73 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 19th day of November, 1998.

MARY ALLEN NEEL, RPR
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Tallahassee, Florida 32301
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 981042-EM EXHIBIT NO. 38
COMPANY/
WITNESS: Duke Energy
DATE: 12-2-98

Tuesday November 3, 1:41 pm Eastern Time

Company Press Release

SOURCE: Dynegy Inc.

Related Quotes

DUK	62 3/8	-3/8
DYN	15	-1/16

delayed 20 mins - disclaimer

Dynegy Finalizes North Carolina Power Plant

HOUSTON, Nov. 3 /PRNewswire/ -- Dynegy Inc. (NYSE: DYN - news) announced today it is moving forward with final permitting and construction of its 800 MW electric generating facility in Rockingham County, North Carolina. Construction will begin upon receipt of final environmental permits and the plant will be in service in June of 2000.

Dynegy chairman and chief executive officer Chuck Watson noted, ``This project exemplifies Dynegy's strategy to develop a diverse portfolio of generation assets to combine with our established energy marketing and trading capabilities. This project will increase our generation portfolio to more than 5,000 MW capacity and we will announce additional new projects like Rockingham in the near future."

Duke Energy's electric utility unit, Duke Power, signed an integrated power purchase agreement on September 30, 1998, with the Dynegy project affiliate Rockingham Power, LLC to purchase 600 MW of electric capacity and energy from the generating facility. The signed agreement represents consummation of a contract contemplated by a letter of intent signed in April 1998, as a result of Dynegy's response to Duke Power's 1997 Request for Proposals.

Under the agreement Duke Power will purchase 600 MW of electric capacity and energy for three and a half years beginning July 1, 2000. Additional terms provide Duke Power with the option to extend its purchases for up to five years, and allow Dynegy to make wholesale power sales to other companies when Duke Power is not calling for energy deliveries from the plant. The balance of the power from Rockingham will be utilized in Dynegy's power marketing business.

``Transactions such as this power purchase agreement are the next step in the evolution to an open market for power. During the term of the agreement, Duke Power has access to capacity at a reasonable price delivered from a facility located in our service area. When the agreement ends, Rockingham Power will be a merchant power plant selling into the region at the then- current market price," said Curtis Davis, senior vice president, power generation for Duke Power. ``The facility will continue to provide value to Duke Power customers by contributing to the capacity available in North and South Carolina."

Dynegy Inc. is one of the leading marketers of energy products and services in North America. The name

Dynegy reflects the company's evolution from a natural gas marketing company to a dynamic energy company with a full energy network to meet the growing challenges of the energy market of the future. Through its leadership position in gathering, processing, transportation, independent power generation and marketing of energy, the company provides energy solutions to its customers in North America and the United Kingdom. More information on Dynegy is accessible at http://www.dynegy.com.

Duke Power is a business unit of Duke Energy Corporation (NYSE: DUK - news). Duke Energy is a global energy company with more than $24 billion in assets. Duke energy companies provide electric service to approximately 2 million customers; operate pipelines that deliver 12 percent of the natural gas consumed in the United States; and are leading marketers of electricity, natural gas and natural gas liquids. Globally the companies develop, own and operate energy facilities and provide engineering, management, operating and environmental services. Contact Duke Energy on the World Wide Web at http://www.duke-energy.com.

SOURCE: Dynegy Inc.

More Quotes and News:
- Duke Energy Corp (NYSE:DUK - news)
- Dynegy Inc (NYSE:DYN - news)

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 39
COMPANY/ WITNESS: Duke Energy
DATE: 12-3-98

McGUIREWOODS BATTLE & BOOTHE LLP PRACTICE AREAS

MERCHANT POWER SCOREBOARD

Important Updates:

- Amergen to convert GPU facility into first nuclear merchant capacity (Disaggregation)
- Calpine Pasadena plant begins operation (Currently Operational)
- Construction commenced on US Gen Charlton plant (Under Construction)
- New projects announced in NY, IL, RI, TX, WI, LA, CA and CA (Plans Reported)

Compiled by Stephen H. Watts, II
Last updated: September 24, 1998

As the U.S. electric power industry moves towards restructuring, the author and many other observers agree that "merchant" power generation capacity—meaning capacity that has been either acquired or developed without long-term offtake commitments—will be the norm if a workably competitive marketplace is achieved. In the course of speaking on this subject around the country, the author has collected from reported sources a base of information on the progress of merchant power activity that may be of interest to power industry participants and which is presented here. The information on international merchant projects is intended to serve as examples only for comparison to U.S. experience. The Merchant Power Scoreboard will be updated and supplemented with future developments. For more information see our Power Resources Team.

Contents:

Merchant Experience in the United States

Currently Operational - 10,020 MW

EXHIBIT
#5
D0105 11-16-98

Under Construction - 2,283 MW
Under Development - 7,962-8,252 MW
Plans Reported - 29,121-33,954 MW
Terminated - 240-750 MW
Disaggregation - 59,739 MW
CPCN/Siting
Rating Agency Criteria

Merchant Experience Abroad

Broad merchant-type experience in specific markets
Often small portion of capacity allocated to spot market
Examples

Feedback - send your comments and questions to Stephen H. Watts, II

Merchant Experience in the U.S.

Currently Operational

CA (Cool Water)—Houston Industries acquired the gas-fired 628 MW Cool Water plant from Southern California Edison 4/6/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement —HI has renamed the facility Alta Power

CA (Ellwood)—Houston Industries acquired the gas-fired 48 MW Ellwood plant from Southern California Edison 4/6/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement—HI has renamed the facility Oeste

CA (El Segundo)—NRG/Dynergy Power (unit of NGC) acquired the gas-fired 1,020 MW El Segundo plant from Southern California Edison 4/6/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement—NRG and Dynergy Power each own 50%--"must-run" facility under reliability service contract to ISO, with excess power offered at market-based rates

CA (Etiwanda)—Houston Industries acquired the gas-fired 1,030 MW Etiwanda plant from Southern California Edison 4/6/98 (see Disaggregation, below) -- operated by SCE under 2 year O & M Agreement—"must-run" facility under reliability service contract to ISO, with excess power offered at market-based rates—HI has renamed the facility Mountain Vista

CA (Highgrove)—Thermo Ecotek acquired the gas-fired 154 MW Highgrove plant from Southern California Edison 4/15/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement

CA (Huntington Beach)—AES acquired the gas-fired 563 MW Huntington Beach plant from Southern California Edison 5/15/98 (see Disaggregation, below) -- operated by SCE under 2 year O & M Agreement—"must-run" facility under reliability service contract to ISO, with excess power offered at market-based rates -- AES has entered into long-term tolling agreement with Williams Energy services under which Williams delivers gas to the facility for conversion into power to be owned and marketed by Williams—project debt financing provided by syndicate of banks led by Credit Suisse First Boston

CA (Long Beach)—NRG/Dynergy Power (unit of NGC) acquired the gas-fired 530 MW Long Beach plant from Southern California Edison 3/31/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement—NRG and Dynergy Power each own 50%—"must-run" facility under reliability service contract to ISO, with excess power offered at market-based rates

CA (Long Beach)—AES acquired the gas-fired 2,083 MW Alamitos plant from Southern California Edison 5/15/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement—"must-run" facility under reliability service contract to ISO, with excess power offered at market-based rates—AES has entered into long-term tolling agreement with Williams Energy services under which Williams delivers gas to the facility for conversion into power to be owned and marketed by Williams—project debt financing provided by syndicate of banks led by Credit Suisse First Boston

CA (Mandalay)—Houston Industries acquired the gas-fired 570 MW Mandalay plant from Southern California Edison 4/6/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement—"must-run" facility under reliability service contract to ISO, with excess power offered at market-based rates—HI has renamed the facility Ocean Vista

CA (Redondo Beach) -- AES acquired the gas-fired 1,310 MW Redondo Beach plant from Southern California Edison 5/15/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement—"must-run" facility under reliability service contract to ISO, with excess power offered at market-based rates—AES has entered into long-term tolling agreement with Williams Energy services under which

Williams delivers gas to the facility for conversion into power to be owned and marketed by Williams—project debt financing provided by syndicate of banks led by Credit Suisse First Boston

CA (San Bernardino)—Thermo Ecotek acquired the gas-fired 126 MW San Bernardino plant from Southern California Edison 4/15/98 (see Disaggregation, below)—operated by SCE under 2 year O & M Agreement

CO (Rifle)—Citizens Power, without investing equity, has restructured existing gas-fired 80 MW American Atlas QF cogeneration project into a merchant facility —Citizens bought out existing PPA and will supply contracted quantities to utility purchaser, Public Service of Colorado, from wholesale market—project owner has received benefit of buyout and is free to operate facility as merchant—Citizens has no commitment to market power from the facility

MA (Milford)—150 MW gas-fired combined cycle plant—acquired by American National Power from Enron and Jones Capital—83 MW under long-term contract to New England Power Co.—remainder sold into NEPOOL

MA (Pepperell)—38 MW—Indeck purchase of existing cogeneration facility from Kenetech

ME (West Enfield and Jonesboro)—Indeck Energy Services and Ridgewood Power (preferred equity participant)—6/97 restart of 49 MW of wastewood-fired capacity (24.5 MW West Enfield and 24.5 MW Jonesboro)—capacity sold to NEPOOL on emergency basis during Summer of 1997, to be followed by merchant sales into regional grid

NM (Bloomfield)—74 MW Milagro cogeneration facility at Williams Field Services gas processing facility—developed, owned and operated by Williams Field Services—power marketed by Duke Energy Trading and Marketing

TX (Channelview)—590 MW gas-fired Cogen Lyondell facility owned by Dynergy Power (unit of NGC)—steam host is ARCO Chemical, which also takes 70 MW of power—configured as 6 gas turbines and one steam turbine, all GE —initially built without offtake commitments and began operation 1985—financed under long term lease—capacity later contracted to Texas Utilities for 5 years—operator is affiliate Dynergy Power Operating Company— now selling in open market via affiliate Electric Clearinghouse

TX (Old Ocean)—330 MW refinery residue gas and natural

gas-fired simple cycle cogeneration facility at Phillips Petroleum's Sweeny 175,000 bbl/day refinery complex —developed by CSW Energy—Phillips to purchase 2,000,000 lbs/hour of steam—power market is Phillips (1/3 of production) and Texas grid—Unit 1 (110 MW) synchronized with ERCOT 8/21/97—designed and constructed by NEPCO of Redmond, WA, using three 115 MW Westinghouse Model 501D5A combustion turbines, for estimated cost of $200 million—financing to be provided by Westdeutsche Landesbank Girozentrale and John Hancock Mutual Life Insurance under a 22 year $149 million non-recourse, senior secured term loan representing 80%/20% debt/equity project capital structure, with closing scheduled for 2Q 1998

TX (Pasadena)—240 MW natural gas-fired cogeneration facility at Phillips Petroleum's Houston Chemical Complex—developed by Calpine Corp—power market is Phillips (90 MW for 20 years) and Texas grid—20 year steam offtake by Phillips is 20,000 lb/hr—$150 million construction project financing from ING Capital, upon completion of construction to be converted into $100 million term financing from ING, $50 million equity from Calpine—Moody's has rated project debt Ba2—construction commenced 2/97, projected COD 3d Q 1998—gas supplier (45 MMBtu/d) is Aquila Energy under 15 year agreement—Calpine says plant will have 15% return at $.022/KWH dispatch— Calpine has signed short term contracts to sell power from the facility—50 MW to West Texas Utilities (unit of Central & South West) for period 7/1/98 to 12/31/98—150 MW to Texas Utilities Electric for two years beginning 12/1/99—Calpine has now sold a total of 140 MW for 1998, 90 MW in 1999, 240 MW in 2000 and 240 MW in 2001—COD 7/7/98, 3 months ahead of schedule—cost $131 million, 21 million below budget—sponsor claims up to 40% greater efficiency than traditional gas-fired plants— constructor H.P. Zachry—major plant equipment includes Westinghouse 501F turbine, Nooter/Eriksen HRSG and Mitsubishi steam turbine

TX (Wharton)—78 MW Newgulf generation facility purchased by CSW Energy in 1996 and recommissioned as merchant peaker plant

WV (Ft. Martin)—276 MW of existing Ft. Martin Unit No. 1—AYP Energy (Allegheny Power) acquisition from Duquesne in October of 1996

WI (Cassville)—53 MW—Mid-America Power (Power Systems, Ltd., Bearden-Beaty & Associates, WPS-Power Development and Burns & McDonnell) conversion of former Dairyland Coop coal-fired E. J. Stoneman plant—WPS affiliate

Energy Services, Inc. conducts wholesale power sales and trading—may be repowered to 300 MW of gas-fired capacity for 1999-2000 (see Plans Reported, below)

▲ TOP

Under Construction

CT (Bridgeport)—520 MW gas turbine plant at existing United Illuminating site—developer is Bridgeport Energy (Duke Energy Power Services and United Illuminating)—estimated cost $260 million—Siemens Power Corp. is equipment and construction supplier—Duke/Fluor Daniel is owner's engineer and will support long-term operation—2 simple cycle turbines totaling 340 MW to be completed by June 1998, with 2 heat-recovery generators bringing total capacity to 520 MW in 1999—of existing 655 MW at site, 85 MW of oil-fired capacity to be shut down and two other units refurbished and perhaps converted to gas—in exchange for providing site, UI gets option for 1/3 of output, with rest to be sold into N.E. merchant market—fuel supply and offtake marketing by Duke Energy Trading & Marketing—Connecticut Siting Council held 8/6/97 that no Certificate of Environmental Compatibility and Public Need required (see CPCN/Siting, below)—Southern Connecticut Gas Co. has agreed to construct 11-mile gas pipeline and provide gas service—10/2/97 Connecticut Department of Environmental Protection granted waiver allowing construction to begin immediately—construction to financed internally—first turbine/generator set delivered 12/28/97—DPUC issued decision 12/31/97 approving UI transmission line tap to serve Bridgeport Energy—DPUC issued decision 1/28/98 appearing UI site lease and grant of easement to Bridgeport Energy

MA (Agawam)—274 MW gas-fired greenfield facility—developed by Berkshire Power (Power Development Corp. and El Paso Energy)—approved by Massachusetts Energy Facilities Board 6/96—ABB to furnish machinery and O&M developer conducted revert to RFP for offtake—fuel supply (45 MMcf/d) and offtake marketing by El Paso Energy Marketing Co.—Massachusetts DPU has designated Berkshire Power as a public utility, exempting the facility from local zoning requirements—financing proposals received from 12 banks—financing provided by Kredietbank of New York—construction began 12/97

MA (Charlton)—400 MW gas-fired Millenium

facility—developer is U.S. Generating—construction began 7/1/98, with COD expected for mid-2000— EPC vendor is Bechtel Power Corp.—gas and steam turbines are by Westinghouse

MA (Dighton)—169 MW gas-fired combined, cycle facility—co-developers are Energy Management, Inc. (EMI) and Calpine—COD 1999 for sales to NEPOOL—EMI will operate the plant—Calpine investment is $16 million with preferred payment stream to produce 12% return—ABB awarded $27 million contract to supply power train—CoEnergy Trading Co. (affiliate of MCN Energy) will provide gas supply (12 Bcf/yr for 20 years) and management services— Parsons Energy and Chemicals Group selected for EPC—construction began 10/97—financing offers received from 6 of 10 banks solicited—senior non-recourse financing by Toronto Dominion Bank, Teachers Insurance and Annuity Fund and Calpine—Algonquin has applied to FERC for approval to transport 33,000 Dth/d of natural gas to the project

NV (Boulder City)—Houston Industries and Enova Corp.—gas-fired 480 MW combined cycle El Dorado Energy plant in Southern Nevada—equity 50/50 split—estimated Cost $280 Million—COD 3d Q 1999—no underlying contracts for steam or power sales—construction commenced 4/98 by Kiewit International for estimated $280 million—project includes 100 KW solar generation plant with PV and dish-sterling technology under consideration—non recourse financing from Union Bank of Switzerland—50% of fuel procurement and offtake market to be handled by HI affiliate NorAm Energy Services, with remaining 50% to be handled by Enova affiliates AIG Trading and Energy Pacific—location will facilitate sales to CalPx, Nevada Power, and Arizona and New Mexico markets

TX (Ingleside)—Occidental Energy Ventures and Conoco Global Power are developers—Ingleside Cogeneration L.P. 440 MW gas-fired cogeneration plant—steam production (1,100 kpph of process steam) and up to 235 MW generation capacity to be sold to adjacent chemical plants owned by affiliates Oxychem and DuPont—financial closing 12/23/97—sole arranger and underwriter is Societe Generale—construction start early 1998—26E 7FA gas turbines, ABB steam turbine—EPC by Duke/Fluor Daniels—installed cost estimated to be $210 million—COD expected 1/2000—Oxychem will manage construction, operate plant under long-term contract, and purchase majority of power and steam production—plant to be QF and sell excess power into Texas power markets

▲ TOP

Under Development

CA (Otay Mesa)—660-700 MW gas-fired peaking or combined cycle facility in southern San Diego County near the California-Mexico border—developer is U.S. Generating—California Energy Commission issued exemption from Notice of Intent filing requirement 12/11/96—estimated capital cost $250 million if simple cycle, $350 million if combined cycle—construction to begin 1999 with COD in 2001

CA (Sutter Co.)—480 MW gas-fired facility near Yuba City at site of existing Greenleaf cogen facility—developer is Calpine Corp. estimated cost $255 Million—California Energy Commission issued exemption from Notice of Intent filing requirement 6/25/97—application for certification filed 12/19/97—construction to begin 1998 and COD in 1999—gas to be provided by Calpine affiliate Montis Niger, Inc.—CEC finding of data adequacy issued 1/21/97, beginning review process

CA (Victorville)—680-830 MW gas-fired peaking or combined cycle facility at Southern California International Airport (formerly George Air Force Base)—developer is High Desert Power Project (Constellation Energy and Inland Energy)—California Energy Commission issued exemption from Notice of Intention filing requirement 3/5/97 and application for certification was filed 6/30/97—estimated capital cost at least $600 million—construction to begin 1999-2001, with COD 2000-2002—project website is http://www.highdesertpower.com/—CEC Finding of Data adequacy issued 12/3/97, beginning review process —CEC Informational hearing and site visit scheduled for 1/15/98

CT (Killingly) -- US Generating is developing a gas-fired 802 MW plant -- estimated cost $400 million

ME (Jay)—150 MW gas-fired cogeneration plant at International Paper Company plant—developer is Polsky Energy sub Androscoggin Energy—gas to be delivered through 18 Mmcf/day of capacity reserved on planned Portland Natural Gas Transmission pipeline—operation to commence when gas deliveries begin, perhaps as early as end of 1998—financing closed 6/2698 with Credit Suisse First Boston, without concessions from vendors such as deferred payments for equipment or discounted fuel costs during project

start-up—constructor is Black & Veatch Construction—heat rate to be less than 6,000 Btu/kWh—project has "step-in" rights to IPC's existing 100 MW capacity in case mill closes—IPC to have no minimum steam take obligation

MS (Batesville)—LS Power plans to build 800 MW gas fired merchant facility—will be connected to TVA and Entergy grids—construction to begin mid 1998 with COD in 2000—LS will issue RFP for wholesale purchases from the plant—decision to build as merchant followed TVA decision to drop its option for offtake—estimated cost $400 million

MO (Dunklin Co.)—Associated Electric Cooperative Inc. and Duke Energy plan to build 250 MW gas-fired facility—AECI to purchase 125 MW, 125 MW to be marketed jointly by AECI and Duke Energy Trading and Marketing—gas transportation by Duke affiliate Texas Eastern Transmission Corp.—COD 1999—Siemens Power to oversee construction and provide O&M—cost estimated at $100 million—siting approval received 10/97—AECI has appealed NO_x limitation in Missouri Department of Natural Resources permit

NH (Alexandria)—Indeck has purchased closed-down 15 MW wood burning plant originally developed by Bristol Energy—closed in 1994 after PSNH buyout of PPA—to re-open by mid-1998 for sale to wholesale and retail markets in New England

OR (Klamath Falls)—developer is Pacificorp—240 MW facility in Oregon to serve munis and IOUs—Oregon Energy Facility Siting Council issued exemption from need standard 8/1/96

OR (Umatilla Co.)—500 MW gas-fired facility near Hermiston—developer is U.S. Generating

PA (Archibald)—PEI Power Corp. plans to convert 25 MW culm-fired cogeneration plant shut down in 1997 following PPA buyout by PP&L to 70 MW gas-fired facility—landfill gas methane will fuel 25 MW, with the remainder fueled by natural gas—power to be marketed by PEI marketing affiliate

PA (Hazleton)—existing 130 MW gas-fired facility—purchased by Williams Energy Group from Continental Energy Associates for operation as merchant plant beginning 12/97—second phase will repower facility to 250 MW by mid-1999—Williams will act as power marketer

RI (Tiverton)—265 MW gas-fired plant—developer is Energy Management, Inc. (EMI)—EMI will operate the

facility—Calpine has been granted option to purchase participation as co-general partner for $40 million, with 70% of current cash flow until initial equity investment is recovered, with 50% of project cash flows to each partner over life of the project—Calpine to provide power marketing and fuel management services—UtiliCorp United affiliate Aquila Energy has signed $500 million, 8 year gas supply contract for up to 46 mmcf/d, under which Aquila assumes a portion of the facility's gas-to-power price risk by partially subordinating gas payments to senior debt

TX (Edinburg)—1,000 MW gas-fired combined cycle facility—co-developers are American National Power and US Generating—construction to be in two phases of 500 MW each, with COD for Phase 1 in June 0f 2000

TX (Edinburg)—700 MW gas-fired combined cycle Magic Valley facility being developed by Calpine Corp.—increased from 430 MW following award of Magic Valley Coop RFP to Calpine (see Plans Reported, below)—COD 2001—40% more efficient than average gas-fired plant in Texas—other possible customers include Central Power & Light (up to 285 MW) and Public Utility Board of Brownsville (up to 20-30 MW), as well as possible customers in Northern Texas and Mexico—Magic Valley Coop has committed to take 250-400 MW for 20 years, with option to increase capacity to serve load growth—according to reports, construction to begin 4thQ 1999—reports indicate that, in response to capacity shortage on Central Power & Light's transmission system that had threatened the viability of the Calpine project, CP&L and Magic Valley have agreed to pay for a new $125 million transmission line and Calpine has agreed to limit its claim for access priority to its 250 MW commitment to Magic Valley

TX (Gregory)—300-400 MW gas-fired cogeneration facility at Reynolds Metals' Sherwin alumina production plant near Corpus Christi—original developer LG&E Power joined by co-developer Columbia Electric (unit of Columbia Energy Group) 6/98

TX (Mission)—CSW plans to develop the gas-fired 500 MW Frontera project in the Rio Grande Valley—construction to begin 8/98, with COD for 2 170 MW units in summer 1999 and full COD by end of 1999—Duke/Fluor Daniel will be EPC—power to be sold into ERCOT—plant to be located in service area of CSW affiliate Central Power & Light

VA (Accomac Co.)—300 MW oil-fired peaking facility on Eastern Shore of Virginia—developer, Commonwealth Chesapeake Corporation, proposes to sell into LSEs in PJM—

State Corporation Commission issued Final order 8/5/98 granting CPCN based on 1998 legislation (see CPCN/Siting below) and conditioned on COD within 3 years and on execution of agreements necessary to transmit power to PJM or, alternatively, to Old Dominion Electric Coop before COD

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Plans Reported

AZ (Mojave Co.)—Calpine—500 MW gas-fired combined cycle South Point to be located on Fort Mojave Indian Tribe reservation—estimated cost $500-550/KW—40% claimed efficiency improvement over existing fleet— gas to be delivered via El Paso or Western Pipeline—COD 2000

CA (Long Beach)—Enron is reported to be planning to develop two 500 MW merchant facilities near the Port of Long Beach

CA (Pittsburg)—Enron Capital & Trade Resources—500 MW gas-fired merchant plant—85% of production to be sold into California Power Exchange on merchant basis, with 15% to be sold to USS Posco steel mill— Enron will fund the project 100% but own only 40%, with City of Pittsburg owning 60%

CA (Pittsburg)—Calpine and Bechtel Enterprises have announced plans to develop a gas-fired 535-800 MW facility at a Dow Chemical site—sponsors state that the new facility will use 40% less fuel compared to average existing capacity and will use advanced emissions control technology that will reduce No_x emissions by 43% and CO_2 by almost 40%, compared to existing Bay Area facilities—COD expected 2001

CA (Vernon)—Sunlaw Cogeneration— 550-850 MW twin gas turbine facility—COD scheduled for 2002—Ultra-Low emission environmental (EM-ONE) facility

CT (Milford)—Power Development Co. and El Paso Energy—544 MW gas-fired merchant plant—permitting began 2/98, construction to begin early 1999 and COD by end of 2000—estimated cost $224 million—machinery and EPC from ABB Power Generation and Black & Veatch—shutdown of Connecticut Yankee nuclear facility and uncertain future of Millstone plants seen as making CT target for merchant development

CT—Power Development Corp.—merchant plants (in addition

to Berkshire, MA, Westfield, MA and Milford, CT projects mentioned above) totaling 1,000 MW at sites in Connecticut with COD in 2000, costing $224— machinery and EPC from ABB Power Generation and Black & Veatch

CT (Wallingford)—PPL Global has announced plans to investigate feasibility for a 500 MW merchant facility to be constructed by Stone & Webster

FL (New Smyrna Beach)—Duke Energy Power Services—500 MW gas-fired greenfield facility—estimated cost $70 million—30 MW reserved for City of New Smyrna Beach, with remainder to be sold on merchant basis—Duke filed petition at Florida PSC 11/4/97 seeking declaration that it was entitled to file for determination of need under Florida Electrical Power Plant Siting Act—PSC issued order 1/13/98 denying Duke's petition based on holding that, because granting the petition would constitute a statement of general applicability carrying implications for the electric power industry statewide, Duke would have to file a request for a rulemaking proceeding (see CPCN/Siting)

GA (Columbus)—Sonat Energy Services and Calpine have announced formation of a joint venture to develop a gas-fired, 680 MW peaking project to be called the Cataula Facility—COD set for 6/2000—plant will connect to Georgia Integrated Transmission System, providing direct access to Georgia Power, Municipal Electric Authority of Georgia, Oglethorpe Power and the City of Dalton—Sonat Energy Services will be managing partner and provide gas supply and market power output to potential customers—Sonat Energy Services has issued RFP to fully subscribe the plant's full 680 MW, of which Georgia Power has already committed to 215 MW for 5 years—project was originally sited and permitted by US Generating and subsequently transferred to Sonat Energy Services

IL (Elwood)—Dominion Energy and Peoples Energy (Chicago) have announced plans to develop a gas-fired 300 MW peaking merchant facility—COD 6/99—estimated cost $90 million—turnkey commitment being negotiated with GE for two turbine-generator sets

IL (Roxana)—Houston Industries plans to develop a gas-fired 634 MW cogeneration merchant facility at Wood River Refining Co. (division of Equilon Enterprises, a joint venture of Shell and Texaco)—host processes 275,000 barrels/day of crude oil into gasoline, jet and diesel fuels and other products such as lubricants, asphalt and propane—power will be sold through affiliate, NorAm Energy Services—estimated cost

with Central Maine Power

ME—FPL Group—plans to convert Wyman Station in Yarmouth, ME from oil to gas and build 2 new 500 MW plants, one at Wyman and one at Mason Station in Wiscasset, ME, after Wyman and Mason stations are purchased from Central Maine Power (See Disaggregation)

ME—Industry and Energy Group (IEG) of Falmouth, ME is exploring feasibility of building 500 MW gas-fired merchant facility for an estimated cost of $250 million

MI (Wyandotte)—Wyandotte Energy (Nordic Electric and City of Wyandotte) are to develop 480 MW gas-fired merchant plant—City to receive minority interest in exchange for strategic site location, ancillary support of water and wastewater, marketing and operations support—City's profits will go to reduce electric rates to municipal customers

NH (Londonderry)—AES and Conservation Law Foundation have announced proposal to develop gas-fired 700 MW facility—COD 2001—CLF to serve as non-investing consultant to develop environmental guidelines for project resulting from "collaborative" of environmental groups and local representatives—project to be "anchor" for environmentally-oriented industrial park and provide heat to other facilities in the park

NH (Newington)—Tractebel Power and Sprague Energy—have announced plans to develop 170-700 MW gas-fired merchant facility—estimated cost $125-250 million—construction to began 12/99 with COD 2001—site at Sprague oil terminal on Piscatauqua River near gas pipeline being developed by Portland Natural Gas Transmission and Martimes and Northeast Pipeline

NH (Newington)—Southern Co.—525 MW gas-fired facility—estimated cost—$175-200 million—COD 2000

NJ (West Deptford)—U.S. Generating—800 MW Mantua Creek gas-fired, combined cycle facility will be first merchant facility in Southern New Jersey— to be located on a 300 acre parcel abutting the Delaware River and opposite the Gloucester County Utilities Authority—COD 2002

NM (Dona Ana Co.)—Dynergy Power (unit of NGC) is to develop 220 MW gas-fired Santa teresa facility—site near Mexican border to be leased from State of New Mexico—fuel supply to be procured by NGC's gas marketing unit—COD 2000

$350-400 million—construction to start 4Q 1999 with COD 2001

MA (Bellingham)—Infrastructure Development Corp. plans to develop 1,035 MW facility—estimated cost $600 million

MA (Bellingham and Blackstone)—American National Power plans to build two 550 MW gas-fired facilities, for total of 1,100 MW—ANP will create a $1.5 million compensation pool for each plant to protect property owners against devaluation, has promised to give each town $4 million for infrastructure repairs and conservation measures, and expects to pay $2.3 million in annual property taxes in each town

MA (Weymouth, Everett, Framingham and Medway)—Sithe Energies, Inc. has announced plans to develop up to 2,800 MW of new merchant capacity at existing generation stations acquired from Boston Edison—1,500 MW has been proposed for the Edgar Station in Weymouth—Sithe has applied to NEPOOL for transmission service for the following sites: 1,750 MW for Mystic Station in Charlestown, 1,500 MW for Edgar Station in Weymouth, 1,500 MW for Medway Station in West Medway and 750 MW for Framingham Station in Framingham, all with in-service date of 2001

MA (Westfield)—Power Development Corp.—272 MW facility

ME (Ashland & Chester)—Alternative Energy, Inc.—reverse RFP for sales of up to 56 MW from two existing wood-fired projects in Chester, ME and Ashland, ME that have been idle since early 1990s when PPAs with Bangor Hydro and Central Maine Power were bought out

ME (Gorham)—American National Power—$270 million, 600 MW gas-fired combined cycle facility for COD in 2000, to be served by planned Portland Natural Gas Transmission pipeline

ME (Rumford)—Energy Management, Inc.—265 MW facility

ME (Westbrook)—International Power Partners (recently merged with Thermo Group)— 300 MW gas-fired facility to be developed—estimated cost $150-200 million—to be served with gas from western Canada via planned Portland Natural Gas Transmission System pipeline

ME (Westbrook)—SAPI—39 MW of excess power from cogeneration facility available 11/1/97 upon expiration of PPA

NV—Biogen Partners—convert/repower existing 14.5 MW coal waste-fired facility south of Las Vegas to 56 MW gas-fired merchant plant

NY (Athens)—U.S. Generating proposes to construct the 1,080 MW, gas-fired Athens Generating merchant facility to be located in service territory of Central Hudson—estimated cost $500 million—siting approval required by Board of Electric Generation Siting and the Environment—gas to be delivered via Iroquois Pipeline—power to be transmitted over Niagara Mohawk's 345 KV Leeds-to-Pleasant Valley line

NY—Megan-Racine Associates—seeking bids for gas-fired 50 MW plant in NY near Canadian border—shut down in 1996 after steam turbine failed—capacity could be "backhauled" to Ontario Hydro to offset deliveries to NY—interconnects with NiMo at Canton, NY and has access to Trans Canada pipeline

NY (Scriba)—Sithe Energies plans to construct 750 MW of gas-fired merchant capacity at the site of its existing Independence Station cogeneration facility

OH (Shadyside)—Ohio National Energy L.L.C. (ONE) affiliate of Ohio Edison, plans to develop 280 MW of merchant capacity—project will use clean coal technology to burn waste-coal in circulating fluidized bed boiler at Edison's 495 MW R.E. Burger Plant power station— project has 15 year $700 million marketing agreement with National Power PLC affiliate NP Energy—financing will use tax-exempt securities—construction to start 4Q 1998, with COD late 2000 or early 2001—ONE plans to repower Burger Units 1,2 and 3 with National Power Partners' circulating fluidized bed technology into a 280 MW merchant facility able to burn coal waste with average heating value of 5,500 Btu/lb and ash content of 50%, while meeting or exceeding air emission standards

OR (Hermiston)—Hermiston Power Partners (Idaho Power affiliate Ida-West Energy and TransCanada Pipelines)—460 MW gas-fired cogeneration facility—J.R. Simplot is steam host—original power offtake purchaser Bonneville Power Administration has agreed to convert to right of first refusal—some or all of power offtake may be marketed as merchant capacity

RI (Johnston)—Houston Industries proposes to develop gas-fired 500 MW Hope Energy project—power to be sold into deregulated markets in RI and New England—estimated cost $250 million—COD 2001—33 acre site purchased from

Rhode Island Resource Recovery Corp.

RI (North Smithfield)—Tuspani Water Co., landowner, plants to develop 250-750 MW plant

TX (Grimes Co.)—800 MW gas-fired facility —power is to be marketed by Power Team (affiliate of PECO Energy) —potential markets are in ERCOT, Southeast, Midwest and Florida plant to be connected to both ERCOT and Eastern Interconnect—estimated cost $200 million—plant to begin operation in 2000—Grimes County has granted 10 year tax abatement of 75%, leaving only $ 50 taxed until 2008

TX (Marion)—Panda Energy has announced plants to develop a gas-fired, 740 MW Panda Guadalupe facility—estimated cost $100 million—to be located near the Lower Colorado River Authority's Marion Switching Station -- will sell into ERCOT without the need for additional transmission lines— project is expected to purchase cooling water from the Guadalupe-Blanco River Water Authority, which will also be involved in treating the discharge water—Panda states that the plant will need 1/3 less fuel and water than traditional steam plants—gas will come from bothe Pacific Gas & Electric-Texas (formerly Valero) and Oasis gas pipelines

TX (Paris)—Panda Energy has announced plans to construct a 1,000 MW gas-fired plant—construction to begin 1/99 and be completed 6/2000—9 mile pipeline will connect the plant to multiple suppliers—plant will interconnect with Texas Utilities Electric for sale within ERCOT and Southwest Power Pool

TX (Three Rivers)—U.S. Generating and Ultramar Diamond Shamrock—as part of planned 7 year, $2 billion alliance between PG&E and UDS, U.S. Generating plans to build 750 MW gas-fired cogeneration facility at UDS refinery—excess energy over refinery needs to be sold at wholesale in TX

WA (Sumas)—U.S. Generating—240 MW facility

WI (Cassville)—Mid-American Power (see Currently Operational)—construction plans announced for increase to 300 MW of gas-fired capacity at existing Cassville, WI facility—size could be increased to 500 MW

WI (DePere)—Polsky Energy—has closed construction and term financing with ABN-Amro for 255 MW gas fired cogeneration facility at International Paper's Nicolet Paper mill—up to 75 MW may be built for merchant market during years 2000-2004 pending industrial-host need for full project

capacity—WI PSC authorized limited merchant activity based on CPCN exemption for owner consumption of 70% or more of KWH at manufacturing facilities

WI—Wisconsin Electric Power, Wisconsin Power & Light and Madison Gas & Electric seek 250 MW, 150 MW, and 100 MW respectively, from "quasi-merchant" capacity (see CPCN/Siting—Wisconsin) in upcoming advance plan proceeding

WI—Polsky Energy has announced plans to develop gas-fired 525 MW peaking facility, of which Alliant Utilities would purchase 150 MW and 375 MW would be merchant—first plant announced under Wisconsin Reliability Act (see CPCN/Siting below)—COD 6/2000—two sites are under discussion: adjacent to Alliant-WP&L Rockdale substation in Dane County and in town of Johnston, Rock County, near major Alliant-WPL transmission line—estimated cost $140 million

WI—LS Power may be preparing to develop 400-750 MW facility in Christina Township, adjacent to Rockdale

WY (Gillette)—Black Hills Corp.—80 MW Wygen coal-fired project at Black Hills' Wyodak mine

WY (Wright)—North American Power Group—200-250 MW waste-coal fired plant at ARCO Coal's Black Thunder mine—mine acquired by Arch Coal 6/98

WY (Wright)—Zeigler Coal Holding—240 MW coal-fired plant as part of coal upgrading project at its North Rochelle mine

Other:

Besicorp Group and Kamine Development—are seeking "business combinations" for possible conversion of existing gas-fired cogeneration facilities (Beaver Falls Cogeneration 79 MW, Syracuse Cogeneration 79 MW, Carthage Cogeneration 58 MW, South Glens Falls Cogeneration 55 MW) in the event of termination of existing PPAs under Niagara Mohawk's Master restructuring Agreement

Chilgener SA, of Santiago, Chile—has formed Mega Energy Group of America (MEGA) to acquire and develop $ 1 billion of generating capacity primarily in the Northeast US, including merchant capacity. MEGA is headquartered in Annapolis, MD and is managed by a group of former Duke/Louis Dreyfus executives led by Rhem Wooten, MEGA president and CEO

Pacificorp has sold its western U.S. NUG unit to NRG Energy in order to focus on Northeast U. S. merchant and international projects

Utilicorp United and Air Products & Chemicals have announced the formation of a partnership to develop gas-fired projects in the Midwest

Calpine Corp.—up to 10 merchant projects through 2003 in California, Texas, and Arizona, including the Pasadena, TX, Sutter Co., CA, and Edinburgh, TX projects mentioned above—Calpine expects new plants to have 35% to 40% more efficiency and full cost recovery at $.013/KWH, compared to average of $.022/KWH and 11,000 BTU/KWH for incumbent plants—Calpine has announced plans to acquire 70 MW cogeneration plant at Dow Chemical site in Pittsburg, CA and may sell excess on merchant basis—Calpine has annnounced joint venture with Bechtel Enterprises to develop 2,000 MW of merchant capacity, costing $1 billion, in the San Francisco, CA Bay Area, beginning with 535-800 MW project at Pittsburg Dow Chemical site (see Plans Reported)

Duke/Louis Dreyfus and Puget Sound Power & Light—joint venture to develop merchant capacity in Pacific Northwest

CNG Energy Services—50-240 MW facility in Pacific Northwest

Progress Energy—has announced plans to develop plants in Georgia (up to 500 MW by 1999), Florida, North Carolina, South Carolina

Columbia Energy Group and Westcoast Power—plan to develop three gas-fired cogeneration merchant projects in the Northeast totaling 1,000 MW—development cost $600-700 million—first project to be completed late 2000 or early 2001—total fuel requirement estimated at 160,000 drcf/d—negotiations underway with potential steam hosts

BG&E and Goldman, Sachs have formed Orion Power Holdings to acquire merchant and other electric generating plants in the U.S. and Canada under strategic alliances with BG&E units Constellation Power Source and Constellation Operating Services

Dominion Energy affiliate Kincaid Generation LLC acquired coal-fired 1108 MW Kincaid Power Station in central IL from Commonwealth Edison 2/27/98 (see Disaggregation below)—15 year offtake comitment to sell capacity and energy back to ComEd—plant will become merchant at end of

sellback period—$265 million of Reg. 144A bonds issued 4/30/98 for permanent financing and funding capital improvements

Dynergy Power plans to develop 600 MW gas-fired facility in Rockingham Co., NC—Duke Power has committed to take 600 MW 6/2000-2/2003, with option to extend through 12/2008—facility will be operated as merchant upon expiration of Duke commitment

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Terminated

FL (Polk Co.)—Duke Energy Power Services—240-750 MW gas-fired combined cycle facility to be constructed at site of IMC-Agrico (IMCA) phosphate production complex in Central Florida—IMCA uses 380 MW and has 125-130 MW of cogeneration—proposed facility to be owned by partnership formed by IMCA and Duke, with IMCA to lease 120 MW of capacity for its own use and remainder to be leased to Duke for sale on the open market—IMCA filed petition at Florida PSC 10/10/97 seeking declaration that proposed project would not result in retail sale or cause IMCA or its lessor to be deemed a public utility or subject to PSC regulation as such—Duke and IMCA filed petition at PSC seeking declaration that they were entitled to file for determination of need under Florida Electrical Power Plant Siting Act—PSC issued orders 1/13/98 (a) denying the Duke/IMCA petition based on holding that, because granting the petition would constitute a statement of general applicability carrying implications for the electric power industry statewide, Duke/IMCA would have to file a request for a rulemaking proceeding; and (b) setting IMCA's petition for hearing—IMCA petition withdrawn 2/3/98—project terminated

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Disaggregation

likely to result in the creation of merchant capacity

Commonwealth Edison—sale of 2 coal-fired plants (1,108 MW Kincaid and 590 MW State Line) with 15 year fixed rate buyback—State Line to Southern Energy closed 12/97—sale of Kincaid to Dominion Energy closed 2/98

NEES—4,000 MW (fossil and hydro)—sold to U.S. Generating for $1.59 Billion—sale approved by FERC 2/25/98—sale approved by FERC (2/25/98) and PSCs of RI, CT, MA, VT (6/29/98) and NH (7/20/98)

PG&E—7,363 MW (8 plants, representing 98% of fossil capacity)—2,645 MW to be sold to Duke Energy Power Services for $501 Million by 3/31/98—4,712 MW of fossil plants and one geothermal to be auctioned beginning 3/16/98

Southern California Edison—10,000 MW (all fossil plants)—AES Corp. acquired 3,956 MW for $781 million 5/15/98—Houston Industries acquired 2,276 MW for $237 million 4/6/98—NRG/ NGC Destec acquired 580 MW for $29 million 3/31/98 and 1,020 MW for $117.5 million 4/6/98—Thermo Ecotek acquired 280 MW for $9.5 million plus assumption of liabilities 4/6/98—Houston Industries to acquire 1,500 MW Ormond Beach plant for $43 million

Central Maine Power—2,150 MW (incl. 500 MW of NUG contracts)—1,185 MW of hydro, fossil and biomass to be sold to FPL Group for $846 Million

Commonwealth Energy System—1,675 MW (incl. 675 MW of NUG contracts)—982.1 MW to be sold to Southern Co. for $462 million— Southern to supply 33% of CES standard offer

Eastern Utilities Associates—1,065 MW (incl. 165 MW of nuclear capacity and 522 MW of PPAs)—bids received from 15 potential purchasers but were too low for all but 300 MW—280 MW to be sold to Southern Co. for $75 million—Southern to supply 30% of EUA standard offer

Boston Edison—2,000 MW (all fossil)—sold to Sithe Energies 5/15/98 for $536 Million plus $121 Million for 6 mos. transitional power sales agreement and commitment to build 2,800 MW of new capacity on Edison sites

Boston Edison—670 MW Pilgrim nuclear plant

New York State Electric & Gas (NYSEG) proposed to auction 2,346 MW of coal-fired generation units as part of a restructuring settlement negotiated with the staff of the New York Public Service Commission—NYSEG announced 8/3/98 that 6 NY facilities owned by NYSEG affiliate NGE Generation totalling 1,424 MW (675 MW Kintigh Station in Town of Somerset, Niagara County; 300 MW Milliken Station in Town of Lansing, Tompkins County; 160 MW Greenidge Station in Town of Dresden, Yates County; 125 MW Goudey Station in Town of Union, Broome County; 70 MW Hickling Station in Town of Corning, Steuben County; and 70 MW

Jennison Station in Town of Bainbridge, Chenango County) to be sold to successful bidder AES for $959 million—NYSEG also announced 8/3/98 that the 1,884 MW Homer City Generating Station in Pennsylvania (NYSEG owns 50% interest, GPU owns 50%) would be sold to Edison Mission Energy for $ 900 million

Medina Power Co. is offering for sale a 15 MW gas-fired cogeneration plant in Buffalo, NY—plant was shut down in 1996 after PPA was acquired back from Niagara Mohawk

Niagara Mohawk—auction of 4,600 MW (fossil and hydro)

GPU—5,300 MW (fossil and hydro) plus Oyster Creek and Three Mile Island nuclear plants—GPU announceed 8/3/98 that the 1,884 MW Homer City Generating Station in Pennsylvania (GPU owns 50%, NYSEG owns 50%) would be sold to Edison Mission Energy for $1.8 billion

Orange & Rochland—auction of 980 MW

San Diego Gas & Electric—2,375 MW (2000 MW fossil, 200 MW QF contracts and 175 MW other power contracts)

Montana Power—1,543 MW(incl. hydro, fossil, leased and PPAs)

Western Massachusetts Electric—auction of 541 MW thermal and hydro plants and contracts

Fitchburg Gas and Electric—auction of 87 MW of plants and contracts

Bangor Hydro—166 MW (hydro, fossil and contracts)

Consolidated Edison—to auction 2/3 of its 5,500 MW of capacity in NYC

United Illuminating—1,208 MW (oil & gas) in CT and 129 MW of PPAs—book value of installed capacity $220 million

GPU—has agreed to sell 872 MW Three Mile Island Unit 1 nuclear generating plant to Amergen (50%Peco Energy, 50% British Energy)—price $100 million ($23 million for pressurized water reactor and $77 million for fuel) plus additional amounts through 2010 based on price of market clearing price of power—price less than $30/kW compared to $300-700/kW for recent fossil purchases—GPU to pre-fund $320 decommissioning fund, with Amergen to be responsible for decommissioning, currently scheduled for 2014—GPU to purchase output during 2000-2001, after which facility will be

first U.S. nuclear merchant plant

Puget Sound Energy—50% of Colstrip plants and 25% of two others all in Montana, in addition to 7% of the Centralia plant

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CPCN/Siting

CT—Bridgeport Energy (see Under Construction)—Connecticut Siting Council held 8/6/97 that no Certificate of Environmental Compatibility and Public Need required to construct the project—Department of Public Utility Control issued decision 12/31/97 approving UI transmission tap to serve Bridgeport Energy—SPUC issued decision 1/28/98 approved UI site lease and grant of easement to Bridgeport energy

FL—PSC held 12/16/97 Duke not eligible to apply for Determination of Need, which is the first step in siting process, for New Smryna and IMCA plants (see Plans Reported above) and decided to hold hearing on exemption of IMCA portion of Duke/IMCA project as self-generation—Duke/IMCA project has been terminated—Duke plans to proceed with New Smyrna project which has been increased to 500 MW

MA—Berkshire Power (see above)—siting approved by Massachusetts Energy Facilities Siting Board 6/96—declaration of "public utility" status & exemption from local zoning issued by MEFSB 10/22/97

MA—Dighton Power (see above)—siting approved by Massachusetts Energy Facilities Siting Board 7/8/97

OR—Oregon HB 3283 eliminates need as criterion for facility siting approval (replaced by CO_2 reduction standard)—passed 6/97

VA—Patowmack Power Partners—185 MW facility in Loudoun County, VA—Siemens Power Ventures—CPCN denied by Virginia State Corporation Commission 10/95

VA—1998 General Assembly enacted HB 755, codified as 1998 Acts of Assembly, Chapter 92 authorizing State Corporation Commission to approve construction of non-rate based generating facilities upon finding that the facility will have no material adverse effect on electric utility rates or reliability of electric service and will not otherwise be contrary

to the public interest—SCC also required to consider effect on the environment and establish conditions necessary or desirable to minimize adverse environmental impact—legislation effectively removes need as a criterion for all non-rate based generation facilities, utility-owned or otherwise—became effective 3/13/98—enabled 8/5/98 SCC approval of CPCN application of Commonwealth Chesapeake (see Under Development)

WI—Wisconsin PSC—ruled 4/97 that state law precludes merchant plants from meeting need criterion for obtaining CPCN—law does not apply to plants of less than 12 MW, to purchase of existing plant or to owner using at least 70% of kwh at site for manufacturing— 9/18/97 PSC announced intent, pending legislative solution, to create opportunities for merchant plants by no longer requiring long term contract with a Wisconsin utility, considering non-traditional evidence of need (e.g. plant location to support system reliability), and requiring Wisconsin utilities to demonstrate viability of their plans to meet future capacity needs—10/1/97 PSC, along with major utilities, recommended legislation to allow merchant power plants without guarantee of utility contract or having to show need in advance plane or CPCN proceeding 10/9/97 letter ruling advanced concept of "quasi-merchant" capacity, under which a plant is granted a PPA for 3-8 years and then competes as a merchant, and held that need can be established by showing that power will be sold to 3 or fewer nearby customers, that a "reasonable percentage" of the plant output would be sold in-state at wholesale and that, due to its location, the plant would provide needed transmission support enabling power transfer into the state

WI—1997 Act 204, introduced by Gov. Thompson, has been enacted to address reliability issues—CPCN licensing will still be required for "wholesale merchant plants" but need is not a criterion and PSC also may not consider alternative sources of energy or economic factors—"wholesale merchant plant" defined to mean a facility that does not provide service to any retail customers and is owned by a person not a public utility or by a utility affiliate with PSC approval—new law to be effective 9/1/98

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Rating Agency Criteria

Standard & Poor's (http://www.ratings.com/projectfinance/iprojfinindex.htm)

- Global Project Finance, 7/96
- Global Project Finance, 3/97
- Global Project Finance, 9/97

Fitch Investors Service (http://www.fitchinv.com)

- Power Projects in a Less Regulated World, 9/12/97

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Merchant Plant Experience Abroad

Broad merchant-type experience in specific markets

- U.K.
- Argentina
- Chile
- Norway
- Australia (Victoria)
- Canada (Alberta)

Relatively small portion of individual facility capacity allocated to spot market

Examples:

Dequeco River,Chile

- Project to develop 2 hydro facilities totaling 118.7 MW
- 40% of output sold under long term and medium term contracts to utilities and industries
- Project value $150 million, of which 60-65% is senior debt
- Commercial bank lender Credit Suisse, 15 years (3 years for construction, 3 year term loan refinance option)
- Sponsors—Chilean developer, Spanish engineering company, Chilean contractor, Spanish utility
- Established, transparent power market—tariff available for market analysis and periodic redetermination
- No political risk insurance
- Local agent bank
- Open access to wholesale and retail customers
- High rate of growth in power demand

Guacolda,Chile

- Two 150 MW coal-fired units, one existing, one to be

constructed
- Long-term PPAs estimated at 86% of sales in 1996 and 76% in 1997
- Total project costs $451 million
- Rule 144A financing $180 million ($100 million at 7.60% due 2001, $80 million at 7.95% due 2003) rated Baa3 by Moody's, BBB- by S&P, BBB by Duff & Phelps, underwriter Merrill Lynch
- Sponsors are large Chilean distribution utility (50%), largest Chilean conglomerate with power and fuel investments (20.63%), family of private Chilean investors with major coal investments (20.63%) and Chile's largest coal producer (8.74%)
- Sponsor coal producer is coal supplier to the project
- Facility marginal costs are among lowest of existing thermal units on regional grid, where consumption exceeds production

Aguaytia - first private greenfield project in Peru

- Gas-fired 155 MW facility, simple cycle expandable to combined cycle
- No PPAs at closing
- Component of integrated $258.2 million combined electric/gas project driven by government priority to develop nearby 30 Bcf Camisea gas field
- Commercial bank lender Trust Co. of the West, $78 million for 12 years
- Sponsor equity $152 million—Maple Gas (Canadian producer and project manager), 2 U.S. gas companies (El Paso and Panenergy), 2 U.S. power companies (Illinois Power and Penn Power & Light) and Scudder Stevens & Clark fund
- Each sponsor pledged pro rata share of equity
- Estimated project revenues 70% power sales, 30% sales of propane, butane, natural gas and gasoline
- Medium term loan planned with local bank to cover VAT on construction activities
- $200 million of political risk insurance

Feedback

send your comments and questions to Stephen H. Watts, II

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 981042-EM EXHIBIT NO. 40
COMPANY/
WITNESS: Duke Energy
DATE: 12-2-98

1997 ANNUAL REPORT

FLORIDA PROGRESS CORPORATION

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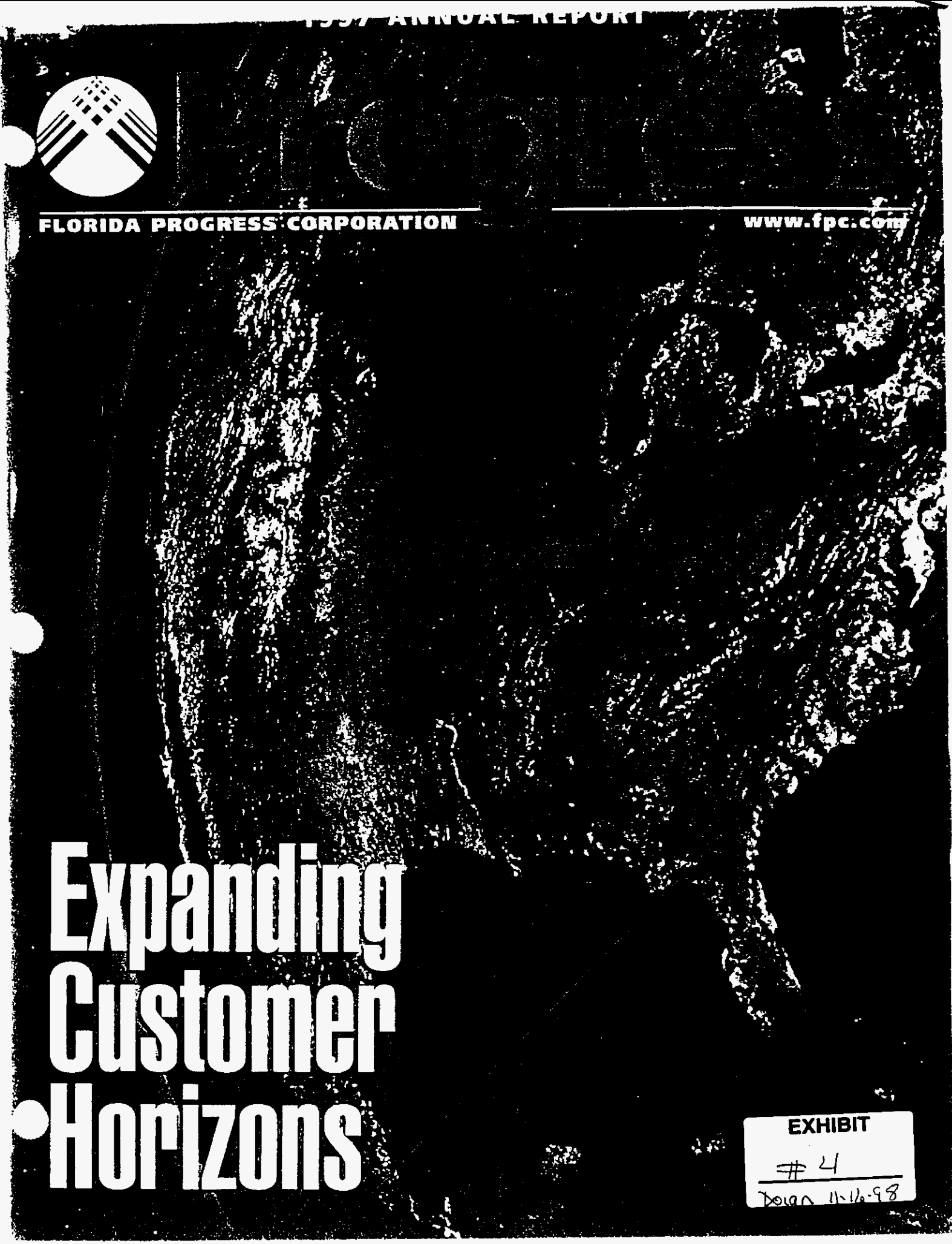


Expanding Customer Horizons

EXHIBIT

4

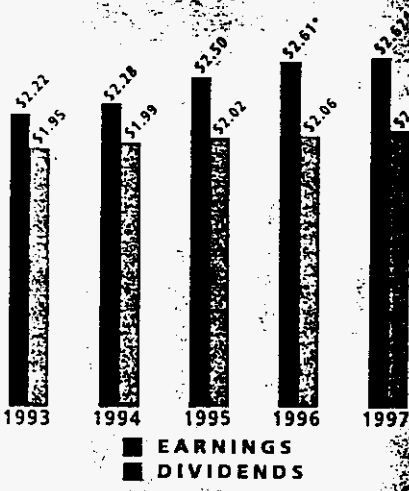
Dolan 11-16-98

FINANCIAL HIGHLIGHTS

(DOLLARS IN MILLIONS EXCEPT PER SHARE AMOUNTS)	1997	1996	ANNUAL GROWTH RATES (IN PERCENT) 1996-1997	1992-1997
OPERATING RESULTS				
Utility revenues	$2,448.4	$2,393.6	2.3	6.7
Diversified revenues (continuing)	867.2	764.3	13.5	25.3
Income from continuing operations before nonrecurring items	254.3	252.4	0.8	6.7
Loss from nonrecurring items and discontinued operations	(200.0)	(28.0)		
Net income	54.3	224.4	(75.8)	(20.9)
DATA PER SHARE				
Earnings:				
Utility before nonrecurring item	$2.48	$2.40	3.3	4.5
Diversified continuing before nonrecurring items	.14	.21	(33.3)	(2.6)
Nonrecurring items, net and discontinued operations	(2.06)	(.29)		
Consolidated	.56	2.32	(75.9)	(22.9)
Dividends	2.10	2.06	1.9	2.0
Book value	18.30	19.84	(7.8)	(1.6)
Closing stock price	39¼	32¼	21.7	3.8
Stock price range	27¾ - 39¼	31⅝ - 36¾		
FINANCIAL POSITION AT DECEMBER 31				
Assets	$5,160.0	$5,348.4	(3.5)	3.0
Total capitalization	4,417.3	3,773.6	17.1	3.2
Capitalization structure:				
Short-term debt, including current maturities	5.2%	1.0%		
Long-term debt	53.8	47.1		
Preferred stock	.8	.9		
Common stock equity	40.2	51.0		
OTHER STATISTICS				
Return on common equity	2.3%	10.9%		
Dividend yield	5.4%	6.4%		
Average common shares outstanding (in millions)	97.1	96.8	.3	2.6
Employees	7,990	7,291	9.6	1.8
Registered shareholders	48,550	54,195		

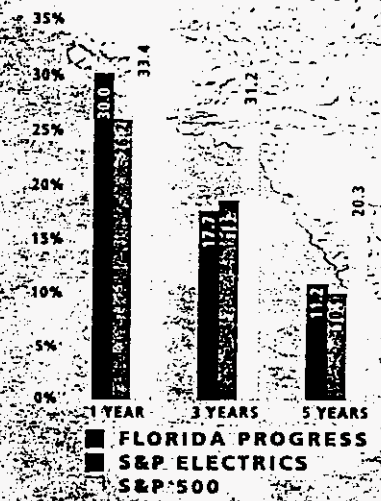
SEE NOTE 8 TO THE FINANCIAL STATEMENTS FOR BUSINESS SEGMENT INFORMATION.

EARNINGS AND DIVIDENDS PER SHARE



*From continuing operations before nonrecurring items

AVERAGE ANNUAL TOTAL RETURNS** FOR THE PERIOD ENDED DECEMBER 31, 1997



**Includes the reinvestment of dividends

FLORIDA PROGRESS AT A GLANCE

Florida Progress Corporation is a diversified electric utility holding company based in St. Petersburg, Florida. It reported 1997 full-year revenues in excess of $3 billion and assets of approximately $5.8 billion.

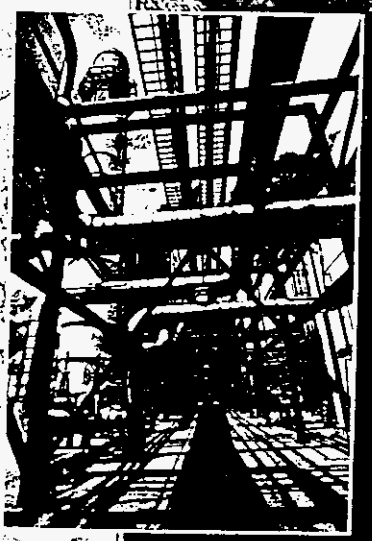
The corporation's principal operating units are Florida Power Corporation, an electric utility located in one of the fastest-growing areas in the country, and Electric Fuels Corporation, a diversified energy and transportation company.

Florida Progress today is expanding customer horizons, building on nearly 100 years of providing customers with superior electric service, and leveraging two decades of experience in coal operations, marine transportation and rail services. The company's growth is driven by developing innovative and flexible solutions that meet the evolving needs of its current customers while aggressively expanding its customer base.

Florida Power Corporation

Florida Power serves 1.3 million customers in central and northern Florida. Its service territory covers 20,000 square miles in 32 counties, including the major Gulf Coast urban centers of St. Petersburg and Clearwater and the fast-growing central Florida area around Orlando.

Approximately 4.5 million people live and work within Florida Power's territory — a number projected to top 5 million by the year 2000.



Electric Fuels Corporation

Electric Fuels, a fast-growing energy and transportation company, currently has operations in 19 states, Canada and Mexico. The company has coal mining operations in Kentucky and Virginia, an efficient river barge and towboat fleet, and operates one of the largest integrated providers of rail services in the United States.

Shareholders

Approximately 50 percent of the stock of Florida Progress Corporation is held by individual shareholders, and of the 48,000-plus registered holders of the company, more than 20,000 reside in Florida.

FLORIDA PROGRESS CORPORATION

AUDITING AND FINANCIAL ANALYSIS
DIVISION, FPSC

Progress

FLORIDA PROGRESS CORPORATION 1997 ANNUAL REPORT

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Citrus Grower and Investor

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GROUP VICE PRESIDENT
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SECRETARY
Kathleen M. Haley

*Term expires at the 1998 Annual Shareholders Meeting

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1997 A Year of Transitions

Nineteen ninety-seven was a pivotal year for Florida Progress — a year of important transitions that has set the stage for our future growth.

Management forcefully addressed major challenges — in particular, issues surrounding our Crystal River nuclear plant and Mid-Continent Life Insurance Company. The marketplace responded with strong support, as is reflected in our total return for the year which exceeded the total return for the S&P Electrics.

In addressing those two situations, we incurred charges and costs that seriously impacted earnings. First, we faced substantial costs for expenses from the prior year's shutdown of the Crystal River nuclear plant, including investments in extensive modifications that were required to prepare the unit for return to productive service. Second, we provided for a loss of our investment in Mid-Continent, which had been placed in receivership, and accrued for additional legal costs. As a consequence of these charges, which totaled $2.06 per share and are further discussed later in this letter, we reported earnings of $54.3 million, $.56 per share compared with $2.32 per share the prior year.

Dr. Jack B. Critchfield

By addressing those issues, we begin clearing the way for Florida Progress to move forward, focusing on the solid strategy that we have to expand our businesses and preparing for the coming evolution of the electric utility markets.

Looking ahead, we can see that our growth into the next century will be founded on customer growth, achieved by doing more for our current customers and adding new customers. This strategy is reflected in the theme of our report to you for this year, "Expanding Customer Horizons."

In part, that growth will be driven by the continued strong economic performance of our home state of Florida — which remains a national leader in population, new home, and utility customer growth.

Growth will also come from new territories beyond our familiar borders as we further expand our reach through ventures like the Cadence national energy services marketing alliance we formed in 1997 and the continued expansion of Electric Fuels Corporation, our energy and transportation subsidiary.

GROWTH STRATEGY

Florida Progress' plans for future growth have provided important impetus to investor confidence. These plans focus on three primary goals designed to ensure a prominent national role for Florida Progress:

- Developing a national retail energy business that provides access to at least 10 million customers. By applying the market insights and expertise gained from serving the predominantly retail customer base in our home market, we believe Florida Progress can play a leading role in expanding the national retail energy sector over the next five years.
- Maximizing the opportunities that economic growth in Florida and the

Richard Korpan

southeastern United States offers for expanding revenues and earnings from generation, transmission and distribution of electricity. In 1997 alone, we added over 22,000 electric customers in Florida, a growth of nearly 2 percent.

• Continuing to support double-digit earnings growth at Electric Fuels.

Collectively, these growth initiatives drive the overall program of expanding customer horizons that is the foundation of Florida Progress' future.

EARNINGS

Examining our 1997 performance provides a sound basis for confidence in future growth. Florida Progress' reported earnings fell to $54.3 million. However, excluding the one-time charges noted previously, our 1997 consolidated earnings from continuing operations were $254.3 million. These figures compare favorably with $252.4 million in 1996 and $238.9 million in 1995.

At the operating level, excluding the impact of the one-time nuclear-related charges, our electric utility, Florida Power Corporation, experienced an earnings per share growth of 3.3 percent and contributed $2.48 a share in operating earnings. This performance reflected continuing revenue growth at Florida Power, 2.3 percent over 1996 revenues, primarily due to customer growth and improvement in the economy. Electric Fuels Corporation earnings per share grew 18 percent to $.33 a share.

CRYSTAL RIVER

The nuclear plant has been out of service for maintenance and repairs since September 1996. This work was necessary to restore operating margins as required by the Nuclear Regulatory Commission. The costs associated with the shutdown of Florida Power's Crystal River nuclear plant during 1997 had a significant negative impact on this year's earnings. However, completion of the maintenance and repairs should prepare the unit for a successful restart and operation as a world-class nuclear facility.

There were two principal components of the impact of the Crystal River shutdown and modifications on 1997 earnings: $100 million in additional nuclear operation and maintenance expenses, and $73 million for unrecoverable fuel-replacement costs. While most of the operation and maintenance costs were necessary to fully address safety system design issues, Florida Power also performed work that should enable the plant to be a productive asset in the future. These charges totaled $1.10 per share for 1997.

Preparations for Crystal River's return to service and the investments that have now been made in its facilities and operations pave the way for solid contributions to future performance. Aggressively solving this problem ranks as one of our most significant accomplishments of 1997.

MID-CONTINENT

The other key impact on earnings was the provision for loss of our investment in Mid-Continent and the accrual of legal costs totaling $.96 per share. Florida Progress took these actions after concluding that we were unlikely to recover our investment in Mid-Continent. As noted in last year's Annual Report, Mid-Continent does not fit Florida Progress' long-term business objectives.

Florida Progress acquired Mid-Continent in 1986, at which time it sold a popular death benefit insurance policy. In 1996, Mid-Continent replaced this policy with a new product after it was determined that premiums on that policy would have to be raised. Mid-Continent began discussions in 1996 with the Insurance Commissions in Texas and Oklahoma, where most Mid-Continent policy holders reside, to increase premiums and lower dividends on those policies.

But in April 1997, the Oklahoma Commissioner obtained Oklahoma District Court approval to temporarily seize control of Mid-Continent, claiming both that the insurer's reserves were understated and that it could not raise premiums.

The court later agreed that Mid-Continent had the right to raise premiums and ordered the Commissioner to present a rehabilitation plan. The court also ruled that the company remain in receivership. Mid-Continent's appeal of that decision to the Oklahoma Supreme Court is pending. In the closing days of 1997, the Oklahoma Commissioner filed a lawsuit against Florida Progress in the District Court, seeking damages related to the Mid-Continent matter.

The actions of the Oklahoma Commissioner have significantly impaired the value of our investment in Mid-Continent. Florida Progress believes that the claims are without merit and will vigorously defend itself against the lawsuit.

MILESTONES

In addition to developments mentioned above, Florida Progress milestones in 1997 included:

• Key management changes that ensure the company has the leadership to take it into the next century. As part of the planned transition, Richard Korpan was promoted to CEO of Florida Progress, a position that chairman Dr. Jack Critchfield had held since 1990. Also, Joseph Richardson was named CEO of our principal operating subsidiary, Florida Power. Joined by Electric Fuels CEO Richard Keller and Florida Progress executive vice president Stanley Garnett, this team is ready to steer Progress forward on a strong growth track.

• The buy-out of Tiger Bay purchased power contracts — part of our aggressive strategy to reduce our long-term purchased power contract commitments, a move that is expected to save our customers $2 billion over the next 30 years.

• Electric Fuels' contribution of $.33 to earnings per share — a product of ongoing, double-digit earnings growth, before nonrecurring items, that has boosted that unit's performance a full 21.6 percent annually over the last five years.

• The ongoing transition to a Strategic Business Unit (SBU) structure at Florida Power, first announced in

1996, moved forward. Redefining Florida Power along functional lines y dividing the organization into three SBUs enables our electric generation, transmission and distribution, and marketing operations to more closely focus their attention on the needs of their respective future customers while still meeting today's needs.

• During 1997, the evolution to the SBU structure was complemented by the start of a corporate-wide management effort called Reinvention. Reinvention focuses on redefining work procedures and improving processes to be more cost effective, while pursuing new opportunities to increase profits. Working from both directions, Reinvention will improve our ability to serve customers efficiently and compete effectively in the evolving energy markets of the future.

1997 STOCK PRICE PERFORMANCE

An important measure for shareholders is the performance of our stock in the marketplace. Florida Progress' are price in the opening months of 97 reflected market concerns about the costs of bringing our Crystal River nuclear plant back online and investing in improvements for its future. During the second half of 1997, renewed investor confidence led to an impressive recovery that raised Florida Progress shares to $39¼ on December 31, contributing to a total annual return of 30 percent.

On a longer-term basis, over the past five years Florida Progress stock has outperformed the S&P Electrics Index. In addition, we're pleased to report that the share price of Echelon International Corporation, which was spun off to shareholders in December 1996, has increased almost 70 percent in 1997.

ANNUAL DIVIDEND

As we expanded customer horizons in 1997, we also increased the dividend we pay our shareholders. While that continued a history of dividend growth, the board has increasingly focused its attention on our dividend payout ratio — which at 80 percent (on a recurring earnings basis) is significantly below peak levels reached several years ago.

The Florida Progress board will continue to examine the dividend policy to ensure that both the dividend payout and dividend rate are appropriate, given the industry outlook for utilities, our business plan and projected earnings growth.

Our current five-year business plan forecasts sustained earnings growth of 4 to 5 percent annually, and confidence in earnings growth remains a key factor in determining dividend policy.

UTILITY OPERATIONS

Florida Power took key steps in 1997 that position it to successfully compete in the increasingly competitive energy marketplace that is developing in the United States.

Preparing our Crystal River nuclear plant for a return to service was a commitment to customers and shareholders that was successfully fulfilled through the dedication and hard work of Crystal River employees.

Florida Power's three SBUs each refined their individual business approaches in 1997.

At Florida Power's Energy Solutions℠, the primary retail interface with residential and business customers, the

THE OPERATING COMMITTEE

The management philosophy and strategic direction of Florida Progress flows from the company's Operating Committee, a four-person group of senior executives that sets the tone and themes for the company's strategic approach to its future. Balancing the needs of customers, shareholders and employees, while ensuring that Florida Progress fulfills its roles within its communities, is the responsibility of the Operating Committee. Expanding customer horizons — by motivating and encouraging every operation and individual within the company to become more customer-focused and by strategically planning the growth of the company and its customer base — is the mission of these individuals.

Joseph Richardson, Stanley Garnett II, Richard Keller, Richard Korpan

focus is on developing flexible and creative solutions to customers' energy needs. Projects in 1997 ranged from customer convenience services, such as developing ATM-style electronic terminals where customers will be able to pay their bills, to beginning the rollout of new services, like lightning surge protection for an entire home, and experiments with advanced two-way energy metering and control technology.

Energy Supply, our power plant and generation business unit, underwent major organizational change in 1997. The previously separate nuclear and fossil-fuel divisions were combined under a single management — improving overall management efficiency and providing for increased strategic coordination of Florida Power's total energy output. Additionally, the internal operations and reporting structures of Energy Supply were reorganized to enable managers and employees to expand their focus to achieve commercial as well as operational excellence. These strategies equip Energy Supply to meet the challenges of achieving competitive generating costs.

The Energy Delivery business unit, which already operates the most efficient electric distribution network in the state, continued to invest in improvements to maintain the high levels of reliable service that Florida Power customers have come to expect. At the same time, Energy Delivery moved to utilize its core expertise in new entrepreneurial initiatives — winning construction contracts to build electric transmission facilities outside Florida Power's service territory, and developing telecommunications facilities for lease to others — that expand the horizons of its operations and people.

Throughout the year, Florida Power continued its multi-faceted drive to prepare for the increasingly competitive energy marketplace that is developing in the United States. Anticipating the opportunities presented by Florida's growth, the company is constructing the Hines Energy Complex, which will be Florida's newest high-efficiency fossil-fueled power station. Through cost reduction initiatives like the Tiger Bay buy-out, Florida Power is improving its competitive position. Customer focus, efficiency, and the active pursuit of opportunities will be hallmarks of success in that future marketplace.

ELECTRIC FUELS CORPORATION

The multiple operations of our Electric Fuels subsidiary contributed significantly to earnings momentum in 1997.

Acquisitions and business expansions by Progress Rail Services Corporation were a major driver of Electric Fuels' growth. Already one of the country's largest integrated providers of services to the railroad industry, serving customers that include the country's leading railroads, Progress Rail continues to aggressively explore opportunities for growth in the consolidating rail services sector.

MEMCO Barge Line, Inc. (MEMCO), our inland barging company, took vital steps to recoup from the impact of record flooding on the Ohio and Mississippi Rivers early in the year and keep pace with customer demand. About 200 new barges were added to MEMCO's fleet in 1997. With plans to add another 200 barges in 1998, MEMCO will further cement its position of owning the youngest dry cargo fleet on the Inland Water System.

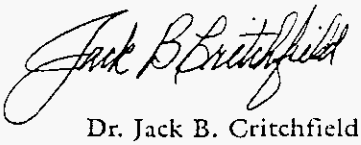
At our coal operations, current projections indicate a continuation of relatively flat sales. We are, however, exploring opportunities in coal bed methane and natural gas. Meanwhile, we retain a reserve of high-quality, low-sulfur coal, which is valued by customers for use in specialty industrial applications as well as for energy generation.

EXPANDING CUSTOMER HORIZONS

This year of transition has set the stage for Florida Progress to advance aggressively into our future. It has required great effort on the part of the employees throughout our organizations, effort which we as senior managers recognize and appreciate. The future calls on all of us, management and employees, to lift our sights and alter our focus — to truly expand our horizons. Clearly, corporate growth in a competitive environment will require expanding our customer base and expanding the ways in which we serve our current customers. That is why we believe the best report we can provide to our shareholders is a report that focuses on our customers — on their needs and expectations. We hope you will find this annual report as accessible and informative as any report in the pages of your favorite business magazine.

PASSING THE BATON

This is the last letter to shareholders that we jointly sign — the responsibilities of the chairman's position will soon pass between us. But as we both look back on the transitions and successes of 1997, we can see the firm foundation for future expansion.

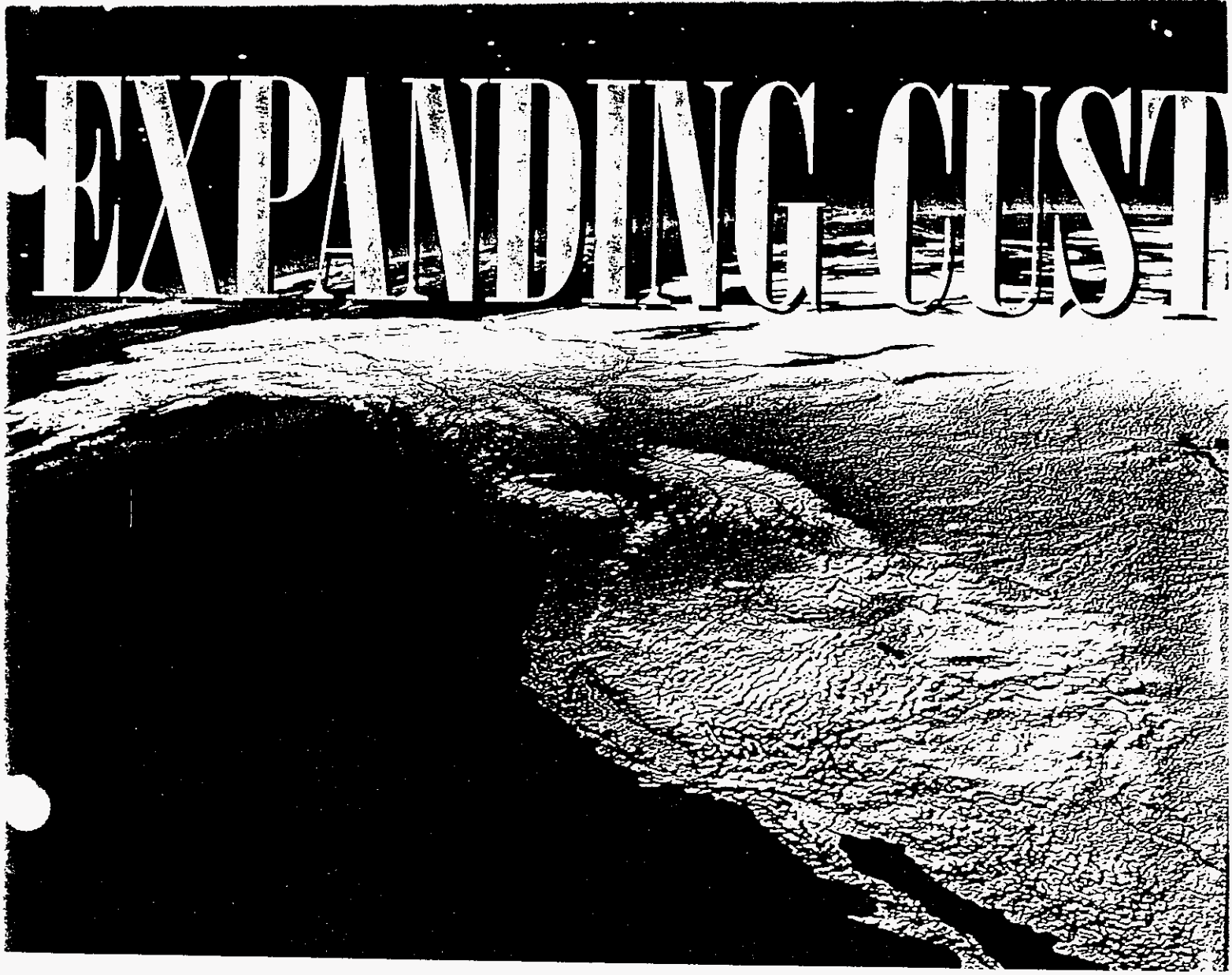


Dr. Jack B. Critchfield
Chairman of the Board

Richard Korpan
President and Chief Executive Officer

February 5, 1998

EXPANDING CUST



Expanding customer horizons. It's more than just a catchy theme for our cover story. As this report demonstrates in detail, expanding customer horizons reflects a philosophy that lies at the very core of Florida Progress' strategy for growing into the future. These horizons are both practical and conceptual. There are the horizons of geography, which are expanding as more Florida Progress businesses broaden their customer bases outside the company's long-time Florida home. There are the horizons of innovation that Florida Progress must push to create new categories of products and services for new and existing customers. There are the horizons of customer perception that must also be expanded in order for that key audience to begin seeing Florida Progress in new and different ways.

But all these future horizons inevitably bring us back to one core concept — customers. And it reflects the appreciation at Florida Progress of one simple idea — without customers there simply is no business.

That might seem so basic an idea that it appears almost foolish to report it in print. But it is a notion that utility companies, operating historically as protected monopolies, were viewed as ignoring by some critics. Instead, it was claimed, utilities at times operated as though they believed they could take their customers for granted.

This report shows that this claim can't be directed against today's Florida Progress. Florida Progress and its two principal operating subsidiaries, Florida Power and Electric Fuels, each demonstrate, through their day to day management and in their business planning, that their focus is on customers, current and prospective. This focus is on building customer relationships, learning how best to satisfy and retain customers, and how to continue serving them reliably and efficiently.

That customer focus is why Florida Power divided its operations into three Strategic Business Units (SBU's) — Energy Supply, Energy Delivery and Energy Solutions™ — in order to get their management and staff out into the field, bringing them "closer to the customer."

At the corporate level, Florida Progress CEO Richard Korpan and his senior managers have set three primary goals for the company in very customer-focused terms. First, Korpan says that over the next five years the company intends to expand its retail customer base, the number of residences and businesses with which it has customer relationships, from 1.3 million to 10 million.

The two other goals are also customer based:

• Expanding Florida Power's generation, transmission and distribution operations as the base of energy customers throughout its region grows.

• Continuing double-digit earnings growth at Electric Fuels by expanding its operations to serve more customers.

That growth will involve gaining new customers and serving current customers in new ways. It will mean leveraging "core competencies," taking the essential skills that make Florida Progress successful today and applying them in new ways to create new products and services for new customers. Above all, it will mean listening to customers, understanding and anticipating their needs and wants.

Thus, the story of Florida Progress' future will be the story of its customers. That's why we've styled this report in "magazine" format, and filled its pages with accounts of what how customers see the array of products and services available from Florida Progress today and what they are looking for in the future.

These stories show how expanding customer horizons will determine the future progress of this company.

Marvin and Gladys Goldstein

Customers Hold the Key

For most Florida Power customers, the single most important thing about electricity is that the power is there when they flip the switch. Providing reliable and safe energy in an energy-intensive environment is what they have come to expect from Florida Power in nearly 100 years of excellent service.

As one Florida resident, Mrs. Brockway, puts it, *"Florida Power has come through always...through storms and all, there's never been anything with our electricity that strayed from the path of comfort."*

The perspectives of two other energy customers mirror the range of challenges and opportunities that the Energy Solutions℠ business unit of Florida Power Corporation faces as it prepares to expand the horizons of its business into an era of increased competition.

"Competition would certainly be worth looking into — depending on the charge for service. Cutting down on (energy) costs is very important to us," says Joe Saavedra.

"Competition should cut prices...but the cheapest price isn't always the best alternative — it's often worth paying more to get the best service," according to George Andras.

Electric customers like Mrs. Brockway, Joe Saavedra, and George Andras have in other essential service providers, like telephone companies, offer an increasingly greater range of services and choice. Sometime in the future,

Leticia and Joe Saavedra

Beth and George Andras

consumers will likely find more choice coming to the electric market as well. How will Florida Power respond?

From a customer perspective, the news is good. Even as Florida Power maintains its long-standing focus on meeting today's customer need for reliable and safe electricity, it is developing the programs and services that will make it a formidable player in the more competitive marketplace of the future.

Building on a solid reputation among customers for reliability and service, Florida Power has developed service packages targeted to the needs of distinct market segments. One is the Senior Privileges program — providing a large range of services including the PowerPay flexible due-date option that allows customers to change their payment date to more closely match their income flow, and large-print and braille bills for the visually impaired.

Marvin and Gladys Goldstein took advantage of another service — the free Home Energy Check, designed to measure the efficiency of their home and their energy use: *"It was very informative and very candid. The young woman who did the inspection found we could use additional insulation. Florida Power even provided names of people to call and pricing."*

In many ways, past habits and horizons already are being stretched in customers' minds. According to a recent survey, more than 60 percent of Florida Power customers have switched their long-distance telephone provider at least once. In such market segments, consumers are getting used to greater choice — in both services and service providers. Florida Power is stepping up to the plate to meet those expanding customer horizons.

One example is automatic lightning surge protection that can safeguard an entire home. With a service territory that covers an area called "The Lightning Capital of the USA," this is the kind of practical and valuable service that expands Florida Power's business and customer horizons at the same time.

Florida Power's approach doesn't stop with just electric service. Creating and selling new and innovative offerings for home and business also are in the cards as part of an expanded vision of the broader role an energy company can play beyond simply selling a commodity.

That matches a vision George Andras volunteered — *"It would be a great idea to be able to go to one company for a package of services, like getting home security and electricity from the same place. I'd get to know one person, like John, our service rep from Florida Power, who would handle these things for me. And since I'm already a customer, I imagine I'd get a break on the price of other services."*

There's good news in all this evolution for Florida Power and the shareholders of corporate parent Florida Progress. Research shows that nearly 75 percent of current customers say they would be inclined to purchase new products or services from Florida Power.

Florida Power already has an enviable track record making innovative energy-related services work for the customer and for the company. In fact, Florida Power operates the country's largest Energy Management program. More than half of Florida Power's residential

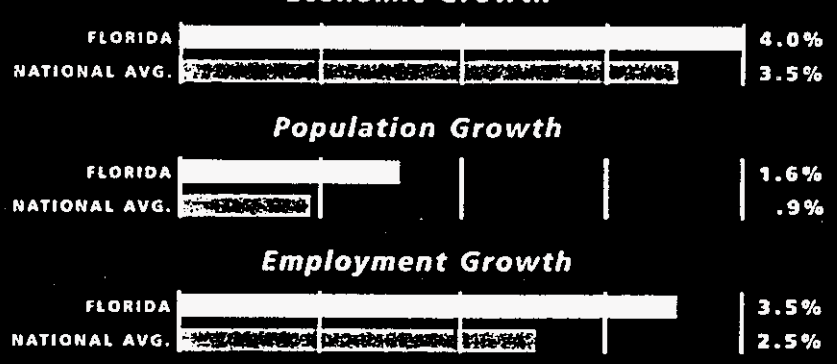
customers have signed up to participate in this program that can provide them with significant cost savings by allowing Florida Power to interrupt service to selected appliances during periods of peak demand.

The Brockway and Andras families both participate in Energy Management. Mrs. Brockway is an enthusiastic supporter: *"I wanted to conserve energy — it's an important part of everybody's life."* Moving on from an Energy Management experience they say has been "great," the Andrases have joined a new Florida Power experiment at Hunters Creek, a large residential community south of Orlando, Florida. They are participating in a two-way communication link that allows for remote meter reading, outage detection, and enhanced time-of-day pricing.

Based on its Energy Management experience, Florida Power is confident it can install, operate, manage and deliver the kinds of service programs that produce clear customer benefits and offer new business opportunities in the expanding energy environment.

FLORIDA'S ECONOMIC ENGINE

Florida Power's growth prospects are favorable. The horizons for customer growth are expanding faster in its home state than nationally. This strength is driven by the engine of Florida's robust economic growth. Some telling statistics:



The impact for Florida Power is impressive, with 1997 growth:
New Residential Customers: 2.1%

**estimated*

ALWAYS ON CALL

Serving customer needs is a round-the-clock mission for Florida Power, and nowhere more so than at the Customer Solutions Call Centers in Winter Park and Clearwater, Florida. Their operating directive is "24 x 7," meaning that Florida Power's customer service associates are ready to answer customer questions and inquiries on the customer's schedule, not ours, twenty four hours a day, seven days a week. Shown here, Florida Power president Joseph Richardson reviews records of the day's customer inquiries with senior customer service associate Josephine Leeks.

MARCHING TO THE CUSTOMER'S BEAT

"*I'm a retailer — where does it say I'm supposed to be an expert on power costs?*" That's the reality that confronts Service Merchandise assistant vice president, utilities and energy management, Bill Nickerson, as he faces the separate electric bills and power requirements of 358 Service Merchandise stores in 38 states. But now, Nickerson has found a partner in Cadence Network LLC, a new energy services company in which Florida Progress is a key player.

Why did Nickerson select Cadence℠ over the other 30-odd competitors that have knocked on his door? *"Cadence said, 'Tell me about your needs, let us understand more about your business.' They didn't hype or promise guarantees — they said, 'We'll work with you to offer the best possible products, the best possible service.'"*

Service Merchandise's Bill Nickerson

With a stated goal of increasing its retail customer access from a base of 1.3 million in 1997 to 10 million, Florida Progress would appear to face a formidable challenge. That growth objective won't be achieved through expansion within its home state alone. But the story of Cadence shows how Florida Progress intends to succeed in building a national retail energy services platform by identifying new customer opportunities and serving their unique needs.

Three innovative energy companies, Florida Progress, Cinergy and New Century Energies, established Cadence September 1997 as a new marketing and service entity. Cadence's mission is to help customers like Service Merchandise, large national companies that do business in diverse locations, manage their energy costs.

Service Merchandise exemplifies the new kinds of business opportunities the changing energy markets will provide for Florida Progress. With its own pressing need to manage all costs for maximum efficiency in a tight-margin retail business, managing the energy needs and usage of its individual locations has been a high priority for Service Merchandise's Bill Nickerson. And customer need drives business opportunity for those who know how to listen.

For a start, Cadence will coordinate the monthly billing for 90 Service Merchandise stores in 11 states. This includes not only collecting their bills, but also analyzing the energy usage patterns and efficiency opportunities for each location. Among the services it offers customers (where regulations allow) Cadence will use its knowledge of the energy market to negotiate with local power companies to secure the best energy rates available on behalf of its national clients.

Cadence provides a package of energy services that responds directly to unmet needs of specific customers in the marketplace. It is a brand commitment reflected in the name Cadence — meaning a steady, predictable beat — a commitment built on consistently delivering results.

Bill Nickerson is already impressed: *"In the first 30 days, they've attacked issues efficiently and rapidly. They're doing a darn good job of enforcing, policing and running it smoothly."*

Nickerson's experience demonstrates that success is all about listening to customers — existing and potential. It is about finding out what they need, and expanding your horizons to be able to serve those needs, or expanding the

INTRODUCING A NEW ENERGY COMPANY THAT MARCHES TO THE BEAT OF A DIFFERENT DRUMMER.

We are like no other energy company in the world. We are brand new, yet we have decades of experience. We will provide national service, yet we possess regional expertise. We want to sell you our product, yet save you money. At Cadence, we deliver a wide variety of products and services including full service energy management, state-of-the-art billing, information services, and commodity procurement to multi-site commercial customers. To a changing industry, we bring you the peace of mind that comes from knowing that you are working with a company that is backed by three of the finest energy companies in the country: Cinergy Corporation, Florida Progress Corporation and New Century Energies (a company formed from the merger of Public Service Company of Colorado and Southwestern Public Service Company). Together these three companies give Cadence the power to deliver on our promises. At Cadence, we move to a faster pace. If this is the kind of partnership you'd like, call us at 1-888-227-1551.

Cadence.

Consistently Delivering Results
www.cadence.net

customer's own horizons to appreciate how the products and services that are offered can be of practical value. It is precisely the kind of customer-focused outlook that is necessary for success in a competitive environment, and for which many traditional utilities are criticized as lacking.

And the opportunity is great. Large, multi-site commercial customers like Service Merchandise represent an energy market in excess of $60 billion.

From the Florida Progress perspective, in addition to its customer advantages, the Cadence venture has given each of its owners a significant boost to its own local reach. This affiliation has established a working relationship among three regional companies whose combined customer base is more than 4.3 million customers, a relationship that these companies intend to explore for additional opportunities.

Shopping at Service Merchandise flagship store

Acting with a combination of innovation and aggressiveness, Florida Progress is showing that dramatically expanding the customer horizons, growing beyond the borders of Florida and the Southeast, is an achievable goal.

PRECISELY WHAT THE CUSTOMER NEEDS

The evolution to a service-based economy has created increased customer demand for electricity of truly premium quality — or more precisely, electricity that is consistently delivered within precise engineering tolerances. Companies in the financial services and insurance sectors, for example, rely on huge mainframe computers to store and retrieve the data that is the heart of their business and that can be corrupted and distorted by even momentary disruptions in electrical supply. Power fluctuations from lightning strikes that would go unnoticed by most customers can create havoc for, and negative financial impact on, these customers.

Expanding the typical horizons of the utility business, Florida Power offers Equipoise℠, a branded package of "Premium Power" services, to ensure these customers uninterrupted delivery of power that meets their precise technical requirements.

Shown here, a static transfer switch is being installed at the new home of Dutch insurance giant Aegon's American subsidiary, Western Reserve Life, now under construction in St. Petersburg, Florida.

This Equipoise system is designed to continuously monitor the power quality being delivered over two entirely separate distribution circuits. Were the active circuit to sustain any power fluctuation, the automatic switch would transfer power from the alternate circuit virtually instantaneously, protecting the sensitive computers on which Aegon depends.

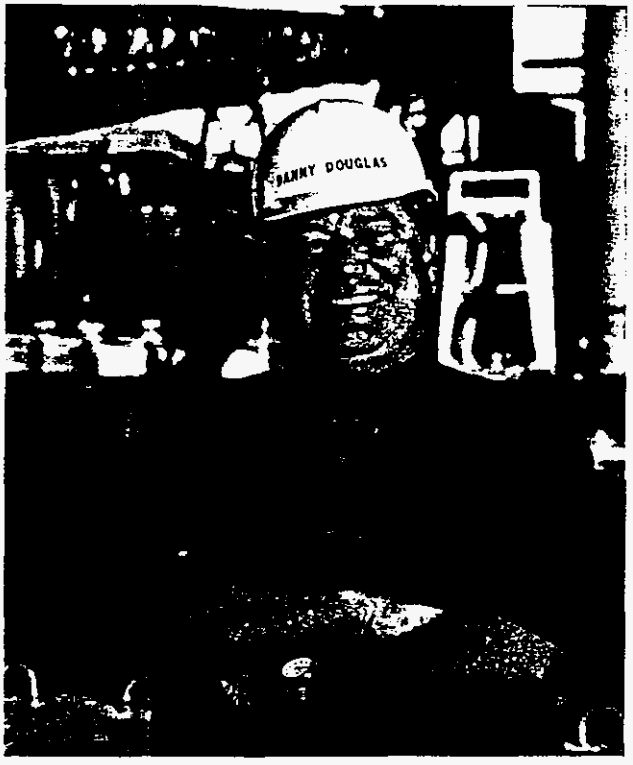
THE KNOW WITHIN

"I never really thought of myself as a customer before. Now that I'm going to be a customer, I'll be seeing it from both sides and know what it's like to walk in a customer's shoes. That will help me to focus better on meeting customers' needs," says Danny Douglas, plant manager of Florida Power's Crystal River 1 & 2 power plants.

s Florida Power's business ...nits prepare for the future, a transformation is sweeping through the company — a transformation that will have important implications for all of Florida Power's customers.

George Marks headed the redesign efforts at Energy Supply, the business unit responsible for making the commodity — electricity — that Florida Power sells. He explains: *"The thrust of this organizational redesign is to prepare us for a more competitive future. To get ready, our way of operating power plants will be different. Our managers will focus not just on operational excellence, but on commercial excellence as well, running each plant as a business. We know we have to reduce the cost of our product to succeed in a competitive market. By structuring ourselves internally as vendors and customers, we will better manage our business, ...rol our costs, and improve service to our external ...mers."*

Danny Douglas already runs two power plants that are among the nation's most efficient coal-fired generating stations.



Florida Power's Danny Douglas

According to *Electric Light and Power*, Florida Power's Crystal River 1 & 2 consistently rank in the top 25 among the thousands of such plants in the country.

But the wholesale market for electricity is swiftly changing. Large-scale customers like municipal utilities, power cooperatives, and a new class of customers called power marketers, are able to shop around for power, free to buy the basic commodity from anywhere in the country if the base cost plus transmission fees are attractive. That ups the ante for Douglas and other managers of Energy Supply's 56-unit generating fleet who must make sure their plants can compete in a market increasingly based on price. They'll need to do more than just operate well-run plants solely to serve the requirements of Florida Power's dispatch operators.

But the internal redesign at Energy Supply now gives Douglas an important new tool to use to meet that task — the freedom as a customer to exercise choice in contracting for the maintenance services he needs. The Energy Supply Services Group, the unit that maintains Florida Power's plants and generating equipment, has in turn been expanding its outside contracting business to ensure it is competitive and can continue selling its services to Douglas.

Florida Power's Energy Supply organization is expanding customer horizons not just outward, but inward as well. Introducing expanded customer choice inside the company is a key to keeping internal costs down, and thus better serving external customers.

The importance of adapting to that new environment can't be made clearer than by listening to one of those wholesale customers talk about needs. Tim Woodbury heads up power purchasing for Florida Power's largest wholesale customer, Tampa-based Seminole Electric Cooperative: "*We look for flexibility in negotiating power supply contracts, for optionality — the ability to adjust contracts as market conditions change — and, of course, for low cost. The market is changing fast, and with this increased uncertainty customers are looking at purchased power options with shorter terms. A 'long-term' purchase arrangement used to mean 20 years. Now it is more in the range of five to ten.*"

Seminole Electric's Tim Woodbury and Mark Daley of Florida Power's Power Marketing Team

As those timeframes shrink, and the industry moves steadily toward a more instantaneous "spot" market for electricity, Florida Power Energy Supply has developed its own wholesale Power Marketing group as the sales organization to serve customers like Seminole. Power Marketing also operates within Florida Power as the agent for making sure Energy Supply meets the power needs of the company's own retail

USING OUR TALENTS

Customer horizons are being expanded in ways apart from the geographical and the simple addition of traditional electric customers. Already recognized as building and operating one of the most efficient electric distribution networks in the country, the Energy Delivery business unit of Florida Power — the division responsible for the utility's "poles and wires" — in 1997 focused on applying its core competencies in system design and construction to new businesses and new customers beyond the traditional scope of electric utilities. One new customer initiative is the design and construction of electric substations for other utility companies, such as the one pictured here for Lakeland Electric and Water; another is Project 400 — a 400-mile-long fiber-optic telecommunications network that shares Florida Power electric towers and whose telecom capacity is leased to long distance telephone providers.

As important as the new revenue streams these projects generate is the focus they demand on identifying and meeting the needs and expectations of new classes of customers — customers from outside the traditional Florida Power fold. That customer-focused mind-set will be a key to thriving in the competitive future.

business unit, Energy Solutions™. From either perspective, Power Marketing's job is to find the most efficient sources of power, whether from Energy Supply's own generation fleet or on the open market. To accomplish that, the group uses a state-of-the-art facility, the Trading Center, to track available generating resources, market opportunities and pricing, transmission capabilities, and other factors on a real time basis to make the most efficient buy/sell decisions possible.

Establishing a Power Marketing group was a customer-oriented concept that is an important step forward. Seminole's Woodbury says, *"That group has provided a renewed focus within Florida Power, a clear effort on trying to be more responsive to the power supply needs of its wholesale customers. The group's ability to be responsive to our needs is evidenced by the fact that two of our most recent power supply contracts have been awarded to Florida Power."*

For all the customers of Florida Power, from large wholesalers like Seminole to a retired couple in a Clearwater condo, Energy Supply's redesign will mean a company more focused on customer needs and determined to ensure efficient power for their future.

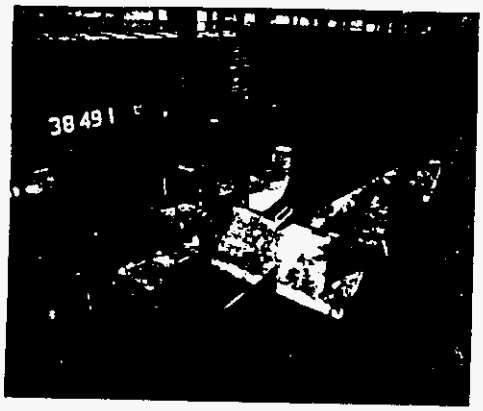
Energy Supply Services, for example, is successfully bidding on external work and has earned a reputation for being one of the best in our marketplace at complex tasks such as boiler and turbine repairs; winning utility and industrial contracts in Florida and even internationally. As one example, in conjunction with Energy Supply's sale of a gas turbine unit that no longer fit Florida Power's generating mix, Energy Supply Services handled the set-up and recommissioning of the unit for the customer, Bahamas Electric Corporation. Spreading its costs over a larger customer base and winning bids externally, Energy Supply Services is able to give key customers like Danny Douglas at Crystal River 1 & 2 the best possible price on service.

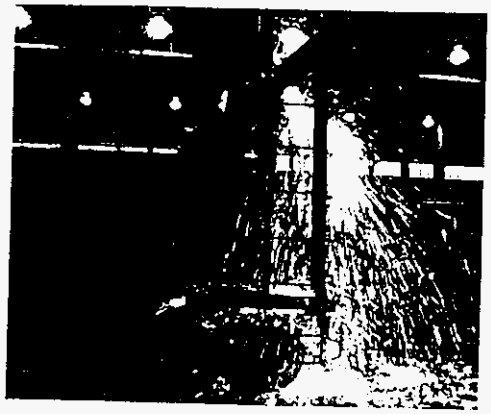
DELIVERING THE GOODS

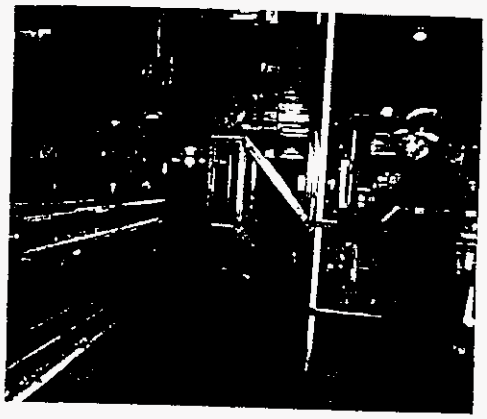
For the present, the customer horizons of Florida Power are largely determined by the geographic confines of the 20,000 square miles in a 32-county service territory that we operate within our home state. Inside those borders, "getting the juice" to customers — residential, small business, commercial, wholesale, industrial — is the job of the Energy Delivery business unit. Fulfilling its mandate to provide reliable, efficient service to a growing Florida customer base requires an impressive combination of state-of-the-art technologies, superior design and maintenance capabilities, a dedicated workforce, and the tried-and-true delivery mechanism of "poles and wires." But it all pays off in delivering customers reliable service — with a reliability factor of 99.97%. Comprising that network are:

28,933	CIRCUIT MILES OF TRANSMISSION AND DISTRIBUTION LINES
362	SUBSTATIONS
850	TRANSFORMERS
2,807	CIRCUIT BREAKERS
84	CAPACITOR BANKS
213	REGULATORS
1,320,077	CUSTOMER ACCOUNTS

Constantly striving to improve the service we provide customers, Energy Delivery is carrying that network into the future with an ongoing program of capital investment to maintain and improve reliability. For example, in 1997 the company invested approximately $800,000 for the installation of an Automatic Outage Detection System across the entire service territory. When complete, this system will track momentary and extended outages in a manner that will help diagnose system problems and more effectively target maintenance activities. In the future, the system may provide outage data directly to the outage restoration system, thus reducing outage times for our customers.







RELATIONSHIPS ARE WHAT COUNT

"Why would one of the country's largest railroads make a long-term commitment to purchase the output of a start-up operation like Progress Rail's brand new Decoursey trackworks facility? It all goes back to the kind of relationship we've developed in more than 10 years of working with Progress Rail and its president, Billy Ainsworth. As the business has grown, our relationship has grown until it's more a partnership than a business relationship. ... Trust comes into it — we believed in them based on our past experience," says John Basso, vice president, supply and services management, CSX Transportation.

Solid customer relationships are the key to expanding customer horizons in the ure. The fastest growing business thin the Electric Fuels portfolio, Progress Rail, is taking on new customers along with finding more ways to serve current customers. Today, Progress Rail is one of the country's largest integrated providers of services to the railroad industry. It is a growing force in a consol idating industry. But it's no surprise that growth is really built around long-term customer relationships. Typical are the relationships Progress Rail has with two leading U.S. railroads — CSX Transportation and Illinois Central.

John Basso of CSX Transportation

Take Progress Rail's state-of-the art Decoursey trackworks facility, which opened in 1996. That facility is already selling more than $30 million a year worth of track components — turnouts, switches and other key rail items, with the bulk of its output dedicated to supplying the needs of the nation's largest railroads.

"Illinois Central has an intense focus on asset utilization," explains the railroad's president and CEO, E. Hunter Harrison. *"A key part of that effort is managing our supply chain for maximum efficiency. We rely on vendors who are flexible, innovative and who can create added value. From our perspective as a customer, that's a definition of Progress Rail."*

Progress Rail built Decoursey's success on past work performed for Illinois Central and CSX. Both relationships go back more than a decade. Starting in 1986, Progress Rail began handling scrap materials from various operations at CSX. Ever since, their relationship has been a constant process of expanding horizons, both for the customer and for Progress Rail. Progress Rail went from handling scrap to refurbishing freight car components for CSX, and later moved into refurbishing key elements of the railroad's trackwork.

The history is similar at Illinois Central, where director, materials management, Dan Drier stresses the flexibility and willingness to try innovative new approaches that characterize the Progress Rail relationship. He cites the example of Progress Rail's solution to a leasing dilemma that faced his railroad. Illinois Central had an option to purchase 1,700 well-used rail cars it had on lease, but needed only 1,000. Progress Rail created a program to refurbish the cars at its Decoursey Rail Car Repair facility, deliver the 1,000 Illinois Central required, and use its resources and contacts to place third-party leases on the remainder. *"That was a win-win all around — one that matched our corporate objectives for asset utilization,"* Drier says.

According to Basso of CSX Transportation, the railroad played a key role in suggesting to Progress Rail that it use its experience in refurbishing trackwork to expand into supplying new trackwork, and to invest in a new facility — Decoursey — to handle the job. That's the kind of suggestion that only a truly satisfied customer can make.

Now, Progress Rail is expanding its horizons into new markets and new territories by acquiring rail services companies in California and up the West Coast into Canada. In addition, Progress Rail finalized a long-term contract to provide integrated services to TFM, a recently-privatized railroad in northeast Mexico that is a joint venture whose members include TMM and Kansas City Southern. All that growth is founded on the basis of the reputation for quality work and quality customer relationships that Progress Rail has established wherever it has operated.

Today, the entrepreneurial spirit that guides Progress Rail's customer focus is infusing the rest of Florida Progress and helping the company expand all its horizons.

E. Hunter Harrison of Illinois Central

Dan Drier of Illinois Central

WHERE CUSTOMERS COUNT

The most broad and expansive array of customer relationships within the Florida Progress portfolio belongs to Electric Fuels. The horizons of its customer base today are extensive — stretching from Canada to Mexico and from east to west coast for Progress Rail's operations, throughout the Mississippi and Ohio River systems for MEMCO's barge network, on to ocean-going tugs and interstate rail transportation at Electric Fuels. Today's expansive horizons contrast with Electric Fuels' historic origins as the Appalachian-based coal supplier for Florida Power's fuel needs.

Electric Fuels' customer line-up includes:

Rail Services

All major Class 1 railroads in North America

Over 1,000 railroad-related customers and shortline railroads

Inland Marine

519 shippers

Energy and Related Services

26 utility companies

39 industrial companies

50 users of terminal/shipping operations

Electric Fuels' continued drive to expand customer horizons works across multiple levels — expanding its businesses through ongoing acquisitions of operating assets, building new facilities and expanding current ones, expanding the customer bases of individual operations, and introducing existing customers enhanced product and service offerings. These expansion efforts hold continuing promise for the future, just as they powered the group's double-digit earnings growth in 1997.

FINANCIAL INFORMATION

MANAGEMENT'S DISCUSSION & ANALYSIS

OPERATING RESULTS

Florida Progress' 1997 consolidated earnings from continuing operations were $54.3 million. This compares to $250.7 million in 1996 and $238.9 million in 1995. Florida Progress' 1997 operating results were negatively impacted by the extended outage of Florida Power's Crystal River nuclear plant and the provision for loss on its investment in Mid-Continent Life Insurance Company. These two events reduced Florida Progress' 1997 earnings by $200 million or $2.06 per share.

Excluding these one-time charges, Florida Progress' 1997 consolidated earnings from continuing operations were $254.3 million. This compares with $252.4 million in 1996 and $238.9 million in 1995. Florida Power earned $240.9 million in 1997 before nuclear outage costs, compared with $232.6 million in 1996 and $217.3 million in 1995. Earnings from recurring diversified operations were $13.4 million in 1997, compared with $19.8 million in 1996 and $21.6 million in 1995.

EARNINGS PER SHARE

	1997	1996	1995
orida Power Corporation	$2.48	$2.40	$2.27
Electric Fuels Corporation	.33	.28	.25
Mid-Continent Life Ins. Co.	-	.02	.07
Other	(.19)	(.09)	(.09)
Diversified	.14	.21	.23
Continuing operations before nonrecurring items	2.62	2.61	2.50
Nuclear outage costs	(1.10)	-	-
Loss related to Mid-Continent Life Ins. Co.	(.96)	-	-
Provision for loss on coal properties	-	(.26)	-
Gain on sale of business	-	.24	-
Total continuing operations	.56	2.59	2.50
Discontinued operations	-	(.27)	-
Consolidated	$ .56	$2.32	$2.50

Excluding nuclear outage costs, Florida Power's 1997 earnings per share were up 3.3 percent over 1996, primarily due to strong customer growth. During 1997, Florida Power added more than 22,000 customers. Customer growth among residential and commercial customers averaged about 2 percent in 1997 and 1996.

Florida Power's Crystal River nuclear plant was out of service ing 1997 to address design issues related to the plant's safety .ems. As a result of the outage, Florida Power's earnings were reduced by $1.10 per share. This resulted from $100 million in additional nuclear operating and maintenance expenses and $73 million of disallowed replacement power costs. (See Extended Nuclear Outage Costs on page 22.)

In April 1997, Mid-Continent Life Insurance Company was placed in receivership over allegations that its policy reserves were inadequate. While Mid-Continent has appealed an Oklahoma district court judge's ruling to keep Mid-Continent in receivership, Florida Progress has recorded a provision for the loss on its investment in Mid-Continent as well as an accrual for legal fees for pending litigation. This resulted in a $.96 after-tax charge to 1997 earnings. (See Mid-Continent Life Insurance Company on page 24.)

In 1996, Florida Progress divested Echelon International Corporation, formerly Progress Credit Corporation, through a tax-free stock dividend. This resulted in a $26.3-million charge to earnings for the write-down of certain assets of Echelon and other costs. Also in 1996, Florida Progress sold its 80-percent interest in Advanced Separation Technologies, Inc. for $56 million and realized an after-tax gain of $23.5 million, or $.24 per share.

Lastly, Electric Fuels recorded a $25.2-million after-tax charge to 1996 earnings to establish a provision for loss on its unprofitable coal properties, now available for sale. The provision was necessary because management did not consider the unfavorable market conditions for low-sulfur coal to be temporary.

While significant, the one-time charges incurred in 1997 and 1996 should not affect the future earnings prospects of Florida Progress. Florida Power's growing customer base and good cost control combined with the expanding operations of Electric Fuels are the fundamental drivers of earnings growth for Florida Progress. The growth of these core businesses is forecasted to provide earnings per share growth of four to five percent annually for Florida Progress over the next five years.

The financial return on Florida Power's common equity was 13 percent in 1997 before considering nonrecurring items, compared with 12.9 percent in 1996 and 12.7 percent in 1995. Florida Power's above average customer growth and continued control over operating and maintenance costs should enable Florida Power to maintain its return on equity and continue its earnings growth while pursuing strategic initiatives designed to prepare the utility for a more competitive environment. Return on equity from the energy and transportation subsidiary was 17.3 percent in 1997, 14 percent in 1996 before its provision for loss on coal properties and 13.8 percent in 1995.

FLORIDA POWER CORPORATION

Industry Restructuring

The electric utility industry is undergoing changes designed to increase competition in an industry that, since inception, has been considered a natural monopoly. Starting with the Public Utilities Regulatory Policies Act of 1978 (PURPA) and the Energy Policy

't of 1992 (EPA of 1992), competition in the wholesale electric ieration market has greatly increased, especially from non-utility generators of electricity.

In 1996, the Federal Energy Regulatory Commission (FERC) issued new rules on transmission service to facilitate competition in wholesale generation on a nationwide basis. The rules give greater flexibility and more choices to wholesale power customers.

The effect of these changes on the wholesale generation market has been significant. In the last five years, power supplied by non-utility generators has increased over 100 percent. From 1990 through 1995, non-utility generation capacity grew at a rate of 47 percent, compared to utility generation capacity which grew at a rate of two percent.

Electricity in Florida is supplied largely through existing generation capacity located in the state. Florida's peninsular shape and limited transmission access into the state set Florida apart from other regions of the country.

The amount of electricity that presently can be imported into Florida from adjoining states is limited to about ten percent of the total daily demand for electricity in Florida. Most of the demand for electricity is in the southern portion of the state, which increases the amount of transmission line losses when importing electricity from a generating source outside the state.

These two unique characteristics of Florida make it difficult to compete in the Florida wholesale generation market without access to generation resources within the state.

The regulatory changes described above relate to the wholesale ket for electricity which is regulated by federal law. The sale of electricity to residential, commercial and industrial customers is governed by the states. To date, several states have adopted legislation that would give retail customers the right to choose their electricity provider (retail choice) and many other states are considering the issue.

California, Pennsylvania and some states in the New England region, where legislation to allow retail choice has passed, have rates that are well above the national average. In states where electricity rates are more competitive, such as Florida, there has been less incentive to push forward legislative proposals concerning retail choice.

In addition to restructuring activity in various states, there have been several industry restructuring bills introduced in Congress. A key issue concerning the passage of any industry restructuring legislation by federal lawmakers is whether the federal government has the authority to mandate legislation by the states. Several of the federal bills being considered require states to implement retail choice between 2000 and 2003.

The changes taking place in the industry today have caused many companies to develop new corporate strategies. Some of these corporate strategies include alliances, mergers with or acquisitions of other electric or gas utilities or other types of service providers ıding home security and telecommunications companies.

uring the last five years there have been 30 mergers or acquisitions of investor-owned utilities announced, of which 11 have been completed and the others are either pending regulatory approval or have been withdrawn.

While it may be several years before retail choice exists in Florida, Florida Progress believes that retail choice will eventually exist in every state. The Company has developed a corporate strategy to compete in a more competitive marketplace. Florida Progress is focused on establishing a national retail energy services business to efficiently develop new products and services for its customers.

To be successful in this market, a retail services company will likely need a sizeable number of customers in order to realize the economies of scale necessary to keep the cost of such products and services competitive. Florida Progress has set a goal of achieving a customer base of at least 10 million and will pursue this goal through joint ventures, alliances, mergers, acquisitions or some combination thereof. In September 1997, Florida Progress entered into a joint venture with two other utilities, Cinergy Corp. and New Century Energies. The joint venture, named Cadence℠, is a marketing alliance aimed at providing national chain account customers with a variety of energy management services and products.

An important and frequently contentious issue surrounding industry restructuring is the recovery of "stranded costs." Stranded costs include the generation assets of utilities whose value in a competitive marketplace would be less than their current book value as well as above-market purchased power commitments to qualifying facilities. States that have passed legislation for industry restructuring have provided for utilities to recover some portion of their stranded costs.

Assessing the amount of stranded costs for a utility requires various assumptions about future market conditions including the future price of electricity. For Florida Power, the single largest stranded cost issue lies with its commitments to qualifying facilities.

Florida Power is continuing to seek ways to mitigate the impact of escalating payments from contracts it was obligated to sign under provisions of the federal Public Utilities Regulatory Policies Act of 1978.

In 1997 Florida Power reduced its purchased power commitments by over 20 percent through the buy-out of the Tiger Bay purchased power contracts.

Utility Revenues and Sales

Florida Power's operating revenues were $2.4 billion in 1997 and 1996, compared to $2.3 billion in 1995.

The utility's retail kilowatt-hour sales were essentially level in 1997 when compared to 1996. The lack of sales growth was due primarily to milder weather in 1997 than 1996. Kilowatt-hour sales in 1996 were up 2.9 percent when compared to 1995.

Normally, Florida Power's revenues are heavily influenced by weather, especially among residential customers. However in 1995, Florida Power, as ordered by the Florida Public Service Commission, began a three-year test of residential revenue decoupling. This ratemaking concept is designed to eliminate the direct link between kilowatt-hour sales and revenues. Under revenue decoupling, abnormal weather does not impact earnings from residential sales, which represents the single-largest customer

group for Florida Power. A change in customer usage due to extreme heating or cooling conditions would not have a material effect on Florida Power's earnings, whereas customer growth and higher usage due to nonweather-related factors can affect earnings.

Over the three-year period, the earnings impact of residential revenue decoupling was not material. As of December 31, 1997, the cumulative adjustment to revenues was a reduction of less than $.5 million. Florida Power does not intend to seek approval to use residential revenue decoupling beyond 1997. The termination of residential revenue decoupling will likely result in Florida Power's earnings being subject to greater fluctuation due to changes in weather. (See Note 1 on page 32.)

Fuel and Purchased Power

Fuel and purchased power costs are recovered primarily through an adjustment recovery clause established by state and federal regulators. Fluctuations in these costs have little impact year to year on net income, but could become increasingly important in a more competitive environment. (See Extended Nuclear Outage Costs below for discussion of replacement power costs not recovered through the adjustment recovery clause.)

Factors influencing fuel and purchased power costs include demand for electricity, the availability of generating plants and the price of electricity purchased from qualifying facilities and other utilities.

Total fuel and purchased power expenses for 1997, including amounts incurred as a result of the nuclear outage, were up $80.7 million over 1996 due largely to the extended outage of Florida Power's Crystal River nuclear plant. The outage forced Florida Power to replace nuclear generation with other, higher-cost replacement power. (See Extended Nuclear Outage Costs below.)

In 1996, fuel and purchased power expenses increased $73.5 million compared to 1995. This was due to increased purchased power costs and higher system requirements.

The nuclear plant is not scheduled to be taken out of service until 1999, which will be for refueling. Having the nuclear plant in service for most of 1998 should help lower Florida Power's fuel and purchased power costs for 1998 when compared to 1997.

As mentioned above, a key factor influencing Florida Power's purchased power costs are the prices paid to qualifying facilities for electricity. Currently, Florida Power receives 830 megawatts of total capacity from qualifying facilities. This amount is down 220 megawatts from 1996 due to the buy-out of the Tiger Bay purchased power contracts. (See Impact of Tiger Bay Buy-Out on page 23.)

In addition to the Tiger Bay buy-out, the Florida Public Service Commission (FPSC) approved Florida Power's buy-out of the last four years and seven months of a cogeneration contract between Florida Power and Pasco Cogen Ltd. Florida Power has one other petition before the FPSC that involves the buy-out of purchased power commitments.

In 1997, the company spent $233.6 million for purchased power for all cogeneration contracts. This represented approximately 23 percent of system fuel and purchased power expenses for the year. Costs associated with those contracts raised Florida Power's system average cost for generation in 1997 and 1996, and this trend is expected to continue based on the contracts currently in place and the escalating payment schedules associated with each contract.

Florida Power will continue its effort to mitigate the impact of escalating payments from its purchased power contracts. Under the provisions of PURPA, Florida Power was obligated to sign contracts with those qualifying facilities.

Florida Power's present strategy is to pursue opportunities to buy-down or buy-out those contracts whose prices are projected to be above future market prices.

While this strategy requires paying higher amounts in the short-term, the long-term benefit to customers can be significant. Long-term savings to customers resulting from the buy-out of the Tiger Bay purchased power contracts are estimated to be more than $2 billion over the next 30 years.

Other Utility Expenses

Utility operation and maintenance expenses increased by $8.9 million in 1997 exclusive of nuclear outage costs. The increase was due primarily to costs associated with planned fossil plant outages and expenditures designed to improve reliability and customer service.

In 1996, operation and maintenance expenses increased by $19.7 million when compared with the previous year, primarily due to additional costs associated with the outage of the nuclear plant as well as expenses related to improving service and reliability.

Cost control is a primary focus of each strategic business unit at Florida Power as each looks for ways to efficiently meet its customers' needs. This has resulted in Florida Power's recurring operation and maintenance costs growing at an annual rate below inflation since 1994.

It is one of management's goals to continue to limit increases in operation and maintenance costs to less than the national inflation rate.

Recoverable energy conservation program costs increased by $4.4 million in 1997 over 1996. In 1996 these costs decreased by $21.4 million from the previous year due to a reduction in the credits paid to customers who participated in the company's load management program.

The change had no significant impact on earnings because Florida Power recovers substantially all of these costs through a clause in electric rates similar to the fuel adjustment clause. Florida Power does not expect the level of energy conservation costs to vary materially in the future from the 1997 expenditure level since little growth is forecast for this program.

In 1997, Florida Power wrote-off approximately $20 million of contract termination costs related to the Tiger Bay buy-out. In 1996, Florida Power amortized approximately $31 million related to two oil-fired power plants and a canceled transmission line.

Extended Nuclear Outage Costs

In September 1996, Florida Power's Crystal River nuclear plant was taken out of service to fix an oil pressure problem in the main turbine. When the repairs were completed in October 1996, Florida Power decided to keep the plant shut down to address certain backup safety system design issues.

The Nuclear Regulatory Commission (NRC) had been critical of lant's overall performance in 1996 and in January 1997 .d the nuclear plant on its "Watch List" as a plant whose operations would be monitored closely until Florida Power demonstrates a period of improved performance. In March 1997, the NRC outlined necessary actions Florida Power must complete before returning the nuclear plant to service.

In late January 1998, Florida Power notified the NRC that it had completed all of the requirements and was subsequently granted permission to restart the plant. Florida Power's Crystal River nuclear plant is expected to be returned to service in February 1998.

Florida Power's operating results for 1997 were significantly impacted by the costs associated with the extended outage. These costs included $100 million in additional operation and maintenance expenses and approximately $173 million in replacement power costs. Capital expenditures related to the outage were $42 million in 1997.

In June 1997, the FPSC approved a settlement agreement between Florida Power and several parties who objected to Florida Power recovering replacement power costs resulting from the extended outage.

The settlement allows Florida Power to recover, through rates charged to customers, approximately $38 million of $174 million of replacement power costs incurred from September 1996 th· ·igh December 1997. Florida Power can begin recovering the illion once the plant has been operating at 100-percent power for 14 consecutive days. Of the remaining $136 million, $63 million was recorded as a regulatory asset and is being amortized over four years. The remaining $73 million was expensed in 1997 and, along with the $100 million of additional operation and maintenance costs, is classified as "Extended Nuclear Outage Costs" on the consolidated statements of income. The amortization of the $63-million regulatory asset is being recovered by the suspension of an annual accrual for fossil plant dismantlement costs for a period of up to four years.

Actual replacement power costs incurred in 1998 prior to the nuclear plant's return to service will be expensed as incurred.

The settlement agreement also provided that, for purposes of monitoring Florida Power's earnings, the FPSC would exclude the nuclear outage costs when assessing Florida Power's regulatory return on equity. Florida Power is currently allowed to earn between 11 and 13 percent on its common equity. By excluding these outage costs, Florida Power's future earnings capacity will not be penalized for the one-time charge for outage costs.

Impact of Tiger Bay Buy-Out

In July 1997, Florida Power bought-out the purchased power contracts related to a 220-megawatt cogeneration facility (Tiger Bay). In addition to buying-out the purchased power contracts, Florida Po· acquired the 220-megawatt facility. Costs associated with t nination of the purchased power contracts and the acquisition of the facility totaled $445 million. Tiger Bay was Florida Power's largest cogeneration supplier, representing more than 20-percent of the company's total capacity received from qualifying facilities. The purchase was funded primarily through the issuance of medium-term notes with maturities ranging from two to 10 years at interest rates between six and seven percent.

The FPSC-approved purchase allowed Florida Power to record a regulatory asset of approximately $350 million for contract termination costs and add $75 million to its electric plant.

Florida Power continues to collect from customers an amount equal to what it would have been allowed to recover for capacity and energy payments made in accordance with the original Tiger Bay purchased power contract. Based on the contract's capacity payment schedule, Florida Power should recover enough revenues by the year 2008 to fully amortize the regulatory asset and related interest charges.

The Tiger Bay expenses including operation and maintenance, depreciation, interest and property taxes are expected to be absorbed through Florida Power's growing base revenues. These additional expenses are expected to be about $20 million annually. The utility's base revenues increase largely from the addition of new retail customers, particularly residential customers.

DIVERSIFIED OPERATIONS

In 1997, Florida Progress established a provision for loss on its $87 million investment in Mid-Continent Life Insurance Company and accrued for litigation costs. (See Mid-Continent Life Insurance Company on page 24.) In 1996, Florida Progress made two restructuring decisions that had a significant impact on earnings from diversified operations. The spin-off of Echelon resulted in a $26.3-million after-tax charge to earnings while the sale of Advanced Separation Technologies contributed an after-tax gain of $23.5 million. Another item that affected 1996 diversified earnings was the provision for loss on unprofitable coal properties owned by Electric Fuels. This resulted in an after-tax charge of $25.2 million.

The actions taken to restructure its diversified operations reflect management's commitment to establishing a diversified group of businesses more closely aligned to its core utility operations.

ELECTRIC FUELS CORPORATION

Electric Fuels, Florida Progress' energy and transportation subsidiary, has three principal business units: energy and related services, inland marine transportation, and rail services. Florida Progress continues to build on Electric Fuels' existing operations through internal expansion and by pursuing new market opportunities, primarily with its inland marine transportation and rail services units.

Over the last five years Electric Fuels has grown significantly:

	1993	1994	1995	1996	1997	Five-Year Growth Rate
			(In millions)			
Revenues	$ 581	$ 784	$ 844	$ 881	$1,037	17.4%
Earnings	$14.9	$22.6	$24.0	$27.1*	$ 32.1	21.6%
Assets	$ 397	$ 489	$ 574	$ 620	$ 799	19.4%

**Before provision for loss on coal properties*

Most of the growth of Electric Fuels has come from acquisitions in its rail services business unit and expansion of the inland marine barge fleet.

During 1997 and 1996, Progress Rail Services expanded its operations through acquisitions of railcar repair shops, railcar leasing and metal recycling operations. Over this period Progress Rail's acquisitions totaled nearly $71 million.

Today, Progress Rail is one of the largest integrated suppliers of rail services in the United States, with locations in 16 states. Revenues from rail services in 1997 were $476.3 million, an increase of $122.6 million or 35 percent over 1996. The increase reflects the expansion of these operations as well as an increase in demand for rail services as railroads continue outsourcing much of their service and repair needs.

Expansion of MEMCO, Electric Fuels' inland marine transportation unit, has been achieved primarily through the purchase of river barges. MEMCO's fleet of barges, which hauls coal, agricultural products and other dry bulk products along the Ohio and lower Mississippi rivers, totaled approximately 900 at the end of 1997. During 1997 and 1996 MEMCO added approximately 300 new high-capacity river barges to its fleet and plans to purchase 200 additional barges and two new towboats in 1998.

Further expansion of the barge fleet depends largely on the future demand for barge capacity and MEMCO's ability to secure long-term contracts with guaranteed volumes for hauling. MEMCO's objective is to maintain at least 70 percent of its large capacity under long-term contracts. The remaining capacity is used to take advantage of new market opportunities as they arise.

Electric Fuels' energy and related services business unit includes coal operations, river terminal services and off-shore marine transportation. Annual sales of coal average about 12 million tons of which five to six million tons are sold to Florida Power. In 1997, increased tonnage of coal transported by Electric Fuels' energy and related business unit resulted in improved earnings compared to 1996. In December 1996, Electric Fuels established a provision for loss on certain coal properties after it determined that depressed market conditions for low-sulfur coal were not temporary. The impact of the write-down was a one-time after-tax charge to earnings of $25.2 million.

Electric Fuels' business plan for its coal operations includes supplying Florida Power with high-quality, competitively-priced coal and increasing output from company-operated mines which can be directed to more profitable niche markets.

Earnings from Electric Fuels in 1997 were $32.1 million, up $5 million over 1996 earnings before the provision for loss on unprofitable coal properties. Although Electric Fuels' earnings continued to grow at a double-digit rate, 1997 earnings were lower than the company's target for the year because of March floods along the Ohio and Mississippi rivers that temporarily disrupted barge traffic terminal services.

Partially offsetting the impact of the floods were increased earnings from rail services and the energy and related services business units. Acquisitions and higher production at a trackworks facility contributed to the improved results at Progress Rail. Increased coal deliveries to Florida Power's Crystal River coal units resulted in higher volumes of coal transported by the energy and related services division.

The higher volume was due largely to increased coal requirements of Florida Power's coal-fired plants. The lack of availability of its nuclear plant in 1997 forced Florida Power to increase the generation of its coal plants.

MID-CONTINENT LIFE INSURANCE COMPANY

When Mid-Continent was acquired in 1986, it sold a popular, low-priced death-benefit insurance policy. In 1996, Mid-Continent replaced this policy with a new product after it was determined that premiums on the old policy would have to be raised.

Mid-Continent was hoping to rebuild market share and achieve increased profitability with the new product, but sales did not meet management's expectations. In December 1996, Mid-Continent reduced its work force in an effort to compete on a more focused and cost-efficient basis and was developing a plan to raise premiums on its prior low-priced death benefit policy.

The business plan would increase premiums and lower dividends so that a projected reserve shortfall in 2020 could be avoided. Mid-Continent discussed the outline of its plan with the Insurance Commissions of both Texas and Oklahoma, states where the majority of Mid-Continent's policyholders reside.

On April 14, 1997, the Oklahoma Commissioner obtained approval from the Oklahoma County District Court to temporarily seize control of the operations of Mid-Continent. The Commissioner claimed that Mid-Continent's policy reserves were currently understated and that the company could not raise premiums to address this issue.

During hearings on this matter, the Commissioner's actuary conceded that if Mid-Continent could raise premiums, it was not insolvent. Although the judge agreed with Mid-Continent that it had the right to raise premiums, in May he ordered the company to remain in receivership.

On June 18, 1997, Mid-Continent appealed this decision to the Oklahoma Supreme Court.

The actions taken by the Commissioner since April significantly impacted Mid-Continent's business plan for addressing its projected reserve deficiency. Since the court's decision in May, the probability of Florida Progress recovering any of its investment has become unlikely.

This is due in part to the Commissioner's failing to file a plan of rehabilitation for Mid-Continent as ordered by the court. In addition, the Commissioner filed a lawsuit in December 1997 against Florida Progress and several other defendants.

The suit claims that, because of the level of control exerted by Florida Progress over Mid-Continent, the assets of Florida Progress should be made available to Mid-Continent to satisfy policyholder and creditor claims. Florida Progress believes that the Commissioner's lawsuit is without merit and that Florida Progress has been a very responsible parent of Mid-Continent.

Florida Progress intends to vigorously defend itself and other defendants against these charges.

Based on these events, Florida Progress recorded a provision for the loss on its investment in Mid-Continent and accrued for estimated legal costs. This reduced 1997 earnings by $.96 a share.

OTHER

Florida Progress does not anticipate incurring significant costs related to modifications of the Company's information systems to prepare for the year 2000. In addition, the Company expects to complete the modifications on time.

Florida Progress has adopted several new accounting standards during the last three years. (See Note 1 on page 32.)

Florida Power and a former company subsidiary have been notified by the U.S. Environmental Protection Agency that each is or may be a potentially responsible party for the cleanup costs of several contaminated sites. (See Note 11 on page 43.)

Florida Progress has off-balance sheet risk related to debt of unconsolidated partnerships. (See Note 11 on page 42.) Florida Power entered into a single forward treasury lock agreement in 1997 to effectively fix the treasury rate component of an anticipated issuance of medium-term notes. (See Note 2 on page 35.)

Florida Progress is involved in other litigation as described in Note 11 on page 43.

Even though the inflation rate has been relatively low during the last three years, inflation continues to affect Florida Progress by reducing the purchasing power of the dollar and increasing the cost of replacing assets used in the business. This has a negative effect on Florida Power because regulators generally do not consider this economic loss when setting utility rates. However, such losses are partly offset by the economic gains that result from the repayment of long-term debt with inflated dollars.

LIQUIDITY AND CAPITAL RESOURCES

Cash from operations has been the primary source of capital for Florida Progress. Other sources of capital over the last three years include proceeds from the sales of properties and businesses, debt financing, issuance of common stock and the orderly withdrawal from the company's lending and leasing and real estate portfolio.

Florida Progress has issued new equity in recent years primarily to fund Florida Power's construction program. Florida Power is forecasting lower construction expenditures in the years ahead. The utility does not expect construction to require any significant increase in equity or debt over the next five years. Because of the reduced equity requirements, the dividend reinvestment plan began purchasing shares in the open market instead of issuing new shares beginning in July 1996.

For the first half of 1996 and for all of 1995 approximately $57 million of new equity was issued through the Company's dividend reinvestment plan.

Florida Progress contributed $12.5 million in 1996 and $50 million in 1995 to Florida Power from the proceeds of the dividend reinvestment plan. These funds were used to further strengthen Florida Power's financial position.

Florida Progress' capital structure as of December 31, 1997, was 40.2 percent common equity, 59 percent debt and .8 percent preferred stock of Florida Power. On December 31, 1996, Florida Progress' capital structure was 51 percent common equity, 48.1 percent debt and .9 percent preferred stock. The increase in debt in 1997 over 1996 is due primarily to the buy-out of the Tiger Bay purchased power contracts. Florida Progress' current goal is to maintain capital structures for its utility and diversified operations at levels that will enable its subsidiaries to preserve their current credit ratings.

CREDIT RATINGS

	STANDARD & POOR'S	MOODY'S	DUFF & PHELPS
Florida Power Corporation			
First mortgage bonds	AA-	Aa3	AA-
Medium-term notes	A+	A1	A+
Commercial paper	A-1+	P-1	D-1+
Progress Capital Holdings, Inc.			
Medium-term notes	A	A2	
Commercial paper	A-1	P-1	

FLORIDA POWER CORPORATION

Florida Power's construction expenditures in 1997 totaled about $387 million. This was primarily for distribution lines related to the utility's growing customer base and the construction of a new 470-megawatt power plant scheduled to begin commercial operation in the fall of 1998. Florida Power's five-year construction program totals $1.2 billion for the 1998-2002 forecast period. It includes planned expenditures of $294 million, $263 million, $210 million, $268 million and $204 million for 1998 through 2002. Florida Power expects these construction expenditures will be financed primarily with internally generated funds.

In July 1997, Florida Power issued $450 million of medium-term notes primarily to finance the buy-out of purchased power contracts associated with the 220-megawatt Tiger Bay cogeneration facility. (See Impact of Tiger Bay Buy-Out on page 23.)

Amendments to the Clean Air Act in 1990 require electric utilities to reduce sulfur dioxide emissions. Florida Power is meeting these requirements with minimal capital expenditures.

In 1997, Florida Power's net cash flow to capital expenditures was 76 percent. In addition to funding its construction commitments with cash from operations, Florida Power receives equity from Florida Progress and accesses the capital markets through the issuance of commercial paper, medium-term notes and first mortgage bonds.

Florida Power has a medium-term note program, providing for the issuance of either fixed or floating interest rate notes, with maturities that may range from nine months to 30 years. Florida Power has available for issuance $400 million of medium-term notes.

Florida Power's interim financing needs are funded primarily through its commercial paper program. The utility has a $300 million, 364-day revolving bank credit facility and a $200 million five-year facility, which are used to back up commercial paper. (See Note 6 on page 37.)

In 1997, debt levels increased at Florida Power largely due to the costs associated with the extended nuclear outage and the buy-out of the Tiger Bay purchased power contracts. Florida Power used additional cash generated by operations to redeem $105 million of preferred stock in 1996 and reduced total debt levels by about $145 million in 1995.

Florida Power's embedded cost of long-term debt was 7 percent as of December 31, 1997 and 7.2 percent as of December 31, 1996.

DIVERSIFIED OPERATIONS

Progress Capital Holdings, Inc., the downstream holding company of Florida Progress, consolidates the collective financial strength of Florida Progress' diversified operations and, with the benefit of a guaranty and support agreement with Florida Progress, helps to lower the cost of capital of the diversified businesses. Progress Capital funds diversified operations primarily through the issuance of commercial paper and medium-term notes. (See Note 6 on page 37.)

Progress Capital has a medium-term note program for the issuance of either fixed or floating interest rate notes, with maturities that may range from nine months to 30 years. In 1997 and 1996, Progress Capital issued $35 million and $178 million of medium-term notes, respectively, with maturities ranging from five to 10 years, leaving $87 million of medium-term notes available for issuance. The proceeds were primarily used to repay maturing medium-term notes and for other corporate purposes.

Progress Capital also has two revolving bank credit facilities: a 364-day, $100-million facility and a five-year, $300-million facility. These facilities are used to back up commercial paper. (See Note 6 on page 37.)

In 1997, total diversified capital expenditures were about $120 million, primarily for operations at Electric Fuels. During 1997, $50 million was for the purchase of barges and $23.3 million for acquisitions by Progress Rail. In 1996, Progress Capital received net proceeds of $53 million from the sale of Advanced Separation Technologies and expended $54 million related to acquisitions made by Electric Fuels or its affiliates.

In 1998, diversified capital expenditures are expected to be $125 million and are designated for operations of Electric Fuels. The inland marine transportation unit plans to add approximately 200 new barges in 1998 as it continues to take advantage of market opportunities to expand its business.

Electric Fuels' rail services unit is expected to continue to grow by expanding geographically into the Midwest and western markets. These expenditures are expected to be funded through cash generated internally and from outside financing sources.

DIVIDEND POLICY

Florida Progress evaluates its dividend policy on an annual basis to ensure that the dividend payout and dividend rate are appropriate given the business plan, projected earnings growth and outlook for the electric utility industry. Florida Progress' 5-year business plan forecasts sustained earnings growth of 4 to 5 percent annually, a key factor in determining dividend policy.

FORWARD-LOOKING STATEMENTS

In this report, Florida Progress has projected sustained earnings per share growth of 4 to 5 percent annually over the next five years, indicated that confidence in earnings growth remains a key factor in determining dividend policy, and established a goal to develop a national retail energy business that provides access to at least 10 million customers. Florida Progress has indicated that it believes that retail choice eventually will exist in every state, and that Florida Power's above average customer growth and continued control over operating and maintenance costs should enable it to maintain its return on equity and continue its earnings growth while pursuing strategic initiatives designed to prepare the utility for a more competitive environment. Florida Progress also has projected expansion of Electric Fuels, and indicated that it will vigorously defend itself against a lawsuit related to Mid-Continent, which Florida Progress believes is without merit.

RISK FACTORS

These statements, and any other statements contained in this report that are not historical facts, are forward-looking statements that are based on a series of projections and estimates regarding the economy, the electric utility industry and the Company's other businesses in general, and on key factors which impact the Company directly. The projections and estimates relate to the pricing of services, the actions of regulatory bodies, the success of new products and services, and the effects of competition.

Key factors that have a direct bearing on the Company's ability to attain these projections include continued annual growth in customers, successful cost containment efforts and the efficient operation of the Company's existing and future generating units. Also, in developing its forward-looking statements, the Company has made certain assumptions relating to productivity improvements and the favorable outcome of various commercial, legal and regulatory proceedings, and the lack of disruption to its markets.

If the Company's projections and estimates regarding the economy, the electric utility industry and key factors differ materially from what actually occurs, or if various proceedings have unfavorable outcomes, the Company's actual results could vary significantly from the performance projected.

Consolidated Statements of Income

FOR THE YEARS ENDED DECEMBER 31, 1997, 1996 AND 1995 (IN MILLIONS, EXCEPT PER SHARE AMOUNTS)

	1997	1996	1995
REVENUES:			
Electric utility	$2,448.4	$2,393.6	$2,271.7
Diversified	867.2	764.3	736.1
	3,315.6	3,157.9	3,007.8
EXPENSES:			
Electric utility:			
Fuel	458.1	409.7	431.3
Purchased power	490.6	531.6	436.5
Energy conservation cost	67.0	62.6	84.0
Operation and maintenance	422.3	413.4	393.7
Extended nuclear outage –			
O&M and replacement power costs	173.3	–	–
Depreciation	325.9	324.2	293.7
Taxes other than income taxes	193.6	183.6	176.2
	2,130.8	1,925.1	1,815.4
Diversified:			
Cost of sales	753.9	642.9	624.6
Provision for loss on coal properties	–	40.9	–
Loss related to life insurance subsidiary	97.6	–	–
Other	60.7	66.6	58.9
	912.2	750.4	683.5
INCOME FROM OPERATIONS	272.6	482.4	508.9
INTEREST EXPENSE AND OTHER:			
Interest expense	158.7	135.9	139.4
Allowance for funds used during construction	(9.7)	(7.5)	(7.3)
Preferred dividend requirements of Florida Power	1.5	5.8	9.7
(Gain) on sale of business	–	(44.2)	–
Other expense (income), net	1.4	(4.2)	(9.9)
	151.9	85.8	131.9
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	120.7	396.6	377.0
Income taxes	66.4	145.9	138.1
INCOME FROM CONTINUING OPERATIONS	54.3	250.7	238.9
DISCONTINUED OPERATIONS, NET OF INCOME TAXES	–	(26.3)	–
NET INCOME	$ 54.3	$ 224.4	$ 238.9
AVERAGE SHARES OF COMMON STOCK OUTSTANDING	97.1	96.8	95.7
EARNINGS PER AVERAGE COMMON SHARE:			
Continuing operations	$ .56	$ 2.59	$ 2.50
Discontinued operations	–	(.27)	–
	$ .56	$ 2.32	$ 2.50

ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THESE FINANCIAL STATEMENTS.

Consolidated Balance Sheets

DECEMBER 31, 1997 AND 1996 (DOLLARS IN MILLIONS)

	1997	1996
ASSETS		
PROPERTY, PLANT AND EQUIPMENT:		
Electric utility plant in service and held for future use	**$6,166.8**	$5,965.6
Less: Accumulated depreciation	**2,511.0**	2,335.8
Accumulated decommissioning for nuclear plant	**223.7**	193.3
Accumulated dismantlement for fossil plants	**128.5**	119.6
	3,303.6	3,316.9
Construction work in progress	**279.4**	140.3
Nuclear fuel, net of amortization of $356.7 in 1997 and 1996	**66.5**	59.9
Net electric utility plant	**3,649.5**	3,517.1
Other property, net of depreciation of $219.3 in 1997 and $173.8 in 1996	**437.7**	309.3
	4,087.2	3,826.4
CURRENT ASSETS:		
Cash and equivalents	**3.1**	5.2
Accounts receivable, net	**373.7**	265.0
Inventories, primarily at average cost:		
Fuel	**77.6**	67.1
Utility materials and supplies	**91.9**	95.4
Diversified materials	**126.8**	125.5
Underrecovery of fuel costs	**34.5**	82.6
Income taxes receivable	**16.8**	–
Other	**50.9**	48.2
	775.3	689.0
OTHER ASSETS:		
Investments:		
Loans receivable, net	**24.0**	68.1
Marketable securities	**–**	217.9
Nuclear plant decommissioning fund	**266.7**	207.8
Joint ventures and partnerships	**54.6**	41.9
Deferred insurance policy acquisition costs	**–**	120.9
Deferred purchased power contract termination costs	**348.2**	–
Other	**204.0**	176.4
	897.5	833.0
	$5,760.0	$5,348.4

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THESE FINANCIAL STATEMENTS.

	(DOLLARS IN MILLIONS)	
	1997	1996
CAPITAL AND LIABILITIES		
COMMON STOCK EQUITY:		
Common stock without par value, 250,000,000 shares authorized, 97,062,954 shares outstanding in 1997 and 97,007,182 in 1996	**$1,209.0**	$1,208.3
Retained earnings	**567.0**	716.5
Unrealized loss on securities available for sale	**–**	(.6)
	1,776.0	1,924.2
CUMULATIVE PREFERRED STOCK OF FLORIDA POWER:		
Without sinking funds	**33.5**	33.5
LONG-TERM DEBT	**2,377.8**	1,776.9
TOTAL CAPITAL	**4,187.3**	3,734.6
CURRENT LIABILITIES:		
Accounts payable	**253.2**	193.2
Customers' deposits	**97.1**	81.8
Taxes payable	**12.0**	41.2
Accrued interest	**56.8**	48.3
Other	**74.8**	78.5
	493.9	443.0
Notes payable	**214.8**	4.1
Current portion of long-term debt	**15.2**	34.9
	723.9	482.0
DEFERRED CREDITS AND OTHER LIABILITIES:		
Deferred income taxes	**471.2**	475.4
Unamortized investment tax credits	**85.7**	93.5
Insurance policy benefit reserves	**–**	325.3
Other postretirement benefit costs	**107.4**	100.0
Other	**184.5**	137.6
	848.8	1,131.8
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
	$5,760.0	$5,348.4

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THESE FINANCIAL STATEMENTS.

Consolidated Statements of Cash Flows

FOR THE YEARS ENDED DECEMBER 31, 1997, 1996 AND 1995 (DOLLARS IN MILLIONS)

	1997	1996	1995
OPERATING ACTIVITIES:			
Income from continuing operations	$ 54.3	$250.7	$238.9
Adjustments for noncash items:			
Depreciation and amortization	364.2	366.7	352.7
Extended nuclear outage – replacement power cost	73.3	–	–
Provision for loss on investment in life insurance subsidiary	86.9	–	–
Gain on sale of business	–	(44.2)	–
Provision for loss on coal properties	–	40.9	–
Deferred income taxes and investment tax credits, net	(30.7)	(56.6)	(38.0)
Increase in accrued post-employment benefit costs	8.6	15.5	16.8
Net change in deferred insurance policy acquisition costs	(1.7)	(14.5)	(14.5)
Net change in insurance policy benefit reserves	52.7	60.3	42.5
Changes in working capital, net of effects from acquisition or sale of businesses:			
Accounts receivable	(108.3)	35.4	(35.2)
Inventories	2.2	(10.9)	(29.1)
Overrecovery (underrecovery) of fuel cost	(33.1)	(82.3)	1.5
Accounts payable	58.3	21.6	16.4
Taxes payable	(47.1)	21.0	(7.6)
Other	1.2	(13.5)	29.0
Other operating activities	(38.2)	(19.2)	7.3
Cash provided by continuing operations	442.6	570.9	580.7
Cash used by discontinued operations	–	(8.9)	(17.6)
	442.6	562.0	563.1
INVESTING ACTIVITIES:			
Property additions (including allowance for borrowed funds used during construction)	(513.6)	(264.0)	(331.4)
Purchase of loans and securities, net	(11.0)	(70.4)	(28.9)
Acquisition of businesses	(32.7)	(53.8)	(9.2)
Cogeneration facility acquisition and contract termination costs	(445.0)	–	–
Proceeds from sales of properties and businesses	24.3	61.1	13.1
Investing activities of discontinued operations	–	56.5	69.8
Other investing activities	(52.7)	(37.0)	(15.0)
	(1,030.7)	(307.6)	(301.6)
FINANCING ACTIVITIES:			
Issuance of long-term debt	482.8	178.0	–
Repayment of long-term debt	(34.9)	(190.4)	(45.8)
Increase (decrease) in commercial paper with long-term support	130.6	(15.3)	1.0
Redemption of preferred stock	–	(106.4)	(5.0)
Sale of common stock	–	18.5	38.4
Equity contributions to discontinued operations	–	(23.7)	–
Dividends paid on common stock	(203.8)	(199.5)	(193.4)
Increase (decrease) in short-term debt	210.8	4.1	(55.3)
Financing activities of discontinued operations	–	85.2	(9.7)
Other financing activities	.5	(4.0)	(1.2)
	586.0	(253.5)	(271.0)
NET INCREASE (DECREASE) IN CASH AND EQUIVALENTS	(2.1)	.9	(9.5)
Beginning cash and equivalents	5.2	4.3	13.8
ENDING CASH AND EQUIVALENTS	$ 3.1	$ 5.2	$ 4.3
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for:			
Interest (net of amount capitalized)	$142.7	$128.7	$135.5
Income taxes (net of refunds)	$141.7	$189.3	$214.7

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THESE FINANCIAL STATEMENTS.

Consolidated Statements of Shareholders' Equity

HE YEARS ENDED DECEMBER 31, 1997, 1996 AND 1995 (DOLLARS IN MILLIONS, EXCEPT PER SHARE AMOUNTS)

	COMMON STOCK	RETAINED EARNINGS	UNREALIZED GAIN (LOSS) ON MARKETABLE SECURITIES	CUMULATIVE PREFERRED STOCK OF FLORIDA POWER	
				WITHOUT SINKING FUNDS	WITH SINKING FUNDS
Balance, December 31, 1994	$1,148.1	$842.9	$ (6.6)	$113.5	$30.0
Net income		238.9			
Common stock issued – 1,245,267 shares	39.5				
Cash dividends on common stock ($2.02 per share)		(193.4)			
Unrealized gain on marketable securities			8.7		
Preferred stock redeemed – 50,000 shares					(5.0)
Balance December 31, 1995	1,187.6	888.4	2.1	113.5	25.0
Net income		224.4			
Common stock issued – 586,555 shares	20.7				
Echelon International stock dividend		(194.5)			
Cash dividends on common stock ($2.06 per share)		(199.5)			
Unrealized loss on marketable securities			(2.7)		
Preferred stock redeemed – 1,050,000 shares		(2.3)		(80.0)	(25.0)
nce, December 31, 1996	1,208.3	716.5	(.6)	33.5	–
Net income		54.3			
Common stock issued – 55,772 shares	.7				
Cash dividends on common stock ($2.10 per share)		(203.8)			
Reversal of unrealized loss on marketable securities due to deconsolidation			.6		
Balance, December 31, 1997	$1,209.0	$567.0	$ –	$ 33.5	$ –

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THESE FINANCIAL STATEMENTS.

NOTE 1

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General — Florida Progress Corporation (the Company) is an exempt holding company under the Public Utility Holding Company Act of 1935. Its largest subsidiary, representing 85% of total assets, is Florida Power Corporation (Florida Power), a public utility engaged in the generation, purchase, transmission, distribution and sale of electric energy primarily within Florida.

The consolidated financial statements include the financial results of the Company and its majority-owned operations. All significant intercompany balances and transactions have been eliminated. Investments in 20%- to 50%-owned joint ventures are accounted for using the equity method.

Effective December 31, 1997, the Company deconsolidated the financial statements of Mid-Continent. Florida Progress' investment in Mid-Continent will prospectively be accounted for under the cost method. The deconsolidation has not been reflected in the financial statements of prior periods.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions. This could affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. These estimates involve judgments with respect to various items including various future economic factors which are difficult to predict and are beyond the control of the Company. Therefore actual results could differ from these estimates.

Regulation — Florida Power is regulated by the Florida Public Service Commission (FPSC) and the Federal Energy Regulatory Commission (FERC). The utility follows the accounting practices set forth in Financial Accounting Standard (FAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." This standard allows utilities to capitalize or defer certain costs or revenues based on regulatory approval and management's ongoing assessment that it is probable these items will be recovered through the ratemaking process.

Florida Power has total regulatory assets (liabilities) at December 31, 1997 and 1996 as detailed below:

	1997	1996
	(IN MILLIONS)	
Deferred purchased power contract termination costs	$348.2	$ -
Replacement fuel (extended nuclear outage)	55.0	-
Underrecovery of fuel costs	34.5	82.6
Revenue decoupling	21.8	(3.6)
Unamortized loss on reacquired debt	16.8	18.4
Other regulatory assets, net	25.2	24.6
Net regulatory assets	$501.5	$122.0

The utility expects to fully recover these assets and refund the liabilities through customer rates under current regulatory practice.

If Florida Power no longer applied FAS No. 71 due to competition, regulatory changes or other reasons, the utility would make certain adjustments. These adjustments could include the write-off of all or a portion of its regulatory assets and liabilities, the evaluation of utility plant, contracts and commitments and the recognition, if necessary, of any losses to reflect market conditions.

Utility Plant — Utility plant is stated at the original cost of construction, which includes payroll and related costs such as taxes, pensions and other fringe benefits, general and administrative costs, and an allowance for funds used during construction. Substantially all of the utility plant is pledged as collateral for Florida Power's first mortgage bonds.

The allowance for funds used during construction represents the estimated cost of equity and debt for utility plant under construction. Florida Power is permitted to earn a return on these costs and recover them in the rates charged for utility services while the plant is in service. The average rate used in computing the allowance for funds was 7.8%.

Utility Revenues, Fuel and Purchased Power Expenses — Revenues include amounts resulting from fuel, purchased power and energy conservation adjustment clauses, which are designed to permit full recovery of these costs. The adjustment factors are based on projected costs for a 6 or 12-month period. The cumulative difference between actual and billed costs is included on the balance sheet as a current regulatory asset or liability. Any difference is billed or refunded to customers during the subsequent period.

In December 1997, Florida Power ended the three-year test period for residential revenue decoupling which was ordered by the FPSC and began in January 1995. Decoupling eliminates the direct link between kilowatt-hour sales and revenues. A nonfuel revenue target is determined by multiplying a revenue per customer amount by the total number of residential customers. Differences between target revenues and actual revenues are included as a regulatory asset or liability on the balance sheet. The regulatory asset at December 31, 1997 will be collected from customers beginning April 1998 through the energy conservation cost recovery clause as directed by the FPSC decoupling order.

Florida Power accrues the nonfuel portion of base revenues for services rendered but unbilled.

The cost of nuclear fuel is amortized to expense based on the quantity of heat produced for the generation of electric energy in relation to the quantity of heat expected to be produced over the life of the nuclear fuel core.

Income Taxes — Deferred income taxes are provided on all significant temporary differences between the financial and tax basis of assets and liabilities using presently enacted tax rates in accordance with FAS No. 109, "Accounting for Income Taxes."

Deferred investment tax credits, subject to regulatory accounting practices, are amortized to income over the lives of the related properties.

Depreciation and Maintenance — The Company provides for depreciation of the cost of properties over their estimated useful lives primarily on a straight-line basis. Florida Power's annual provision for depreciation, including a provision for nuclear plant decommissioning costs and fossil plant dismantlement costs, expressed as a percentage of the average balances of depreciable utility plant, was 4.8% for 1997, 4.9% for 1996 and 5% for 1995.

The Financial Accounting Standards Board (FASB) is in the process of modifying its project addressing the accounting for obligations related to the decommissioning of nuclear power plants.

The fossil plant dismantlement accrual has been suspended for a period of four years, beginning July 1, 1997. (See Note 9 on page 40.)

Florida Power charges maintenance expense with the cost of repairs and minor renewals of property. The plant accounts are charged with the cost of renewals and replacements of property units. Accumulated depreciation is charged with the cost, less the net salvage, of property units retired.

Florida Power accrues a reserve for maintenance and refueling expenses anticipated to be incurred during scheduled nuclear plant outages.

Insurance Premiums, Policy Acquisition Costs and Benefit Reserves — Accounting policies governing the recognition of income and expense for the life insurance subsidiary were in effect until December 31, 1997.

Due to the deconsolidation of the financial results of Mid-Continent in the Florida Progress' consolidated financial statements, accounting policies relating to the balance sheet were in effect only for amounts presented in the 1996 Florida Progress Consolidated Balance Sheet.

Life insurance premiums are recognized as revenues over the premium-paying periods of the policies.

The Company defers recoverable costs in its insurance operations that directly relate to the production of new business. These costs are amortized over the expected premium-paying period. Benefit reserves are established out of each premium payment to provide for the present value of future insurance policy benefits. The Company reviews the adequacy and recoverability of the deferred acquisition costs and the benefit reserves based on a gross premium reserve analysis of the in-force business.

Significant assumptions used in this analysis include estimates of future premium increases, mortality rates, withdrawal rates, expense rates, and investment yield. The assumptions are based on the Company's actual experience adjusted for the effect of future actions affecting the in-force business. Although these assumptions are the Company's best estimate of the future experience, actual results may vary in either direction and could significantly impact income in the period of change.

Accounting for Certain Investments — The Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. The Company's investments in debt and equity securities are classified and accounted for as follows:

Type of Security	Accounting Treatment
Debt securities held to maturity	Amortized cost
Trading securities	Fair market value with unrealized gains and losses included in earnings
Securities available for sale	Fair market value with unrealized gains and losses, net of taxes, reported separately in shareholders' equity

See Note 2 on page 35 for securities held to maturity or available for sale. The Company had no investments in assets classified as trading securities at December 31, 1996 and only held securities classified as available for sale at December 31, 1997. A decline in the market value of any security available-for-sale or held-to-maturity that falls below cost results in a reduction in carrying amount to fair value if the decline is not considered temporary. The impairment is charged to earnings and a new cost basis for the security is established. Premiums and discounts are amortized or accreted over the life of the related held-to-maturity security as an adjustment to yield using the effective interest method. Dividend and interest income are recognized when earned.

Accounting for Long-Lived Assets — Long-lived assets and certain identifiable intangibles subject to the provisions of FAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. FAS No. 121 also amends FAS No. 71, "Accounting for the Effects of Certain Types of Regulation," to require that regulatory assets, which include certain deferred charges, be charged to earnings if such assets are no longer considered probable of recovery. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceed the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

Stock-Based Compensation — Under its Long-Term Incentive Plan (LTIP), the Company grants selected executives performance shares, which upon achievement of performance criteria for a three-year performance cycle can result in the award of shares of common stock of Florida Progress or cash if certain stock ownership requirements are met. The Company accounts for its LTIP in accordance with the provisions of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," as allowed under FAS No. 123, "Accounting for Stock-Based Compensation."

Environmental — The Company adopted the American Institute of Certified Public Accountants Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" on January 1, 1997. The SOP requires, among other things, environmental remediation liabilities to be accrued when the criteria of FAS No. 5, "Accounting for Contingencies," have been met. The SOP also provides guidance with respect to the measurement of remediation liabilities. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably stimated. Such accounting is consistent with the Company's current method of accounting for environmental remediation costs and, therefore, adoption of this new statement did not have a material impact on the Company's financial position, results of operations or liquidity.

New Accounting Standards — In June 1996, the FASB issued FAS No. 125, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." FAS No. 125 provides accounting and reporting standards effective for transfers and servicing of financial assets and extinguishments of liabilities occurring after December 31, 1996 and is to be applied prospectively. There was no material effect on net income as a result of adopting this standard.

In February 1997, the FASB issued FAS No. 128, "Earnings per Share," (EPS). It replaces the standards for computing EPS under APB Opinion No. 15, "Earnings per Share," and makes the computations comparable to international EPS standards. The Company adopted this statement for financial statements issued for the period ended December 31, 1997. Adoption of this statement did not have an impact on earnings per share, therefore no restatement was necessary for prior periods.

Also in February 1997, the FASB issued FAS No. 129, "Disclosure of Information about Capital Structure," which designates certain disclosure requirements for public and nonpublic entities. The Company adopted this statement for financial statements issued for the period ended December 31, 1997. As the Company already disclosed the information required by FAS No. 129, adoption of this statement did not have any effect on the financial disclosures of the Company.

In June 1997, the FASB issued FAS No. 130, "Reporting Comprehensive Income" which establishes standards for reporting comprehensive income. The standard defines comprehensive income as all changes in equity of an enterprise during a period except those resulting from shareholder transactions. All components of comprehensive income are required to be reported in a financial statement that is displayed with equal prominence as existing financial statements. The Company will be required to adopt this statement January 1, 1998. As the standard addresses reporting and presentation issues only, there will be no impact on earnings from the adoption of this standard.

Also in June 1997, the FASB issued FAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" which establishes standards for additional disclosure about operating segments for interim and annual financial statements. The standard requires financial and descriptive information be disclosed for segments meeting certain materiality criteria whose operating results are reviewed for decisions on resource allocation and for which discrete financial information is available. It also establishes standards for related disclosures about products and services, geographic areas, and major customers. The Company will be required to adopt this statement for financial statements for the fiscal year ending December 31, 1998 and for interim periods thereafter. As the standard addresses reporting and disclosure issues only, there will be no impact on earnings from the adoption of this standard.

In January 1998, the FASB issued FAS No. 132, "Employers' Disclosures about Pensions and Other Post-retirement Benefits" which revises current note disclosure requirements for employers' pensions and other retiree benefits. The Company will be required to adopt this statement for financial statements for the year ending December 31, 1998. The standard addresses reporting and disclosure issues only, and there will be no impact on earnings from the adoption of this standard.

NOTE 2

FINANCIAL INSTRUMENTS

Estimated fair value amounts have been determined by the Company using available market information and discounted cash-flow analysis. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates may be different than the amounts that the Company could realize in a current market exchange.

The Company's exposure to market risk for changes in interest rates relates primarily to the Company's marketable securities and long-term debt obligations.

At December 31, 1997, Florida Power held a single forward treasury lock agreement to effectively fix the treasury rate component of an anticipated issuance of $150 million of medium-term notes in February 1998. The financial impact of this contract, which will result in either a cash payment or receipt, will be deferred and recognized as an adjustment to interest expense over the life of the new notes. The Company had no derivative financial instruments outstanding at December 31, 1996.

At December 31, 1997 and 1996, the Company had the following financial instruments with estimated fair values and carrying amounts:

	1997		1996	
(IN MILLIONS)	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
ASSETS:				
Loans receivable:				
Echelon International	$ -	$ -	$ 32.9	$ 32.9
Life insurance business:				
Loans secured by real estate	-	-	4.1	4.4
Policy loans	-	-	11.0	10.1
	$ -	$ -	$ 48.0	$ 47.4
Marketable securities:				
Available for sale:				
Life insurance business	$ -	$ -	$ 144.6	$ 144.6
Nuclear decommissioning fund	266.7	266.7	207.8	207.8
Held to maturity	-	-	73.3	76.8
CAPITAL AND LIABILITIES:				
Long-term debt:				
Florida Power Corporation	$1,746.9	$1,801.1	$1,317.7	$1,335.3
Progress Capital Holdings	646.1	656.5	494.1	497.1

The December 31, 1997 balances reflect the deconsolidation of Mid-Continent Life's financial statements from the Company's consolidated financial statements. (See Note 11 on page 42).

NOTE 3

INCOME TAXES

(IN MILLIONS)	1997	1996	1995
Components of income tax expense:			
Payable currently:			
Federal	$86.6	$179.7	$157.3
State	10.5	23.0	18.8
	97.1	202.7	176.1
Deferred, net:			
Federal	(22.4)	(41.9)	(27.5)
State	(.5)	(6.9)	(2.0)
	(22.9)	(48.8)	(29.5)
Amortization of investment tax credits, net	(7.8)	(8.0)	(8.5)
	$66.4	$145.9	$138.1

The primary differences between the statutory rates and the effective income tax rates are detailed below:

	1997	1996	1995
Federal statutory income tax rate	35.0%	35.0%	35.0%
State income tax, net of federal income tax benefits	5.4	2.6	2.8
Amortization of investment tax credits	(6.4)	(2.0)	(2.2)
Provision for loss on investment in life insurance subsidiary	24.9	-	-
Other	(4.5)	.6	.1
Effective income tax rates	54.4%	36.2%	35.7%

The following summarizes the components of deferred tax liabilities and assets at December 31, 1997 and 1996:

(IN MILLIONS)	1997	1996
Deferred tax liabilities:		
Difference in tax basis of property, plant and equipment	$539.0	$544.1
Deferred acquisition costs	-	35.9
Investment in partnerships	19.7	20.1
Deferred book expenses	34.1	12.7
Other	29.7	22.9
Total deferred tax liabilities	$622.5	$635.7
Deferred tax assets:		
Loss reserves not currently deductible	$ 17.0	$ 69.5
Accrued book expenses	110.8	90.6
Unbilled revenues	17.6	17.6
Other	11.7	18.2
Total deferred tax assets	$157.1	$195.9

At December 31, 1997 and 1996, Florida Progress had net noncurrent deferred tax liabilities of $471.2 million and $475.4 million and net current deferred tax assets of $5.8 million and $35.6 million, respectively. The Company expects the results of future operations will generate sufficient taxable income to allow for the utilization of deferred tax assets.

NOTE 4

NUCLEAR OPERATIONS

Florida Power's Crystal River nuclear plant began an extended outage in September 1996, which caused Florida Power to incur $100 million in additional operation and maintenance expenses in 1997. The plant was placed on the Nuclear Regulatory Commission's (NRC) "Watch List" in January 1997, as a plant whose operations will be closely monitored until Florida Power demonstrates a period of improved performance. In January 1998, the NRC granted Florida Power permission to restart the plant. (See Note 9 on page 40.)

Jointly Owned Plant — The following information relates to Florida Power's 90.4% proportionate share of the nuclear plant at December 31, 1997 and 1996:

(IN MILLIONS)	1997	1996
Utility plant in service	$673.8	$643.6
Construction work in progress	49.3	14.8
Unamortized nuclear fuel	66.5	59.9
Accumulated depreciation	341.0	309.5
Accumulated decommissioning	223.7	193.3

Net capital additions/(retirements) for Florida Power were $64.7 million in 1997 and $(16.5) million in 1996. Depreciation expense, exclusive of nuclear decommissioning, was $29 million in 1997 and $28.3 million in 1996. Each co-owner provides for its own financing. Florida Power's share of the asset balances and operating costs is included in the appropriate consolidated financial statements. Amounts exclude any allocation of costs related to common facilities.

Decommissioning Costs — Florida Power's nuclear plant depreciation expenses include a provision for future decommissioning costs, which are recoverable through rates charged to customers. Florida Power is placing amounts collected in an externally managed trust fund. The recovery from customers, plus income earned on the trust fund, is intended to be sufficient to cover Florida Power's share of the future dismantlement, removal and land restoration costs. Florida Power has a license to operate the nuclear unit through December 3, 2016, and contemplates decommissioning beginning at that time.

In November 1995, the FPSC approved a new site-specific study that estimated total future decommissioning costs at approximately $2 billion, which corresponds to $453.8 million in 1997 dollars. Florida Power's share of the retail portion of annual decommissioning expense is $20.5 million. Florida Power's annual expense for the wholesale portion is $1.2 million.

Fuel Disposal Costs — Florida Power has entered into a contract with the U.S. Department of Energy (DOE) for the transportation and disposal of spent nuclear fuel. Disposal costs for nuclear fuel consumed are being collected from customers through the fuel adjustment clause at a rate of $.001 per net nuclear kilowatt-hour sold and are paid to the DOE quarterly. Florida Power currently is storing spent nuclear fuel on-site and has sufficient storage capacity in place for fuel consumed through the year 2010.

NOTE 5

PREFERRED AND PREFERENCE STOCK AND SHAREHOLDER RIGHTS

The authorized capital stock of the Company includes 10 million shares of preferred stock, without par value, including 2 million shares designated as Series A Junior Participating Preferred Stock. No shares of the Company's preferred stock are issued and outstanding. However, under the Company's Shareholder Rights Agreement, each share of common stock has associated with it approximately two-thirds of one right to purchase one one-hundredth of a share of Series A Junior Participating Preferred Stock, subject to adjustment, which is exercisable in the event of certain attempted business combinations. If exercised, the rights would cause substantial dilution of ownership, thus adversely affecting any attempt to acquire the Company on terms not approved by the Company's Board of Directors. The rights have no voting or dividend rights and expire in December 2001, unless redeemed earlier by the Company.

The authorized capital stock of Florida Power includes three classes of preferred stock: 4 million shares of Cumulative Preferred Stock, $100 par value; 5 million shares of Cumulative Preferred Stock, without par value; and 1 million shares of Preference Stock, $100 par value. No shares of Florida Power's Cumulative Preferred Stock, without par value, or Preference Stock are issued and outstanding. A total of 334,967 shares, of the 335,000 authorized, of Cumulative Preferred Stock, $100 par value, were issued and outstanding at December 31, 1997 and 1996.

Florida Power redeemed 1,050,000 shares of its Cumulative Preferred Stock in 1996 and 50,000 shares in 1995.

Cumulative Preferred Stock for Florida Power is detailed below:

Dividend Rate	Current Redemption Price	Shares Outstanding	Outstanding at December 31, 1997 & 1996
			(IN MILLIONS)
4.00%	$104.25	39,980	$ 4.0
4.40%	$102.00	75,000	7.5
4.58%	$101.00	99,990	10.0
4.60%	$103.25	39,997	4.0
4.75%	$102.00	80,000	8.0
		334,967	$33.5

All Cumulative Preferred Stock series are without sinking funds and are not subject to mandatory redemption.

NOTE 6

DEBT

The Company's long-term debt at December 31, 1997 and 1996, is scheduled to mature as follows:

	Interest Rate	1997	1996
		(IN MILLIONS)	
FLORIDA POWER CORPORATION			
First mortgage bonds:			
Maturing in 1999	6.50%	$ 75.0	$ 75.0
Maturing 2002 and 2003	6.50%(a)	280.0	280.0
Maturing 2008	6.88%	80.0	80.0
Maturing 2021 through 2023	7.98%(a)	400.0	400.0
Pollution control revenue bonds:			
Maturing 2014 through 2027	6.59%(a)	240.9	240.9
Notes maturing			
1997-1998	6.67%	1.5	22.8
1999-2008	6.60%(a)	474.5	24.5
Commercial paper, supported by revolver maturing November 30, 2002	5.85%(a)	200.0	200.0
Discount, net of premium, being amortized over term of bonds		(5.0)	(5.5)
		1,746.9	1,317.7
PROGRESS CAPITAL HOLDINGS:			
Notes maturing:			
1997-1998	9.90%	10.0	20.0
1999-2008	6.90%(a)	329.0	294.0
Commercial paper, supported by revolver maturing November 30, 2002	5.92%(a)	300.0	169.4
Other debt, maturing through 2006	6.78%(a)	7.1	10.7
		2,393.0	1,811.8
Less: Current portion of long-term debt		15.2	34.9
		$2,377.8	$1,776.9

(a) WEIGHTED AVERAGE INTEREST RATE AT DECEMBER 31, 1997.

The Company's consolidated subsidiaries have lines of credit totaling $900 million, which are used to support commercial paper. The lines of credit were not drawn on as of December 31, 1997. Interest rate options under the line of credit arrangements vary from subprime or money market rates to the prime rate. Banks providing lines of credit are compensated through fees. Commitment fees on lines of credit vary between .06 and .10 of 1%.

The lines of credit consist of four revolving bank credit facilities, two each for Florida Power and Progress Capital Holdings, Inc. The Florida Power facilities consist of $300 million with a 364-day term and $200 million with a five-year term. The Progress Capital facilities consist of $100 million with a 364-day term and $300 million with a five-year term. In 1997, both 364-day facilities were extended to November 1998. In addition, both five-year facilities were extended to November 2002. Based on the duration of the underlying backup credit facilities, $500 million of outstanding commercial paper at December 31, 1997, and $369.4 million of outstanding commercial paper at December 31, 1996, are classified as long-term debt. Additionally, as of December 31, 1997 Florida Power and Progress Capital Holdings had $179.8 million and $35.0 million, respectively of outstanding commercial paper classified as short-term debt.

Florida Power has a public medium-term note program providing for the issuance of either fixed or floating interest rate notes. These notes have maturities ranging from nine months to 30 years. A balance of $400 million is available for issuance.

Florida Power has registered $370 million of first mortgage bonds which are unissued and available for issuance.

Progress Capital has a private medium-term note program providing for the issuance of either fixed or floating interest rate notes, with maturities ranging from nine months to 30 years. A balance of $87 million is available for issuance under this program.

The combined aggregate maturities of long-term debt for 1998 through 2002 are $15.2 million, $143.6 million, $77.6 million, $183.0 million and $632.2 million, respectively. In addition, about 12% of Florida Power's outstanding first mortgage bonds have an annual 1% sinking fund requirement. These requirements, which total $1 million annually for 1998 through 2002, are expected to be satisfied with property additions.

Florida Progress has unconditionally guaranteed the payment of Progress Capital's debt as defined in an amended and restated support agreement.

NOTE 7

RETIREMENT BENEFIT PLANS

Pension Benefits — The Company and certain of its subsidiaries have a noncontributory defined benefit pension plan covering most employees. The benefits are based on length of service, compensation and Social Security benefits. The participating companies make annual contributions to the plan based on an actuarial determination and consideration of tax regulations and funding requirements under federal law. Based on actuarial calculations and the funded status of the pension plan, the Company was not required to contribute to the plan for 1997, 1996 or 1995.

Shown below are the components of the net pension expense calculations for those years:

(IN MILLIONS)	1997	1996	1995
Service cost	$ 15.3	$ 16.2	$ 13.4
Interest cost	33.4	31.3	30.1
Actual earnings on plan assets	(131.6)	(88.0)	(124.4)
Net amortization and deferral	64.0	29.5	77.7
Net pension benefit recognized	$ (18.9)	$(11.0)	$ (3.2)

The following weighted average actuarial assumptions at January 1 were used in the calculation of pension expense:

	1997	1996	1995
Discount rate	7.50%	7.25%	8.25%
pected long-term rate of return	9.00%	9.00%	9.00%
ate of compensation increase	4.50%	4.50%	5.00%

The following summarizes the funded status of the pension plan at December 31, 1997 and 1996:

(IN MILLIONS)	1997	1996
Accumulated benefit obligation:		
Vested	$359.3	$326.1
Nonvested	40.8	31.5
	400.1	357.6
Effect of projected compensation increases	100.1	94.4
Projected benefit obligation	500.2	452.0
Plan assets at market value, primarily listed stocks and bonds	769.0	655.0
Plan assets in excess of projected benefit obligation	$268.8	$203.0
Consisting of the following components:		
Unrecognized transition asset	$ 25.5	$ 30.4
Unrecognized prior service cost	(14.7)	(6.3)
Unrecognized net actuarial gains	236.7	176.4
Prepaid pension costs	21.3	2.5
	$268.8	$203.0

Due to changes in interest rates, the Company used a discount rate of 7.25% to calculate the pension plan's 1997 year-end funded status. The change in the discount rate from 7.5% at December 31, 1996, to 7.25% at December 31, 1997, increased the projected benefit obligation by $17.4 million and is expected to increase the annual pension costs by $1.8 million, beginning in 1998.

In 1997 the Board of Directors approved a restructuring of the Plan effective January 1, 1998. The existing plan will be split into two separate plans, one covering eligible bargaining unit employees and the other covering all other eligible employees. Plan assets will be allocated to each plan in accordance with applicable law. The restructuring is expected to have a minimal effect on funded status and periodic pension costs.

Other Post-retirement Benefits — The Company and some of its subsidiaries provide certain health care and life insurance benefits for retired employees. Employees become eligible for these benefits when they reach retirement age while working for the Company.

The net post-retirement benefit costs for 1997, 1996 and 1995 are detailed below:

(IN MILLIONS)	1997	1996	1995
Service cost	$ 3.2	$ 5.3	$ 5.1
Interest cost	10.4	12.4	13.5
Amortization of unrecognized transition obligation	3.4	6.1	6.1
Actual earnings on plan assets	(.4)	(.3)	(.3)
	$16.6	$23.5	$24.4

The following summarizes the plan's status, reconciled with amounts recognized in the Company's balance sheet at December 31, 1997 and 1996:

(IN MILLIONS)	1997	1996
Accumulated post-retirement benefit obligation:		
Retirees	$ 92.7	$100.4
Fully eligible active plan participants	1.2	3.1
Other active plan participants	59.3	81.2
Plan assets at fair value, primarily municipal securities	(6.4)	(4.7)
	146.8	180.0
Unrecognized transition obligation	(55.0)	(97.2)
Unrecognized net gains	15.6	17.2
Accrued post-retirement benefit cost	$107.4	$100.0

The following weighted average actuarial assumptions were used in the calculation of the year-end status of other post-retirement benefits:

	1997	1996
Discount rate	7.25%	7.50%
Rate of compensation increase	4.50%	4.50%
Health care cost trend rates:		
Pre-Medicare	9.00%-5.00%	9.50%-5.25%
Post-Medicare	7.25%-4.75%	7.50%-5.00%

The transition obligation is being accrued through 2012. A one-percentage point increase in the assumed health care cost trend rate for each future year would have increased the 1997 current service and interest cost by approximately $.8 million and the accumulated post-retirement benefit obligation as of December 31, 1997, by about $9.6 million. The change in the discount rate from 7.5% at December 31, 1996, to 7.25% at December 31, 1997, increased the projected benefit obligation by $4.4 million and is expected to increase annual post-retirement benefit costs by $.3 million, beginning in 1998.

Due to different retail and wholesale regulatory rate requirements, Florida Power began making quarterly contributions in 1995 to an irrevocable external trust fund for wholesale ratemaking, while continuing to accrue postretirement benefit costs to an unfunded reserve for retail ratemaking. Florida Power contributed approximately $1.3 million in both 1997 and 1996, to the trust fund.

NOTE 8

BUSINESS SEGMENTS

The Company's principal business segments are utility and diversified operations. The utility is engaged in the generation, purchase, transmission, distribution and sale of electric energy. Electric Fuels Corporation's (Electric Fuels) operations include energy and related services, inland marine transportation and rail services. Other diversified operations include ownership of a life insurance subsidiary.

The Company's business segment information for 1997, 1996 and 1995 is summarized below. No single customer accounted for 10% or more of unaffiliated revenues.

(IN MILLIONS)	1997	1996	1995
Revenues:			
Utility	$2,448.4	$2,393.6	$2,271.7
Diversified:			
Electric Fuels, combined:			
Coal sales to electric utility	285.1	272.1	236.8
Sales to external customers	751.4	609.0	607.0
Other	115.8	155.3	129.1
	3,600.7	3,430.0	3,244.6
Eliminations	(285.1)	(272.1)	(236.8)
Revenues from external customers	$3,315.6	$3,157.9	$3,007.8
Income from operations:			
Utility	$ 317.6	$ 468.5	$ 456.3
Diversified:			
Electric Fuels recurring, combined	71.5	61.4	52.1
Electric Fuels loss provision	-	(40.9)	-
Loss related to life insurance subsidiary	(97.6)	-	-
Other diversified	(18.9)	(6.6)	.5
	272.6	482.4	508.9
Interest and other expense	151.9	85.8	131.9
Income from continuing operations before income taxes	$ 120.7	$ 396.6	$ 377.0
Identifiable assets:			
Utility	$4,887.0	$4,263.7	$4,284.7
Diversified:			
Electric Fuels, combined	799.1	619.8	573.6
Other diversified	73.9	464.9	692.1
	$5,760.0	$5,348.4	$ 5,550.4
Depreciation and amortization:			
Utility	$ 333.8	$ 341.1	$ 329.7
Diversified:			
Electric Fuels, combined	27.4	23.5	21.2
Other diversified	3.0	2.1	1.8
	$ 364.2	$ 366.7	$ 352.7
Capital additions:			
Utility	$ 395.0	$ 222.9	$ 289.2
Diversified:			
Electric Fuels, combined	117.5	40.6	40.5
Other diversified	1.1	.5	1.7
	$ 513.6	$ 264.0	$ 331.4

In December 1997, Florida Progress recorded a provision for loss on its investment in Mid-Continent Life and accrued for related legal costs, totaling $97.6 million. (See Note 11 on page 42.)

In December 1996, Electric Fuels revised its assessment that low-sulfur coal market prices were depressed temporarily. Electric Fuels decided to close and dispose of its unprofitable coal operations and recorded a provision for loss of $40.9 million, as shown above.

NOTE 9

RATES

Florida Power's retail rates are set by the FPSC. Florida Power's last general rate case was approved in 1992 and allowed a 12% regulatory return on equity with an allowed range between 11% and 13%.

Extended Nuclear Outage — In June 1997, a settlement agreement between Florida Power and all parties who intervened in Florida Power's request to collect replacement fuel and purchased power costs resulting from the extended outage of its nuclear plant was approved by the FPSC. The plant has been off-line since September 1996 to address certain design issues related to its safety systems.

Florida Power incurred $174 million in total system replacement power costs through the end of 1997. In accordance with the settlement agreement, Florida Power recorded a charge of approximately $73 million for retail replacement power costs incurred that will not be recovered through its fuel adjustment clause. Of the remaining $101 million, Florida Power will recover approximately $38 million through its fuel adjustment clause. The remaining $63 million of replacement power costs was recorded as a regulatory asset and is being amortized for a period of up to four years. The amortization of the regulatory asset is being recovered by the suspension of fossil plant dismantlement accruals during the amortization period. Actual replacement power costs incurred ›r to the nuclear unit's return to service in excess of the /4 million, will be expensed as incurred.

The parties to the settlement agreement have agreed not to seek or support any increase or reduction in Florida Power's base rates or the authorized range of its return on equity during the four-year amortization period. The settlement agreement also provided that for purposes of monitoring Florida Power's future earnings, the FPSC will exclude the nuclear outage costs when assessing Florida Power's regulatory return on equity. The agreement resolves all present and future disputed issues between the parties regarding the extended outage of the nuclear plant.

Tiger Bay Buy-out — In 1997, Florida Power bought out the Tiger Bay purchased power contracts for $370 million and acquired the cogeneration facility for $75 million, for a total of $445 million. Of the $370 million of contract termination costs, $350 million was recorded as a regulatory asset and the remaining $20 million was written off. Florida Power recorded $75 million as electric plant.

The regulatory asset is being recovered pursuant to a stipulation agreement between Florida Power and several intervening parties which was approved by the FPSC in June 1997. The amortization of the regulatory asset is calculated using revenues collected under the fuel adjustment clause as if the purchase power agreements related to the facility were in effect, less the actual fuel costs and the related debt interest expense. This will continue until the regulatory asset is fully amortized. Florida Power has the option to accelerate the amortization.

NOTE 10

DISCONTINUED OPERATIONS

On November 21, 1996, the Company's Board of Directors declared a spin-off distribution to common shareholders of record on December 5, 1996, of the common shares of Echelon International Corporation (Echelon), which comprised the Company's lending, leasing and real estate operations. Common shares were distributed on the basis of one share of Echelon common stock for every 15 shares of the Company's common stock.

In connection with the spin-off in 1996, the Company has presented Echelon as a discontinued operation in the accompanying Consolidated Statements of Income. As of the date of the spin-off, the net assets of Echelon were $194.5 million. This amount has been charged against the Company's retained earnings in the accompanying December 31, 1996 Consolidated Balance Sheet to reflect the distribution of Echelon common shares on December 18, 1996. A summary of net assets distributed is as follows:

(IN MILLIONS)	
Cash and equivalents	$ 53.8
Assets held for sale	26.8
Leases and loans receivable, net	272.0
Property and equipment, net	126.0
Other assets	39.9
Total assets	518.5
Total liabilities	(324.0)
Net assets distributed	$ 194.5

Summarized income statement information relating to Echelon's results of operations (as reported in discontinued operations) is as follows:

	Year ended December 31,	
(IN MILLIONS)	1996	1995
Sales and revenues	$63.2	$50.0
Loss from operations (net of income tax)	-	-
Provision for loss on disposition of assets (net of income tax benefits of $11.3)	(18.0)	-
Spin-off transaction costs (net of income tax benefits of $1.8)	(8.3)	-
Total discontinued operations	$(26.3)	$ -

Fiscal year 1996 includes results of operations through December 18, 1996. Results of operations include allocated interest expense of $8.7 million and $11.7 million for 1996 and 1995 respectively.

NOTE 11
OMMITMENTS AND CONTINGENCIES

Fuel, Coal and Purchased Power Commitments — Florida Power has entered into various long-term contracts to provide the fossil and nuclear fuel requirements of its generating plants and to reserve pipeline capacity for natural gas. In most cases, such contracts contain provisions for price escalation, minimum purchase levels and other financial commitments. Estimated annual payments, based on current market prices, for Florida Power's firm commitments for fuel purchases and transportation costs, excluding delivered coal and purchased power, are $40 million, $46 million, $47 million, $47 million and $48 million for 1998 through 2002, respectively, and $464 million in total thereafter. Additional commitments will be required in the future to supply Florida Power's fuel needs.

Electric Fuels has entered into several contracts with outside parties for the purchase of coal. Electric Fuels also has entered into several operating leases, and rental or royalty agreements, relating to transportation equipment and coal procurement and processing. The annual obligations under these contracts and leases, including transportation costs, are $163.1 million, $82.0 million, $50.2 million, $45.7 million and $32.2 million for 1998 through 2002, respectively, and $64.1 million in total thereafter. The total cost incurred for these commitments is $219.6 million in 1997, $221.4 million in 1996 and $235.2 million in 1995.

Florida Power has long-term contracts for about 460 megawatts of purchased power with other utilities, including a contract with The Southern Company for approximately 400 megawatts of purchased power annually through 2010. This represents 4.5% of Florida Power's total current installed system capacity. Florida Power has an option to lower these Southern purchases to approximately 200 megawatts annually with a three-year notice. The purchased power from Southern is supplied by generating units with a capacity of approximately 3,500 megawatts and is guaranteed by Southern's entire system, totaling more than 30,000 megawatts.

As of December 31, 1997, Florida Power had entered into purchased power contracts with certain qualifying facilities for 946 megawatts of capacity with expiration dates ranging from 2002 to 2025. The purchased power contracts provide for capacity and energy payments. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the qualifying facilities meeting certain contract performance obligations. In most cases, these contracts account for 100% of the generating capacity of each of the facilities. Of the 946 megawatts under contract, approximately 830 megawatts currently are available to Florida Power. All commitments have been approved by the FPSC. Florida Power does not plan to increase the level of purchased power currently under contract.

The FPSC allows the capacity payments to be recovered through a capacity cost recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel adjustment clause.

Through the buy-out of the Tiger Bay purchased power contracts for $370 million, Florida Power reduced its long-term purchased power commitments by 20 percent. Florida Power recorded $350 million of the contract termination costs as a regulatory asset and wrote off $20 million of the contract termination costs in 1997. (See Note 9 on page 40.)

Florida Power incurred purchased power capacity costs totaling $292.3 million in 1997, $284 million in 1996 and $260.1 million in 1995. The following table shows minimum expected future capacity payments for purchased power commitments. Because the purchased power commitments have relatively long durations, the total present value of these payments using a 10% discount rate also is presented. These amounts assume that all units are brought into service as contracted and meet contract performance requirements:

	Purchased Power Capacity Payments		
(IN MILLIONS)	Utilities	Cogenerators	Total
1998	$ 59	$ 206	$ 265
1999	60	215	275
2000	60	223	283
2001	33	230	263
2002	32	236	268
2003-2025	248	5,802	6,050
Total	$492	$6,912	$ 7,404
Total net present value			$ 2,573

The purchased power contracts with qualifying facilities employ separate pricing methodologies for capacity payments and energy payments. Florida Power has interpreted the pricing provision in these contracts to allow it to pay an as-available energy price rather than a higher firm energy price when the avoided unit upon which the applicable contract is based would not have been operated.

Four qualifying facilities filed suit against Florida Power over the contract payment terms. Florida Power entered into settlement agreements with three of the four qualifying facilities. Two of those agreements have been approved by the FPSC and the litigation has been dismissed. In September

1997, the FPSC reversed its original decision and voted to deny Florida Power's request to approve the third settlement agreement. As a result of the FPSC denial, the settlement expired by its own terms in October 1997. In December 1997, the state court action with the third cogenerator was set for trial in late 1998. Florida Power's dispute with the fourth cogenerator has been set for trial in federal court for late 1998, but no trial date has been set for a parallel contract dispute in state court. Management does not expect that the results of these legal actions will have a material impact on Florida Power's financial position, operations or liquidity.

Mid-Continent Life Insurance Company (Mid-Continent) — A series of events in 1997 have significantly jeopardized Mid-Continent's ability to implement a plan to eliminate a projected reserve deficiency resulting in the impairment of Florida Progress' investment in Mid-Continent, its wholly owned life insurance subsidiary.

On April 14, 1997, the Insurance Commissioner of the State of Oklahoma (the Insurance Commissioner) received legal approval to temporarily seize control of the operations of Mid-Continent, and in May 1997, the Oklahoma County District Court granted the Insurance Commissioner's application to place Mid-Continent into receivership. The Insurance Commissioner had alleged that Mid-Continent's reserves were understated by more than $125 million, thus causing Mid-Continent to be statutorily impaired. The Insurance Commissioner further alleged that Mid-Continent had violated Oklahoma law relating to deceptive trade practices in connection with the sale of its "Extra Life" insurance policies and was not entitled to raise premiums, a key element to Mid-Continent's plan to address the projected reserve deficiency. While sustaining the receivership, the court also ruled that premiums could be raised. Both sides have appealed the decision to the Oklahoma Supreme Court. In December 1997, the Insurance Commisioner filed a lawsuit against Florida Progress and certain directors and officers making a number of allegations and seeking access to Florida Progress' assets to satisfy policyholder and creditor claims. Florida Progress believes that the Commissioner's lawsuit is without merit and intends to vigorously defend itself and the other defendants against these charges. The ultimate outcome of the matter cannot presently be determined. Accordingly, the Company has made no provision for any loss.

Another element of Mid-Continent's plan to eliminate the projected reserve deficiency was to offer a new life insurance product. However, as a result of the Commissioner's actions, which resulted in Mid-Continent being placed in receivership, agents were reluctant to sell the new policy. This also prompted insurance commissioners in several states to enter cease and desist orders prohibiting Mid-Continent from writing new policies.

As a result of the Oklahoma Commissioner's efforts to block Mid-Continent from raising insurance premiums, his failure to offer any formal plan to eliminate the projected reserve deficiency, the legal proceedings, and the cease and desist orders, Florida Progress now believes the full amount of its $86.9 million investment in Mid-Continent at December 31, 1997 is impaired. Therefore, the Company recorded a provision for loss on investment of $86.9 million in 1997. In addition, tax benefits of approximately $11 million related to the excess of the tax basis over the book value in the investment in Mid-Continent as of December 31, 1997, were not recorded because of uncertainties associated with the timing of a tax deduction. Florida Progress also recorded an accrual at December 31, 1997 for legal fees associated with defending its position in current Mid-Continent legal proceedings.

Mid-Continent's financial statements have been deconsolidated effective December 31, 1997. The investment will prospectively be accounted for under the cost method.

Advanced Separation Technologies (Advanced Separation) - Florida Progress sold its 80% interest in Advanced Separation Technologies to Calgon Carbon Corp. (Calgon) in December 1996 for $56 million in cash. Calgon filed a lawsuit in January 1998 alleging misstatement of Advanced Separation's 1996 revenues, assets and liabilities, seeking damages and granting Calgon the right to rescind the sale. The lawsuit also accuses Florida Progress of failing to disclose flaws in Advanced Separation's manufacturing process and a lack of quality control. No projection of an outcome or estimate of a potential liability, if any, can be determined at the date of issuance of these financial statements. Florida Progress intends to vigorously defend itself against this lawsuit.

Construction Program - Substantial commitments have been made in connection with the Company's construction program. In 1998, Florida Power has projected construction expenditures of $294 million, primarily for electric plant and nuclear fuel. Electric Fuels has projected capital additions of $125 million in 1998, primarily for barges and towboats.

Off-Balance Sheet Risk — Several of the Company's subsidiaries are general partners in unconsolidated partnerships and joint ventures. The Company or subsidiaries have agreed to support certain loan agreements of the partnerships and joint ventures. These credit risks are

not material to the financial statements and the Company ...siders these credit risks to be minimal, based upon the ...t values supporting the partnership liabilities.

Insurance — Florida Progress and its subsidiaries utilize various risk management techniques to protect assets from risk of loss, including the purchase of insurance. Risk avoidance, risk transfer and self-insurance techniques are utilized depending on the Company's ability to assume risk, the relative cost and availability of methods for transferring risk to third parties, and the requirements of applicable regulatory bodies.

Florida Power self-insures its transmission and distribution lines against loss due to storm damage and other natural disasters. Pursuant to a regulatory order, Florida Power is accruing $6 million annually to a storm damage reserve and may defer any losses in excess of the reserve.

Under the provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, Florida Power, as an owner of a nuclear plant, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. If total third-party claims relating to a single nuclear incident exceed $200 million (the amount of currently available commercial liability insurance), Florida Power could be assessed up to $79.3 million per incident, with a maximum ...ssessment of $10 million per year.

...lorida Power is a member of the Nuclear Electric ...surance, Ltd. (NEIL), an industry mutual insurer, which provides business interruption and extra expense coverage in the event of a major accidental outage at a covered nuclear power plant. Florida Power is subject to a retroactive premium assessment by NEIL under this policy in the event loss experience exceeds NEIL's available surplus. Florida Power's present maximum share of any such retroactive assessment is $2.7 million per policy year.

Florida Power also maintains nuclear property damage insurance and decontamination and decommissioning liability insurance totaling $2.1 billion. The first layer of $500 million is purchased in the commercial insurance market with the remaining excess coverage purchased from NEIL. Florida Power is self-insured for any losses that are in excess of this coverage. Under the terms of the NEIL policy, Florida Power could be assessed up to a maximum of $9.5 million in any policy year if losses in excess of NEIL's available surplus are incurred.

Florida Power has never been assessed under these nuclear indemnities or insurance policies.

Contaminated Site Cleanup — The Company is subject to regulation with respect to the environmental impact of its operations. The Company's disposal of hazardous waste through third-party vendors can result in costs to clean up facilities found to be contaminated. Federal and state statutes authorize governmental agencies to compel responsible parties to pay for cleanup of these hazardous waste sites.

Florida Power and former subsidiaries of the Company, whose properties were sold in prior years, have been identified by the U.S. Environmental Protection Agency (EPA) as potentially responsible parties (PRPs) at certain sites, including a coal gasification plant site in Sanford, Florida (Sanford site) that Florida Power previously owned and operated. There are five parties, including Florida Power, that have been identified as PRPs at the Sanford site. Liability for the cleanup costs of these sites is joint and several.

Negotiations are underway with the EPA to define the extent of contamination that may be attributable to the Company's previous operation at the site. The discussions and resolution of liability for cleanup costs could cause Florida Power to increase its estimate of its liability for cleanup costs. Although estimates of any additional costs are not currently available, the outcome is not expected to have a material effect on the Company's financial position, results of operations or liquidity.

In addition to these designated sites, there are other sites where affiliates may be responsible for additional environmental cleanup.

The Company believes that its subsidiaries will not be required to pay a disproportionate share of the costs for cleanup of any of these sites. The Company's best estimates indicate that its proportionate share of liability for cleaning up all sites ranges from $2.5 million to $7.5 million. It has reserved $4.7 million against these potential costs.

Age Discrimination Suit — Florida Power and Florida Progress have been served with an age discrimination lawsuit involving 116 former Florida Power employees and one current employee. While no dollar amount was requested in the lawsuit, each plaintiff seeks back pay, reinstatement or front pay through their projected dates of normal retirement, costs and attorneys' fees. In October 1996, the court approved an agreement between parties to provisionally certify this case as a class action suit under the Age Discrimination in Employment Act. Estimates of the potential liability associated with this lawsuit, if any, remain pending until the final decision on whether to certify the case as a class action suit has been made. A decision regarding the class action status is expected in 1998.

QUARTERLY FINANCIAL DATA (UNAUDITED)

(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)	THREE MONTHS ENDED MARCH 31	JUNE 30	SEPT. 30	DEC. 31
1997				
OPERATING RESULTS				
Revenues	$747.5	$797.3	$922.5	$848.3
Income (loss) from operations	95.0	(34.6)	199.0	13.2
Net income (loss)	42.0	(38.2)	102.0	(51.5)
DATA PER SHARE				
Earnings (loss) per common share	0.43	(0.39)	1.05	(0.53)
Dividends per common share	.525	.525	.525	.525
Common stock price per share:				
High	32 7/8	31 5/8	33 5/16	39 1/4
Low	29 3/4	27 3/4	31 1/4	31 5/8
1996				
OPERATING RESULTS				
Revenues	$730.4	$773.6	$879.0	$774.9
Income from operations	107.2	125.0	189.3	60.9
Net income from continuing operations	48.3	58.7	98.1	45.6
Loss from discontinued operations	–	(25.0)	–	(1.3)
Net income	48.3	33.7	98.1	44.3
DATA PER SHARE				
Earnings:				
Continuing operations	.50	.61	1.01	.47
Discontinued operations	–	(.26)	–	(.01)
Consolidated	.50	.35	1.01	.46
Dividends per common share	.515	.515	.515	.515
Common stock price per share:				
High	36 3/8	34 3/4	35 1/8	34 1/2
Low	33	32 1/2	33 1/2	31 5/8

The business of Florida Power is seasonal in nature and comparisons of earnings for the quarters do not give a true indication of overall trends and changes in the Company's operations. Effective December 31, 1997, the Company deconsolidated the financial statements of Mid-Continent Life Insurance Company and established a provision for loss for the full amount of its investment. The deconsolidation has not been reflected in the consolidated financial statements of prior periods. In 1996, the divestiture of Echelon International Corporation is reflected in the loss from discontinued operations.

Management's Report

...o Our Shareholders:

Management is responsible for the integrity and objectivity of the financial and operating information contained in the consolidated financial statements and other sections of this Annual Report. These statements were prepared in accordance with generally accepted accounting principles and necessarily include amounts that are based on judgments and estimates by management.

Florida Progress Corporation maintains internal control systems and related policies and procedures designed to provide reasonable assurance that assets are safe-guarded, that transactions are executed as authorized and are properly recorded, and that accounting records may be relied upon for the preparation of consolidated financial statements and other financial information. These policies and procedures include a Code of Conduct program intended to ensure employees adhere to the highest standards of personal and professional integrity. The design, monitoring and revision of internal control systems involve, among other things, ...agement's judgment with respect to the relative cost and ...pected benefits of specific control measures. The company also maintains an internal auditing function that evaluates and formally reports on the adequacy and effectiveness of internal controls, policies and procedures.

In addition, the audit committee of the board of directors, consisting solely of outside directors, meets periodically with management, the internal auditors and the independent auditors to review matters related to internal controls, audit results, financial statements and financial reporting. Annually, the audit committee recommends to the board of directors the selection of independent auditors. Both the independent auditors and the internal auditors periodically meet alone with the audit committee and have free access to the committee at any time.

For Management,

Jeffrey R. Heinicka

...rey R. Heinicka
...ior Vice President and Chief Financial Officer

Independent Auditors' Report

To the Shareholders of Florida Progress Corporation:

We have audited the accompanying consolidated balance sheets of Florida Progress Corporation and subsidiaries as of December 31, 1997 and 1996, and the related consolidated statements of income, cash flows, and shareholders' equity for each of the years in the three-year period ended December 31, 1997. These financial statements are the responsibility of Florida Progress Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Florida Progress Corporation and subsidiaries as of December 31, 1997 and 1996, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1997, in conformity with generally accepted accounting principles.

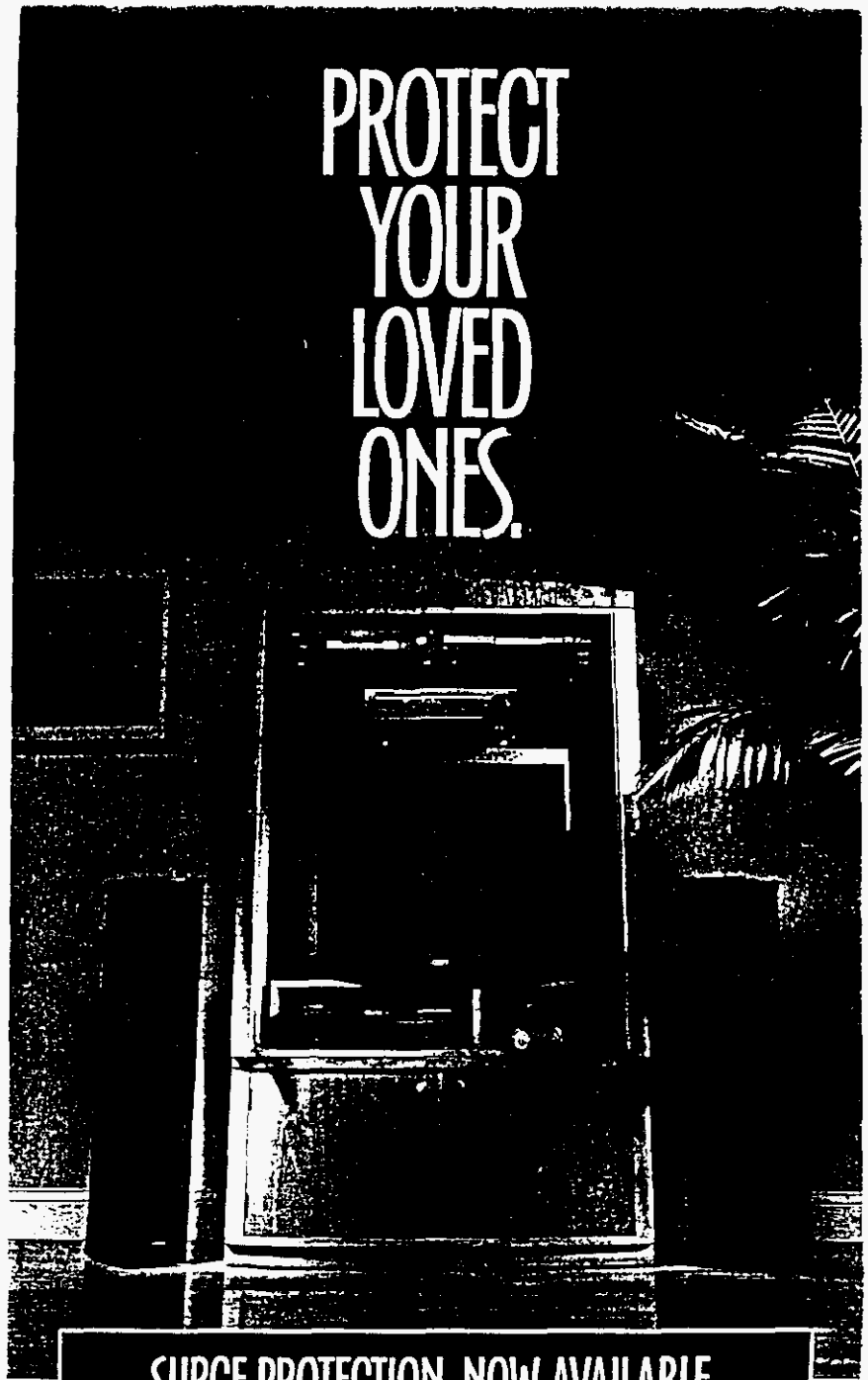
KPMG Peat Marwick LLP

St. Petersburg, Florida
January 26, 1998

SELECTED DATA 1992 - 1997

	Annual Growth Rates (in percent) 1992-1997	1997	1996
FLORIDA PROGRESS CORPORATION			
Summary of operations (in millions):			
Utility revenues	6.7	$2,448.4	$2,393.6
Diversified revenues (continuing)	25.3	867.2	764.3
Income from continuing operations before nonrecurring items	6.7	254.3	252.4
Income from continuing operations	(21.6)	54.3	250.7
Income (loss) from discontinued operations and change in accounting		-	(26.3)
Net income	(20.9)	54.3	224.4
Balance sheet data (in millions):			
Total assets	3.0	$5,760.0	$5,348.4
Capitalization:			
Short-term capital	5.3	$ 230.0	$ 39.0
Long-term debt	7.6	2,377.8	1,776.9
Preferred stock	(31.1)	33.5	33.5
Common stock equity	.4	1,776.0	1,924.2
Total capitalization	3.2	$4,417.3	$3,773.6
Common stock data:			
Average shares outstanding (in millions)	2.6	97.1	96.8
Earnings per share:			
Utility before nonrecurring item	4.5	$2.48	$2.40
Diversified continuing before nonrecurring items	(2.6)	.14	.21
Consolidated continuing before nonrecurring items	4.0	2.62	2.61
Consolidated continuing	(23.6)	.56	2.59
Discontinued operations and change in accounting		-	(.27)
Consolidated	(22.9)	0.56	2.32
Dividends per common share	2.0	2.10	2.06
Dividend payout		375.3%	88.9%
Dividend yield		5.4%	6.4%
Book value per share of common stock	(1.6)	$18.30	$19.84
Return on common equity		2.9%	10.9%
Common stock price per share:			
High		39 1/4	36 3/8
Low		27 3/4	31 5/8
Close	3.8	39 1/4	32 1/4
Price earnings ratio (year-end)		70.1	13.9
FLORIDA POWER CORPORATION			
Electric sales billed (millions of KWH):			
Residential	3.3	15,079.8	15,481.4
Commercial	4.2	9,257.3	8,848.0
Industrial	5.2	4,187.8	4,223.7
Total retail sales	4.0	30,850.3	30,784.8
Total electric sales	4.0	33,289.9	33,492.5
Residential service (average annual):			
KWH sales per customer	1.2	12,993	13,560
Revenue per customer	4.8	$1,115	$1,138
Ratio of earnings to fixed charges (SEC method)		2.75	4.80
Embedded cost of long-term debt	(1.4)	7.0%	7.2%
Embedded cost of preferred stock	(8.8)	4.6%	4.6%
Operating data:			
Net system capability (MW)	2.0	7,717	7,341
Net system peak load (MW)	2.9	8,066	8,807
Construction expenditures (in millions)	(3.9)	$387.2	$217.3
Net cash flow to capital expenditures	7.9	76%	175%
Average number of customers	2.1	1,314,508	1,292,075
Number of full-time employees	(3.7)	4,799	4,629

	1995	1994	1993	1992
	$2,271.7	$2,080.5	$1,957.6	$1,774.1
	736.1	644.8	430.3	281.1
	238.9	212.0	196.0	183.8
	238.9	212.0	196.0	183.8
	-	-	.6	(8.1)
	238.9	212.0	196.6	175.7
	$5,550.4	$5,453.1	$5,338.0	$4,978.8
	$ 173.7	$ 99.9	$ 195.2	$ 177.6
	1,662.3	1,835.2	1,840.5	1,651.3
	138.5	143.5	148.5	216.0
	2,078.1	1,984.4	1,820.5	1,737.6
	$4,052.6	$4,063.0	$4,004.7	$3,782.5
	95.7	93.0	88.3	85.4
	$2.27	$2.05	$2.06	$1.99
	.23	.23	.16	.16
	2.50	2.28	2.22	2.15
	2.50	2.28	2.22	2.15
	-	-	.01	(.09)
	[illegible]0	2.28	2.23	2.06
	[illegible]2	1.99	1.95	1.905
	81.0%	87.7%	87.6%	93.0%
	5.7%	6.7%	5.9%	5.9%
	$21.55	$20.85	$20.40	$19.85
	11.8%	11.1%	11.1%	10.6%
	35 3/4	33 5/8	36 3/8	33 1/4
	29 3/8	24 3/4	31 1/4	27 7/8
	35 3/8	30	33 5/8	32 5/8
	14.2	13.2	15.1	15.8
	14,938.0	13,863.4	13,372.6	12,825.8
	8,612.1	8,252.1	7,884.8	7,544.1
	3,864.4	3,579.6	3,380.8	3,254.5
	9,499.5	27,675.2	26,528.3	25,414.0
	2,402.6	30,014.6	28,647.8	27,375.5
	13,282	12,597	12,420	12,214
	$1,114	$1,038	$983	$884
	4.41	3.90	3.83	3.84
	7.2%	7.1%	6.8%	7.5%
	6.8%	6.8%	6.8%	7.3%
	7,[illegible]47	7,295	7,563	6,998
	[illegible]	6,955	6,729	6,982
	$[illegible]3.4	$319.5	$426.4	$472.9
	125%	103%	63%	52%
	271,784	1,243,891	1,214,653	1,182,170
	4,658	4,972	5,807	5,806



SURGE PROTECTION. NOW AVAILABLE.

Your stereo. Your PC. Your VCR. Why not show them how much you love them by giving them the best surge protection package available. Our plan includes plug-in suppressors for your electronics and meter-based protection. And our trained electricians will [illegible] the installation is handled quickly [illegible] from surge protection. Because [illegible]

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Florida Power

CALL TOLL-FREE 1-888-999-8856 FOR MORE INFORMATION.

ONLY AVAILABLE TO FLORIDA POWER CORPORATION CUSTOMERS.

INVESTOR INFORMATION

Stock Plan

The Company offers the Progress Plus Stock Plan as an economical, convenient and flexible way to purchase shares of Florida Progress common stock. Plan participants can purchase stock directly from the Company and reinvest all or a portion of their quarterly dividends without paying typical brokerage fees. Those eligible for the plan are:

- Registered shareholders of Florida Progress.
- Nonshareholders who are Florida residents.
- Employees of the Company and its subsidiaries.

The plan is offered only by means of a prospectus, which can be obtained by contacting the Company's transfer agent and registrar.

Correspondence and inquiries concerning the plan, dividend checks, address changes, financial publications and the transfer of common stock certificates of Florida Progress or preferred stock certificates of Florida Power should be directed to the Company's transfer agent and registrar:

BankBoston, N.A.
c/o Boston EquiServe
Mail Stop 45-02-64
P. O. Box 8040
Boston, MA 02266-8040
(800) 352-1121

PROGRESS PLUS
STOCK PLAN

Common Stock Dividends

Record dates are normally on or about the fifth day of March, June, September and December. Quarterly dividend checks are mailed to reach shareholders on or about the 20th day of March, June, September and December.

Common Stock Listed

New York Stock Exchange
Pacific Stock Exchange
Ticker symbol: FPC
Newspaper listing: FlaPrg

1997 SEC Form 10-K

Copies of the Company's 1997 SEC Form 10-K, without exhibits, will be supplied to shareholders without charge by directing requests to:

Investor Services
Florida Progress Corporation
P. O. Box 14042 (A3C)
St. Petersburg, FL 33733
(800) 937-2640

Auditors

KPMG Peat Marwick LLP
St. Petersburg, FL

Analysts' Contact

Greg Beuris
Investor Relations
(813) 866-4442
Fax (813) 866-4986

Corporate Offices

Florida Progress Corporation
Barnett Tower
One Progress Plaza
St. Petersburg, FL 33701

INTERNET Address: www.fpc.com

The Florida Progress home page on the Internet's World Wide Web has information about the holding company and its subsidiaries; the company stock price, which is updated every 15 minutes; SEC filings, including the 1997 Annual Report; news releases and market performance.

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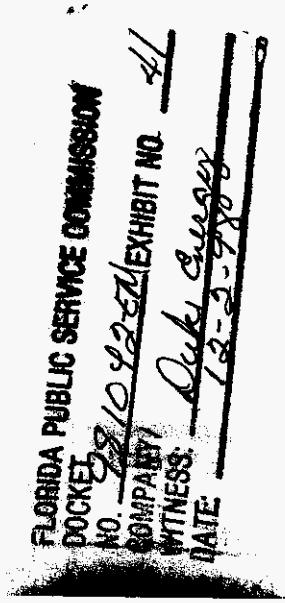

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 1997

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone	I.R.S. Employer Identification Number
1-8349	**FLORIDA PROGRESS CORPORATION** A Florida Corporation One Progress Plaza St. Petersburg, Florida 33701 Telephone (813) 824-6400	59-2147112
1-3274	**FLORIDA POWER CORPORATION** A Florida Corporation 3201 34th Street South St. Petersburg, Florida 33711 Telephone (813) 866-5151	59-0247770

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Florida Progress Corporation: Common Stock without par value and Preferred Stock Purchase Rights	New York Stock Exchange Pacific Stock Exchange
Florida Power Corporation: None	

Securities registered pursuant to Section 12(g) of the Act:

Florida Progress Corporation: None

Florida Power Corporation: Cumulative Preferred Stock, par value $100 per share

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. YES X . NO .

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

EXHIBIT
6
Doran 11-16-98

The aggregate market value of the voting stock held by non-affiliates of Florida Progress Corporation as of December 31, 1997 was $3,743,134,026 (determined by subtracting the number of shares held by directors and executive officers of Florida Progress Corporation from the total number of shares outstanding, then multiplying the difference times the closing sale price from the New York Stock Exchange Composite Transactions).

The aggregate market value of the voting stock held by non-affiliates of Florida Power Corporation as of February 28, 1998 was $-0-. As of February 28, 1998, there were issued and outstanding 100 shares of Florida Power Corporation's common stock, without par value, all of which were held, beneficially and of record, by Florida Progress Corporation.

The number of shares of Florida Progress Corporation common stock without par value outstanding as of December 31, 1997 was 97,062,954.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for Florida Progress Corporation dated March 12, 1998, relating to the 1998 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K represents separate filings by Florida Progress Corporation and Florida Power Corporation. Florida Power Corporation makes no representations as to the information relating to Florida Progress Corporation's diversified operations.

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GLOSSARY

When used herein, the following terms will have the meanings indicated:

TERM	MEANING
1935 Act	Public Utility Holding Company Act of 1935
APB	Accounting Principles Board
AST	Advanced Separation Technologies, Incorporated
Btu	British thermal units
CAAA	Clean Air Act Amendments of 1990
Calgon	Calgon Carbon Corporation
CERCLA or Superfund	Comprehensive Environmental Response Compensation and Liability Act
Commissioner	Insurance Commissioner of the State of Oklahoma
CR3	Florida Power's nuclear generating plant, Crystal River Unit No. 3
Dade	Metropolitan Dade County
DOE	United States Department of Energy
Echelon	Echelon International Corporation
Electric Fuels	Electric Fuels Corporation
EMF	electromagnetic fields, or electric and magnetic fields
EPA	United States Environmental Protection Agency
EPA of 1992	Energy Policy Act of 1992
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
Financial Statements	Florida Progress' Consolidated Financial Statements and Florida Power's Financial Statements, for the year ended December 31, 1997 contained under Item 8 herein
Florida Power	Florida Power Corporation
Florida Progress	Florida Progress Corporation
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
Georgia Power	Georgia Power Company
KV	kilovolts
KVA	kilovolt amperes
KWH	kilowatt hours
Lake	NCP Lake Power, Inc.
LTIP	Florida Progress Long-Term Incentive Plan
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MEMCO	MEMCO Barge Line, Inc.
MICP	Management Incentive Compensation Plan
Mid-Continent	Mid-Continent Life Insurance Company
Montenay	Montenay Power Corporation
MW	megawatts
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Council
NRC	United States Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act
OCL	Orlando Cogen Limited, Ltd.
PAA	Proposed Agency Action
PCBs	polychlorinated biphenyls
Progress Capital	Progress Capital Holdings, Inc.
Progress Credit	Progress Credit Corporation
Progress Packaging	Progress Packaging Corporation
Progress Rail	Progress Rail Services Corporation
Proxy Statement	The definitive proxy statement dated March 12, 1998, relating to Florida Progress' 1998 Annual Meeting of Shareholders
PRP	potentially responsible party, as defined in CERCLA

PURPA	Public Utility Regulatory Policies Act of 1978
QFs	qualifying facilities
RI/FS	Remedial Investigation and Feasibility Study
Sanford site	gasification plant site, Sanford, Florida
SBUs	Strategic Business Units
SEC	United States Securities and Exchange Commission
Seminole	Seminole Electric Cooperative, Inc.
SERP	Florida Progress Corporation Supplemental Executive Retirement Plan
SOP	Statement of Position issued by American Institute of Certified Public Accountants
SNF	spent nuclear fuel
the nuclear plant	Florida Power's nuclear generating plant, Crystal River Unit No. 3
the utility	Florida Power Corporation

PART I

ITEM 1. BUSINESS

FLORIDA PROGRESS

Florida Progress Corporation ("Florida Progress," which term includes consolidated subsidiaries unless otherwise indicated), is a diversified electric utility holding company. Florida Progress' revenues for the year ended December 31, 1997 were $3.3 billion and assets at year end were $5.8 billion. Its principal executive offices are located at One Progress Plaza, St. Petersburg, Florida 33701, telephone number (813) 824-6400. The Florida Progress home page on the Internet's World Wide Web is located at http://www.fpc.com. Florida Progress was incorporated in Florida on January 21, 1982.

Florida Progress defines its principal business segments as utility and diversified operations. Florida Power Corporation ("Florida Power" or "the utility"), Florida Progress' largest subsidiary, is the utility segment and encompasses all regulated public utility operations. See Item 1 "Business Utility Operations - Florida Power". Progress Capital Holdings, Inc. ("Progress Capital") is the downstream holding company for Florida Progress' diversified subsidiaries which consolidates the financing of non-utility operations. The diversified operations segment includes Electric Fuels Corporation ("Electric Fuels"), an energy and transportation company. For information concerning the operating profit and assets attributable to the business segments, see Note 8 to Florida Progress' consolidated financial statements and Florida Power's financial statements for the year ended December 31, 1997 contained herein under Item 8 (the "Financial Statements").

In December 1996, Florida Progress spun off Echelon International Corporation ("Echelon"). Echelon, successor to Progress Credit Corporation ("Progress Credit"), was the Florida Progress subsidiary with lending, leasing and real estate operations. The spin-off was accomplished through a tax-free stock dividend to Florida Progress' shareholders, thus completing a strategy begun in 1991 to exit those businesses.

Florida Progress is a public utility holding company under the Public Utility Holding Company Act of 1935 ("1935 Act"). Florida Progress is exempt from registration with the United States Securities and Exchange Commission ("SEC") under the 1935 Act and attendant regulation because its utility operations are primarily intrastate.

UTILITY OPERATIONS - FLORIDA POWER

Florida Power was incorporated in Florida in 1899, and is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity. Florida Power has a system generating capacity of 7,717 megawatts ("MW"). In 1997, the utility accounted for 74% of Florida Progress' consolidated revenues and 85% of its assets. Florida Power contributed $134.4 million to Florida Progress' earnings after the reduction for nuclear outage costs.

Florida Power provided electric service during 1997 to an average of 1.3 million customers in west central Florida from its headquarters in St. Petersburg. The service area covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. Of Florida Power's 1997 electric revenues billed, approximately 55% were derived from residential sales, 24% from commercial sales, 9% from industrial sales, 6% from other retail sales and 6% from wholesale sales. Important industries in the territory include phosphate and rock mining and processing, electronics design and manufacturing, and citrus and other food processing. Other important commercial activities are tourism, health care, construction and agriculture.

COMPETITION

Florida Power continued to prepare for increased competition in the electric utility industry. In 1996, the utility began the transition to a strategic business unit organization, and in 1997 continued to redefine Florida Power along functional lines. By dividing the organization into three Strategic Business Units ("SBUs"), the electric generation, transmission and distribution, and marketing operations are given the opportunity to more closely focus their attention on the needs of their respective future customers while still meeting today's needs. In 1997, the evolution to the SBU structure was complemented by the start of a corporate-wide management effort called Reinvention. Reinvention focuses on redefining work procedures and improving processes to be more cost effective, while pursuing new opportunities to increase profits.

For additional information with respect to Florida Power and competition, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") - Operating Results - Florida Power Corporation - "Utility Competition - Industry Restructuring".

FUEL AND PURCHASED POWER

GENERAL: Florida Power's consumption of various types of fuel depends on several factors, the most important of which are the demand for electricity by Florida Power's customers, the availability of various generating units, the availability and cost of fuel, and the requirements of federal and state regulatory agencies. Florida Power's energy mix for the last three years is presented in the following table:

ENERGY MIX PERCENTAGES*

Fuel Type	1997	1996	1995
Coal	45%	43%	39%
Oil	18%	16%	12%
Nuclear	0%	6%	19%
Gas	6%	3%	4%
Purchased Power	31%	32%	26%

* See "NUCLEAR" below for information regarding an extended outage at Florida Power's nuclear generating plant beginning in September 1996 and continuing until February 1998.

Florida Power is permitted to pass the cost of recoverable fuel and purchased power to its customers through fuel adjustment clauses. In June 1997, Florida Power reached an agreement with the Florida Public Service Commission ("FPSC") regarding costs related to the extended nuclear outage. (See Notes 1 and 9 to the Financial Statements).

The future prices for and availability of various fuels discussed in this report cannot be predicted with complete certainty. However, Florida Power believes that its fuel supply contracts, as described below, will be adequate to meet its fuel supply needs.

Florida Power's average fuel costs per million British thermal units ("Btu") for each year of the five-year period ended December 31, 1997 were as follows:

	AVERAGE FUEL COST (per million Btu)				
	1997	1996	1995	1994	1993
Coal	$1.91	$1.91	$1.93	$1.96	$1.96
Oil	2.75	2.80	2.70	2.39	2.49
Nuclear	--	.50	.49	.55	.54
Gas	2.87	2.78	1.98	2.46	4.27
Weighted Average	2.24	2.04	1.69	1.75	1.79

OIL AND GAS: Oil is purchased under contracts and in the spot market from several suppliers. The cost of Florida Power's oil is determined by world market conditions. Management believes that Florida Power has access to an adequate supply of oil for the reasonably foreseeable future. Florida Power's natural gas supply is purchased under firm contracts and in the spot market from numerous suppliers and is delivered under firm, released firm and interruptible transportation contracts. Florida Power believes that existing contracts for oil are sufficient to cover its requirements when natural gas transmission that is purchased on an interruptible basis is not available.

NUCLEAR: Florida Power has one nuclear generating plant, Crystal River Unit No. 3 ("CR3" or "the nuclear plant"). After completing a record performance in 1995 by achieving a capacity factor of 100%, CR3 was shut down for much of 1996 and all of 1997. Beginning in February 1996, the plant underwent a scheduled refueling outage that lasted until May 1996, when the plant returned to service. In September 1996, an oil pressure problem in the main turbine forced the plant to shut down until repairs could be made. After the repairs were completed in October, the plant remained down while certain backup safety system design issues were addressed. CR3 returned on-line in February 1998. For more information regarding the outage, see Item 7 "MD&A - Operating Results - Florida Power Corporation - Extended Nuclear Outage Costs" and Note 9 to the Financial Statements.

Nuclear fuel is processed through four distinct stages. Stage I and Stage II involve the mining and milling of the natural uranium ore to produce a concentrate and the conversion of this uranium concentrate into uranium hexafluoride. Stage III and Stage IV entail the enrichment of the uranium hexafluoride, and the fabrication of the enriched uranium hexafluoride into usable fuel assemblies. Florida Power has contracts in place which provide for a supply of enriched uranium and fuel fabrication through 2004.

It will be necessary for Florida Power to enter into future fuel contracts to cover the differences between the total unit lifetime requirements of CR3 and the requirements covered by existing contracts. Although no assurances can be given as to the future availability or costs of such contracts, Florida Power expects that future contract commitments will be obtained at the appropriate time.

Spent nuclear fuel ("SNF") is stored at CR3 pending disposal under a contract with the United States Department of Energy ("DOE"). (See Note 4 to the Financial Statements.) At the present time, Florida Power has facilities on site for the temporary storage of SNF generated through the year 2010.

COAL: Florida Power anticipates a requirement of approximately 5,800,000 tons of coal in 1998. Current environmental regulations limit sulfur content, at 12,000 Btu per pound, to 1.2% for Crystal River Unit Nos. 1 and 2, and 0.7% for Unit Nos. 4 and 5. Most of the coal is expected to be supplied from the Appalachian coal fields of the United States. Approximately two-thirds of the coal is expected to be delivered by rail and the remainder by barge. The coal is supplied by Electric Fuels pursuant to contracts between Florida Power and Electric Fuels.

For 1998, Electric Fuels has long-term contracts with various sources for approximately 60% of the coal requirements of Florida Power's coal units. These long-term contracts have price adjustment provisions. Electric Fuels expects to acquire the remainder in the spot market and under short-term contracts. Electric Fuels does not anticipate any problem obtaining the remaining Florida Power requirements with short-term contracts and in the spot market. (See Note 11 to the Financial Statements.)

PURCHASED POWER: Florida Power, along with other Florida utilities, buys and sells economy power through the Florida energy brokering system. In addition, Florida Power has long-term contracts for the purchase of approximately 465 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 400 MW. Also, Florida Power has entered into purchased power contracts with certain qualifying facilities ("QFs") for 946 MW of capacity, of which 831 MW have been completed and are currently operating. The capacity currently available from QFs represents about 9% of Florida Power's total system capacity. The purchased power component was reduced in 1997 primarily through the purchase of the Tiger Bay Cogeneration Facility. See Item 2 "Properties - Utility Operations", Item 7 "MD&A - Fuel and Purchased Power" and Note 11 to the Financial Statements.

REGULATORY MATTERS AND FRANCHISES

Florida Power is subject to the jurisdiction of the FPSC with respect to retail rates, customer service, planning, construction of facilities, accounting, issuance of securities and other matters. In addition, Florida Power is subject to regulation by the Federal Energy Regulatory Commission ("FERC") with respect to transmission and sales of wholesale power, accounting and certain other matters. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus a reasonable rate of return on its equity. Increased competition, as a result of industry restructuring, may affect the ratemaking process. See Item 7 "MD&A - Florida Power - Utility Competition - Industry Restructuring".

The FPSC oversees the retail sales of the state's investor-owned utilities. The FPSC authorizes retail "base rates" that are designed to provide a utility with the opportunity to earn a specific rate of return on its "rate base", or average investment in utility plant. These rates are intended to cover all reasonable and prudent expenses of utility operations and to provide investors with a fair rate of return. The FPSC generally allows utilities to recover fuel, purchased power and conservation costs through an adjustment charge on monthly electric bills. Beginning in 1995, the FPSC ordered Florida Power to conduct a three-year test of revenue decoupling for its residential customers. This test ended December 31, 1997. (See Notes 1 and 9 to the Financial Statements.)

Florida Power is interconnected with 22 municipal and 9 rural electric cooperative systems. Major wholesale power sales customers include Seminole Electric Cooperative, Florida Municipal Power Agency and Reedy Creek Utilities District. During 1997, about 6% of Florida Power's electric revenues were from wholesale customers whose rates are subject to the jurisdiction of the FERC.

For further information with respect to rates, see Note 9 to the Financial Statements.

Florida Power's CR3 nuclear plant is subject to regulation by the United States Nuclear Regulatory Commission ("NRC"). The NRC's jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety, antitrust considerations and environmental impact. Florida Power has a 90.4% ownership interest in CR3. (See Note 4 to the Financial Statements.)

By virtue of state and municipal legislation, Florida Power holds franchises with varying expiration dates to provide electric service in nearly all municipalities in which it distributes electric energy. Approximately 99% of revenues from customers in incorporated areas are covered by franchises. The

general effect of these franchises is to grant Florida Power the right to enter upon and use streets, alleys and other public places for erecting and maintaining poles, wires and other apparatus for the sale and distribution of electric energy. All but one of the existing franchises cover a 30-year period from the date granted, the maximum allowed by Florida law. The one exception is a franchise that covers a 10-year period from the date granted. There are 112 franchises, of which 5 expire before December 31, 2000, 26 expire before December 31, 2001, 33 expire between January 1, 2002 and December 31, 2012, and 48 expire between January 1, 2013 and December 31, 2027.

ENVIRONMENTAL MATTERS

Florida Power is subject to federal, state and local regulations dealing with air and water quality and other environmental matters.

AIR: All of Florida Power's air emission sources meet the air quality standards currently set by the Florida Department of Environmental Protection ("FDEP") and/or the United States Environmental Protection Agency ("EPA").

The Clean Air Act Amendments of 1990 ("CAAA"), under Title IV, Acid Rain Control, set a permanent cap on emissions of sulfur dioxide and nitrogen oxides beginning in the year 2000. The cap is to be implemented in two phases. Phase I limitations became effective in 1995 and Phase II cap will be effective in 2000. Florida Power has not been and does not expect to be materially affected by either Phase I or Phase II. In addition, nitrogen oxide emissions from coal units are being limited by the CAAA. Continuous emission monitors were installed on most of Florida Power's units by the end of 1994 as required under Title IV of the CAAA at a total cost of $11 million. To meet Phase II limitations, Florida Power expects to spend about $10 million by 2000 to implement a strategy based primarily on burning cleaner fuels and installing burners that reduce nitrogen oxide emissions on some coal units.

Under Title III of the CAAA, the EPA is studying the emission of hazardous air pollutants and, where appropriate, promulgating emission limitations for specific source categories. Depending on the results of these studies and the EPA's determination of the need for additional limitations, Florida Power could be required to incur additional capital expenditures and operating expenses.

Under Title V of the CAAA, Florida Power is required to pay annual operating fees based on the previous year's emissions. In 1998, these fees are expected to total approximately $800,000 and may increase to approximately $1 million by 2000.

Florida Power's construction program includes approximately $7 million of planned environmental expenditures for air quality projects for the two-year period ending December 31, 1999.

WATER: To help meet the future electricity needs of its customers, Florida Power is building a new power plant complex in Polk County, Florida. Florida Power plans to have the complex's first plant on line during the fourth quarter of 1998. This plant will use combined cycle technology and be capable of producing up to 470 MW of power. (See Item 2, "Properties - Utility Operations - Planned Generation".) Approximately $27.6 million was spent through December 31, 1997 on environmental projects related to site development, mainly for water resource related facilities. Florida Power expects that approximately $600,000 of additional costs will be expended on environmental projects related to site development. In addition, Florida Power's construction program includes approximately $4 million of additional environmental expenditures for water resource projects at other Florida Power facilities for the two-year period ending December 31, 1999.

WASTE MATERIALS: Florida Power is nearing completion of its program to reduce electrical equipment utilizing polychlorinated biphenyls ("PCB"). All regulatory compliance dates have been met. All PCB transformers (i.e. those having greater than 500 ppm PCB) have been removed from Florida Power's electric generating plants, except for one small plant. Removal of PCB transformers from this final

plant will be delayed until Florida Power decides whether and for how long the plant will remain in operation.

STORAGE TANK PROGRAM: The regulation of underground and above-ground storage tanks has expanded to affect virtually every Florida Power storage tank with a capacity of 100 gallons or greater, including vehicular fuel tanks, bulk fuel storage tanks, mineral acid tanks, hazardous material tanks and compression vessels. The FDEP's storage tank regulations require the replacement or upgrading of tanks that are not protected from corrosion, and the installation of release detection and containment capabilities for spills and leaks. These requirements must be met by 1999. Florida Power expects the annual operating expense and construction expenditures through 1999 related to compliance with these regulations to be $1 million and $3 million, respectively.

Under a FDEP program, revenues from taxes on imported oil either have been or are expected to be used to reimburse Florida Power for the majority of past storage tank contamination cleanup expenditures. In March 1995, the Governor of Florida ordered a moratorium on this FDEP program. However, Florida Power expects to receive reimbursement for cleanup activities completed prior to the moratorium. The FDEP has implemented a new reimbursement program that should reimburse Florida Power for the majority of storage tank contamination clean- up expenditures incurred after the moratorium. The expenditures needed to clean up the remaining storage tank contamination are not expected to be material.

With expansion of regulation and the resulting increased monitoring of tank systems and oil filled electrical equipment, further expenditures for contamination cleanup and retrofitting and upgrading equipment are likely, but these expenditures are not expected to be material to Florida Power.

ELECTROMAGNETIC FIELDS: The potential adverse effect of electromagnetic fields, or electric and magnetic fields ("EMF"), upon human health continues to be an important issue in the siting, construction and operation of electric transmission and distribution systems. EMF from a variety of sources, including transmission and distribution lines, has been the subject of many studies and much public discussion in recent years. Currently, the National EMF Research and Public Information Dissemination Program is in its fifth and final year of an in depth research program. This program was co-funded by federal and private utilities, including Florida Power. The findings, to be presented to the U.S. Congress in 1998, are expected to have a major impact on the EMF issue.

Because of its exclusive jurisdiction to regulate EMF associated with electric transmission and distribution lines and substation facilities in Florida, the FDEP has adopted rules that establish certain EMF limits for new transmission lines and substations. The rules also require an annual review of the state of the scientific research into the potential adverse effects of EMF upon human health. The staff of the FDEP provided its progress report to the Environmental Regulation Commission in February 1997. Based on its review of the scientific research, the staff recommended that no revision of the current EMF standards be made at that time. The Environmental Regulation Commission adopted the staff's recommendation and made no revision to EMF standards. Florida Power believes that compliance with these EMF rules, which at present essentially maintain the status quo with respect to regulated EMF exposure levels, will not have a material adverse effect on the cost of constructing or maintaining new transmission lines or substations. However, there always is a potential for lawsuits brought by plaintiffs alleging damages caused by EMF.

Florida Power's management monitors and reports to Florida Power's Board of Directors at least annually on developments in research concerning the potential health effects of EMF, EMF mitigation technologies and procedures, and significant actions by principal federal and Florida agencies related to EMF.

OTHER ENVIRONMENTAL MATTERS: Florida Power has received notices from the EPA that it is or could be a potentially responsible party ("PRP") under the Comprehensive Environmental Response Compensation and Liability Act ("CERCLA" or "Superfund") and the Superfund Amendment and Reauthorization Act and may be liable, together with others, for the costs of cleaning up several contaminated sites identified by the FDEP. In addition to these designated

other sites where Florida Progress affiliates may be responsible for additional environmental cleanup. For further information concerning certain environmental matters relating to Florida Power, see paragraphs 8 and 11 under Item 3 "Legal Proceedings" and "Contaminated Site Cleanup" in Note 11 to the Financial Statements.

EMPLOYEES

As of December 31, 1997, Florida Power had 4,799 full-time employees. The International Brotherhood of Electrical Workers represents approximately 2,058 of these full-time employees. The current union contract was ratified in May 1997 and expires in December 1999.

DIVERSIFIED OPERATIONS

Florida Progress' diversified operations are owned directly or indirectly through Progress Capital, a Florida corporation and wholly owned subsidiary of Florida Progress. Progress Capital holds the capital stock of, and provides funding for, Florida Progress' non-utility subsidiaries. It's primary subsidiary is Electric Fuels Corporation. Formed in 1976, Electric Fuels is an energy and transportation company with operations organized into three business units. Electric Fuels' energy and related services business unit supplies coal to Florida Power's Crystal River Energy Complex and other utility and industrial customers. Electric Fuels' inland marine transportation business unit, MEMCO Barge Line, Inc. ("MEMCO"), transports coal and dry-bulk cargoes primarily along the Mississippi and Ohio rivers. The rail services business unit, led by Progress Rail Services Corporation ("Progress Rail"), is one of the largest integrated processors and suppliers of railroad materials in the country. With operations in 16 states, Progress Rail offers a full range of railcar parts, rail and other track material, railcar repair facilities, railcar scrapping and metal recycling as well as railcar sales and leasing.

As of December 31, 1997, Progress Capital and its subsidiaries had 3,162 full-time employees. (For additional information with respect to Progress Capital and its subsidiaries, see Item 7 "MD&A - Operating Results - Diversified Operations" and paragraph 10 of Item 3 "Legal Proceedings.")

COMPETITION

Florida Progress' non-utility subsidiaries compete in their respective marketplaces in terms of price, service reliability, location and other factors. Electric Fuels competes in several distinct markets: its coal operations compete in the eastern United States utility and industrial coal markets; its marine transportation and barge operations compete in the coal, grain and bulk products transportation markets on the Ohio and lower Mississippi rivers; its marine equipment repair business competes in the inland river and gulf coast repair markets; and its rail operations compete in the railcar repair, parts and associated services markets in the eastern United States and, to a limited extent, in the midwest and west. Factors contributing to Electric Fuels' success in these markets include a competitive cost structure, strategic locations and, in the case of its marine transportation operations, a modern fleet. There are, however, numerous competitors in each of these markets, although no one competitor is dominant in any industry. The business of Electric Fuels and its subsidiaries, taken as a whole, is not subject to significant seasonal fluctuation.

For further information with respect to Florida Progress' non-utility subsidiaries and competition, see Item 7 "MD&A - Operating Results - Diversified Operations".

ENVIRONMENTAL MATTERS

Electric Fuels is subject to federal, state and local regulations which govern air and water quality, waste disposal and other environmental matters. The coal mining business is affected primarily by the Clean Water Act, the Clean Air Act and the Surface Mining Control and Reclamation Act of 1977. The transportation and the railcar and marine repair businesses are primarily affected by the

Resource Conservation and Recovery Act, the Emergency Planning and Community Right-To-Know Act and the Clean Water Act.

The Environmental Services Department of Electric Fuels reviews existing and emerging environmental regulations, disseminates applicable environmental information throughout the organization and conducts site specific environmental compliance audits. Transactional environmental assessments are performed on new acquisitions to determine the potential environmental liabilities associated with the facilities being considered. Compliance with environmental laws and regulations has not had a material effect on Electric Fuels' capital expenditures, earnings or competitive position, and Electric Fuels does not anticipate making any material capital expenditures for environmental facilities through the end of 1999.

For further information concerning certain environmental matters relating to Florida Progress' diversified operations, see paragraph 12 under Item 3 "Legal Proceedings" and Note 11 "Commitments and Contingencies", Notes to the Financial Statements.

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EXECUTIVE OFFICERS

Roy A. Anderson, Senior Vice President, Energy Supply, and Chief Nuclear Officer of Florida Power, Age 49.

Mr. Anderson became Senior Vice President, Nuclear Operations, effective January 20, 1997, was named Chief Nuclear Officer, effective April 1, 1997, and now serves as the Senior Vice President of Energy Supply. Prior to joining Florida Power, Mr. Anderson was employed by Carolina Power and Light, where he held numerous executive officer positions since 1993 in the areas of nuclear operations, fossil generation, and distribution and customer service. From 1987 to 1993, he was employed by Boston Edison Company where he served as Plant Manager, Vice President and ultimately as Senior Vice President, Nuclear Operations.

Kenneth E. Armstrong, Vice President and General Counsel of Florida Progress and Florida Power, Age 50.

Mr. Armstrong has served as General Counsel of Florida Progress since July 1990 and as Vice President since April 1992. In April 1995, he became Vice President and General Counsel of Florida Power. In addition to these positions, Mr. Armstrong served as Assistant Secretary of Florida Progress from April 1992 to April 1993 and as Secretary from April 1993 to April 1996. He also served as Assistant Secretary of Florida Power from 1987 until April 1993 and as Secretary from April 1993 until April 1996.

Janice B. Case, Senior Vice President, Energy SolutionsSM of Florida Power, Age 45.

Mrs. Case was named Senior Vice President, Energy Solutions[SM] effective June 1, 1997, after serving as Vice President since 1996. From October 1990 until July 1996, she served as Vice President, Suncoast Florida Region of Florida Power.

Jack B. Critchfield, Chairman of the Board of Florida Progress, Age 64.

Since June 1, 1997, Dr. Critchfield's principal occupation has been as shown above. Since 1983, he has held numerous executive positions with Florida Progress and its subsidiaries including President, Chief Executive Officer, Chief Operating Officer, Group Vice President, President of Electric Fuels and Vice President of the Eastern and Ridge Divisions of Florida Power. He has been a director of Florida Power since 1988 and served as a director from 1975 through 1978 and as Chairman of its Board from 1990 until April 1996. He is a director of Florida Progress.

Michael B. Foley, Jr., Senior Vice President, Energy Delivery of Florida Power, Age 54.

Since July 1996, Mr. Foley's principal occupation has been as shown above. Mr. Foley served as Vice President in that position since February 1995. From October 1988 until February 1995, Mr. Foley served as Director of System Planning of Florida Power.

Stanley I. Garnett, II, Executive Vice President of Florida Progress, Age 54

Mr. Garnett was appointed Executive Vice President of Florida Progress, effective June 1, 1997. From 1996 and until he joined Florida Progress, Mr. Garnett was employed as Senior Advisor by Putnam, Hayes & Bartlett, Inc., an economic and management consulting firm. From 1981 to 1995, he was employed by Allegheny Power System, Inc., where he served as Vice President, Legal and Regulatory and Chief Legal Officer and ultimately as Senior Vice President and Chief Financial Officer. He is a director of Baycorp Holdings, Ltd.

Jeffrey R. Heinicka, Senior Vice President and Chief Financial Officer of Florida Progress and Florida Power, Age 43.

From December 1990 until appointment to his current positions in 1994, Mr. Heinicka served as Vice President and Treasurer of Florida Progress. Mr. Heinicka also served as Vice President and Treasurer of Florida Power from April 1993 to March 1994, a position he held concurrently with his Vice President and Treasurer position at Florida Progress.

Richard D. Keller, Group Vice President, Energy and Transportation of Florida Progress, and President and Chief Executive Officer, Electric Fuels, Age 44.

Since May 1990, Mr. Keller's principal occupation has been as shown above. He has served as President and Chief Executive Officer of Electric Fuels since February 1988.

Richard Korpan, President and Chief Executive Officer of Florida Progress, and Chairman of the Board of Florida Power, Age 56.

Since June 1, 1997, Mr. Korpan's principal occupation has been as shown above. He has held the position of President since 1991, and became Chief Executive Officer of Florida Progress in June 1997. Since April 1996 he has also served as Chairman of the Board of Florida Power, and until June 1, 1997, as Chief Executive Officer of Florida Power. He joined Florida Progress in 1989 as Executive Vice President and Chief Financial Officer. He is a director of SunTrust Bank of Tampa Bay.

Joseph H. Richardson, Group Vice President, Utility Group of Florida Progress and President and Chief Executive Officer of Florida Power, Age 48.

Since 1996, Mr. Richardson's principal occupation has been as Group Vice President, Utility Group of Florida Progress and President and Chief Operating Officer of Florida Power. Effective June 1, 1997, he was appointed Chief Executive Officer, in addition to President, of Florida Power. From April 1995 to April 1996, he served as Senior Vice President, Energy Distribution of Florida Power. From October 1993 to April 1995, he served as Senior Vice President, Legal and Administrative Services, and General Counsel of Florida Power. From August 1991 through April 1995, Mr. Richardson also held the position of Senior Vice President of Florida Progress. He was President and Chief Executive Officer of Talquin Corporation, a former subsidiary of Florida Progress from May 1990 until September 1993. He is a director of Echelon.

There are no family relationships between any director or any executive officer of Florida Progress or Florida Power. The executive officers serve at the pleasure of their respective Boards of Directors. Each executive officer is appointed annually.

ITEM 2. PROPERTIES

Florida Progress believes that its physical properties and those of its subsidiaries are adequate to carry on its and their businesses as currently conducted. Florida Progress and its subsidiaries maintain property insurance against loss or damage by fire or other perils to the extent that such property is usually insured. (See Note 11 to the Financial Statements.) Substantially all of Florida Power's utility plant is pledged as collateral for Florida Power's First Mortgage Bonds. Certain river barges and tug/barge units owned or operated by Electric Fuels are subject to liens in favor of certain lenders.

UTILITY OPERATIONS

GENERATION: As of December 31, 1997, the total net winter generating capacity of Florida Power's generating facilities, including CR3, was 7,717 MW. This capacity was generated by 13 steam units with a capacity of 4,661 MW and 45 combustion turbine units with a capacity of 3,056 MW. Florida Power's ability to use its generating units may be adversely impacted by various governmental regulations affecting nuclear operations and other aspects of Florida Power's business. (See "Regulatory Matters and Franchises" and "Environmental Matt-

under Item 1 "Business - Utility Operations - Florida Power.") Operation of these generating units may also be substantially curtailed by unanticipated equipment failures or interruption of fuel supplies. Florida Power expects to have sufficient system capacity, access to purchased power and demand-side management capabilities to meet anticipated future demand.

Florida Power's existing generating plants (all located in Florida) and their capacities at December 31, 1997 are as follows:

Plants	Primary Fuel	Location (County)	Steam MW	Combustion Turbine MW	Winter Net Maximum Dependable Capacity MW
Crystal River:		Citrus			
Unit #1	Coal		373	-	373
Unit #2	Coal		469	-	469
Unit #3	Uranium		755*	-	755
Unit #4	Coal		717	-	717
Unit #5	Coal		717	-	717
			3,031		3,031
Anclote:		Pasco			
Unit #1	Oil		517	-	517
Unit #2	Oil		517	-	517
Bartow	Oil	Pinellas	449	217	666
Turner	Oil	Volusia	-	200	200
Intercession City**	Oil	Osceola	-	912	912
DeBary	Oil	Volusia	-	786	786
Higgins	Oil	Pinellas	-	148	148
Bayboro	Oil	Pinellas	-	232	232
Avon Park	Oil	Highlands	-	64	64
Rio Pinar	Oil	Orange	-	18	18
Suwannee River	Oil	Suwannee	147	201	348
Tiger Bay	Gas	Polk	-	236	236
University of Fla.	Gas	Alachua	-	42	42
			4,661	3,056	7,717

* Represents 90.4% of total plant capacity. The remaining 9.6% of capacity is owned by other parties. The CR3 nuclear plant was shut down in September 1996 for repairs and to address certain backup safety system design concerns. CR3 was restarted in February 1998.

** Florida Power and Georgia Power Company ("Georgia Power") are co-owners of a 168-MW advanced combustion turbine located at Florida Power's Intercession City site. Georgia Power has the exclusive right to the output of this unit during the months of June through September. Florida Power has that right for the remainder of the year.

PLANNED GENERATION AND ENERGY SALES: Florida Power has agreed to sell 605 MW of year round capacity to Seminole Electric Cooperative, Inc. ("Seminole") from 1999 through 2001. While 150 MW of this transaction represents a continuation of existing business, 455 MW represents new sales to Seminole. In addition, Florida Power has agreed to sell from 150 to 300 MW to Seminole from 2000-2002. This contract was awarded to Florida Power as a result of a competitive bidding process initiated by Seminole.

In 1992, the FPSC granted Florida Power a certificate of need to build 470 MW of new generation using combined cycle technology. In September 1994, Florida Power purchased approximately 8,100 acres of mined-out phosphate land for the new power plant site. The site is located in Polk County, Florida, approximately 50 miles east of Tampa, and has been designated the Hines Energy Complex. Site development activities were completed in 1996. Commencement of construction of the initial unit began in January 1997. The first power block is a 470-MW

combined cycle unit that is expected to come on line during the fourth quarter of 1998. Florida Power plans to use natural gas to fuel the first phase of the Hines Energy Complex. (See Item 7 "MD&A - Liquidity and Capital Resources - Florida Power Corporation".)

Florida Power has obtained capacity on the Florida Gas Transmission Company's system for the transportation of natural gas to the Hines Energy Complex in Polk County. Florida Power began using the capacity in January 1998. This transportation will serve a portion of the plant's requirements. Florida Power also has contracted for natural gas supply and its transportation for the remaining portion of the plant's requirements.

Some of the capacity at the Hines Energy Complex will be used to meet the requirements of a wholesale contract signed in 1995, in which Florida Power agreed to sell an additional 455 MWs to Seminole Electric Cooperative, beginning in 1999.

In connection with the construction of new power plants in Florida, the FPSC requires each investor-owned electric utility to engage in a competitive bidding process for the construction of new generation, unless the utility demonstrates on a case-by-case basis that such a process is not in the best interests of the utility's ratepayers.

NUCLEAR PLANT AND NUCLEAR INSURANCE: Information regarding nuclear plant and nuclear insurance is contained in Note 4 "Nuclear Operations" and Note 11 "Commitments and Contingencies," Notes to the Financial Statements.

TRANSMISSION AND DISTRIBUTION: As of December 31, 1997, Florida Power distributed electricity through 362 substations with an installed transformer capacity of 42,392,415 kilovolt amperes ("KVA"). Of this capacity, 28,690,260 KVA is located in transmission substations and 13,702,155 KVA in distribution substations. Florida Power has the second largest transmission network in Florida. Florida Power has 4,622 circuit miles of transmission lines, of which 2,620 circuit miles are operated at 500, 230, or 115 kilovolts ("KV") and the balance at 69 KV. Florida Power has 24,311 circuit miles of distribution lines which operate at various voltages ranging from 2.4 to 25 KV.

Florida Power along with 21 other in-state electric utilities and 14 non-utilities comprise the Florida Reliability Coordinating Council ("FRCC"), which was approved by the North American Electric Reliability Council ("NERC") as the tenth region of NERC. The FRCC is responsible for ensuring the reliability of the bulk power electric system in peninsular Florida.

Florida Power and five other FRCC transmission providers have established Florida Open Access Sametime Information System. This is a single internet location where transmission customers may obtain transmission information and submit requests for service or resell service rights.

DIVERSIFIED OPERATIONS

Electric Fuels owns and/or operates approximately 5,000 railcars, 50 locomotives, 900 river barges and 30 river towboats that are used for the transportation and shipping of coal, steel and other bulk products. Through joint ventures, Electric Fuels has five oceangoing tug/barge units. An Electric Fuels subsidiary, through another joint venture, owns one third of a large bulk products terminal located on the Mississippi River south of New Orleans, which handles coal and other products. Electric Fuels provides drydocking and repair services to towboats, offshore supply vessels and barges through operations it owns near New Orleans, Louisiana.

Electric Fuels controls, either directly or through subsidiaries, coal reserves located in eastern Kentucky and southwestern Virginia. Electric Fuels owns, in fee, properties that contain estimated proven and probable coal reserves of approximately 185 million tons and controls, through mineral leases, additional estimated proven and probable coal reserves of approximately 30 million tons. The reserves controlled by Electric Fuels include substantial quantities of high quality, low sulfur coal that is appropriate for use at Florida Power's existing generating units. Electric Fuels' total production of coal during 1997 was approximately 3.2 million tons.

In connection with its coal operations, Electric Fuels subsidiaries, own and operate an underground mining complex in southeastern Kentucky and southwestern Virginia. Other Electric Fuels subsidiaries own and operate surface and underground mines, coal processing and loadout facilities and a river terminal facility in eastern Kentucky, a railcar-to-barge loading facility in West Virginia, and three bulk commodity terminals: one on the Ohio River in Cincinnati, Ohio, and two on the Kanawha River near Charleston, West Virginia. Electric Fuels and its subsidiaries employ both company and contract miners in their mining activities.

An Electric Fuels subsidiary owns railroad car repair and parts reconditioning and rail and trackworks facilities in 16 states and Mexico, including a railcar hydraulic cushioning unit manufacturing and reconditioning facility in Fort Worth, Texas. Electric Fuels subsidiaries are also involved in scrap metal recycling and railcar leasing.

Another subsidiary of Electric Fuels owns and operates a manufacturing facility at the Florida Power Energy Complex in Crystal River, Florida. The manufacturing process utilizes the fly ash generated by the burning of coal as the major raw material in the production of lightweight aggregate used in construction building blocks. Electric Fuels also operates an environmental testing laboratory in Tampa, Florida.

ITEM 3. LEGAL PROCEEDINGS

Purchased Power Contracts with Qualifying Facilities ("QFs")

Florida Power has interpreted the pricing provision in these contracts to allow it to pay an as-available energy price rather than a higher firm energy price when the avoided unit upon which the contract is based would not have been operated. Several QFs filed suit against Florida Power over the level of payments made by Florida Power under the contracts. All but the three discussed below have been settled. Four QFs are involved in matters pending before the FPSC. Additional details regarding the legal proceedings with these four QFs are covered in paragraphs 1, 2, 3 and 4 below:

1. In re: Conservation Cost Recovery Clause, Florida Public Service Commission, Docket No. 960002-EG

   In re: Petition for Approval of Early Termination Amendment to Negotiated Qualifying Facility Contract with Orlando Cogen Limited, Florida Public Service Commission, Docket No. 961184-EQ.

In October 1996, Florida Power filed a petition with the FPSC seeking approval of an early termination amendment with Orlando Cogen Limited, L.P. ("OCL") which would reduce the term of the contract with OCL from 30 years to 20 years, expiring in the year 2013. In return for terminating the last ten years of the contract, the amendment provides for the payment to OCL of $49,405,000 over a five-year period, which the petition asks to recover from retail customers through Florida Power's capacity cost recovery clause. In February 1998, the FPSC denied Florida Power's petition to approve the early termination amendment.

2. Metropolitan Dade County and Montenay Power Corp. v. Florida Power Corporation, Circuit Court of the Eleventh Circuit for Dade County, Florida, Case No. 96-09598-CA-30

   Metropolitan Dade County and Montenay Power Corp. v. Florida Power Corporation, U.S. District Court, Southern District, Miami Division, Case No. 96-0594-C.V.-LENNARD

On February 13, 1996, Metropolitan Dade County ("Dade") and Montenay Power Corp. ("Montenay") filed a complaint in the above-referenced state court seeking a declaratory judgment that their interpretation of the energy pricing provision in the contract is correct, and damages in excess of $1.3 million for breach of that contract. On May 14, 1996, Dade and Montenay filed suit against Florida Power in the above-referenced federal district court based on essentially the same facts as presented in the state court case, but alleging violations of federal antitrust laws and demanding unspecified treble damages. In March 1997, the plaintiffs amended the federal court case to include Florida Progress and Electric Fuels. A jury trial date has been set for October 1998 in the federal case and in the meantime, the case has been referred to mediation.

On February 23, 1998, Florida Power filed a petition with the FPSC for a Declaratory Statement that the previous FPSC approved negotiated contract between the parties limits energy payments thereunder to the avoided costs based upon an analysis of a hypothetical unit having the characteristics specified in the contract.

3. NCP Lake Power, Inc. v. Florida Power Corporation, Florida Circuit Court, Fifth Judicial Circuit for Lake County, Case No. 94-2354-CA-01

   In re: Petition for Expedited Approval of Settlement Agreement With Lake Cogen Ltd., Public Service Commission, Docket No. 961477-EQ

On October 21, 1994, NCP Lake Power, Inc. ("Lake"), a general partner of Lake Cogen, Ltd., filed suit in the above-referenced circuit court against Florida Power asserting breach of contract and requesting a declaratory judgment. On January 23, 1996, the court entered a partial summary judgment for Lake ordering Florida Power to pay the firm energy cost rate when the avoided

been operating, and the as available energy cost rate during those times when the avoided unit would not have been operating.

In October 1996, Lake filed suit against Florida Power seeking unspecified damages for breach of contract with respect to Florida Power's interpretation of the pricing provision in the contract. In December 1996, Florida Power and Lake resolved their dispute by executing a final settlement agreement, subject to approval by the FPSC and lenders to Lake. In November 1997, the FPSC denied approval of the settlement agreement. Lake filed a petition protesting the FPSC's decision, and Florida Power filed a motion to dismiss Lake's petition as moot. In March 1998, the FPSC voted to dismiss the Petition for expedited approval of the settlement agreement because the agreement upon which the petition was based has expired. The case has been set for trial in November 1998.

4. **In re: Standard Offer Contract for the Purchase of Firm Capacity and Energy From a Qualifying Facility Between Panda-Kathleen L.P. and Florida Power Corporation, Florida Public Service Commission, Docket No. 950110-EI**

   Florida Power Corporation v. Panda-Kathleen Corp., United States District Court for the Middle District of Florida, Tampa Division, Case No. 95-2145-CIV-T-25-B.

On January 23, 1995, Florida Power petitioned the FPSC for a declaratory statement that Florida Power's standard offer contract is not available to Panda if it constructs a 115 MW facility. Florida Power's petition further sought a declaration that the contact term is 20 years rather than 30 years. Panda intervened in the proceeding and filed its own declaratory statement petition on the issues raised by Florida Power and raised additional issues regarding postponement of significant milestone dates in the contract pending the FPSC's resolution of the issues in the proceeding.

On May 20, 1996, after a hearing, the FPSC issued an order ruling against Panda on two of the three material issues in the case. First, the FPSC held that Panda's proposed 115 MW facility does not comply with the 75 MW limitation contained in the FPSC's standard offer rules. The FPSC found that the 75 MW limitation applies to the output of the plant, not to the contract's committed capacity. Second, the FPSC held that under its rules, Florida Power is required to make capacity payments for 20 years rather than for 30 years as argued by Panda. Third, the FPSC ruled against Florida Power by extending for 19 months the "milestone" dates contained in the standard offer contract, including the construction commencement date and the commercial in-service date.

On September 18, 1997, the Florida Supreme Court ruled that the FPSC had jurisdiction over this matter and further affirmed the FPSC's May 20, 1996 order. On February 11, 1998, Panda filed a petition for a writ of certiorari with the U.S. Supreme Court to review the Florida Supreme Court decision, and Florida Power has filed its response.

On January 6, 1998, Panda filed a motion with the FPSC to again extend the "milestone" dates. Florida Power has opposed Panda's motion to extend the milestone dates. On February 25, 1998, Florida Power sent Panda a Notice of Default for its failure to adhere to the previously revised milestone dates, conditioned upon the FPSC's denial of Panda's motion.

5. **Wanda L. Adams, et al. v. Florida Power Corporation and Florida Progress Corporation, U.S. District Court, Middle District of Florida, Ocala Division, Case No. 95-123-C.V.-OC-10.**

On October 13, 1995, Florida Power and Florida Progress were served with a multi-party lawsuit involving 17 former Florida Power employees. The plaintiffs generally alleged discrimination in violation of the Age Discrimination and Employment Act and wrongful interference with pension rights in violation of the Employee Retirement Income Security Act as a result of their involuntary terminations during Florida Power's reduction in force. While no dollar amount is specified, each Plaintiff seeks back pay, reinstatement or front pay through their projected dates of normal retirement, costs and attorney's fees.

The plaintiffs subsequently filed several motions attempting to add more plaintiffs, including one present employee who contends he was demoted because of his age.

On November 10, 1995, Florida Power filed its answer, a motion to dismiss Florida Progress, and a counterclaim against five of the plaintiffs who signed releases, promising, among other things, not to sue Florida Power with respect to matters involving their employment or termination. The counterclaim seeks enforcement of the agreement, dismissal of plaintiffs' complaints, and an award of attorneys fees and costs of litigation.

On October 29, 1996, a joint stipulation to provisionally certify the case as a class action pursuant to the Age Discrimination in Employment Act was approved. A notice was sent to all former employees involuntarily discharged during the reduction in force, who were 40 years of age or older at the time of their discharge, informing them of their right to opt into this action if they believed they were discriminated against on the basis of age. Florida Power reserved the right to file a motion to decertify the class at the end of the opt-in period.

On May 28, 1997, the final day for individuals to "opt into" this action, 61 additional former employees elected to do so, for a total of 117 plaintiffs. On August 28, 1997, the parties filed an amended case management report which included a proposed schedule. To date, no scheduling order has been entered.

6. **Florida Power Corporation v. United States, U.S. Court of Federal Claims, Civil Action No. 96-702C.**

On November 1, 1996, Florida Power filed suit against the U.S. Government alleging breach of contract and illegal taking of property without just compensation. The suit arises out of several contracts under which the government provided uranium enrichment services at fixed prices. After Florida Power paid for all services provided under the contracts, the government, through federal legislation enacted in 1992, imposed a retroactive price increase in order to fund the decontamination and decommissioning of the government's gaseous diffusion uranium enrichment facilities. The government is collecting this increase through an annual "special assessment" levied upon all utilities that had enrichment services contracts with the government. Collection of the special assessments began in 1992 and is scheduled to continue for a fifteen-year period.

To date, Florida Power has paid more than $9.5 million in special assessments, and if continued throughout the anticipated fifteen-year life, the special assessments would increase the cost of Florida Power's contracts by more than $23 million.

Florida Power seeks an order declaring that all such special assessments are unlawful, and an injunction prohibiting the government from collecting future special assessments, and damages of approximately $9.5 million, plus interest. On December 23, 1996, the case was stayed pending the U.S. Supreme Court's potential review of a similar case. (Yankee Atomic Electric Co. v. U.S.). There, a petition for a writ of certiorari has been filed by Yankee Atomic Electric Co.

7. **Gulf Power et al. v. United States of America and the Federal Communications Commission, U.S. District Court, Northern District of Florida, Pensacola Division, Case No. 3:96-CV-381-LAC**

On July 30, 1996, Florida Power together with Gulf Power Company, Alabama Power Company, Georgia Power, Mississippi Power Company, Ohio Edison Company and Duke Power Company filed suit challenging the constitutionality of the pole attachment amendments to the Telecommunications Act of 1996. The suit seeks a declaration that the pole attachments are unconstitutional because they impose a mandatory obligation on utilities to provide access to poles they own or control to cable television and telecommunications service providers without providing just compensation for this use. The claim is based on the Fifth

the United States Constitution which provides that private property shall not be taken for public use without just compensation. The suit also seeks a permanent injunction against the Federal Communications Commission preventing it from enforcing the mandatory access provision.

In February 1997, the Association for Local Telecommunications Services and American Communication Services intervened as party defendants in this case. On February 21, 1997, Florida Power filed a Motion for Summary Judgment. On March 20, 1997, the defendants filed their Motion for Summary Judgment. Oral arguments on the motions were on February 18, 1998.

On March 6, 1998, the Court granted the U.S.'s Motion for Summary Judgment. The judge opined that while mandatory access to utility poles constitutes a "taking", it was not an unconstitutional taking and just compensation would have to be determined.

8. *Sanford Gasification Plant Site, Sanford, Florida*

The Sanford Gasification Site is a former manufactured gas site located in the city of Sanford, Florida. It began operation in the 1880's and continued through the early 1950's. Originally owned by Southern Utilities Company, the plant was purchased in 1924 by the City of Sanford, then sold again in 1928 to Sanford Gas Company. Sanford Gas Company, which merged into Florida Power Corporation in 1944, operated the plant until 1946 when it was sold to South Atlantic Gas Company (later Atlanta Gas Company). The plant was conveyed three more times, being purchased by the current owner, Florida Public Utilities, in 1965. The FDEP began investigating the site in 1990. Florida Public Utilities initiated an action styled Florida Public Utilities Company v. Florida Power Corporation, Florida Power and Light Company, Atlanta Gas Company and City of Sanford, Florida, United States District Court of the Middle District of Florida, Orlando Division, Civil Action No. 92-115-C.V.-ORL-19, seeking contribution for cleanup from former owners or operators of the site, including Florida Power. That action was dismissed without prejudice on February 17, 1995.

On June 27, 1996, the EPA completed an Expanded Site Investigation/Remedial Investigation at the site. On July 11, 1997, the EPA sent a general and special notice letter which advised Florida Power and other PRPs of their potential liability for cleanup. The investigation concluded that such release or threatened release includes the site itself and down gradient contamination in sediment through an unnamed tributary for storm water drainage flowing through Cloud Branch Creek into Lake Monroe.

On October 20, 1997, the PRPs filed a good faith offer to conduct a Remedial Investigation and Feasibility Study ("RI/FS"), which, if accepted by the EPA would allow the PRPs to perform and finance cleanup activities at the site under the guidance of the EPA. The PRPs have reached a tentative agreement on an allocation of costs to fund the RI/FS and subsequent remedial work up to $1.5 million. Additional contributions for subsequent cleanup costs will be negotiated among the PRPs as the scope of clean-up efforts become more defined. (See Note 11 "Commitments and Contingencies," Notes to the Financial Statements).

9. Northern States Power Company et al. v. United States Department of Energy, U.S. Court of Appeals for the D.C. Circuit, Case No. 97-1065.

On January 31, 1997, in response to the DOE's announcement that it would be unable to meet its statutory obligation to commence disposing of spent nuclear fuel by January 31, 1998, Florida Power joined approximately 35 other utilities with nuclear power plants in this lawsuit against DOE under the Nuclear Waste Policy Act ("NWPA"). The NWPA and contracts between the utilities and DOE require utilities to make payments into the Nuclear Waste Fund based on each kilowatt hour of electricity generated and sold from nuclear plants. In exchange, the NWPA and those contracts require DOE to begin disposing of utilities' spent nuclear fuel by January 31, 1998. In their lawsuit, the utilities requested the U.S. Court of Appeals for the D.C. Circuit to (1) order DOE to begin accepting spent fuel not later than January 31, 1998, (2) declare

that the utilities are relieved of their obligation to make payments into the Nuclear Waste Fund unless and until DOE commences disposing of their spent fuel, and (3) prohibit DOE from taking any adverse action against utilities suspending payments.

In its November 14, 1997 ruling, the D.C. Circuit affirmed its previous decision in Indiana Michigan Power Co. v. DOE, 88 F.3d 1272 (D.C. Cir. 1996), and held that DOE has an unconditional obligation to begin disposing of spent fuel by January 31, 1998. The court also prohibited DOE from using the "unavoidable delays" clause in its contracts with the utilities as a means of avoiding its unconditional obligation to begin accepting utility spent fuel by January 31, 1998. Although the court refused to require DOE to begin accepting utility spent fuel based on its view that utilities had a potentially available remedy under their contracts with DOE, the D.C. Circuit nonetheless retained jurisdiction in the event DOE failed to comply with the court's mandate.

On December 29, 1997, DOE requested rehearing of the D.C. Circuit's decision asserting that the D.C. Circuit lacked jurisdiction to hear the case. On that same day, Yankee Atomic Electric Company filed a separate rehearing petition of the Northern States decision requesting a move fuel order from the court. Unlike most other utility petitioners in the Northern States case, Yankee Atomic has largely completed decommissioning its nuclear plant and has fully paid its Nuclear Waste Fund fees.

Based on statements made by DOE in its rehearing petition, approximately 40 states and state utility commissions and more than 40 utilities, including Florida Power, filed motions to enforce the mandate issued by the D.C. Circuit in Northern States. The state and utility petitions, filed on January 30, 1998 and February 19, 1998 respectively, request the D.C. Circuit for relief similar to that sought in the Northern States litigation.

Failure of DOE to accept spent nuclear fuel will not immediately affect Florida Power, which has sufficient on-site spent nuclear fuel storage capacity through the year 2010.

10. **State of Oklahoma, ex rel. John P. Crawford, Insurance Commissioner v. Mid-Continent Life Insurance Company, District Court of Oklahoma County, State of Oklahoma, Case No. CJ-97-2518-62**

State of Oklahoma, ex rel, John P. Crawford, Insurance Commissioner as Receiver for Mid-Continent Life Insurance Company v. Florida Progress Corporation, a Florida corporation, Jack Barron Critchfield, George Ruppel, Thomas Steven Krzesinski, Richard Korpan, Richard Donald Keller, James Lacy Harlan, Gerald William McRae, Thomas Richard Dlouhy, Andrew Joseph Beal and Robert Terry Stuart, Jr.

On April 14, 1997, the Insurance Commissioner of the state of Oklahoma ("Commissioner") received approval from the Oklahoma County District Court to temporarily seize control of the operations of Mid-Continent Life Insurance Company ("Mid-Continent"). On May 23, 1997, the District Court of Oklahoma County granted the application of the Commissioner to place Mid-Continent into receivership and ordered the Commissioner to develop a plan of rehabilitation for Mid-Continent. The Commissioner alleged that Mid-Continent's reserves were understated by more than $125 million, thus causing Mid-Continent to be statutorily impaired, and further alleged that Mid-Continent had violated Oklahoma law relating to deceptive trade practices in connection with the sale of its "Extra Life" insurance policies. Mid-Continent is appealing the decision to the Supreme Court of Oklahoma. Mid-Continent believes it is not statutorily impaired because the court ruled that it could raise premiums on the insurance policies at issue.

In connection with this matter, the Commissioner of Insurance of the State of Texas entered a cease and desist order on July 10, 1997, prohibiting Mid-Continent from writing any new policies in the state of Texas. The Texas Commissioner cited the lack of permanent management at, and plan of rehabilitation for, Mid-Continent and the alleged reserve deficiency as reasons for the action.

On December 22, 1997, the Commissioner filed with the court a petition for damages against the defendants alleging alter ego, negligence, breach of fiduciary duty, misappropriation of funds, unjust enrichment, ultra vires, violation of Oklahoma statutory insurance law, violation of Oklahoma statutory corporate law, and seeking equitable relief.

On February 13, 1998, the Commissioner filed with the court a "Report Regarding Rehabilitation Plan". This report did not put forward a serious rehabilitation plan, but rather stated that the Commissioner has filed a petition seeking recovery of damages from the defendants, the proceeds of which would be used to offset the alleged reserve deficiencies.

On February 26, 1998, the defendants filed motions to dismiss the petition and Mid-Continent filed a response to the report regarding the Commissioner's rehabilitation plan and requested approval of its proposed plan of rehabilitation. Mid-Continent's proposed rehabilitation plan presents a multi-faceted approach to rehabilitation, including raising premiums. A hearing before the court has been set on March 17, 1998, for the proposed rehabilitation plans. A hearing before the court has been set on the motions to dismiss on April 17, 1998.

Florida Progress intends to vigorously defend itself and other defendants against these charges and support Mid-Continent in its efforts to gain the court's approval of its rehabilitation plan. (See Item 7 MD&A, "Mid-Continent Life Insurance Company").

11. *Peak Oil Company, Missouri Electric Works, 62nd Street, AKO Bayside, and Bluff Electric.*

Florida Power has been notified by the EPA that it is or could be a PRP with respect to each of the above Superfund sites. Based upon the information presently available, Florida Power has no reason to believe that its total liability for the cleanup of these sites will be material or that it will be required to pay a significantly disproportionate share of those costs. However, these matters are being reported because liability for cleanup of certain sites is technically joint and several, and because the extent to which Florida Power may ultimately have to participate in those cleanup costs is not presently determinable.

12. Zellwood Groundwater Superfund Site

In 1992, Florida Progress was notified by the EPA that Progress Packaging Corporation ("Progress Packaging") is or could be a PRP in reference to the Zellwood Groundwater site. Florida Progress sold the assets of Progress Packaging in 1988. The EPA issued Special Notice Letters to potentially responsible parties in 1996. Florida Progress has been advised orally by the EPA that if no letter was received, then Progress Packaging will not be held liable for any damages related to this matter. Progress Packaging did not receive a letter. On November 7, 1996, Florida Progress requested written confirmation from the EPA that Progress Packaging was not mailed a Special Notice Letter. No confirmation has been received to date. Based upon the above stated information and the fact that the last written communication received from the EPA was in 1994, the file on this matter has been closed. This report concludes this matter for reporting purposes.

13. *In re: Petition of* IMC-Agrico Company for a Declaratory Statement Confirming Non-Jurisdictional Nature of Planned Self-Generation, Florida Public Service Commission, Docket No. 971313-EI.

In re: Petition of Duke Mulberry Energy, L.P., and IMC-Agrico Company for a Declaratory Statement Concerning Eligibility to Obtain Determination of Need Pursuant to Section 403.519, Florida Statutes, Florida Public Service Commission, Docket No. 971337-EI.

In re: Petition of Duke Energy New Smyrna Beach Power Company, LLP for a Declaratory Statement Concerning Eligibility to Obtain Determination of

Need Pursuant to Section 403.519, Florida Statutes, Florida Public Service Commission Docket No. 971446-EI.

IMC-Agrico Company, a retail customer of Florida Power and Duke Energy Power Services, announced their intention to construct, own and operate a natural gas-fired combined cycle power plant in Florida, with a capacity of between 240 and 750 megawatts. A portion of the plant's capacity would be used in IMC-Agrico's operations and the remainder sold on a "merchant plant" basis to wholesale customers by an affiliate of Duke Energy.

IMC-Agrico filed a petition with the FPSC in 1997, seeking a declaratory statement that its proposed ownership and operation of an interest in the plant will constitute self generation and not render it a public utility subject to regulation by the FPSC. On November 14, 1997, Florida Power filed a Petition for Leave to Intervene in this proceeding. Florida Power's petition asserts that IMC has provided insufficient information to enable the FPSC to determine whether its proposal constitutes a non-jurisdictional retail sale. On December 16, 1997, the FPSC decided to set this matter for a hearing pursuant to the Administrative Procedures Act, at the conclusion of which, a decision would be rendered on the jurisdictional question. On February 3, 1998, IMC-Agrico filed notice of withdrawal of its petition.

In Docket No. 971337-EI, IMC-Agrico and Duke Mulberry Energy, L.P. petitioned the FPSC for a declaratory statement that the joint venture to construct and own a generation plant gave them standing as an "Applicant" under the Power Plant Siting Act to seek a Determination of Need from the FPSC for the proposed plant. On November 17, 1976, Florida Power filed a Petition for Leave to Intervene, asserting that the declaration being sought raised broad and serious policy questions that are inappropriate for consideration in a declaratory statement proceeding. On December 16, 1997, the FPSC agreed with the Florida Power position and denied the IMC-Agrico/Duke petition. The FPSC directed its staff to review the matter and submit recommendations on the appropriate proceeding to be utilized in reviewing similar merchant plant requests.

In Docket No. 971446-EI, Duke Energy New Smyrna Beach Power Company, LLP petitioned the FPSC for a declaratory statement that its proposed plant near New Smyrna Beach gave it standing as an "Applicant" under the Power Plant Siting Act. On December 16, 1997, the FPSC denied the petition on the same grounds as reported regarding FPSC Docket No. 971337-EI, above.

This concludes the IMC-Agrico, Duke Mulberry Energy, L.P. and Duke Energy New Smyrna Beach Power Company, LLP petitions for reporting purposes.

14. Florida Power Corporation and Seminole Electric Cooperative v. Ronald J. Schultz, Circuit Court for Citrus County

On December 15, 1997, Florida Power and Seminole filed suit against the Citrus County Property Appraiser and Citrus County Tax Collector contesting 1997 ad valorem tax assessments on pollution control equipment at the Crystal River site. Florida Power is seeking, among other things, a $5 million refund of all taxes paid in excess of those lawfully due.

Under Florida Statutes, pollution control facilities are subject to assessment for ad valorem taxation at an amount which does not exceed the market value of such facilities as salvage. Florida Power contends that the 1997 assessment has the effect of assigning a taxable value to Florida Power's pollution control equipment of approximately $286 million. On February 19, 1998, Property Appraiser Schultz filed a motion for summary judgment.

15. Calgon Carbon Corporation v. Potomac Capital Investment Corporation, Potomac Electric Power Company, Progress Capital Holdings, Inc., and Florida Progress Corporation, United States District Court for the Western District of Pennsylvania, Civil Action No. 98-0072.

Calgon Carbon Corporation ("Calgon") filed a complaint on January 12, 1998, asserting securities fraud, breach of contract and other claims in connection with the sale to it by two of the defendants in December 1996

in Advanced Separation Technologies, Incorporated ("AST"), a corporation engaged in the business of designing and assembling proprietary separation equipment. Prior to closing, Progress Capital, a wholly owned subsidiary of Florida Progress, owned 80 percent of the outstanding stock of AST and Potomac Capital Investment Corporation (an entity unaffiliated with PCH or Florida Progress) owned 20 percent. Calgon paid PCH an aggregate of approximately $57.5 million in respect of PCH's share of AST's stock. Calgon claims that AST's assets and revenues were overstated and liabilities and expenses were understated for 1996. Calgon also alleges undisclosed facts relating to accounting methodology, poor products, manufacturing and quality control problems and undisclosed warranty claims. Calgon seeks damages, punitive damages and the right to rescind the purchase. Florida Progress and PCH intend to vigorously defend this case.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

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PART II

ITEM 5. MARKET FOR THE REGISTRANTS' COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

FLORIDA PROGRESS

Florida Progress' common stock is listed on the New York Stock Exchange and the Pacific Stock Exchange. The high and low price per share of Florida Progress' common stock for each quarterly period and the dividends per common share paid on shares of Florida Progress' common stock during the last two fiscal years appear in Item 8 on the "Quarterly Financial Data" table for Florida Progress at the end of the Notes to the Financial Statements, and is incorporated herein by reference.

In February 1998, Florida Progress' Board announced an increase of 4 cents per share in the common stock quarterly dividend, which on an annual basis would increase the dividend from $2.10 to $2.14 per share. This represents an annual dividend growth rate of 1.9%. In 1997, Florida Progress' dividend payout ratio from continuing operations before non-recurring items was 80.18% of earnings. Information concerning the Florida Progress dividend payout ratio and dividend policy is set forth in Item 7 "MD&A - Liquidity and Capital Resources".

Florida Progress' Restated Articles of Incorporation do not limit the dividends that may be paid on its common stock. However, the primary source for payment of Florida Progress' dividends consists of dividends paid to it by Florida Power. Florida Power's Amended Articles of Incorporation and its Indenture dated as of January 1, 1944, under which it issues first mortgage bonds, contain provisions restricting dividends in certain circumstances. At December 31, 1997, Florida Power's ability to pay dividends was not limited by these restrictions.

Florida Progress and Progress Capital have entered into a Second Amended and Restated Guaranty and Support Agreement dated as of August 7, 1996, pursuant to which Florida Progress has unconditionally guaranteed the payment of Progress Capital's debt (as defined in the agreement).

Florida Progress did not sell any equity securities during 1997 that were not registered under the Securities Act.

The approximate number of equity security holders of Florida Progress is as follows:

Title of Class	Number of Registered Holders* as of December 31, 1997
Common Stock without par value	48,550

* The computation of registered holders includes record holders as well as individual positions in the Progress Plus Stock Plan.

FLORIDA POWER

All of Florida Power's common stock is owned by Florida Progress, and as a result there is no established public trading market for the stock. For the past three years, Florida Power has paid quarterly dividends to Florida Progress totaling the amounts shown in the Statements of Shareholder's Equity in the Financial Statements.

Florida Power's amended articles of incorporation, and its Indenture dated as of January 1, 1944, as supplemented, under which it issues first mortgage bonds, contain provisions restricting dividends in certain circumstances. At December 31, 1997, Florida Power's ability to pay dividends was not limited by these restrictions.

ITEM 6. SELECTED FINANCIAL DATA

	Annual Growth Rates (in percent) 1992-1997	1997	1996	1995	1994	1993	1992
FLORIDA PROGRESS CORPORATION							
Summary of operations (in millions)							
Utility revenues	6.7	$2,448.4	$2,393.6	$2,271.7	$2,080.5	$1,957.6	$1,774.1
Diversified revenues (continuing)	25.3	867.2	764.3	736.1	644.8	430.3	281.1
Income from continuing operations	(21.6)	54.3	250.7	238.9	212.0	196.0	183.8
Income (loss) from discontinued operations and change in accounting	-	-	(26.3)	-	-	0.6	(8.1)
Net income	(20.9)	54.3	224.4	238.9	212.0	196.6	175.7
Balance sheet data (in millions):							
Total assets	3.0	$5,760.0	$5,348.4	$5,550.4	$5,453.1	$5,338.0	$4,978.8
Capitalization:							
Short-term capital	5.3	$ 230.0	$ 39.0	$173.7	$ 99.9	$195.2	$177.6
Long-term debt	7.6	2,377.8	1,776.9	1,662.3	1,835.2	1,840.5	1,651.3
Preferred stock	(31.1)	33.5	33.5	138.5	143.5	148.5	216.0
Common stock equity	.4	1,776.0	1,924.2	2,078.1	1,984.4	1,820.5	1,737.6
Total capitalization	3.2	$4,417.3	$3,773.6	$4,052.6	$4,063.0	$4,004.7	$3,782.5
Common stock data:							
Average shares outstanding (in millions)	2.6	97.1	96.8	95.7	93.0	88.3	85.4
Earnings per share:							
Utility	(7.1)	$1.38	$2.40	$2.27	$2.05	$2.06	$1.99
Diversified (continuing)		(.82)	.19	.23	.23	.16	.16
Discontinued operations and change in accounting	-	-	-	(.27)	-	-	.01	(.09)
Consolidated	(22.9)	.56	2.32	2.50	2.28	2.23	2.06
Dividends per common share	2.0	2.10	2.06	2.02	1.99	1.95	1.905
Dividend payout		375.3%	88.9%	81.0%	87.7%	87.6%	93.0%
Dividend yield		5.4%	6.4%	5.7%	6.7%	5.9%	5.9%
Book value per share of common stock	(1.6)	$18.30	$19.84	$21.55	$20.85	$20.40	$19.85
Return on common equity		2.9%	10.9%	11.8%	11.1%	11.1%	10.6%
Common stock price per share:							
High		39 1/4	36 3/8	35 3/4	33 5/8	36 3/8	33 1/4
Low		27 3/4	31 5/8	29 3/8	24 3/4	31 1/4	27 7/8
Close	3.8	39 1/4	32 1/4	35 3/8	30	33 5/8	32 5/8
Price earnings ratio (year-end)		70.1	13.9	14.2	13.2	15.1	15.8
Other year-end data:							
Number of employees	1.8	7,990	7,291	7,174	7,394	7,825	7,301

[CONTINUED ON NEXT PAGE]

	Annual Growth Rates (in percent) 1992-1997	1997	1996	1995	1994	1993	1992
FLORIDA POWER CORPORATION							
Electric sales (million of KWH)							
Residential	3.3	15,079.8	15,481.4	14,938.0	13,863.4	13,372.6	12,825.8
Commercial	4.2	9,257.3	8,848.0	8,612.1	8,252.1	7,884.8	7,544.1
Industrial	5.2	4,187.8	4,223.7	3,864.4	3,579.6	3,380.8	3,254.5
Total retail sales	4.0	30,850.3	30,784.8	29,499.5	27,675.2	26,528.3	25,414.0
Total electric sales	4.0	33,289.9	33,492.5	32,402.6	30,014.6	28,647.8	27,375.5
Residential service (average annual):							
KWH sales per customer	1.2	12,993	13,560	13,282	12,597	12,420	12,214
Revenue per customer	4.8	$1,115	$1,138	$1,114	$1,038	$983	$884
Revenue per KWH	3.5	$0.0858	$0.0839	$0.0839	$0.0824	$0.0792	$0.0724
Financial Data:							
Operating revenues	6.7	$ 2448.4	$2,393.6	$2,271.7	$2,080.5	$1,957.6	$1,774.1
Net income after dividends on preferred stock	(4.6)	$ 134.4	$ 232.6	$217.3	$190.7	$181.5	$170.2
Total assets	4.2	$4,900.8	$4,264.0	$4,284.9	$4,284.5	$4,259.5	$3,980.6
Long-term debt and preferred stock subject to mandatory redemption	5.8	$1,745.4	$1,296.4	$1,304.1	$1,393.8	$1,433.6	$1,318.3
Total capitalization including short-term debt (in millions)	4.2	$3,727.7	$3,180.8	$3,202.2	$3,265.4	$3,240.4	$3,029.2
Capitalization ratios:							
Short-term capital	2.2	4.9%	0.8%	1.0%	2.8%	5.3%	4.4%
Long-term debt	2.8	46.8%	40.8%	39.9%	41.7%	43.1%	40.8%
Preferred stock	(33.8)	.9%	1.0%	4.3%	4.4%	4.6%	7.1%
Common stock equity	(.1)	47.4%	57.4%	54.8%	51.1%	47.0%	47.7%
Ratio of earnings to fixed charges (SEC method)	(6.5)	2.75	4.80	4.41	3.90	3.83	3.84
Embedded cost of long-term debt	(1.4)	7.0%	7.2%	7.2%	7.1%	6.8%	7.5%
Embedded cost of preferred stock	(8.8)	4.6%	4.6%	6.8%	6.8%	6.8%	7.3%
Operating Data:							
Net system capacity (MW)	2.0	7,717	7,341	7,347	7,295	7,563	6,998
Net system peak load (MW)	2.9	8,066	8,807	7,722	6,955	6,729	6,982
Capital expenditures (in millions)	(3.9)	$387.2	$217.3	$283.4	$319.5	$426.4	$472.9
Net cash flow to capital expenditures	7.9	76%	175%	125%	103%	63%	52%
Fuel cost per million BTU	3.8	$2.24	$2.04	$1.69	$1.75	$1.79	$1.86
Average number of customers	2.1	1,314,508	1,292,075	1,271,784	1,243,891	1,214,653	1,182,170
Number of full-time employees	(3.7)	4,799	4,629	4,658	4,972	5,807	5,806

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OPERATING RESULTS

Florida Progress' 1997 consolidated earnings from continuing operations were $54.3 million. This compares to $250.7 million in 1996 and $238.9 million in 1995. Florida Progress' 1997 operating results were negatively impacted by the extended outage of Florida Power's Crystal River nuclear plant and the provision for loss on its investment in Mid-Continent Life Insurance Company. These two events reduced Florida Progress' 1997 earnings by $200 million or $2.06 per share.

Excluding these one-time charges, Florida Progress' 1997 consolidated earnings from continuing operations were $254.3 million. This compares with $252.4 million in 1996 and $238.9 million in 1995. Florida Power earned $240.9 million in 1997 before nuclear outage costs, compared with $232.6 million in 1996 and $217.3 million in 1995. Earnings from recurring diversified operations were $13.4 million in 1997, compared with $19.8 million in 1996 and $21.6 million in 1995.

EARNINGS PER SHARE

	1997	1996	1995
Florida Power Corporation	$2.48	$2.40	$2.27
Electric Fuels Corporation	.33	.28	.25
Mid-Continent Life Ins. Co.	-	.02	.07
Other	(.19)	(.09)	(.09)
Diversified	.14	.21	.23
Continuing operations before nonrecurring items	2.62	2.61	2.50
Nuclear outage costs	(1.10)	-	-
Loss related to Mid-Continent Life Ins. Co.	(.96)	-	-
Provision for loss on coal properties	-	(.26)	-
Gain on sale of business	-	.24	-
Total continuing operations	.56	2.59	2.50
Discontinued operations	-	(.27)	-
Consolidated	$ .56	$2.32	$2.50

Excluding nuclear outage costs, Florida Power's 1997 earnings per share were up 3.3 percent over 1996, primarily due to strong customer growth. During 1997, Florida Power added more than 22,000 customers. Customer growth among residential and commercial customers averaged about 2 percent in 1997 and 1996. Florida Power's Crystal River nuclear plant was out of service during 1997 to address design issues related to the plant's safety systems. As a result of the outage, Florida Power's earnings were reduced by $1.10 per share. This resulted from $100 million in additional nuclear operating and maintenance expenses and $73 million of disallowed replacement power costs. (See Item 7, "MD&A - Nuclear Outage Costs".)

In April 1997, Mid-Continent Life Insurance Company was placed in receivership over allegations that its policy reserves were inadequate. While Mid-Continent has appealed an Oklahoma district court judge's ruling to keep Mid-Continent in receivership, Florida Progress has recorded a provision for the loss on its investment in Mid-Continent as well as an accrual for legal fees for pending litigation. This resulted in a $.96 after-tax charge to 1997 earnings. (See Item 7, "MD&A - Mid-Continent Life Insurance Company".)

In 1996, Florida Progress divested Echelon International Corporation, formerly Progress Credit Corporation, through a tax-free stock dividend. This resulted in a $26.3-million charge to earnings for the write-down of certain assets of Echelon and other costs. Also in 1996, Florida Progress sold its 80-percent interest in Advanced Separation Technologies, Inc. for $56 million and realized an after-tax gain of $23.5 million, or $.24 per share.

Lastly, Electric Fuels recorded a $25.2-million after-tax charge to 1996 earnings to establish a provision for loss on its unprofitable coal properties, now available for sale. The provision was necessary because management did not consider the unfavorable market conditions for low-sulfur coal to be temporary. While significant, the one-time charges incurred in 1997 and 1996 should not affect the future earnings prospects of Florida Progress. Florida Power's growing customer base and good cost control combined with the expanding operations of Electric Fuels are the fundamental drivers of earnings growth for Florida Progress. The growth of these core businesses is forecasted to provide earnings per share growth of four to five percent annually for Florida Progress over the next five years.

The financial return on Florida Power's common equity was 13 percent in 1997 before considering nonrecurring items, compared with 12.9 percent in 1996 and 12.7 percent in 1995. Florida Power's above average customer growth and continued control over operating and maintenance costs should enable Florida Power to maintain its return on equity and continue its earnings growth while pursuing strategic initiatives designed to prepare the utility for a more competitive environment. Return on equity from the energy and transportation

subsidiary was 17.3 percent in 1997, 14 percent in 1996 before its provision for loss on coal properties and 13.8 percent in 1995.

FLORIDA POWER CORPORATION

Utility Competition - Industry Restructuring

The electric utility industry is undergoing changes designed to increase competition in an industry that, since inception, has been considered a natural monopoly. Starting with the Public Utilities Regulatory Policies Act of 1978 ("PURPA") and the Energy Policy Act of 1992 ("EPA of 1992"), competition in the wholesale electric generation market has greatly increased, especially from non-utility generators of electricity.

In 1996, the FERC issued new rules on transmission service to facilitate competition in wholesale generation on a nationwide basis. The rules give greater flexibility and more choices to wholesale power customers.

The effect of these changes on the wholesale generation market has been significant. In the last five years, power supplied by non-utility generators has increased over 100 percent. From 1990 through 1995, non-utility generation capacity grew at a rate of 47 percent, compared to utility generation capacity which grew at a rate of two percent.

Electricity in Florida is supplied largely through existing generation capacity located in the state. Florida's peninsular shape and limited transmission access into the state set Florida apart from other regions of the country.

The amount of electricity that presently can be imported into Florida from adjoining states is limited to about ten percent of the total daily demand for electricity in Florida. Most of the demand for electricity is in the southern portion of the state, which increases the amount of transmission line losses when importing electricity from a generating source outside the state.

These two unique characteristics of Florida make it difficult to compete in the Florida wholesale generation market without access to generation resources within the state.

The regulatory changes described above relate to the wholesale market for electricity which is regulated by federal law. The sale of electricity to residential, commercial and industrial customers is governed by the states. To date, several states have adopted legislation that would give retail customers the right to choose their electricity provider (retail choice) and many other states are considering the issue.

California, Pennsylvania and some states in the New England region, where legislation to allow retail choice has passed, have rates that are well above the national average. In states where electricity rates are more competitive, such as Florida, there has been less incentive to push forward legislative proposals concerning retail choice.

In addition to restructuring activity in various states, there have been several industry restructuring bills introduced in Congress. A key issue concerning the passage of any industry restructuring legislation by federal lawmakers is whether the federal government has the authority to mandate legislation by the states. Several of the federal bills being considered require states to implement retail choice between 2000 and 2003.

The changes taking place in the industry today have caused many companies to develop new corporate strategies. Some of these corporate strategies include alliances, mergers with or acquisitions of other electric or gas utilities or other types of service providers including home security and telecommunications companies.

During the last five years there have been 30 mergers or acquisitions of investor-owned utilities announced, of which 11 have been completed and the others are either pending regulatory approval or have been

While it may be several years before retail choice exists in Florida, Florida Progress believes that retail choice will eventually exist in every state. Florida Progress has developed a corporate strategy to compete in a more competitive marketplace. Florida Progress is focused on establishing a national retail energy services business to efficiently develop new products and services for its customers.

To be successful in this market, a retail services company will likely need a sizeable number of customers in order to realize the economies of scale necessary to keep the cost of such products and services competitive. Florida Progress has set a goal of achieving a customer base of at least 10 million and will pursue this goal through joint ventures, alliances, mergers, acquisitions or some combination thereof. In September 1997, Florida Progress entered into a joint venture with two other utilities, Cinergy Corp. and New Century Energies. The joint venture, named Cadence, is a marketing alliance aimed at providing national chain account customers with a variety of energy management services and products.

An important and frequently contentious issue surrounding industry restructuring is the recovery of "stranded costs." Stranded costs include the generation assets of utilities whose value in a competitive marketplace would be less than their current book value as well as above-market purchased power commitments to QFs. States that have passed legislation for industry restructuring have provided for utilities to recover some portion of their stranded costs.

Assessing the amount of stranded costs for a utility requires various assumptions about future market conditions including the future price of electricity. For Florida Power, the single largest stranded cost issue lies with its commitments to QFs.

Florida Power is continuing to seek ways to mitigate the impact of escalating payments from contracts it was obligated to sign under provisions of the federal Public Utilities Regulatory Policies Act of 1978. (See Item 3, "Legal Proceedings", Paragraphs 1-4.)

In 1997 Florida Power reduced its purchased power commitments by over 20 percent through the buy-out of the Tiger Bay purchased power contracts.

Utility Revenues and Sales

Florida Power's operating revenues were $2.4 billion in 1997 and 1996, compared to $2.3 billion in 1995.

The utility's retail kilowatt-hour sales were essentially level in 1997 when compared to 1996. The lack of sales growth was due primarily to milder weather in 1997 than 1996. Kilowatt-hour sales in 1996 were up 2.9 percent when compared to 1995.

Normally, Florida Power's revenues are heavily influenced by weather, especially among residential customers. However in 1995, Florida Power, as ordered by the Florida Public Service Commission, began a three-year test of residential revenue decoupling. This ratemaking concept is designed to eliminate the direct link between kilowatt-hour sales and revenues. Under revenue decoupling, abnormal weather does not impact earnings from residential sales, which represents the single-largest customer group for Florida Power. A change in customer usage due to extreme heating or cooling conditions would not have a material effect on Florida Power's earnings, whereas customer growth and higher usage due to nonweather-related factors can affect earnings.

Over the three-year period, the earnings impact of residential revenue decoupling was not material. As of December 31, 1997, the cumulative adjustment to revenues was a reduction of less than $.5 million. Florida Power does not intend to seek approval to use residential revenue decoupling beyond 1997. The termination of residential revenue decoupling will likely result in Florida Power's earnings being subject to greater fluctuation due to changes in weather. (See Note 1 "Summary of Significant Accounting Policies", Notes to the Financial Statements.)

Fuel and Purchased Power

Fuel and purchased power costs are recovered primarily through an adjustment recovery clause established by state and federal regulators. Fluctuations in these costs have little impact year to year on net income, but could become increasingly important in a more competitive environment.

Factors influencing fuel and purchased power costs include demand for electricity, the availability of generating plants and the price of electricity purchased from QFs and other utilities.

Total fuel and purchased power expenses for 1997, including amounts incurred as a result of the nuclear outage, were up $80.7 million over 1996 due largely to the extended outage of Florida Power's Crystal River nuclear plant. The outage forced Florida Power to replace nuclear generation with other, higher-cost replacement power. (See "Extended Nuclear Outage Costs" contained herein.)

In 1996, fuel and purchased power expenses increased $73.5 million compared to 1995. This was due to increased purchased power costs and higher system requirements.

The nuclear plant is not scheduled to be taken out of service until 1999, which will be for refueling. Having the nuclear plant in service for most of 1998 should help lower Florida Power's fuel and purchased power costs for 1998 when compared to 1997. (See Item 7, "MD&A - Extended Nuclear Outage Costs".)

As mentioned above, a key factor influencing Florida Power's purchased power costs are the prices paid to QFs for electricity. Currently, Florida Power receives 831 megawatts of total capacity from QFs. This amount is down 220 megawatts from 1996 due to the buy-out of the Tiger Bay purchased power contracts. (See Item 7, "MD&A - Impact of Tiger Bay Buy-Out".)

In addition to the Tiger Bay buy-out, the FPSC approved Florida Power's buy-out of the last four years and seven months of a cogeneration contract between Florida Power and Pasco Cogen Ltd.

In 1997, Florida Power spent $233.6 million for purchased power under all cogeneration contracts. This represented approximately 23% of system fuel and purchased power expenses for the year.

Costs associated with those contracts raised Florida Power's system average cost for generation in 1997 and 1996, and this trend is expected to continue based on the contracts currently in place and the escalating payment schedules associated with each contract.

Florida Power will continue its effort to mitigate the impact of escalating payments from its purchased power contracts. Under the provisions of PURPA, Florida Power was obligated to sign contracts with those QFs.

Florida Power's present strategy is to pursue opportunities to buy-down or buy-out those contracts whose prices are projected to be above future market prices.

While this strategy requires paying higher amounts in the short-term, the long-term benefit to customers can be significant. Long-term savings to customers resulting from the buy-out of the Tiger Bay purchased power contracts are estimated to be more than $2 billion over the next 30 years.

Other Utility Expenses

Utility operation and maintenance expenses increased by $8.9 million in 1997 exclusive of nuclear outage costs. The increase was due primarily to costs associated with planned fossil plant outages and expenditures designed to improve reliability and customer service.

In 1996, operation and maintenance expenses increased by $19.7 million when compared with the previous year, primarily due to additional costs associated with the outage of the nuclear plant as well as expenses related to improving service and reliability.

Cost control is a primary focus of each strategic business unit at Florida Power as each looks for ways to efficiently meet its customers' needs. This has resulted in Florida Power's recurring operation and maintenance costs growing at an annual rate below inflation since 1994.

It is one of management's goals to continue to limit increases in operation and maintenance costs to less than the national inflation rate.

Recoverable energy conservation program costs increased by $4.4 million in 1997 over 1996. In 1996 these costs decreased by $21.4 million from the previous year due to a reduction in the credits paid to customers who participated in Florida Power's load management program.

The change had no significant impact on earnings because Florida Power recovers substantially all of these costs through a clause in electric rates similar to the fuel adjustment clause. Florida Power does not expect the level of energy conservation costs to vary materially in the future from the 1997 expenditure level since little growth is forecast for this program.

In 1997, Florida Power wrote-off approximately $20 million of contract termination costs related to the Tiger Bay buy-out. In 1996, Florida Power amortized approximately $31 million related to two oil-fired power plants and a canceled transmission line.

Extended Nuclear Outage Costs

In September 1996, Florida Power's Crystal River nuclear plant was taken out of service to fix an oil pressure problem in the main turbine. When the repairs were completed in October 1996, Florida Power decided to keep the plant shut down to address certain backup safety system design issues.

The NRC had been critical of the plant's overall performance in 1996 and in January 1997 placed the nuclear plant on its "Watch List" as a plant whose operations would be monitored closely until Florida Power demonstrates a period of improved performance. In March 1997, the NRC outlined necessary actions Florida Power must complete before returning the nuclear plant to service.

In late January 1998, Florida Power notified the NRC that it had completed all of the requirements and was subsequently granted permission to restart the plant. Florida Power's Crystal River nuclear plant returned to service in February 1998.

Florida Power's operating results for 1997 were significantly impacted by the costs associated with the extended outage. These costs included $100 million in additional operation and maintenance expenses and approximately $173 million in replacement power costs. Capital expenditures related to the outage were $42 million in 1997.

In June 1997, the FPSC approved a settlement agreement between Florida Power and several parties who objected to Florida Power recovering replacement power costs resulting from the extended outage.

The settlement allows Florida Power to recover, through rates charged to customers, approximately $38 million of $174 million of replacement power costs incurred from September 1996 through December 1997. Florida Power can begin recovering the $38 million once the plant has been operating at 100-percent power for 14 consecutive days. Of the remaining $136 million, $63 million was recorded as a regulatory asset and is being amortized over four years. The remaining $73 million was expensed in 1997 and, along with the $100 million of additional operation and maintenance costs, is classified as "Extended Nuclear Outage Costs" on the consolidated statements of income. The amortization of the

$63-million regulatory asset is being recovered by the suspension of an annual accrual for fossil plant dismantlement costs for a period of up to four years.

Actual replacement power costs incurred in 1998 prior to the nuclear plant's return to service will be expensed as incurred.

The settlement agreement also provided that, for purposes of monitoring Florida Power's earnings, the FPSC would exclude the nuclear outage costs when assessing Florida Power's regulatory return on equity. Florida Power is currently allowed to earn between 11 and 13 percent on its common equity. By excluding these outage costs, Florida Power's future earnings capacity will not be penalized for the one-time charge for outage costs.

Impact of Tiger Bay Buy-Out

In July 1997, Florida Power bought-out the purchased power contracts related to Tiger Bay, a 220-megawatt cogeneration facility. In addition to buying-out the purchased power contracts, Florida Power acquired the 220-megawatt facility. Costs associated with the termination of the purchased power contracts and the acquisition of the facility totaled $445 million. Tiger Bay was Florida Power's largest cogeneration supplier, representing more than 20-percent of Florida Power's total capacity received from QFs. The purchase was funded primarily through the issuance of medium-term notes with maturities ranging from two to 10 years at interest rates between six and seven percent.

The FPSC-approved purchase allowed Florida Power to record a regulatory asset of approximately $350 million for contract termination costs and add $75 million to its electric plant.

Florida Power continues to collect from customers an amount equal to what it would have been allowed to recover for capacity and energy payments made in accordance with the original Tiger Bay purchased power contract. Based on the contract's capacity payment schedule, Florida Power should recover enough revenues by the year 2008 to fully amortize the regulatory asset and related interest charges.

The Tiger Bay expenses including operation and maintenance, depreciation, interest and property taxes are expected to be absorbed through Florida Power's growing base revenues. These additional expenses are expected to be about $20 million annually. The utility's base revenues increase largely from the addition of new retail customers, particularly residential customers.

DIVERSIFIED OPERATIONS

In 1997, Florida Progress established a provision for loss on its $87 million investment in Mid-Continent Life Insurance Company and accrued for litigation costs. (See Item 7, "MD&A - Mid-Continent Life Insurance Company".) In 1996, Florida Progress made two restructuring decisions that had a significant impact on earnings from diversified operations. The spin-off of Echelon resulted in a $26.3-million after-tax charge to earnings while the sale of Advanced Separation Technologies contributed an after-tax gain of $23.5 million. Another item that affected 1996 diversified earnings was the provision for loss on unprofitable coal properties owned by Electric Fuels. This resulted in an after-tax charge of $25.2 million.

The actions taken to restructure its diversified operations reflect management's commitment to establishing a diversified group of businesses more closely aligned to its core utility operations.

Electric Fuels Corporation

Electric Fuels, Florida Progress' energy and transportation subsidiary, has three principal business units: energy and related services, inland marine transportation, and rail services. Florida Progress continues to build on Electric Fuels' existing operations through internal expansion and by pursuing new market opportunities, primarily with its inland marine transportation and rail services units.

Over the last five years Electric Fuels has grown significantly:

	1993	1994	1995	1996	1997	Five-Year Growth Rate
			(In millions)			
Revenues	$ 581	$ 784	$ 844	$ 881	$1,037	17.4%
Earnings	$14.9	$22.6	$24.0	$27.1*	$ 32.1	21.6%
Assets	$ 397	$ 489	$ 574	$ 620	$ 799	19.4%

*Before provision for loss on coal properties

Most of the growth of Electric Fuels has come from acquisitions in its rail services business unit and expansion of the inland marine barge fleet.

During 1997 and 1996, Progress Rail expanded its operations through acquisitions of railcar wheel shops, rail welding, and rail anchor manufacturing operations, railcar leasing and metal recycling operations. Over this period Progress Rail's acquisitions totaled nearly $71 million.

Today, Progress Rail is one of the largest integrated suppliers of rail services in the United States, with locations in 16 states. Revenues from rail services in 1997 were $476.3 million, an increase of $122.6 million or 35 percent over 1996. The increase reflects the expansion of these operations as well as an increase in demand for rail services as railroads continue outsourcing certain service and repair needs.

Expansion of MEMCO, Electric Fuels' inland marine transportation unit, has been achieved primarily through the purchase of river barges. MEMCO's fleet of barges, which hauls coal, agricultural products and other dry bulk products along the Ohio and lower Mississippi rivers, totaled approximately 900 at the end of 1997. During 1997 and 1996 MEMCO added approximately 300 new high-capacity river barges to its fleet and plans to purchase 200 additional barges and two new towboats in 1998.

Further expansion of the barge fleet depends largely on the future demand for barge capacity and MEMCO's ability to secure long-term contracts for hauling. MEMCO's objective is to maintain at least 70 percent of its barge capacity under long-term contracts. The remaining capacity is used to take advantage of new market opportunities as they arise.

Electric Fuels' energy and related services business unit includes coal operations, river terminal services and off-shore marine transportation. Annual sales of coal average about 12 million tons of which five to six million tons are sold to Florida Power. In 1997, increased tonnage of coal transported by Electric Fuels' energy and related business unit resulted in improved earnings compared to 1996. In December 1996, Electric Fuels established a provision for loss on certain coal properties after it determined that depressed market conditions for low-sulfur coal were not temporary. The impact of the write-down was a one-time after-tax charge to earnings of $25.2 million.

Electric Fuels' business plan for its coal operations includes supplying Florida Power with high-quality, competitively-priced coal and increasing output from company-operated mines which can be directed to more profitable niche markets. Earnings from Electric Fuels in 1997 were $32.1 million, up $5 million over 1996 earnings before the provision for loss on unprofitable coal properties. Although Electric Fuels' earnings continued to grow at a double-digit rate, 1997 earnings were lower than Electric Fuels' target for the year because of March floods along the Ohio and Mississippi rivers that temporarily disrupted barge traffic and terminal services.

Partially offsetting the impact of the floods were increased earnings from rail services and the energy and related services business units. Acquisitions and higher production at a trackworks facility contributed to the improved results at Progress Rail. Increased coal deliveries to Florida Power's Crystal River coal units resulted in higher volumes of coal transported by the energy and related services division.

The higher volume was due largely to increased coal requirements of Florida Power's coal-fired plants. The lack of availability of its nuclear plant in 1997 forced Florida Power to increase the generation of its coal plants.

Mid-Continent Life Insurance Company

When Mid-Continent was acquired in 1986, it sold a popular, low-priced death-benefit insurance policy. In 1996, Mid-Continent replaced this policy with a new product after it was determined that premiums on the old policy would have to be raised.

Mid-Continent was hoping to rebuild market share and achieve increased profitability with the new product, but sales did not meet management's expectations. In December 1996, Mid-Continent reduced its work force in an effort to compete on a more focused and cost-efficient basis and was developing a plan to raise premiums on its prior low-priced death benefit policy.

The business plan would increase premiums and lower dividends so that a projected reserve shortfall in 2020 could be avoided. Mid-Continent discussed the outline of its plan with the Insurance Commissions of both Texas and Oklahoma, states where the majority of Mid-Continent's policyholders reside.

On April 14, 1997, the Oklahoma Commissioner obtained approval from the Oklahoma County District Court to temporarily seize control of the operations of Mid-Continent. The Commissioner claimed that Mid-Continent's policy reserves were currently understated and that Mid-Continent could not raise premiums to address this issue.

During hearings on this matter, the Commissioner's actuary conceded that if Mid-Continent could raise premiums, it was not insolvent. Although the judge agreed with Mid-Continent that it had the right to raise premiums, in May he ordered Mid-Continent to remain in receivership. Both sides appealed the decision to the Oklahoma Supreme Court.

In December 1997, the Commissioner filed a lawsuit against Florida Progress and certain directors and officers making a number of allegations and seeking access to Florida Progress' assets to satisfy policy holder and creditor claims.

On February 13, 1998, the Commissioner filed with the court a "report Regarding Rehabilitation Plan". This report did not put forward a serious rehabilitation plan, but rather stated that the Commissioner has filed a petition seeking recovery of damages from Florida Progress and certain directors and officers, the proceeds of which would be used to offset the alleged reserve deficiencies.

On February 26, 1998, the defendants filed motions to dismiss the petition and Mid-Continent filed a response to the report regarding the Commissioner's rehabilitation plan and requested approval of its proposed plan of rehabilitation. Mid-Continent's proposed rehabilitation plan presents a multi-faceted approach to rehabilitation, including raising premiums. A hearing before the court has been set on March 17, 1998, for the proposed rehabilitation plans. A hearing before the court has been set on the motions to dismiss on April 17, 1998.

Florida Progress intends to vigorously defend itself and other defendants against these charges and support Mid-Continent in its efforts to gain the court's approval of its rehabilitation plan.

The actions taken by the Commissioner significantly impacted Mid-Continent's business plan for addressing its projected reserve deficiency, leading Florida Progress to conclude that the full amount of its $86.9 million investment in Mid-Continent at December 31, 1997 was impaired. As a result, Florida Progress recorded a provision for loss on its investment in December 1997 and accrued for estimated legal costs, resulting in a $.96 per share reduction to 1997 earnings.

Other

Florida Progress does not anticipate incurring significant costs related to modifications of Florida Progress' information systems to prepare for the year 2000. In addition, Florida Progress expects to complete the modifications on time.

Florida Progress has adopted several new accounting standards during the last three years. (See Note 1 "Summary of Significant Accounting Policies", Notes to the Financial Statements.)

Florida Power and a former company subsidiary have been notified by the U.S. Environmental Protection Agency that each is or may be a potentially responsible party for the cleanup costs of several contaminated sites. (See Note 11 "Commitments and Contingencies", Notes to the Financial Statements.)

Florida Progress has off-balance sheet risk related to debt of unconsolidated partnerships. (See Note 11 "Contingencies", Notes to the Financial Statements.) Florida Power entered into a single forward treasury lock agreement in 1997 to effectively fix the treasury rate component of an anticipated issuance of medium-term notes. (See Note 2 "Financial Instruments", Notes to the Financial Statements.)

Florida Progress is involved in other litigation as described in Note 11, "Commitments and Contingencies", Notes to the Financial Statements.

Even though the inflation rate has been relatively low during the last three years, inflation continues to affect Florida Progress by reducing the purchasing power of the dollar and increasing the cost of replacing assets used in the business. This has a negative effect on Florida Power because regulators generally do not consider this economic loss when setting utility rates. However, such losses are partly offset by the economic gains that result from the repayment of long-term debt with inflated dollars.

LIQUIDITY AND CAPITAL RESOURCES

Cash from operations has been the primary source of capital for Florida Progress. Other sources of capital over the last three years include proceeds from the sales of properties and businesses, debt financing, issuance of common stock and the orderly withdrawal from Florida Progress' lending and leasing and real estate portfolio.

Florida Progress has issued new equity in recent years primarily to fund Florida Power's construction program. Florida Power is forecasting lower construction expenditures in the years ahead. The utility does not expect construction to require any significant increase in equity or debt over the next five years. Because of the reduced equity requirements, the dividend reinvestment plan began purchasing shares in the open market instead of issuing new shares beginning in July 1996.

For the first half of 1996 and for all of 1995 approximately $57 million of new equity was issued through Florida Progress' dividend reinvestment plan.

Florida Progress contributed $12.5 million in 1996 and $50 million in 1995 to Florida Power from the proceeds of the dividend reinvestment plan. These funds were used to further strengthen Florida Power's financial position.

Florida Progress' capital structure as of December 31, 1997, was 40.2 percent common equity, 59 percent debt and .8 percent preferred stock of Florida Power. On December 31, 1996, Florida Progress' capital structure was 51 percent common equity, 48.1 percent debt and .9 percent preferred stock. The increase in debt in 1997 over 1996 is due primarily to the buy-out of the Tiger Bay purchased power contracts. Florida Progress' current goal is to maintain capital structures for its utility and diversified operations at levels that will enable its subsidiaries to preserve their current credit ratings.

CREDIT RATINGS

	Standard & Poor's	Moody's	Duff & Phelps
Florida Power Corporation			
First mortgage bonds	AA-	Aa3	AA-
Medium-term notes	A+	A1	A+
Commercial paper	A-1+	P-1	D-1+
Progress Capital Holdings, Inc.			
Medium-term notes	A	A2	
Commercial paper	A-1	P-1	

Florida Power Corporation

Florida Power's construction expenditures in 1997 totaled about $387 million. This was primarily for distribution lines related to the utility's growing customer base and the construction of a new 470-megawatt power plant scheduled to begin commercial operation in the fall of 1998. Florida Power's five-year construction program totals $1.2 billion for the 1998-2002 forecast period. It includes planned expenditures of $294 million, $263 million, $210 million, $268 million and $204 million for 1998 through 2002. Florida Power expects these construction expenditures will be financed primarily with internally generated funds.

In July 1997, Florida Power issued $450 million of medium-term notes primarily to finance the buy-out of purchased power contracts associated with the 220-megawatt Tiger Bay cogeneration facility. (See Item 7, "MD&A - Impact of Tiger Bay Buy-Out".)

In February 1998, Florida Power announced that it would redeem in March 1998 all of its outstanding $150 million principal amount of First Mortgage Bonds, 8 5/8% series due November 2021, at a redemption price of 105.17% of the principal amount thereof, together with accrued interest. Substantially all of the redemption will be funded using the proceeds from the issuance of $150 million of medium-term notes in February 1998. The notes bear an interest rate of 6 3/4%, and will mature in February 2028.

Amendments to the Clean Air Act in 1990 require electric utilities to reduce sulfur dioxide emissions. Florida Power is meeting these requirements with minimal capital expenditures. (See Item 1, "Business - Environmental Matters".)

In 1997, Florida Power's net cash flow to capital expenditures was 76 percent. In addition to funding its construction commitments with cash from operations, Florida Power receives equity from Florida Progress and accesses the capital markets through the issuance of commercial paper, medium-term notes and first mortgage bonds.

Florida Power has a medium-term note program, providing for the issuance of either fixed or floating interest rate notes, with maturities that may range from nine months to 30 years. Florida Power has available for issuance $250 million of medium-term notes, after the issuance of the $150 million of medium-term notes in February 1998.

Florida Power's interim financing needs are funded primarily through its commercial paper program. Florida Power has a $300 million, 364-day revolving bank credit facility and a $200 million five-year facility, which are used to back up commercial paper. (See Note 6 "Debt", Notes to the Financial Statements.)

In 1997, debt levels increased at Florida Power largely due to the costs associated with the extended nuclear outage and the buy-out of the Tiger Bay purchased power contracts. Florida Power used additional cash generated by operations to redeem $105 million of preferred stock in 1996 and reduced total debt levels by about $145 million in 1995.

Florida Power's embedded cost of long-term debt was 7.0% as of December 31, 1997 and 7.2% as of December 31, 1996.

Diversified Operations

Progress Capital Holdings, Inc., the downstream holding company of Florida Progress, consolidates the collective financial strength of Florida Progress' diversified operations and, with the benefit of a guaranty and support agreement with Florida Progress, helps to lower the cost of capital of the diversified businesses. Progress Capital funds diversified operations primarily through the issuance of commercial paper and medium-term notes.

Progress Capital has a medium-term note program for the issuance of either fixed or floating interest rate notes, with maturities that may range from nine months to 30 years. In 1997 and 1996, Progress Capital issued $35 million and $178 million of medium-term notes, respectively, with maturities ranging from five to 10 years, leaving $87 million of medium-term notes available for issuance. The proceeds were primarily used to repay maturing medium-term notes and for other corporate purposes.

Progress Capital has two revolving bank credit facilities: a 364-day, $100-million facility and a five-year, $300-million facility. These facilities are in place to provide back up for Progress Capital's $400 million commercial paper program. (See Note 6 "Debt", Notes to the Financial Statements.) Progress Capital also has an uncommitted $75 million discretionary line of credit that expires on December 31, 1998, which is used for general corporate purposes.

In 1997, total diversified capital expenditures were about $120 million, primarily for operations at Electric Fuels. During 1997, approximately $50 million was for the purchase of barges and towboats and $23.3 million for acquisitions by Progress Rail. In 1996, Progress Capital received net proceeds of $53 million from the sale of Advanced Separation Technologies and expended $54 million related to acquisitions made by Electric Fuels or its affiliates.

In 1998, diversified capital expenditures are expected to be $125 million and are designated for operations of Electric Fuels. The inland marine transportation unit plans to add approximately 200 new barges and two new towboats in 1998 as it continues to take advantage of market opportunities to expand its business.

Electric Fuels' rail services unit is expected to continue to grow by expanding geographically into the Midwest and western markets. These expenditures are expected to be funded through cash generated internally and from outside financing sources.

Dividend Policy

Florida Progress evaluates its dividend policy on an annual basis to ensure that the dividend payout and dividend rate are appropriate given the business plan, projected earnings growth and outlook for the electric utility industry. Florida Progress' five-year business plan forecasts sustained earnings growth of 4 to 5 percent annually, a key factor in determining dividend policy.

FORWARD-LOOKING STATEMENTS

In this report, Florida Progress has projected sustained earnings per share growth of 4 to 5 percent annually over the next five years, indicated that confidence in earnings growth remains a key factor in determining dividend policy, and established a goal to develop a national retail energy business that provides access to at least 10 million customers. Florida Progress has indicated that it believes that retail choice eventually will exist in every state, and that Florida Power's above average customer growth and continued control over operating and maintenance costs should enable it to maintain its return on equity and continue its earnings growth while pursuing strategic initiatives designed to prepare the utility for a more competitive environment. Florida Progress also has projected expansion of Electric Fuels, and indicated that it

will vigorously defend itself against a lawsuit related to Mid-Continent, which Florida Progress believes is without merit.

Risk Factors

These statements, and any other statements contained in this report that are not historical facts, are forward-looking statements that are based on a series of projections and estimates regarding the economy, the electric utility industry and Florida Progress' other businesses in general, and on key factors which impact Florida Progress directly. The projections and estimates relate to the pricing of services, the actions of regulatory bodies, the success of new products and services, and the effects of competition.

Key factors that have a direct bearing on Florida Progress' ability to attain these projections include continued annual growth in customers, successful cost containment efforts and the efficient operation of Florida Power's existing and future generating units. Also, in developing its forward-looking statements, Florida Progress has made certain assumptions relating to productivity improvements and the favorable outcome of various commercial, legal and regulatory proceedings, and the lack of disruption to its markets.

If Florida Progress' projections and estimates regarding the economy, the electric utility industry and key factors differ materially from what actually occurs, or if various proceedings have unfavorable outcomes, Florida Progress' actual results could vary significantly from the performance projected.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

Florida Progress is exposed to changes in interest rates primarily as a result of its borrowing activities.

A hypothetical 59 basis point increase in interest rates (10% of Florida Progress' weighted average interest rate) affecting its variable rate debt ($714.8 million at December 31, 1997) would have a n immaterial effect on Florida Progress' pre-tax earnings over the next fiscal year. A hypothetical 10% decrease in interest rates would also have an immaterial effect on the estimated fair value of Florida Progress' long-term debt at December 31, 1997.

Florida Power entered into a single forward treasury lock agreement in 1997 to effectively fix the treasury rate component for an anticipated issuance of medium-term notes. The treasury lock agreement was terminated in conjunction with the issuance of the Florida Power 6 3/4% medium-term notes, at an immaterial loss to Florida Power, which will be deferred and recognized as an adjustment to interest expense over the life of the new notes. (See Note 2 "Financial Instruments," Notes to the Financial Statements.)

Commodity Price Risk

Florida Progress is exposed to commodity price risk due to changes in market conditions for fuel and purchased power at Florida Power and coal sales at EFC. Under current regulatory treatment, Florida Power recovers changes in these fuel and purchased power prices through its fuel adjustment clause, with no effect on earnings. A 10% change in the market price of coal at EFC would have an immaterial effect on the earnings of Florida Progress.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO. 42
COMPANY/ WITNESS: Duke Energy
DATE: 12-2-98

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Florida Power Corporation for waiver of Rule 25-22.082, F.A.C., Selection of Generating Capacity.	Docket No. 981360 Submitted for filing: October 20, 1998

PETITION

Florida Power Corporation (Florida Power, or the Company), pursuant to Section 120.542, F.S., and Rule 25-22.082(9), F.A.C., hereby petitions the Florida Public Service Commission (the Commission) for a waiver of Rule 25-22.082, F.A.C., entitled "Selection of Generating Capacity," as such rule may apply to the filing of a petition with the Commission to determine the need for a proposed advanced technology, combined-cycle electric generating plant to be located at Florida Power's Hines Energy Complex in Polk County, Florida. As will be more fully explained below, the requested waiver is based on the unique cost, scheduling, site, environmental, and utility control advantages of the proposed new plant, coupled with a commitment by Florida Power to absorb the additional fixed costs of the plant in its existing base rates until at least 2006 (five years after the plant's in-service date). Collectively, these factors ensure that Florida Power's customers will receive a greater benefit from the construction of its proposed plant than could be provided by any other supply alternative, including any selected under Rule 25-22.082, F.A.C. In support of this petition, Florida Power states as follows:

1. Petitioner, Florida Power, is a public utility subject to the jurisdiction of the Commission under Chapter 366, Florida Statutes. Florida Power's General Offices are located at 3201 34th Street South, St. Petersburg, Florida, 33711.

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Chief, Bureau of Records

DOCUMENT NUMBER-DATE
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2. All notices, pleadings and other communications required to be served on petitioner should be directed to:

James A. McGee, Esquire
Post Office Box 14042
St. Petersburg, FL 33733-4042
Facsimile: (727) 866-4931

For express deliveries by private courier, the address is:

3201 34th Street South
St. Petersburg, FL 33711

Background

3. By petition filed in Docket No. 910759-EI, Florida Power requested the Commission to determine the need for four 235 megawatt, natural gas-fired combined-cycle generating units to be placed in service between 1998 and 2000 at a new power plant site in Polk County, which were then referred to as Polk County Units 1 through 4. By Order No. 25805, issued February 25, 1992, the Commission approved the need for Polk County Units 1 and 2, but deferred a decision on Units 3 and 4 because of several uncertainties regarding the timing of these units' need, including whether a further expansion of the load management program beyond the level projected by Florida Power, or an increase in the estimated amount of contracted cogeneration capacity, might delay the need for these units. The order allowed Florida Power to return to the Commission when the timing of additional needs beyond that satisfied by the approved units became clearer.

4. The Polk County plant site is now known as the Hines Energy Complex. Units 1 and 2 were subsequently redesigned and combined into a single, advanced technology 500 megawatt unit using a so called "two-on-one" configuration[1] and has

[1] Under this configuration, the exhaust gases from two 150 megawatt advanced technology combustion turbine-generator units are fed into waste heat recovery steam generators that power a single 200 megawatt steam turbine-generator unit.

FLORIDA POWER CORPORATION

been designated as Hines 1. The unit is currently in the final stages of construction, with commercial operation scheduled for later this year, at which time it is expected to become one of the most efficient generating plants in the Southeast. Similarly, former Units 3 and 4 have also been redesigned as a virtual twin of Hines 1 and is designated as Hines 2.

Recent Experience

5. Florida Power's last Ten-Year Site Plan, as of December 31, 1997, projected an in-service date for Hines 2 in late 2004. However, because of concerns raised by Staff regarding the adequacy of reserves statewide, and this past summer's extreme weather experience which brought these concerns into sharper focus, Florida Power now proposes to accelerate the in-service date of Hines 2 to the summer of 2001.

6. During the past summer's record-setting heatwave, Florida Power exceeded the previous record summer peak demand set in 1997 on 30 separate days. The peak demand of 8,004 megawatts on July 2nd exceeded the 1997 summer peak by over 540 megawatts and the forecasted 1998 summer peak by over 400 megawatts. In addition, this past summer's experience reinforced the concern that when extreme weather patterns are wide spread throughout the nation or the Southeast region, purchased power provides little or no assistance in meeting critical capacity conditions. During the record and near-record peak demands experienced during the summer, emergency purchases were largely unavailable, and in those instances when purchases were available, they could only be made at unprecedented high prices.

7. Most important, particularly to Florida Power, the prolonged heatwave provided the Company with a practical demonstration that reliance on dispatchable DSM programs for a substantial portion of its generating reserves can be problematic. Since its beginnings in the early 1980's, with the Commission's approval and encouragement, Florida Power has become recognized as a national leader in the use of direct load control programs as an alternative to the construction of additional generating capacity for meeting peak demand. Over this period, Florida Power's residential load management has grown steadily to become by far the largest in the state, and has provided an increasingly large portion of the Company's overall reserves. Traditionally, dispatchable DSM programs such as load management have been viewed as providing the functional equivalent of the reserves that would have been provided by the generating plants that these DSM programs avoided. However, as became apparent when the recent heatwave repeatedly strained the Company's reserves, the human element inherent in these DSM programs imposes certain practical limitations on the extent to which the programs can be used during prolonged periods of high demand without exceeding customer tolerance levels -- limitations that do not exist with real "bricks and mortar" generating plants.

8. Limiting the use of dispatchable DSM programs in a manner that balances customer tolerance with the economic incentive given to customers for their participation is essential to preserve the long term viability of these programs. If these practical limitations on the use of dispatchable DSM programs are not taken into account and, instead, the programs are simply called upon whenever needed irrespective of customer tolerance levels, the effect will be an uncontrolled

deterioration of the programs in the form of rampant attrition and a corresponding loss of the programs' contribution to reserves available to meet peak demand. As last summer's extreme weather demonstrated, using the residential load management program in a prolonged manner that exceeded the tolerance level of many customers resulted in the loss of nearly ten percent of the program's participants in the month of June alone.

9. Florida Power's need to take into account the practical limitations inherent in its dispatchable DSM programs when determining the extent of their use to meet peak demand will necessarily impact these programs' contribution to, and the quality of, the Company's reserves in the future. In recognition of the affect that this will have on system reliability, as well as other significant planning considerations that will be addressed in the Company's later need filing, Florida Power has concluded that the timely addition of new generating capacity is necessary. This new capacity will strengthen system reliability by increasing the reserves available to Florida Power for meeting both winter and summer peak demand conditions, enable the Company to use its dispatchable DSM programs within the limits of customer tolerance by decreasing the proportion of its reserves provided through these programs, and provide Florida Power with additional flexibility in responding to unanticipated events and conditions such as unexpected attrition of DSM program participants or abnormal weather extremes like the record-breaking experience of this past summer.

Advantages of Hines 2

10. Against this increasingly apparent need for additional capacity, the unique characteristics of Hines 2 provides Florida Power with the means to address this need in the most expeditious and cost-effective manner possible. As an initial matter, it should be noted that Hines 2 (previously Polk Units 3 and 4) had been originally scheduled for completion in the 1999-2000 time frame when submitted to the Commission for need approval in 1991. As a result, the unit has the advantage of considerable advance planning and design, as well as the scheduling and cost advantages of previously secured equipment and construction options. Even more important to the unit's ability to be placed in service quickly is the availability of an existing plant site, selected because of its minimal environmental impact, with an infrastructure capable of accommodating Hines 2 with only minor additions. The infrastructure already in place at the Hines Energy Complex includes extensive site development (core sampling, excavation, fill, access roads, etc.), a 2,600 acre cooling pond, complete intake and discharge structures, a fully sized natural gas lateral pipeline, an existing transmission system requiring no additional upgrades,[2] as well as all common facilities and manpower requirements needed to support two-unit operations at the site. Finally, Hines 2 will be able to take advantage of the significantly foreshortened permitting process using abbreviated supplemental procedures authorized under the Power Plant Siting Act for existing sites that have already been subjected to the Act's extensive certification process. Since most of the significant environmental issues associated with the site were resolved when Hines 1 was certified, the time required to complete the supplemental permitting process

[2] An upgrade needed to an existing interconnection with Tampa Electric Company is already in the early planning stages.

for Hines 2 is expected to be reduced substantially, resulting in a minimal impact on the unit's construction schedule.

11. Moreover, satisfying Florida Power's need for capacity with Hines 2 will improve the balance of its total capacity resources between Company-owned generation and purchased power. Florida Power currently has a higher proportion of its total capacity resources provided by purchased power than any other major Florida utility. The diminished level of utility control over the long-term costs and operations of purchased power, as evidenced by the Company's experience with its long-term cogeneration contracts, weighs heavily against an even higher reliance on this capacity resource.

12. Compounding the concern over an undue reliance on purchased power is the practice of the major bond rating agencies to impute a portion of a utility's long-term purchased power obligations to the debt component of its capital structure, which necessitates a commensurate infusion of additional, higher cost equity capital to maintain (in the eyes of the rating agencies) the utility's debt/equity ratio and, thus, its bond rating. In fact, however, the need to add real equity to offset imputed debt *increases*, rather than maintains, the percentage of equity in the utility's actual capital structure, (and with no additional utility asset to support the increased equity). The resulting increase in the utility's overall cost of capital means that its customers may pay for the equity associated with purchased power twice; once for the higher cost of capital reflected in the utility's base rates, and again for the seller's equity costs reflected in the price of the purchased power. The addition of Hines 2 to Florida Power's mix of capacity resources will avoid an exacerbation of these purchased power concerns.

13. As an additional basis for the waiver requested by Florida Power apart from the multi-faceted advantages associated with Hines 2 itself, and for purposes of this petition only, Florida Power commits that it will not initiate any proceeding to increase its current base rates which includes the capital costs and non-fuel operating and maintenance expenses associated with Hines 2 for a period of at least five years from the unit's commercial operation date (or through mid-2006 based on the unit's current in-service schedule).[3] This commitment is conditioned upon the understanding that these capital costs and non-fuel O&M expenses will be considered legitimate utility expenditures for surveillance reporting purposes when Hines 2 is placed in commercial operation, and that this commitment will be effective only when an order issued by the Commission granting this petition in its entirety becomes final and non-appealable.

14. In summary, the unique cost, scheduling, site, environmental, and utility control advantages of Hines 2 would be exceedingly difficult for any other supply alternative to match. When coupled with Florida Power's commitment that Hines 2's fixed costs will not increase customer rates until at least 2006 while immediately flowing through the unit's fuel savings to customers, the advantages of Hines 2 would be virtually impossible to match. Florida Power believes it would be counter-productive for all concerned to engage in a lengthy bid solicitation and evaluation process only to confirm this conclusion, and in doing so, frustrate the unit's most beneficial characteristics -- a short in-service schedule followed by reduced rates.

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[3] Florida Power's intent in making this commitment is to preserve the *status quo* of its current base rates with respect to Hines 2 during the five-year term. Accordingly, by its terms, the commitment does not apply to a base rate proceeding initiated by anyone other than Florida Power, nor does it apply if Florida Power's current base rates (*i.e.*, those rates approved in Docket No. 910890-EI) have been reduced before Hines 2 is placed in service.

These advantages of Hines 2, which ensure that customers will receive the greatest possible benefit from the selection this unit to meet Florida Power's capacity needs, warrants the waiver of Rule 25-22.082, F.A.C.

Criteria for Waiver of Rule 25-22.082

15. Rule 25-22.082, F.A.C., (the Bid Rule, or the Rule) requires investor-owned electric utilities to solicit and evaluate bids for new generating capacity as a prerequisite for requesting a determination of need from the Commission. Subsection (9) of the Rule provides the criteria for waiving this bidding requirement by stating that:

> "The Commission may waive this rule or any part thereof upon a showing that the waiver would likely result in a lower-cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or is otherwise in the public interest." (Emphasis added.)

In addition, Section 120.542 (2), F.S., provides the following two-prong standard for granting waivers or variances to the requirements of an agency rule:

> "Variances and waivers shall be granted when the person subject to the rule demonstrates that the purpose of the underlying statute will be or has been achieved by other means by the person and when application of a rule would create a substantial hardship or would violate principles of fairness." (Emphasis added.)

16. Since the operation of Hines 2 is expected to lower average fuel costs, the overall effect of the base rate commitment described in paragraph 13 above will be to reduce retail rates when Hines 2 is placed in service. Thus, in accordance with subsection (9) of the Bid Rule, the requested waiver "would likely result in a lower-cost supply of electricity to [Florida Power's] general body of ratepayers." In addition, eliminating the time consuming bid solicitation and evaluation process will advance the availability of Hines 2's capacity to meet system peak demand, and

thereby "increase the reliable supply of electricity to [Florida Power's] general body of ratepayers." Moreover, it would not be efficient or "in the public interest" to ask potential capacity suppliers to bid against what amounts to a zero-cost alternative from the ratepayers' perspective that these suppliers cannot possibly match.

17. The requested waiver of the Bid Rule would also serve the purpose of the underlying statute, namely, Section 403.519, F.S., which grants the Commission exclusive authority to determine the need for new electric generating capacity required for certification under the Power Plant Siting Act, Sections 403.501 - 403.518, F.S. The purpose of Section 403.519, *inter alia*, is to ensure that a utility's customers receive the benefit of the most cost-effective generation supply alternative in satisfying the utility's need for new capacity. The Bid Rule seeks to further this purpose by requiring the utility to engage in a rigorous process designed to identify the lowest cost supply alternative, on the premise that, through the ratemaking process, the least cost alternative is synonymous with the alternative that provides the lowest rates to the utility's customers.

18. In this case, however, Florida Power's commitment not to initiate base rate recovery of the capital and non-fuel O&M costs associated with Hines 2 means that customers will not only be provided new capacity at the least cost, it will be provided at *no* cost for at least five years. And when the unit's expected fuel savings are taken into account, customers will actually receive a rate *reduction*. Thus, the requested waiver will serve the purpose of Section 403.519, F.S., by ensuring that Florida Power's customers receive a greater benefit by meeting the Company's need for new capacity with Hines 2 than could be provided by adherence to the Bid Rule.

19. Finally, literal compliance with the Bid Rule would impose a substantial hardship on Florida Power and its customers because (a) Florida Power would be required to devote significant time, effort and resources to a bidding process, with no reasonable expectation that the result could be as beneficial as can be achieved by the requested waiver; (b) Florida Power's customers would lose the benefit of the five-year rate reduction associated with the Company's commitment to forego recovery of Hines 2's base rate costs and the unit's fuel cost savings, and, instead, would incur the rate impact associated with the costs of the supply alternative selected through the bidding process; and (c) the time required to solicit and evaluate bids would significantly delay the availability of new capacity to meet Florida Power's peak demand and thus impair the reliability of the Company's system during the delay.

WHEREFORE, Florida Power Corporation respectfully requests that the Commission grant this petition and waive Rule 25-22.082, F.A.C., as such rule may apply to the filing of a petition with the Commission to determine the need for a proposed new 500 megawatt combined-cycle electric generating plant to be located at Florida Power's Hines Energy Complex.

Respectfully submitted,

OFFICE OF THE GENERAL COUNSEL
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 981042-EM EXHIBIT NO 43
COMPANY/ WITNESS: Nesbitt
DATE: 12-2-98

EXHIBIT 43

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	DOCKET NO. 981042-EM

VOLUME 1
DAY 1

DEPOSITION OF:	Dale M. Nesbitt
TAKEN AT THE INSTANCE OF:	Florida Power & Light
DATE:	Tuesday, November 10, 1998
TIME:	Commenced at 10:25 a.m. Adjourned at 5:15 p.m.
PLACE:	Steel, Hector & Davis 215 South Monroe Street Suite 601 Tallahassee, Florida
REPORTED BY:	NANCY S. METZKE, RPR, CCR

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REGISTERED PROFESSIONAL REPORTERS
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CHARLES A. GUYTON, ESQUIRE, FP&L, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301.

DEBRA SWIM, ESQUIRE, LEAF, 1114 Thomasville Road, Suite E, Tallahassee, Florida 32303.

DOUGLAS HALL, ESQUIRE, Florida Power Corp., Carlton, Fields, 215 South Monroe Street, Fifth Floor, Tallahassee, Florida 32301.

ALSO PRESENT:

MIKE BLAHA, Altos.

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INDEX OF EXHIBITS

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#1	(Late-filed)	49
#2	FRCC supply stack	104
#3	(Late-filed) Florida reporting entities to FERC	145

Whereupon,

DALE M. NESBITT

was called as a witness by FP&L and, after being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. GUYTON:

Q Doctor Nesbitt, my name is Charlie Guyton. I represent Florida Power and Light in this proceeding. If during the course of the deposition today or tomorrow you don't understand what I'm asking, would you stop me and get me to try to reframe it so that we are both on the same page of the hymnal?

A Surely.

Q Okay. I want to start with a few questions following up to staff. First off, are you prepared to make any changes to your testimony? Do you anticipate making any?

A I don't anticipate making any. I noticed a few typographical errors in there that we'll correct.

Q Okay.

MR. McGLOTHLIN: Charlie, may I go off the record with you for a second?

MR. GUYTON: Sure.

(DISCUSSION OFF THE RECORD)

BY MR. GUYTON (Continuing):

Q Doctor Nesbitt, you are employed in this proceeding by Duke New Smyrna or both of the petitioners?

A Well, in this proceeding I'm employed by Duke.

Q Okay. And what specific analysis did Duke ask you to perform?

A For purposes of this proceeding, Duke asked us to provide our most current versions of the NARG model and the Altos North American Electricity model, to provide our best judgments of all the inputs to those models, to interpret the results of those models as they affect the competitiveness, profitability and the market impact of the Duke New Smyrna Beach project.

MR. HALL: I'm sorry, Doctor Nesbitt, you said competitiveness, profitability and?

WITNESS NESBITT: Profitability I think I said. Did I? Could you read that back please. Did I say profitability?

THE COURT REPORTER: Yes.

WITNESS NESBITT: Okay.

MR. HALL: Thank you.

BY MR. GUYTON (Continuing):

Q And when were you asked by Duke New Smyrna to perform this analysis?

A That -- The harbinger that this was coming was in about June of this year, May or June. The analysis was

commissioned in the July time frame, August time frame. I'd have to look at my notes, but several months ago.

Q And when was the analysis performed?

A The analysis was performed in the summer of 1998. And perhaps slipped over into December.

WITNESS NESBITT: Do you recall, Mike, if it slipped over into December?

MR. BLAHA: '98?

WITNESS NESBITT: This analysis upon which this testimony was based, when were the model runs made in the analysis? The summer of '98?

MR. BLAHA: Right.

WITNESS NESBITT: Yeah.

MR. GUYTON: When was it completed?

MR. BLAHA: In July of '98.

WITNESS NESBITT: I think a little later. The testimony was filed September 28th, and we were revising and refining into September as I recall, but the substantive analysis was done July and August.

BY MR. GUYTON (Continuing):

Q So the substantive analysis had been completed at the time that the petitioners filed their determination of need in August?

A I wouldn't know. To define -- you know, the analysis was actually done, done when this document was

filed. You know how consultants work and you know how lawyers work, we work until the last minute; so I wouldn't know when Duke filed --

Q If you had more time, you would still be refining your analysis?

A If we had more time, we would never stop.

Q Okay. What information did you need or have to solicit to run the analysis that wasn't already in your models or your database?

A Solicit from whom?

Q From anyone, from any source.

A Let me answer that this way: The model database that we have is constantly undergoing revision. For example, Mr. Blaha spent some time this summer looking at non-utility-owned generation and inserting -- evolving information from that into the model in various regions of North America. So I would say the process of solicitation of inputs for the model is continuous; it's ubiquitous.

Q Was there any specific information that was required of Duke New Smyrna or Florida to perform your analysis that wasn't in the model database?

A I can't recall any. We did look at the capital cost, the O&M cost, and the heat rate of the proposed unit, which is articulated in my testimony. And that information was provided --

WITNESS NESBITT: Was that provided, Mike, by Duke New Smyrna, or was that provided by --

MR. BLAHA: We did not solicit anything from Duke. The information that I solicited to the cost structure of this type of plant I solicited from my old development colleagues in Central and Southwest Energy.

BY MR. GUYTON (Continuing):

Q Okay. So the capital cost, the O&M cost, and the heat rate cost that, Doctor Nesbitt, you set forth on Page 12 of your testimony was not solicited from Duke New Smyrna?

A Page 12, did you say?

Q Yes, sir.

MR. BLAHA: The heat rate was taken from some previous work I did on New Smyrna in 1997. The capital costs and operating costs, what have you, were not solicited from Duke.

MR. GUYTON: Okay. And what was the source of the capital costs and the heat rate that is shown on Page 12?

MR. BLAHA: Of the capital costs?

MR. GUYTON: Yes, sir.

MR. BLAHA: Polling my former colleagues from the planning department and the development group at Central and Southwest.

MR. GUYTON: And the variable O&M cost that is reported on Page 12, what was the source of the $2.30 per megawatt hour?

MR. BLAHA: The same, former work I had -- former documents that I had for development work that I've done on 7F technology and discussion with my old colleagues.

MR. GUYTON: The heat rate that is shown on Page 12, Line 5, the 6,832 BTU per kilowatt hour at full load, is that intended to be a heat rate indicative of a class of generation, gas combined cycle?

MR. BLAHA: That was the heat rate -- I pulled that heat rate off of an earlier document from some work I did for Duke on Duke New Smyrna.

MR. GUYTON: Is it intended to be a heat rate for a class of gas combined cycle units, or is it intended to be specific to the Duke New Smyrna unit?

MR. BLAHA: That is specific to the Duke New Smyrna Beach. Is the question designed around what we are including for the combined cycle heat rate in the Altos model?

MR. GUYTON: Well, that's going to be the next question I was going to ask, if that is the heat rate that you are using for purposes of the Altos model.

MR. BLAHA: A 72 hundred heat rate was the aggregate heat rate.

MR. GUYTON: For gas combined cycle in the Altos model?

MR. BLAHA: Correct.

MR. GUYTON: All right. So the heat rate of 6,832 was not used in the Altos model?

MR. BLAHA: It was not used for estimating forward prices.

MR. GUYTON: How was it used at all in the Altos model, the heat rate of 6,832?

MR. BLAHA: It was not.

WITNESS NESBITT: It was not used in the Altos model. Let me amplify just for one moment. The Altos model endeavors to represent the aggregate plants in place. The judgment is the aggregate of gas combined cycle units in place demonstrates a 72 hundred heat rate.

BY MR. GUYTON (Continuing):

Q Now that 72 hundred heat rate of units in place, is that of units in place in Florida, or is that broader than Florida?

A The way we did that, there is a -- that 72 hundred number, there is a different number for each region that's represented in the Altos North American model, so it varies by region, but within a region it's common to all the technologies that comprise the aggregate.

Q Is that the value that was used for the Florida

region for combined cycle?

A I'd have to check. I could check that for you.

Q Okay. Do you have the ability to check it here today?

A Yes, I do.

Q Okay. Now I think you said earlier that that was a heat rate for gas combined cycle units in place?

A In place.

Q All right. What heat rate was used for new gas combined cycle units to be added in Florida?

A I'd have to check that in the model. There are two columns of data in there, one is existing units and one is incremental new units, and we can look at those numbers and be precise if you like.

Q Okay. When you check that, if you can also kind of direct me to where I would find that in one of your output tables that you previously provided to us.

A Okay, I would be glad to.

Q Now what was the source of the data for the heat rate of 72 hundred that was used in the model?

WITNESS NESBITT: Mike, you want to --

MR. BLAHA: 72 hundred is the new heat rate, not the existing.

WITNESS NESBITT: We'd have to check those two numbers and then maybe that will help you with your

questions.

MR. GUYTON: Okay. Well, we may need to go ahead and check them now because I have questions about how they were developed and the sources.

WITNESS NESBITT: Okay.

MR. McGLOTHLIN: Go off the record.

(BRIEF RECESS TAKEN)

BY MR. GUYTON (Continuing):

Q Doctor Nesbitt, I've asked you what heat rate that you were using for gas combined cycle units that were in place.

A Okay, and I believe you mentioned within Florida, because they are different by region.

Q Yes. Yes.

A The combined cycle gas only units --

Q Yes, sir.

A -- are 8,336 heat rate for old preexisting units and seven thousand for new units. And that same estimate is used in Florida in both the long-term and the short term versions of the model.

Q Okay. Now while we are there, can you explain what you mean by the long-term and the short-term versions of the model?

A Yes, I believe that's in my testimony. The short-term version of the model simulates one year, and the

price forecasts that were in Staff Request Number 1 were the short-term model. The long-term model goes ahead 20 years and looks at new entry. So the models are identical save for the time frame. The reason we have two models is just to make each computationally more efficient.

Q Where is that in your testimony.

A If we look at Page 13, it talks about the model, if we look at Page 13, Line 23.

Q Yes, sir.

A Okay, it talks about projecting capacity additions. That's in the long-term version.

Q I'm sorry, I thought you said that the long-term -- your testimony discussed that the long-term model was 20 years.

A That's right. It's every one of the next 20 years separated by two-year increments. That's correct. So it's 10 two-year intervals forward in time.

Q Okay. While I have you looking at your heat rates for your gas combined cycle units old and new in Florida, do you have other unit characteristics or data for those units on that screen?

A Yes.

Q Okay. What other information do you have there as regards to the gas combined cycle units?

A Let me go across and I will articulate for you,

and let me pick a representative unit. Let me pick the Florida combined cycle gas only unit. I have the capital cost of entry in dollars per kilowatt.

Q So this would be a new unit?

A Yes, the incremental new build in Florida. I have the variable operating cost, okay, which is a commodotized variable plus fixed operating cost. And by the way, all these definitions are contained in the user guide that we've delivered to you on those three diskettes, as is this database in its entirety. So the variable operating costs, the non-fuel O&M, the old plant heat rate, the new plant heat rate, the planning lead time, how far in advance you have to plan it before you can build it, commercial availability date, a technological change limit. As the technology matures in real term, how much cheaper is it than a technology we'd build today? A thermal efficiency, we call it, limit, the heat rate limit. As the technology matures, how much does the heat rate drop or increase relative to where it is today. A plant life, a tax life, a debt life, an equity finance fraction, whether or not you're allowing the model to build new capacity, a flag, whether or not you are going to constrain the aggregate quantity of energy that flows from this category of plant, a flag, the amount of capacity in gigawatts available in the first model year already installed, okay,

a severance tax, dollars per unit of output, a royalty rate, dollars per dollar of output, a fraction of the capital cost that we'd be allowed to be expensable on your income tax return, and a parameter that characterizes the shape of the short term supply response of the plant. And that's what's resident in the table that I just read from.

Q Okay. Is there unit performance information as to these types of units as well, availability factor, forced outage factor?

A Oh, yeah, there is an -- yeah, it's an availability factor. I'm sorry, I missed that one right across that. There it is. Yes.

Q Okay. Let me go back through those categories that you've shared with us. The capital cost of entry --

A Yes.

Q -- that's expressed in what terms?

A Dollars per kilowatt of installed capacity, excluding all interest during construction. It's the amount on the check that you would have to write to buy the plant from the vendor.

Q The direct?

A Direct capital cost, right.

Q And that is for new plants?

A That's for new plants, yes.

Q Okay. And that for purposes of your analysis was

what for gas combined cycle?

A We have five hundred dollars per kilowatt here in Florida.

Q And the source of that?

WITNESS NESBITT: What's the source of the five hundred dollar estimate, Mike?

MR. BLAHA: Discussions with people we know in the industry.

A Discussions, quotes we've recently seen, publications.

Q The second category I think you mentioned was variable O&M, commodotized variable O&M plus some measure of fixed costs?

(WITNESS NODDED HEAD AFFIRMATIVELY)

Q Okay. What is that value?

A That value for Florida combined cycle gas only is $4.19 per megawatt hour. It's actually quoted in the database in mills per kilowatt hour, but those are the same units, 4.19 mills per kilowatt hour.

Q Okay. Now what is the composition of -- what is included in that number?

WITNESS NESBITT: You want to describe, Mike, how you derived that number from basic cost estimates that you made?

MR. BLAHA: Can we take a break here a second and

see if I can pull up that file, if I have that file?

WITNESS NESBITT: Okay.

BY MR. GUYTON (Continuing):

Q While Mr. Blaha is looking for that, this variable O&M cost that we're looking at of the $4.19 per megawatt hour, is that used for both old and new combined cycle units?

A Yes, it is, with the exception that in the program, and I'll check the number, I assumed that new units were 80% in real terms of that, so I multiplied that by .8 to apply the new units, and I used that number to apply to the old units.

Q That number being the $4.19?

A 4.19, so the new units would be -- four times eight is 32 -- in the 3.2, 3.3 range for the new and the 4.1 range for old. I should articulate that that's all the non-capital, non-fuel costs with one exception, and that is, for new units, there is a fixed annual property tax, insurance and other preservation costs of two and a half percent per year of original cost in real terms.

MR. GUYTON: I'm sorry, would you read that back, please?

(WHEREUPON, THE COURT REPORTER REREAD THE ANSWER)

Q For new units?

A For new units.

Q That's in addition to the 80% of the $4.19?

A That's in addition, yes.

Q Okay. And what is that amount?

A Wait, for old, for -- I have to check what it is. If the question is what is it for old units, I'm going to need to check.

Q No, I'm sorry, I thought you told me that this fixed annual cost for the property tax and the insurance were for new units?

A Yes, is it for new units. It's a non-sunk cost for incremental new units. It would have to be paid if you build it, and it is two and a half percent of the five hundred dollars in this case per kilowatt hour -- per kilowatt, excuse me, that it takes to install the new unit, and that's per annum, and it's in real terms.

Q Does that escalate over time?

A No, it's in real terms, so in nominal dollars it escalates at your inflation multiplier. In real terms, it does not.

Q Okay. And is that expressed -- how is that expressed or quantified? Is that quantified on a per megawatt hour basis, or is that just added to the total variable cost?

A For new units, what we do is we look at the annual preservation cost it takes to build and run the

plant through its life cycle, calculate its present value, and you impute it to the capital cost to build it. So de facto, it's put into the market clearing price, okay, because the capital cost of new units explosively affects the market clearing price when new units are being built.

Q Try me again. You lost me on that response, Doctor Nesbitt.

A Okay. The way that we've simulated new entry, is new entry occurs whenever it's profitable. Okay, it's profitable if new entry -- if the margin, the present value of future margins from the plant, including all the preservation costs, all the cycling costs, all the non-fuel variable costs, plus all the fuel costs, okay, the difference between the price and the sum of those terms, discounted to present value equals or exceeds the capital cost to build it.

Q Okay.

A Okay, that's the investment criteria, and that will internalize all the preservation costs into the price because you won't build it if you don't get it back.

Q Okay. Your -- I posed a question a minute ago about the composition of the variable O&M costs and the fixed costs. Do we have that now?

MR. BLAHA: I do.

MR. GUYTON: Okay. Could you share that with me?

MR. BLAHA: The number was what, 4.19 total?

MR. GUYTON: Yes, sir.

MR. BLAHA: It represents two numbers, 2.36 is consumables, non-fuel consumables of the plant; and 1.83 represents the overhaul cost, major maintenance.

MR. GUYTON: And what are the sources of the consumables?

MR. BLAHA: The sources would be the large plant statistics, the FERC. I believe there are five hundred account -- five hundred number accounts.

MR. GUYTON: For Florida units?

MR. BLAHA: For the Florida units, correct.

MR. GUYTON: For the period -- for the ten-year period you mentioned previously?

MR. BLAHA: Correct.

MR. GUYTON: Okay. How do you use the data for the ten-year period? Do you average it?

MR. BLAHA: What we did was take -- the five hundred accounts are broken down basically by island of plants, so there is the steam island, the turbine island, the boiler island, et cetera. In discussions with former colleagues who had operated power plants and take a look at how these accounts could be allocated to consumables, cycling and preservation categories, we allocated the various accounts to those three categories and came up with

an estimate of the cost per year. The costs were then --

MR. GUYTON: I'm sorry. I apologize for interrupting. Which three categories?

MR. BLAHA: Consumables, cycling, and preservation.

MR. GUYTON: Okay.

MR. BLAHA: We then determined what was the consumable, cycling, and preservation cost per year, and then we averaged over ten years.

MR. GUYTON: Just a simple average?

MR. BLAHA: The average is actually a -- we made that assumption ultimately that it was a log normal type distribution to make the math a little easier.

MR. GUYTON: You've lost me there. What's a log normal type distribution?

MR. BLAHA: Log normal distribution is skewed to -- well, the median -- It's defined as basically where the log of the number is normally distributed. But in essence the median value, which is the 50% point, is less than the mean value. And what we are after here is the mean, the average.

MR. GUYTON: Not a simple average?

MR. BLAHA: It's not a simple average, no.

WITNESS NESBITT: Well stated.

MR. GUYTON: Now originally you gave me a

breakdown of $4.19 per megawatt hour between consumables and overhaul and maintenance?

MR. BLAHA: Correct.

MR. GUYTON: And then in your answer a minute ago, you broke down the cost in three categories, consumables, cycling and preservation?

MR. BLAHA: Correct.

MR. GUYTON: Do cycling and preservation constitute overhaul?

MR. BLAHA: No.

MR. GUYTON: Okay. How does one move from the breakdown of the three costs of consumables, cycling, and preservation to the breakdown of two costs that you've given me of consumables and overhaul maintenance?

MR. BLAHA: Let me see if -- If I don't answer this question directly, I may take a little bit circuitous route to this. Traditionally there are two types of costs: Fixed and variable. Variable tends to be with respect to the output level of the plant. That is what we define as consumables.

MR. GUYTON: Related to the output?

MR. BLAHA: Correct, as the output changes -- Like fuel consumption is the primary consumable in a power plant. As the output changes, the amount of that consumable will also change, so it's variable relative to

the production level decision.

MR. GUYTON: Okay. Now what types of costs would those be?

MR. BLAHA: Fuel -- but they are consumables; this is non-fuel consumables -- water, boiler chemicals. Pollution control consumables would be ammonia if you've got a -- if you're trying to flue gas desulferization or denitrogenization, whatever it's called. Those would be consumables.

MR. GUYTON: And then I interrupted you. You said typically there are two types of costs: Variable and fixed. You said the variable were related to output and the fixed were?

MR. BLAHA: Fixed are not related to output. What we have done is broken the fixed into really two different levels. Cycling, which are avoidable if the unit is not operated; so if the unit is not operated, you are not going to wear and tear the equipment. An overhaul is simply bringing back the equipment back to the original state.

MR. GUYTON: So that's maintenance?

MR. BLAHA: That would be maintenance, but maintenance from our definition is a variable cost because, if you don't run the unit, you don't incur that cost. The other type of fixed costs then would be preservation, which

would be property taxes, insurance, staffing of the plant, those types of costs that you have to incur if the unit is going to be available to operate, to maintain its capability.

MR. GUYTON: So the $4.19 estimate of cost associated with the gas combined cycle unit, $4.19 per megawatt hour, includes $2.36 per megawatt hour of consumables, and those are non-fuel consumables, correct?

MR. BLAHA: Correct.

MR. GUYTON: And then it includes $1.83 of overhaul or maintenance cost?

MR. BLAHA: Correct.

MR. GUYTON: Does that include preservation cost?

MR. BLAHA: It does not include preservation cost.

MR. GUYTON: Does it include cycling cost?

MR. BLAHA: Cycling costs are the $1.83, the maintenance cost.

MR. GUYTON: Okay. The source of this information was conversations that Mr. Blaha had with?

MR. BLAHA: The source of which information? The data was pulled from the FERC filings.

MR. GUYTON: Okay.

WITNESS NESBITT: Let me clarify that. The aggregate data was pulled from the FERC filings. What you

guys have been talking about, the breakdown of that data between categories, the actual breakdown is not relevant to the calculation. It's the aggregate number of $4.19 that enters the calculation, and that was calibrated to observe historical data.

BY MR. GUYTON (Continuing):

Q Now in an earlier answer, Doctor Nesbitt, you said that you used the $4.19 for new units and a value of 80% of -- I'm sorry, I've got that backwards, $4.19 for old units and a value of 80% of that for the new units?

A Subject to check, that's my recollection. I'll check the code and tell you the exact number I used.

Q Okay. And the logic of that?

A The logic of that is new units are going to be better. They are going to require less cycling cost, and in my view vendors are going to commodotize that cycling cost, maintenance cost, and bear the risks themselves and discount it to as low a value as they can because they want to sell units. So there are economic pressures that are bought to bear on vendors, and there are new technologies being embedded in the new plants that drive the cycling costs down and the consumable cost down on new units as compared with the units that exist in the market today.

Q Now when you say vendors, you mean vendors of the machinery?

A Sellers of the machinery, the GEs, the Siemens, et cetera.

Q Okay. Now in your testimony back at Page 12, you speak of the fully commodotized, variable all-in, forward operating and maintenance cost?

A Yes.

Q Would you explain what you mean by "fully commoditized"?

A Yes. What that means is that if I'm a vendor, an equipment provider selling you a plant, I will quote you a maintenance service contract, if you will, at two dollars per megawatt hour or $2.30 per megawatt hour; but I will quote you a guaranteed price based on a megawatt hours basis. Okay, that's fully commoditized because it's expressed per unit of output from the plant. But my judgment is, is new plants and vendors of new plants will charge the customers for those new plants an output based rate to maintain it, not fixed annual, but an output based; and that's what I mean by fully commodotized, all-in.

Q And that is captured in the $4.19 discounted by 80% figure you used for gas combined cycle?

A That's right. That's intended to be capturable.

Q Okay. What do you mean by "variable" here, sir?

A Okay, in Line 10 I presume you are referring to.

Q Yes, sir.

A Let me state that I have assumed that the fully commoditized, variable, all-in forward operating and maintenance cost, the commodotized and variable in that sense are used to express the assumption that the operating and maintenance cost is expressed on a per megawatt hour basis. That's variable per megawatt hour.

Q But it would include both consumables, which are variable in our earlier discussion, as well as overhaul or cycling costs?

A Yes. Yes.

Q Which are more in the nature of fixed costs if I understand our earlier discussion?

A They may be more in the nature of fixed costs, historically they have been; but what I want to be clear is the vendors are offering not fixed annual contracts, as I understand it, but per unit of production based contracts to maintain the units. Different, the future is looking different from the past. They may well be fixed costs from the point of view of the vendor, but the vendor sells them to their customers, i.e. the plant owner, on a pure variable cost, all-in, everything included, commodotized basis.

Q So the assumption of your analysis for new units is that the variable cost components that you're using in

your model is going to be one that reflects not only the purchaser's consumable cost, but also a commodotized maintenance cost to the purchaser as provided by the vendor?

A That's right.

Q Okay.

A That's right.

Q So your underlying assumption in your model is that the purchaser of these new units will not be doing the maintenance itself but will look to the vendor to do the maintenance?

A Let me state that differently. I'm assuming that there is a market for O&M services and the vendors are going to buy from the market. The market price of those services is the fully commodotized O&M cost. Whether or not the plant owner does it him or herself, or whether he or she buys it from a vendor, they buy it at the market price; and this is intended to reflect the market price of cycling and preservation and consumable service.

Q So an individual developer -- The individual developer will do it itself if it believes it can beat that price, or it will contract it out if it believes it can't?

A Yes, but that's not the critical issue. The critical issue is what's the value? What's the fair market price of the O&M service? Whether you do it yourself or

contract it out, the assumption in the model is you will pay the fair market price for that service. If you are more expensive than the market, you are going to lose money at the fair market price. If you are more cost effective than the market, you are going to make money at the fair market price; but you are going to mark to market the value of your O&M service at the market price of that service; that's what we are estimating here.

Q Okay. And you developed a similar type of estimate of commodotized variable, all-in, forward operating costs for all your new generating technologies, did you not?

A That's correct.

Q Okay. So this is not unique to gas combined cycle units?

A No, it's not. It's common. It's an assumption that all O&M services for all plants new and old are marked to market.

Q Okay. But the market price is different for new and old?

A Yes.

Q The market price for new is 80% of old?

A That's correct.

Q Is that true for all your technologies or just for gas combined cycling?

A In this simulation it's common and true for all technologies. We used the same multiplier for all technologies.

Q Okay. Now your development of the fair market value of O&M cost starts with a compilation of data from historic costs incurred by electric utilities in Florida, and without characterizing how the average is done, there is an average of those costs over a period of ten years?

A Yes, as Mr. Blaha has testified, it is an average of those historical costs.

Q Okay. In your discussion of your model in your DMN-15, you speak of part of the fixed costs being used to calculate the market clearing price but not all the fixed costs?

A That's right.

Q What portion of the fixed costs are not captured by your model in the market clearing price?

MR. BLAHA: You want me to give this a shot, Dale?

WITNESS NESBITT: Why don't you get into this because it's a complicated answer. Why don't you start it off, and then I'll amplify it.

MR. BLAHA: It depends upon the technology. The nuclear plant, a considerable amount of fixed costs are not included. Whereas, in a combustion turbine or in a

reciprocating engine, almost all of the costs are included.

WITNESS NESBITT: And you may wonder why. The reason is, the reason that this is a difficult question to answer, traditionally those fixed O&M costs have been thrust upon ratepayers through cost pass-through. The ratepayers have been forced to pay it, okay? That causes those costs to be higher than they would otherwise be in an unregulated market. It's demonstrable in pretty much every market that's been deregulated. So if you eliminate cost pass-through and merchantize thing, the magnitude of the historical fixed O&M drops, just through price and cost competition.

The other problem is the nuclear problem, and to some -- in some cases other technologies. Those fixed costs will have to continue to be passed through to ratepayers and forced on them, or those plants will shut down. If you don't pass the fixed O&M costs through in large measure for a nuclear plant, you'll shut it down because it becomes a nonprofitable facility.

So you have to make an assessment as we have for each technology in each region, what is the nature of the local regulation vis a vis the fixed costs that are going to be passed through in base rates and forced on customers outside the energy markets? And it's the residual of those

fixed costs that are not forced on ratepayers outside the energy markets that are included in the fully commoditized O&M costs that we use to drive the energy market clearing price calculations in the model.

Q Okay. How are those costs recovered outside of the energy markets?

A Are you talking about in the real world, or are you talking about in the model?

Q Well, let's start with the model.

A Let's start with the model. If the costs, and this is true in the real world and the model, if the costs are passed through and forced on ratepayers through some sort of a cost pass-through franchise monopoly regulation that we've had in the past, they do not appear at all in energy prices, okay? And so they are not put into the model at all. They are put in at zero. They are sunk with regard to energy transactions.

Q Now they don't appear in the energy prices that you formulate for purposes of your model although they may appear in rates?

A Okay, they appear in rates. They do not appear in wholesale prices in the real world because the costs are paid by someone else and, therefore, they are not internalized in the prices, as long as they are passed through in base rates, if you are somewhere else, an

outside market clearing price of energy. If plants are merchantized and fixed costs are not allowed to be thrust on customers through a regulatory regime, then those costs must be recovered in prices or those plants don't operate, okay?

Q Then they have to be recovered in the market clearing price?

A Right, to be recovered in the market. That's what a merchant plant is and does. The merchant plant owner must recover all of his or her costs through market transactions in the capacity or energy markets. He does have a regulator handing costs to him through base rates.

Q Okay. For purposes of your analysis, are they, are these costs reflected in the market clearing price or not?

A Yes and no. It depends on the particular plant type we are talking about. Let's take nuclear for an example. The fixed O&M cost of a nuclear plant is not reflected in the price, no, because it's assumed externally to be passed through to ratepayers.

Q Not in any -- not any part of it?

A Not any part of it. The nuclear capacity is represented. It's non-fuel, pure variable O&M and fuel costs are represented. It sits at the head end of the supply stack and dispatches as much as it can dispatch. It

runs as much as it can because its costs are subsidized through rates. Taking a combined cycle of the type that is proposed by Duke New Smyrna Beach, there are no cost pass-throughs assumed, okay? All the fixed O&M, all the non-fuel -- all the variable O&M, and all the fuel has to be recovered through sales of capacity plus energy to the market. Okay, so for combined cycle units, the fixed O&M cost is the fully commodotized, all-in forward maintenance cost. For a nuclear unit, the fixed O&M cost is assumed to be zero. It's paid someone else and doesn't internalize into the energy markets.

Q Okay. Well, let's go through the rest of your types of units and tell me the extent to which the fixed O&M is captured in the cost that you use.

A Okay.

Q Because somewhere in my notes here, I have a list of those. All right. You told me about nuclear. Tell me about coal. First off, are fixed costs treated any differently between high efficiency coal and low efficiency coal?

A My understanding is they are not.

WITNESS NESBITT: Is that right, Mike, the fixed cost of coal units are common across the types?

MR. BLAHA: If I can divert this discussion here for a second, maybe I can clarify this.

What we do is we take a look at basic bidding behavior of the plants, so base load plant is only going to bid in its variable production, it's pure variable production costs, meaning fuel plus consumables. And the primary reason for that is these units can't start and stop very easily. A nuclear plant takes days to get going.

MR. GUYTON: All right. So I guess I need to ask you, for purposes of your analysis, what you find -- what are the types of categories of plants that you've analyzed and you define as base load?

MR. BLAHA: The base load plants would be nukes, high efficiency coals, hydroelectric.

MR. GUYTON: That's it?

MR. BLAHA: That's it.

MR. GUYTON: Okay. Not combined cycle?

MR. BLAHA: Not combined cycle.

MR. GUYTON: Okay. So for purposes of modeling, nuclear units, high efficiency coal units, and hydro units, the cost input for O&M is a pure variable O&M cost?

MR. BLAHA: Correct.

WITNESS NESBITT: That's correct.

MR. GUYTON: It has no component of fixed O&M cost?

MR. BLAHA: Right.

WITNESS NESBITT: That's correct.

MR. BLAHA: Would it be good to pull out that supply stack? Do we have the supply stack?

WITNESS NESBITT: We might.

MR. BLAHA: Because it might be easier to come up and show how we come up the supply stack.

MR. GUYTON: It sounds like it would be helpful if you have it.

MR. McGLOTHLIN: Somewhere.

WITNESS NESBITT: It may have already been provided.

MR. McGLOTHLIN: There is a Xerox copy.

WITNESS NESBITT: Have we provided that to you already?

MR. GUYTON: Well, I don't recall having seen it, but I won't say you haven't provided it. I'm just now getting documents.

WITNESS NESBITT: I think we have.

MR. McGLOTHLIN: That's the only copy I have with me.

MR. GUYTON: Okay. Well, let's go through the rest of the -- Now the next category of plants that you had besides the nuclear, hydro and high efficiency coal are the low efficiency coal?

MR. BLAHA: So low efficiency coal, combined cycle plants, steam turbine plants are in essence cycling

duty type facilities.

MR. GUYTON: Okay. And --

MR. BLAHA: In these plants we, therefore, add the cycling cost because, when they decide to start, if they look prospective forward, you can't recover the maintenance cost and the start cost of what we are defining the cycling cost over the next operating cycle. They would be better off to buy energy off the market and deliver to meet their contractual needs. So that's why we've included in their bidding behavior the cycling cost.

MR. GUYTON: Okay. And for gas combined cycle units, that's the dollar 83 of overall maintenance cost?

MR. BLAHA: Correct.

WITNESS NESBITT: That's correct.

BY MR. GUYTON (Continuing):

Q Okay. Is the breakdown of the consumable and overhaul cost for these types of units shown on the output of -- I'm sorry, on the input or the output tables of your model?

A Neither. The inputs to the model are, as I testified earlier, the aggregate sum number that pertains to each plant. The breakdown of that Mike has in his analytical structure that he used to prepare the database, so it's not --

Q Okay. So that's part of the database and not

part of the model?

A Correct.

Q Okay.

WITNESS NESBITT: You might mention, Mike, the combustion turbines.

MR. GUYTON: So the cost that you use for purposes of modeling low efficiency coal combined cycle units and steam turbine plants, whether they be oil or gas, include pure variable O&M, fuel, and cycling costs?

MR. BLAHA: Correct.

MR. GUYTON: And is that information developed upon a review of Florida units?

MR. BLAHA: It's based on a review of all units throughout the United States. The Florida units are based on the Florida historical numbers.

MR. GUYTON: The Florida units are based on the ten-year average of FERC Form 1 data?

MR. BLAHA: Correct, filed by Florida utilities.

MR. GUYTON: Do you recall which Florida utilities?

MR. BLAHA: Well, definitely FP&L, FPC, and TECO.

MR. GUYTON: Any others?

MR. BLAHA: I'm not sure whether the cities or the co-ops have had to file. I just -- I'd have to go back.

MR. GUYTON: Okay. Well, let's go through the rest of them. What have we not covered yet? We have covered nuclear, coal, hydro. Non-utility generators.

MR. BLAHA: The non-utility generators for the purpose of this study were considered to be, in essence, dump power. They are selling into the market at whatever the contracts were.

MR. GUYTON: So they were marketed per contract?

MR. BLAHA: We just put them in as just energy that was dumped into the market.

MR. GUYTON: How did you price it?

MR. BLAHA: There was no pricing to it.

WITNESS NESBITT: That's not correct. It's at the market. Must-run units, precontracted units sell into the market at the market price, and they were dispatched at the extreme left end of the supply stack.

MR. GUYTON: Now the market price being the marginal price?

WITNESS NESBITT: The calculated market clearing price in the model, the place where the supply and demand curves cross.

MR. BLAHA: That's the price they receive?

WITNESS NESBITT: It's the price they receive.

MR. BLAHA: But their dispatch cost was assumed to be zero?

WITNESS NESBITT: Right.

BY MR. GUYTON (Continuing):

Q So they were treated as base loads for purposes of dispatch?

A No, what they've done is they subtract from demand. They run and they subtract from demand. They are contracted to run, and they dump the energy in. They receive the market clearing price, and that effectively subtracts from demand.

MR. GUYTON: IG/CC were they modeled like the CC, or were they modeled differently?

MR. BLAHA: They are modeled like the CCs.

MR. GUYTON: So they have pure variable O&M, fuel and cycling?

MR. BLAHA: Correct.

MR. GUYTON: Okay. I guess that leaves combustion turbines.

MR. BLAHA: Combustion turbines.

MR. GUYTON: And I think you said earlier that they were modeled total cost, variable and fixed, correct?

WITNESS NESBITT: That's correct.

Mike, you might articulate the combustion turbine cost.

MR. BLAHA: The premise of the model here is that there is no capacity market, and all costs have to be

recovered through an energy only; so when you get to peak hours, a combustion turbine is forced to bid in its preservation costs or it will not recapture those costs and be forced to shut down.

MR. GUYTON: When the aggregation is done for the various types of units into your categories and you're relying on data from individual utility filings, how do you weight the variable costs, if it at all, from one utility to the next?

MR. BLAHA: We have not done any weighting. We just take a look at the regional average and apply it equally to all plants?

WITNESS NESBITT: Let me amplify that answer as well. Again, we want the variable cost to represent the marked to market variable cost.

BY MR. GUYTON (Continuing):

Q I'm sorry, the marked?

A The marked to market, what is the fair market value of the services required to service your plant's variable cost needs. In a market setting that's much less likely to be highly regional or highly utility dependent because you have a market out there. It's a national and a regional market, and you can argue, therefore, that those costs are likely to levelize and become a lot more common than we've seen in the past. And you'll see evidence of

that across the regions if you look at the O&M cost estimates between regions in the country.

I would argue that as you try to simulate going forward a market clearing mechanism it's not a good idea to maintain all the historical bulkenization by region; you get the wrong answer when you do that. I would argue that what we have done is a lot more satisfying. The philosophy to repeat is to get the fair market value of those O&M services and to get them in there in common for all the plants in North America where plants, in my lingo at the moment, is aggregates of plants.

Q But you do bulkenize it by region?

A You bulkenize -- No, you don't bulkenize it. What you do is you specify the costs by region, but what I would argue that is not a good idea is to assume that the cost distinctions that have, that characterize the regions in the past in the regulated regime and have caused relatively large differences between regions will persist. I think that is a wrong assumption.

Q In the market that you're assuming, is it appropriate to assume that the historic costs associated with existing plants are likely to stay at historic levels?

A I think that's wrong.

Q Okay.

A And not just in the market I'm assuming. I think

it's wrong, period.

Q Okay. But that's what your model does for purposes of its projection, does it not?

A Does it keep them constant at historical?

Q Yes.

A No, it doesn't. It does not.

Q Well, it develops the estimate based on historic data, does it not?

A It develops an estimate based on historical data, yes.

Q Okay. Then how is that estimate moved forward?

A As new plants enter, the embedded costs, the incremental costs of the new plants is lower than the cost of the old plants; and so as capital stocks rollover, the cost structure of the industry drops.

Q But your model, to the extent that it continues to model costs for existing plant, reflects the historic cost, does it not?

A Yes and no. The existing plants, if they maintain their same historical high cost structure, don't run any more; they are replaced by new plants.

Q If they are not replaced, you use the historic cost?

A But they are replaced.

Q So all the historic plants are replaced?

A No, not all of them, but a lot of historical plants are replaced.

Q For those that are not replaced, you're still modeling the cost for those plants at their historic cost?

A I'd have to check that. We have learning curves in the model that allow de-escalation in real terms of those costs. I'll check the specific assumptions. I do believe, however, we have not put future cost de-escalation in. So I believe the answer to your question is we have held those historically estimated costs constant in real terms. Subject to check, I believe that's what's in there.

Q But you'll check that?

(WITNESS NODDED HEAD AFFIRMATIVELY)

Q Now your model used or employed a load forecast?

A Yes, it did.

Q Okay. And what was the source of a load forecast for Florida?

A Let me ask Mike who prepared that load forecast to give you the summary of the historical calculations and the projected forward calculations because they mix together to answer your question.

Q Okay.

MR. BLAHA: The forward net energy for load forecast was taken from the NERC ES&D system.

MR. GUYTON: What vintage data?

MR. BLAHA: I believe it was '97.

MR. GUYTON: Would you check? I have reason to believe that it may be '96. Let me back up. Is that the same database that was used for the preparation of DMN-5 and 6?

MR. BLAHA: That I can't -- I can take a look at the two. I have both '96 and '97 on this machine, so I can compare.

MR. GUYTON: Okay. Back up. Let's not divert to DMN-5 and 6.

MR. BLAHA: Okay.

MR. GUYTON: The NERC ES&D data base that was used for load forecast for net energy for load was, as you recall, 1997?

MR. BLAHA: I believe we updated it for '97.

MR. GUYTON: Can you confirm that?

MR. BLAHA: Correct.

MR. GUYTON: Now is that data that was filed with NERC in '97 based upon planning done in '96, or how was that information formulated?

MR. BLAHA: May I verify whether or not it came from the '96 or the '97?

MR. GUYTON: Sure. Sure.

WITNESS NESBITT: Can I take a quick break while he does that?

MR. McGLOTHLIN: Doctor Nesbitt, if I heard correctly, I think you may have said from 1977 forward. If that was the case, did you misspeak?

WITNESS NESBITT: I misspoke. I meant 1997 forward, I'm sorry.

Q So the model recognized existing in-place capacity through 1997 in Florida?

A Right.

Q Okay. And then it added to it capacity that you term as being a lead pipe cinch, anything that was under construction?

A Things that are under construction.

Q Can you identify those units for me?

A I'd have to ask Mike to identify those units and the initial amount of capacity in place in the first year has been delivered to you on one of those diskettes so you can check it against various plants.

Q Okay. Can you tell me where to find the in-place value that I could check?

A Yeah, it's on one of those three diskettes. I think it's called long.zip. It's a 16-megabyte file, and you are going to look in Table 13/22 as indicated in the user guide, which is also on that file; and you are going to look in Column 21, and you are going to see the values of capacity in place in the first model year for every

aggregate in the country, and it's under FL for Florida.

Q And that will be total capacity in Florida?

A Total capacity by plant aggregate type, and then if you add it up, it's total capacity in Florida.

Q But that won't tell me which units are being added beyond what's in place in '97? It won't tell me which specific units because it's aggregate?

A It doesn't matter which specific units are aggregated. It matters what their cost structure is and what type of units they are in the aggregate. It tells you how much of each aggregate is in place as of the first model year.

Q Okay. How do I find out which individual units constitute the capacity that's added between '97 and the first model year in your model?

WITNESS NESBITT: Mike, how did you determine -- He wants to know which units were added between '97 and the first model year by name plate. Which units are added in under construction?

MR. BLAHA: We would have to look into the plant database and determine what are the in-service years.

BY MR. GUYTON (Continuing):

Q And we don't have that plant data base, do we? We just have the inputs to the model?

A I don't believe that you do have it.

Q Okay.

MR. GUYTON: Joe, I don't normally try to ask for late-filed exhibits, but I would like to ask for a late-filed exhibit for this if I may.

MR. McGLOTHLIN: I think it will be all right.

MR. GUYTON: Let's see, planned Florida unit additions. Would the period be 1997 through 2001, the first model unit year being 2002?

MR. BLAHA: I think the first model year is 1998 for the purposes of determining new build schedules.

WITNESS NESBITT: Right.

MR. GUYTON: Okay.

WITNESS NESBITT: Let me clarify that. The first model year is 1998, but the first projection year is the year 2000. In other words, 1998 reflects the initial year capacity mix demand, et cetera. Two years hence, the year 2000, is the first projection year. We are projecting the amount of new cap adds that will come, the market clearing prices, et cetera.

MR. McGLOTHLIN: Let's go off the record for a moment and make sure I understand what is being asked and what is being offered.

(DISCUSSION OFF THE RECORD)

MR. McGLOTHLIN: What do you want to call it.

MR. GUYTON: Planned Florida unit additions; is

that sufficiently descriptive?

MR. McGLOTHLIN: I think the word "under construction" needs to be there because I think there may have been others that were planned but not included in the model.

MR. GUYTON: Planned Florida units under construction?

WITNESS NESBITT: Planned Florida unit additions that are certain.

MR. GUYTON: And what I'm looking for here are the name plate and the type of capacity, and if you can identify the specific units you have in mind.

MR. McGLOTHLIN: I think we are clear.

WITNESS NESBITT: Yeah.

MR. GUYTON: Okay.

BY MR. GUYTON (Continuing):

Q And those units would be under construction over what period of time, or are you going to be able to tell me that without looking at the database?

A Those are units that are under construction and we know are virtually certain when they will come into service. For example, if they are under construction now and we are virtually certain they are going to be in in the year 2000, those are the units that I would consider as falling under the realm of your request. Okay, what I

would consider as not falling under the realm of your request are the units that are proposed and talked about, okay, but as yet haven't been put under construction and, therefore, are not certain.

Q Okay. So for purposes of your model, you have not modeled any proposed or planned units as have been proposed by Florida utilities unless they were under construction as of the end of 1997?

A Yeah, I would say what we've done is units that are certain to come into production in our view, not units that are just chatted about or proposed, but units that are certain to come in, we have endeavored to include those in the capacity mix that exists at the model outset. All other units, whether they are proposed or not proposed, are projected by the model using profitability criteria, how much new capacity is profitable to enter, how much does enter. That's what the model calculation, what is the corresponding market clearing price? So the model adds capacity or doesn't add capacity on an economic basis other than capacity that is virtually certain to enter.

Q How for purposes of your modeling would the repowering of an existing power plant be treated if at all?

A For purposes of modeling the Florida market, what we would have to do to incorporate all the repowering proposals, as I understand them, is to modify the capacity,

which is the unrepowered plant in its cost structure and replace it with the cost structure of the repowered plant. So what you have to do is take an existing steam turbine unit, modify its capacity, change its cost and operating parameters to reflect the repowering option and include that as a separate, if you will, plant aggregate.

Q And that was something that was not done in this particular simulation?

A I believe that was not done.

WITNESS NESBITT: Is that correct, Mike?

MR. BLAHA: No, we did not model it?

WITNESS NESBITT: Now I should add to that there is entry of new combustion turbines predicted by the model. Okay, those new combustion turbines enter at parameters that characterize stand-alone new combustion turbines. The old steam units are not modified by such entry and, therefore, the old steam units are not characterized in terms of repowering, but combustion turbines enter when they are economic. The old units are not modified to reflect the repowering proposals that may or may not be out there.

BY MR. GUYTON (Continuing):

Q Okay. So to the extent that a repowering proposal would repower an existing unit, change its capacity -- I'm sorry, its generating technology and

potentially add new capacity, the new capacity that may be added might be captured in your modeling of new generating technologies but the repowering part of the project would not?

A The repowering part of the project would not except I would -- I would argue it's the same steam turbine unit, the same site, the typically very high fixed O&Ms on existing steam turbines, I would argue would be very well approximated by the high steam turbine unit cost that we have. Our experience with repowerings is they don't cut the high maintenance cost and the high preservation cost of existing steam units. So I would argue that the model in its present state, whereas, it doesn't explicitly name plate the repowering capacity, does a pretty good job of simulating the most important part of those repowering plants; and that is, the persistently high cost of the old steam turbine unit.

Q Now does your model in any way attempt to capture changes at existing power plants designed to upgrade heat rate or improve capacity?

A The existing power plants heat rates and capability are left constant in this simulation.

Q Okay.

A And so are their typically high and persistently high fixed O&Ms.

Q Explain, if you will, how transmission capability is modeled in your simulation.

A Transmission capability is modeled using the following, and let me give you a simple overview, and then let me talk about a little of the complexity. Every region of the model is interconnected to its nearest neighbors by a from to transmission link. Let's take Southern to Florida as an example. There is a link that points from Southern into Florida, and there is a link that points from Florida into Southern. So power is allowed as the economics in price differentials dictate the flow across the transmission link in either hour -- excuse me, in either direction at any time it wants, if you will.

So if the price differential between Southern and Florida is such that the Florida price is higher, that will catalyze flow from Southern to Florida. If the price in Southern is higher than the price in Florida, the Southern to Florida flow will dry up, and the Florida to Southern flow will go up.

Okay, each the transmission linkages which go from a region to its contiguous neighbors is represented by its losses. It is represented by its O&M cost, its tariff, its charge, its non-commodity charge, and by its through-put. And its through-put is the total physical amount of commodity that it can deliver, i.e., the first

contingency capability. So each of the contiguous flows is represented by first contingency capability between contiguous regions.

Q And that is between Florida and Southern?

A Florida and Southern, Southern and VCAR, Southern and Entergy, Southern and TVA, dot, dot, dot. Between every pair of contiguous regions in North America. The Southern to VCAR, V-C-A-R; Southern to TVA; Entergy to Southern; Southern to Florida. So that's the representation of each of the increments of transmission.

As the model finds the market clearing price as articulated in DMN-15, it competes the transmission linkages together with the upward bound on their capability against all of the indigenous generation options in each of the hours or each of the categories of hours of the year, in each of the markets, and picks the most cost effective option.

So transmission competes on an equal footing with generation and vice versa, both for in-bound transmission and out-bound transmission. And the prices throughout North America reflect indigenous generation competing explicitly with and against in-bound and out-bound transmission. Figure 10 in DMN-15, which we talked about earlier, shows how transmission interconnects the regions.

Q Now the competing transmission link that competes

with indigenous generation, the price associated with that is a compilation of generation in another region?

A Keep going. Not quite.

Q Okay. Well, I'm trying to build it, I guess. I haven't heard you mention generation in another region as part of the cost of the transmission.

A It's not part of the cost. It is the fair market price. Let's take Southern and Florida as an example. Transmission from Southern to Florida starts with the fair market price of power in Southern, the fair market price of the power in Southern, adds the transmission cost, and delivers it into Florida if it can compete at that price.

Q And the transmission costs reflect losses?

A They reflect losses, yes.

Q What losses are assumed?

A I believe that's either 2 or 3%. I can check that for you as we sit here right now.

MR. BLAHA: I think it's 3%.

A Is it 3%? I believe it's 3%, subject to check, and I can do that today.

Q Okay. And that's losses from region to region? It doesn't vary by mileage, it's just one region to another?

A That's the way it's simulated in this simulation, yes.

Q Okay. And the transmission that's into Florida, is it assumed only to be transmission available from Southern? We are not talking about something that might be wheeled through Southern to Florida?

A Indirectly we are. The model reflects one, two, three, four, et cetera, region wheels; but the way the model works is it takes the market clearing price of power in Southern, which reflects all the in-bound transmission, all the out-bound transmission, and all the generation within Southern, and then it either pushes that into Florida or not based on the relationship with the Southern to Florida markets. So one, two, three, four, dot, dot, dot level wheels are reflected in the market clearing price in Southern. Moving back upstream, the market clearing price in TVA and Entergy. Moving back upstream, the market clearing place in ECAR and Maine and MAP, et cetera, so it's all interconnected.

Q So the market clearing price in Southern would reflect whatever losses that were incurred with wheeling power into Southern?

A From anywhere and to anywhere, yes.

Q So the loss associated with the transmission from Southern into Florida would just be the 3%?

A It would just be the 3% for that incremental transmission leg from Southern to Florida.

Q And any other incremental transmission legs, for purposes of the model, those losses would already be captured in the price of, the fair market price from the Southern resource?

A Exactly it would, yes.

Q Okay. So you wouldn't have additive losses here that you would need to --

A No, you would not. In other words, each of the losses is accounted for once and only once in one contiguous region wheel.

Q Okay. Now you mentioned some other elements of the transmission cost in addition to losses, O&M costs.

A Right, O&M costs which in our lexicon for transmission, as you'll see in the user guide, is a commodotized transmission wheeling charge. I believe that commodotized transmission wheeling charge between Florida and Southern was set at three dollars a megawatt an hour, subject to check; and I can check that today as well.

Q And you also made mention of a tariff. Is that reflected in the O&M cost?

A Yes, we use the O&M cost to carry the tariff, if you will, to deliver the tariff to the model.

Q So that is not an additive cost to the O&M cost?

A No, it's not, that's correct.

Q And then you mentioned through-put, the first

contingency capability. Can you expand on that?

A Right. What we've done for each of the transmission linkages is to specify the upper bound in terms of megawatts -- it's actually specified in terms of gigawatts -- the maximum capacity through-put that can happen at any time.

Q And that, as you understand it, is what for the Southern/Florida interface?

A That number, subject to check, is about three and a half gigawatts.

Q And for purposes of your modeling of transmission, you do not consider how much of that is available -- you assume that all of that is available, do you not?

A What we assume is that the first contingency capability is available for physical transport from Southern to Florida, and it's physical transport competing against physical generation that sets the market clearing price in Florida. So as much or as little of that transmission as the market wants to buy at the cost it buys, and the transport of power in that example from Southern to Florida affects the price in both markets. It affects the price in Southern, and it affects the price in Florida. So it will buy, in summary answer to your question, as much of that three and a half gigawatts,

subject to check, as is economic for it to buy, but no more; that is an upper bound on what is available.

Q All right. Are there any constraints in your model for any of the capacity that may be committed by contract?

A No, there aren't and there shouldn't be. It's wrong to do that.

Q The power purchases that a utility has under contract as of 1997, are they carried forward as a constant in your model?

A All the power in our model and all the power purchases marked to market and transacted at the market clearing price, okay, so contractual provisions are marked to market; everything transacts at the market clearing price.

Q But the amounts, are they fixed over time, or are they -- do they change over time?

A I'm sorry, the amounts of what?

Q Well, let me back up. In terms of a resource, we talked earlier about non-utility generators. Okay, those are modeled as to the capacity of the generating units in Florida?

A Non-utility generators, yes. The capacity of the generating unit, yes, and its cost, which is assumed to be low.

Q Okay. And that's the power that I think you used the word as "dump power"?

A Mr. Blaha that used that word. The word I would use is it's subtracted from demand. That plant is dispatched, pushed into the system, the energy is put in the market, and it decrements from demand.

Q Okay. And that is modeled not at whatever those units are contractually committed to provide but at the capacity of the generating units themselves?

A For those units, yes.

Q Okay. Doctor Nesbitt, you refer to Mr. Blaha in your testimony as having worked with him on your testimony in the preparation, and I'm just, if I could, trying to get an understanding of what the relative responsibilities of you are and Mr. Blaha. Could you describe that relationship for me, please?

A Yes. Mike -- Well, my responsibility has been to build -- I built the GEM system, okay? My responsibilities are running and interpreting and building the GEM system, contributing the economic market clearing and mathematical methodology, interpreting the results of the model from the perspective of its implication for forward prices, spark spreads, industry decisions on capacity, et cetera; so generally, utilization of the model.

Mr. Blaha has had the responsibility of assembling the database for the model, say, for the gas price forecast. Mr. Blaha has, for example, assembled the North American plant database. He's assembled the transmission capability and cost data base. He's assembled the demand database. He's aggregated those data to the point where they are inserted into the model. Mr. Blaha's responsibilities, I would characterize as being expert and being current in the electric industry and the data that characterizes that industry.

And on the downstream end of the modeling as I call it, Mr. Blaha has assisted me in interpreting the model results and understanding their implications for decision making by our customers and for forward prices and for trading and for mergers and acquisitions and for the other applications that we do. So to summarize I would characterize Mr. Blaha and I as a team. He brings the industry expertise and data, and I bring the economic expertise and decision support. Mr. Blaha and I are the majority owners of Altos Management Partners. As such, we are jointly responsible for the quality and relevance of our product.

MR. GUYTON: This may be a good time to break for lunch. I don't want to forget that we -- Would it be convenient now to go ahead and go back and get the load

forecast information.

MR. BLAHA: If you want. I've got that all --

MR. GUYTON: Okay. Why don't we do that and then break for lunch.

BY MR. GUYTON (Continuing):

Q Earlier I had asked about the load forecast that was employed in your simulation in your model, and you were going to tell me about the load forecast that was used.

A Yes. The load forecast used in the model starts with a database that was assembled by Mr. Blaha, which I'd like him to tell you about and amplify on a little bit, whereby he down loads the 714 information reported to FERC reporting agent by reporting agent over a five-year historical period.

MR. BLAHA: But I think for the purposes of this it was over a three year?

WITNESS NESBITT: It was over a three? I'm sorry. Over a three year period. That gives us a notion of the shape, the time shape of the historical load.

Once we have that, we have to project forward in time for each of the 32 regions of the Altos North American Regional electric model. How does aggregate energy, total energy grow by region and how does it shape grow by region? The assumption we made for this simulation is that the shape stays constant at the average of the three historical

years that Mr. Blaha alluded to, and the growth rates are those that are consistent with the NERC document, the NERC forecasts that Mr. Blaha referenced in the earlier testimony today. And that forecast is made individually by each region in the model, both the load shape and the aggregate energy, if you will, under the load shape. And that forecast is made forward in time for 20 years, ten time intervals separated by two years. Okay, and that goes beyond, as I understand it, the time frame of the NERC forecast so we had to apply Altos's judgment past the timeframe of the NERC forecast, the so-called out years.

MR. GUYTON: How far did the NERC forecast go?

MR. BLAHA: The NERC forecast that we used was the '96 to 2005 data set. I was mistaken in my earlier comment.

MR. GUYTON: So that was data reported to NERC in 1995 for the period '96 through 2005?

MR. BLAHA: It would have been reported in 1996 and became commercially available by FERC -- by NERC in the fourth quarter of '96.

MR. GUYTON: How is that NERC data compiled?

MR. BLAHA: I'm not directly responsible for compiling the data. I can give you my understanding of it.

MR. GUYTON: Okay.

MR. BLAHA: My understanding is that the

utilities submit to the sub regions their forecasts, and the sub regions then submit to the regions and then ultimately to NERC.

BY MR. GUYTON (Continuing):

Q Now Doctor Nesbitt, when you were speaking of the load forecast, you spoke of the energy growth. Are these forecasts only for net energy for load?

A I believe they are.

WITNESS NESBITT: Aren't they, Mike? I believe the net forecast for --

MR. BLAHA: We used the NERC forecast for net energy for load?

WITNESS NESBITT: Yeah, I believe they are.

MR. GUYTON: Okay. You don't use a forecast of demand growth.

MR. BLAHA: What do we mean by demand? You mean demand as in capacity?

MR. GUYTON: Yes.

MR. BLAHA: No.

MR. GUYTON: Or as in load.

MR. BLAHA: As in peak or --

MR. GUYTON: Yes.

MR. BLAHA: No, we do not use a peak forecast. The peak forecast is implicit in the shape of the load duration curve?

WITNESS NESBITT: I believe we do better than that. We want to understand by accessing the detailed 714s precisely what the historical load has been, not just on peak, but throughout the entire spectrum of hours. We need to understand the shape, not just the peak, and we access the historicals painstakingly to get those and then aggregate those up so that we don't have to rely on more summary forecasts of demand growth.

MR. GUYTON: Now I want to make sure I understand this, for net energy for load, the total consumption, you used the '96 reported data?

MR. BLAHA: That's what we used, yes, in this study.

MR. GUYTON: Right. Okay. But to develop your load shapes, you used an average of the data reported to NERC for what years?

MR. BLAHA: To develop the load shapes, it might be helpful if I just walk you through the process. To develop the load shapes we went to the FERC form 714s, which are the hourly loads submitted by every control area in the country.

MR. GUYTON: For what year?

MR. BLAHA: For 19 -- For use in this study, 1993 through 1996.

MR. GUYTON: Okay.

MR. BLAHA: Then what we do is we categorize those by -- we determine the load shapes or load duration curves by hour, which means we break down the information by month, by day type, and then by the 24 hours of the day to come up with a consumption pattern per day per month. And I believe we have an illustration of that in Doctor Nesbitt -- in one of Doctor Nesbitt's exhibits.

WITNESS NESBITT: Actually two of them. Those appear in DMN-3 and 4.

MR. GUYTON: Okay. What data is actually averaged?

MR. BLAHA: I think what you're asking me is we take the hourly demands for the three years, and we want to classify all January Mondays at one o'clock in the morning together across those three years, and all January Mondays at two o'clock in the morning.

MR. GUYTON: So you do the hour by day, by month?

MR. BLAHA: Correct.

MR. GUYTON: So assuming we had, for ease of convenience, four Mondays in each of those years, and I realize that is probably wrong, but we'll nonetheless make the assumption to simplify, to develop your data for January Mondays at 1 p.m., you would have 12 data points that you would average?

MR. BLAHA: Correct.

MR. GUYTON: Okay. And then you -- and that's data that you would use to develop both your monthly and your annual load duration curve?

MR. BLAHA: Correct.

MR. GUYTON: How is the daily load duration curve derived?

MR. BLAHA: If you can bear with me a second, if I can think about it, I can specify this. This is not necessarily a simple process. The load duration curve, in essence, is a cumulative probability function. So if we are going from an hourly to a day, we've got to go from an hourly cumulative distribution function to a daily cumulative distribution function. So in underlying the cumulative distribution function is a density function or a distribution function, and so in essence what we are going to do is add those different -- overlay those different distribution functions on top of each other to come up with a new cumulative distribution function.

MR. GUYTON: The formulation of your load duration curves is done in your model database?

MR. BLAHA: Exogenously, correct. It's done between the hourly database to derive the inputs into the electric pricing model.

WITNESS NESBITT: It's done externally.

MR. GUYTON: Okay. It's done externally, okay.

And it's not reflected in the model inputs -- the curves themselves are not reflected in the model inputs that were provided to Florida Power and Light?

MR. BLAHA: The curves are represented by the inputs.

MR. GUYTON: The inputs are impacted by the curves, but the curves themselves are not in the input.

MR. BLAHA: Correct.

MR. GUYTON: Okay.

WITNESS NESBITT: Let me clarify if I might what has been provided to you guys at Florida Power and Light on the diskettes that we talked about.

BY MR. GUYTON (Continuing):

Q Okay.

A You have in the case of the monthly model, the monthly load duration curves and the monthly energies going forward. So you have in the context of DMN-3 the monthly load duration curves, okay? In the database that was provided you for the 20-year forward model, you have in the context of DMN-3 the curve, the annual load duration curve, the one that starts and sweeps through the entire diagram beginning in the upper left and ends at the lower left, a kind of light gray dotted curve that sweeps obliquely through. You have those for each of the next ten time points in the model, how those change over time and how

those grow over time. So those data are provided to you, and the guide to reading those is in the user guide that's on one of those diskettes that you alluded to in an earlier comment.

Q And for purposes of your forecast or your simulation, you have held the shape of the load duration curves as you developed them constant over the simulation period?

A That's correct. I believe that's correct. The shape was held constant at the historically derived level from the approach that Mike has articulated, and all that has grown are the energy demands.

Q Okay.

MR. GUYTON: Well, we are probably at a good stopping point for lunch, if we are about ready to take a break.

MR. McGLOTHLIN: All right.

(LUNCH RECESS).

BY MR. GUYTON (Continuing):

Q Doctor Nesbitt, before lunch I had asked you a series of questions about your model, specifically about some of the parameters that you show as inputs for each of the models or for each of the types of generating units, and you gave me a long list of items, and we've only covered a few; but I want to make sure I understand some of

the others that you gave me.

A Okay.

Q One of the items that you mentioned shown was a technology change limit.

A That's correct.

Q Would you explain that please?

A The concept that underlies that parameter is as time progresses and as an industry becomes more and more mature, typically it's real cost of implementation per unit of production will drop, and that technological change limit is after the industry becomes extremely mature, a lot of units have been built and a lot of time has passed, how low relative to today's cost will tomorrow's cost get in real terms?

Q Okay. And how is that modeled?

A What the model has internally as a learning curve that starts with today's cost as 1.0, and evolves towards that parameter. Suppose that parameter was set at .8. So if today's cost in the case of a gas combined cycle unit were five hundred dollars per kilowatt installed, the ultimate cost would be five hundred times .8 or four hundred dollars per kilowatt installed. And it follows a geometrically declining learning curve from today's cost of five hundred dollars to the ultimate cost of five hundred dollars times .8 where .8 is that parameter.

Q And that curve would move down over time?

A That curve would move down over time if the tech. change limit that you just talked about is less than 1.0, and it would move up over time if that curve was greater than 1.0 -- excuse me, that parameter was greater than 1.0. It moves towards the parameter.

Q Okay. Did you use the technology change limit for each of the generating technologies?

A Yes, we did.

Q Okay. Can you tell me what the technology change limit was for each of the generation technologies that you modeled?

A Subject to check, and I looked at that over lunch, it's 1.0; so that's constant real costs.

Q So you didn't -- you made no presumption of decline or increase?

A No, that's correct. I think a more accurate way to say it is we presumed there would be neither a decline nor an increase in real terms.

Q For the -- and is that a limit that applies only to the capital cost?

A There are four such limits in the model. There is one that that applies to the capital cost. There is one separate and independent one that applies to the heat rate, a thermal efficiency. There is one that applies to the O&M

cost as a function of when the plant is built, and there is one that applies to the O&M cost as a function of when the plant is operated.

Q And was that 1.0 for each of those in your analysis?

A I'd have to check. There are three others. It was 1.0 for capital, and I'll check for you what it was for heat rate and O&M.

Q Okay.

A I believe, though, it was 1.0, subject to check, in all cases.

Q Okay. And this may go to a similar type of question: The parameters that were developed for gas combined cycle units that you added, were they all the same over the horizon that you identified?

A Which parameters do you mean? You mean the cost and --

Q The cost parameters, the heat rate parameters.

A For new or for old?

Q For new.

A For new. I'm pretty sure, subject to check, those were the same two. You have a new plant, and it stays constant at the .8 multiplier that we talked about throughout the horizon, so it did not itself decrease over the simulation period.

Q Okay. For the new gas combined cycle technology that you modeled, does that assume the F series generator over the entire period?

A I don't think I'd want to associate with a specific technology. If you look at the Siemens or the GE series that perform relatively similarly, it's your best-available technology, I would say. It's the best-available commercial technology that could be built anew in each of the future years.

Q So you've not assumed for purposes of your analysis even as much as 20 years out that there would be or may be an improvement in the technology for gas combined cycle units?

A Nor for anything else, and I don't think that biases the results at all because, if any technology decreases in cost, you've got to assume that every technology decreases in cost; and you don't necessarily have one differentially favored over another by so assuming.

Q And why would one have to assume that if one technology decreased in cost, say, for instance, capital cost, that the capital costs for other technologies would decrease?

A Okay, that's not what I said, or not what I intended to say. But if the O&M cost, we'll say, if the

new units were fully commodotized and relatively common across all the new units, why wouldn't the same O&M providers be able to provide the same reduced commodity cost service to all the old plants as well?

One would argue that any of the improved practices that is resident in O&M cost is through the market going to be transferred across the mix of technologies and plants that are in place. I would make that argument, for example. I would make the argument as well that to assume that the cost of a combined cycle unit doesn't decrease over time is actually a very conservative assumption with regard to Duke New Smyrna Beach, okay? And to the entry of combined cycle, it differentially disfavors the entry of combined cycle relative to the old units out there whose fixed costs are high and are unlikely to decline as much in my view as the incremental entries. Part of the reason we've made that assumption is to be conservative with regard to the price break forecast that we make.

Q Well, it's conservative as to Duke New Smyrna's entry in 2001, but places Duke New Smyrna at an advantage as to entry by other units subsequent to Duke New Smyrna, doesn't it?

A Wrong. That's wrong. Duke New Smyrna does not compete against another new entrants. Duke New Smyrna

competes against the last plant out in the stack, which is not a new entrant. It's not correct to say that it's a horse race between Duke New Smyrna and other new entrants; it's absolutely incorrect. What it is, is a horse race between Duke New Smyrna and the old high-cost and the aging plant that is going to be retired.

This is not the important variable to cost evolution and combined cycle. The important variable that makes Duke New Smyrna so profitable and so valued to Florida is the fact that it's going to displace a high-cost, old and aging plant that would otherwise have to be maintained.

Q You will check the other three FERCs for me, please?

A I will check.

Q What debt life did you assume for gas combined cycle units entering the market?

A I'd have to look that up. I don't recall at the moment.

Q But you did assume some debt financing?

A Yes.

Q Do you recall what percentage was debt financing?

A As I recall, subject to check, the debt equity ratio was 50/50, half debt, half equity.

Q So the equity financing fraction would be one

half?

A .5, yes.

Q You also had a factor in there that had a potential of limiting the amount that was allowed to be built?

A That's correct.

Q Okay. Did you -- was there such a factor in this simulation?

A No. The only thing that limits entry is the market's ability and willingness to absorb it. There is no artificial or external limits imposed.

Q So really what you're projecting in your simulation is potential market entry?

A That's close. What we are projecting in the simulation is entry into the market until such entry is no longer profitable without other restrictions.

Q You also mentioned a couple of other factors, and I'm having difficulty read willing my notes here. A constraint on the adequacy of -- do you recall any factor --

A It doesn't sound like the terminology that I think of. Maybe someone else has that in their notes.

Q At this point I won't ask you to get back on it. You also had a factor in there, gigawatt capacity of; do you recall?

A Yes, the gigawatt capacity is the amount of capacity in place in this aggregate of plants as of the first model year, which was 1998, how much is out there right now as we speak, as the model starts.

Q So that's the indigenous capacity for each type of --

A Indigenous preexisting capacity that is there.

Q Okay. Now I think when I asked you about the unit information you told me that was the unit input information that you had on that screen. Is there other unit input information in the model that is not on that screen?

A Yes, there is.

Q Okay. What additional unit input information is employed in the model?

A Okay, that is going to take a little bit of time. I would have to sign on and read you through it one at a time. I would like to note it's on the disks that you have in the file entitled userguide.doc.

Q Userguide.doc?

A Userguide.doc describes every input to and every output from the model, including generation, transmission, market hubs, everything. So to the extent I can't clarify that for you here in this proceeding, you have the documentation to kind of plow through that.

Q Okay. And Duke New Smyrna's counsel had offered having our technical people call you or some of your technical people. Does that offer still stand?

A From my perspective, yes.

MR. McGLOTHLIN: No changes that I'm aware of.

A Sure. If you like, I can go through that, or we can defer that.

Q Well, let's defer it for the time being.

So that I have a feel for this, can you list for me all the models that you used in your simulation?

A Yes. We used the following models, which are all implemented within the GEMS system for which you have all the documentation, the Altos North American Electric model and the NARG model; and in addition to that we used what we call -- what we called the operating model. Sometimes we call it the LDC model. What that is is a model of the profitability and the performance of an individual unit or plant or perspective Greenfield development or perspective repowering development, any individual project or asset that accepts as input the market clearing prices that come out of one of the aforementioned models, electric or NARG, and it creates projections of operating hours, price duration curves, profitability. So those are the models that we used to summarize the electric model, the NARG model, and the plant operations model.

Q Is the market point -- is there a market point model?

A Market Point is the trade name of the new software system that we have that has not yet been commercially introduced, but we have started to name our -- a lot of our data and other products Market Point. The way to think about Market Point is it's the new generation of GEMS, and it's in beta test mode.

Q Okay. Not employed in your simulation?

A Not employed in the simulation.

Q Okay. Now in addition to those models you have model databases?

A Yes.

Q And you have one for both the North American Regional model and the NARG model?

A That's correct. We have one for the electric model and one for the NARG model, yes.

Q Do you employ any other databases?

A We have, I wouldn't call it a database, but we do input data to the plant operating model, parameters that characterize the specific plant; and those parameters are usually customized. They are always customized to the individual plant being analyzed, so there's data. It's not a data base, but it's data.

Q Okay. Which model did you use to generate your

DMN-7?

A Okay, DMN-7, Column 3, the capacity factor percent, that was generated from, initially, the electric, North American Electric model, and then that was put into the plant operation model. Those are outputs of the plant operation model in Column 3, capacity factor percent. Okay. The rest of it is generated as you see it here. It's just a fairly simple calculation. We know the size of the plant. We know the capacity factor. That gives us generation in megawatt hours. We know the heat rate of the plant. All those things are articulate in the testimony which will give us the primary energy saved. We assume what has been displaced based on the output of the model, and we know the last column. So the only model input gave us Column 3, the rest of it is a self-standing calculation.

Q Okay. And Column 3, the capacity factor, was generated from which model?

A It was generated from both of the above. The electric model, the North American Electric model gave us the market clearing prices on the continent, everywhere, including Florida. We took the prices for Florida and put those into the plant operations model with the specific parameters noted in my testimony for the Duke New Smyrna Beach plant and simulated its operation in the face of those prices, and that gave us Column 3. So it was the

electric model followed by the plant operations model that gave us Column 3.

Q Okay. Now is the plant operation model input and output shown on the diskettes that you provided us?

A No, it's not.

Q Well, good, because we kept on looking for this and couldn't find it.

A Yeah.

Q In your testimony you have some summary of the history of your model.

A Right.

Q And you've stated that several North American electric companies have used the North American Regional Electricity Model. Can you describe the general nature of the models used by each of these companies?

A Let me just --

MR. McGLOTHLIN: You are getting into an area that I understand is quite sensitive and proprietary in nature. Just caution the witness that he doesn't have to answer if it would divulge confidential or proprietary information.

A Right. Let me just state in general terms what I've used the model for, and let me caution that none of this is attributable to any individual organization on that list.

I've used the model for forward price projections, forward spark spread projections, forward risk projections, asset valuations, trading decisions, and new gas pipeline entry decisions, and resource basin and profitability and exploration decisions -- resource basin profitability, exploration, and production decisions.

Q Has the North American Regional Electricity Model been used to make generation planning decisions?

A Yes.

Q By a North American electric utility?

A I'd rather not say.

Q Has the North American Regional Electricity Model been used as a primary model to justify need for a specific power plant to a state governmental siting or need determination agency?

A As far as I know, the North American Electricity Model has never been disclosed to a regulatory body.

Q By that do you mean used in a regulatory proceeding or actually had the model disclosed as to its content?

A Both. It hasn't been disclosed. As far as I know, it hasn't been used.

Q By any type of regulatory agency?

A By any type.

Q Are you aware of the use of the North American Regional Electricity Model to show the -- that a specific power plant was needed for reliability purposes?

A I would return to the answer I just gave. It hasn't been disclosed to any regulatory body or used in any regulatory proceeding that I know of for any purpose.

Q In your testimony, you discuss a review of the GEMS model conducted by EIA. What was the purpose of EIA's intended use of the GEMS model?

A EIA in 1977, '78 contracted with the company that I founded, DFI, to build for them a long-term price-quantity-capacity forecasting capability -- price, dash, quantity, dash, capacity. That model came to be known by them as LEAP, and in the 70s and 80s it served as the centerpiece of EIA's long-run energy forecasting activity.

In approximately 1980, EIA, since this was very broadly disseminated among industry, regulatory and legislative bodies, decided that they better have a validation performed on their model; and the reason that they did that was to make sure it was working right, to make sure it was coded right, to make sure that the data was appropriate, to make sure that it

was comprehensive, to make sure that it was methodologically respectable, to make sure that it was documented, to make sure that they understood the sensitivities of it to its various inputs, to see whether it could simulate recent history or not, to see whether it could simulate the regulatory and economic regime that was out there or not, to see if it could simulate some of the world variables that were out there, like oil price, okay? So they undertook an extremely intensive validation exercise with a third party, Oakridge National Laboratory, to go through the model in great detail and ascertain the answers to all of those questions so that when they made their annual report to congress in their public disclosures they were on safe methodological data and policy recommendation ground; that's why they did it.

Q So the purpose of the EIA's use of the GEMS model was for long-term forecasting?

A That's what they used it for. Yes, that was their purpose.

Q Okay. Do they still use it?

A They don't, as far as I know.

Q When did they quit using it?

A They are perpetual licensees of the GEMS, so they can use it whenever they want. They wouldn't

necessarily tell me whether they were using; however, the office that sponsored it was closed down in the Reagan administration because the Reagan administration elected not to continue the long-range forecasting activity that EIA had done prior to the close down. So the office -- what did they call it? I think it was the Long Range Energy Planning Office -- was terminated sometime during the Reagan administration, approximately '85. And my understanding is that office has not been resurrected.

Q Okay. Is there a document or documents that identify, or that you can identify that discuss the Oakridge's assessment of the EIA -- I'm sorry, of the GEMS model?

A Yes, I have brought along a bibliography that I can give to you that has about 30 such documents listed on it. As I recall, all of those are Oakridge publications and are publicly available.

Q Okay. I'll take you up on your offer.

A I figured you would.

Q Was the GEMS model benchmarked against any other model in the evaluation by Oakridge?

A It was not benchmarked against other models for two reasons. Number 1, there were no other models that were benchmarkable in their judgment, as they

communicated it to me. More importantly, that's not the way those validations were done and are done. Those validations are not simplistic or generic benchmarking against other things. What they are is detailed, go right into the computer code, right into the documentation, right into the data, look at every number, assess its voracity and validity, and then build back up a more aggregate view of the voracity and validity of the model from that detailed analysis of the individual component. So that was not the methodology they used was to benchmark. The methodology they used was highly detailed analysis.

Q In your testimony, you talk some about the market into which the energy and capacity of the Duke New Smyrna unit will be sold. Would you describe the market structure that your model assumes that the power will be sold into?

A Yes. The structure in the model assumes that there is a single aggregate market which we call in the -- in DMN-15 a market hub that characterizes each region, including Florida. All power is sold into that hub and marked to market at that hub, and all power is sold out of that hub and marked to market at that hub.

The market structure is that there is an

aggregate market in Florida. Everybody in that aggregate market sells at and buys at the fair market price and that that fair market price clears that market. There is no excess or shortage of supply. There is no excess or shortage of demand because the price adjusts itself upward and downward over time to clear that market. So the market structure is what I call a fundamental micro-economic market structure where everybody in Florida on the producers side is a price-taking, profit-maximizing producer, and everybody on the consumers side is a cost-minimizing, shop-around consumer looking for the best price for their power.

Q Is this a wholesale market?

A This is a wholesale market in the formulation that we used for this study, yes.

Q Several times in your DMN-15 you speak of the coming merchant market or the merchant electric world. What do you mean by those terms?

A To me a merchant world is one in which there is no guaranteed fixed cost pass-through by anybody. In words that I use, Charles Stalen, former FERC commissioner used, nobody is capable of forcing costs on anybody else in a system; that's a merchant world, okay? And there is no market power. Market power is

precluded. Everybody is a pure competitive, price-taking, profit-maximizing producer or a cost-minimizing consumer. Every plant is privately owned, and every plant de facto is profit center; and that's a merchant world.

Q Okay. Is that the world as it currently exists in Florida?

A As far as I know it's not.

Q Is that the world that you have modeled in your simulation?

A That's the world, yes, that we have modeled in our simulation, a world in which everybody is a price-taking, profit-maximizing producer and a cost-minimizing consumer. It's a world in which you have a robust, complete wholesale power market that clears itself at the market clearing price.

Q Okay. What transitions would have to happen in the Florida market to achieve the merchant world that you've modeled in your simulations?

MR. McGLOTHLIN: Are you speaking to the wholesale market or retail market by your question?

Q Let's start with the wholesale market.

A The wholesale market -- it's not clear that there is only one such transition, but I will give you the scenario that I think will give you that or one

scenario that will give you that, and that's a scenario where you have merchant entry, okay? And you have existing generation sold off as it was in California. That will do it. It's not the only way that will do it, but that will do it.

A world in which you set up a -- another way, that's not the only way. Another way is you set up a highly transparent and discoverable power exchange type mechanism. Either you buy -- having aggregators and traders do that as has happened in some places, or you set up a PX like in California. You force all the transactions to go through it. That makes the prices discoverable and transparent, and when that happens, every plant has to benchmark itself against the exchange price. It's another way that it could conceptually happen. A third way is simply and straightforwardly eliminate all fixed cost pass-through.

Q Now is that on both the wholesale and the retail market or just --

A For the wholesale market. No cost pass-through to the wholesale market. If you mandated that, okay, in my view that would lead to something fairly close to a fully -- if not exactly, equal to a fully merchantized market. There may be others, but those

are three ways. None of which, as I understand it, is -- has occurred in Florida; and none of which, by the way, is necessary for benefits of a newly entering merchant. A new merchant plant can enter a regulated market, create benefits for all the ratepayers just by its very entry.

Q Now you speak of a merchant plant. How do you define a merchant plant in that context?

A The way I define merchant plant is a plant that is privately owned, it's unregulated, and it has absolutely no guarantee of cost pass-through. It has to recover all of its costs through sale of its products at market prices.

Q So a merchant plant could be a plant that sells pursuant to contract or on the spot market?

A It could sell pursuant to contract. It could sell at the spot, right; but it could not be owned by somebody who has fixed cost pass-through rights. That makes it a non-merchant.

Q But the form of contracting for its power doesn't affect its merchant status?

A No, not in my view.

Q Okay. In your Exhibit DMN-15 at Page 24, on the first line of the discussion there, you use the term "deregulation," speaking of it opening up Pandora's

box of competition from Florida. Do you see that?

A Yes, I do.

Q What do you mean by the term "deregulation" there?

A Well, here to me deregulation means in large measure two things: One is elimination of fixed -- of all cost pass-through, elimination of franchise, monopoly and mandated cost pass-through; and the second piece is unbundling of transmission and mandatory open access.

Q The elimination of the franchise monopoly, is that a retail monopoly that you are referring to?

A Wholesale or retail, either one, eliminate cost pass-through; and the markets to which you eliminate that cost pass-through become merchant deregulated markets in my view.

Q Now is deregulation something that is contemplated in your model?

MR. McGLOTHLIN: Can you say what you mean by "contemplated," Charlie?

Q Are you assuming a deregulated market in your simulation?

A Yeah. The simulation that we have for this particular case assumes a deregulated market everywhere. It's not to say that it doesn't simulate

a regulated market, but it does assume deregulation in the sense that I just said. No guaranteed cost pass-through anywhere and full access to transmission.

Q Elimination of the franchise monopoly?

A Let me change that. I don't want you to put that word in my mouth. It's elimination of cost pass-through, not elimination of franchise monopoly, elimination of cost pass-through. I want to clarify when you say it's a franchise monopoly, that's one way to guarantee cost pass-through.

Q I was just trying to use your words, I'm doing my best to take notes here.

A Thank you.

Q At Page 19 of DMN-15, in the lines just before Figure 14, you talk about the transformation of plants from their present highly protected state of fully regulated plants with full cost pass-through. Now are you describing the wholesale market, the retail market or both?

MR. McGLOTHLIN: Do you have the records there, Doctor Nesbitt?

A I'm searching for where are the words. Maybe you can help me with the line numbers. I'm on Page 19?

Q Sorry, it's two lines, three lines -- begins four lines above Figure 14. It's the bottom of that top

paragraph, "When those plants are transformed."

A Yes. As I mentioned before, the Altos model and the configuration that we used it here, doesn't have a retail sector in it; it's only a wholesale market. These comments should be interpreted in the context of generation plants competing to meet a robust competitive wholesale market, okay? And what this statement says is in the past those plants have had the ability to have their costs all transferred downstream to someone at or beyond that wholesale market, and they knew they were going to get them paid back, repatriated.

Q I'm trying to find one other passage, bear with me. At Page 29 of that same exhibit, DMN-15.

MR. McGLOTHLIN: 29?

MR. GUYTON: Yes, sir.

BY MR. GUYTON (Continuing):

Q On the last, in the last paragraph you are talking about prospective entry of new generation units into a region, and in the last line you speak of increasingly easy entry. Would you explain what you mean by that?

A Yes. This is a statement that is intended to convey the idea that if there are barriers to entry that keep otherwise profitable plants out of the

market then what you do is institutionalize spark spreads that are too big. Customers have to pay too much for power, and there is not a big enough market for the fuel. That's really what the previous sentence says. So if you allow plants to enter and you don't restrict entry of otherwise profitable and economic plants, okay, you'll guarantee that long-term prices will never exceed the full incremental cost of entry, which is a condition that you want to have if you care about economic efficiency. You want the price to be capped by as low a number as you can cap it at, and this simply says if you let entry happen, it will be capped at a number no higher than the long-run incremental cost of entry.

Q And so from your perspective increasingly easy entry is positive?

A It augments economic efficiency. It reduces price to consumers, and it creates profitability for producers. It increases reliability because you've got more capacity. The answer is yes, and it decreases risk if it's a merchant plant because the merchants hold the risk, not customers who are forced to accept it as in the old model.

Q If you'd turn over to Page 31 of your DMN-15, there at Figure 25 you show in the more darkly shaded

section the existing plants, do you not?

A Yes, I see that.

Q And then in the lighter gray section are new plants that your model would capture as being added?

A Yes, way off to the right under Number 5, "New Plant Entry," yes.

Q Well, let me make sure that I understand. Is the "New Plant Entry" the white portion at the bottom of the graph or the gray portion at the top of the graph?

A Let me interpret the graph for you and that should help. The lower right boundary of the light gray is the long-run supply curve for electrical energy, and you'll notice that at the left it's comprised of existing plants whose costs may than lower than they are today. It comprised under Number 4 of in-bound transmission, and sooner or later, if it hits the marginal cost of new entry, it's bounded by the marginal cost of new entry. So think of the lower light gray right boundary of as the long-run supply curve for electric energy in Florida for each of the regions that is simulated in the model.

Q Okay. And this graph increases the quantity of capacity as you move from the left to the right?

A Not necessarily.

Q Okay.

A Not necessarily because it's fairly hard to draw in a conceptual diagram like this. You'll note that there is a rounded transmission traunch. Transmission can knock existing generation out of a given region so that actually the amount of indigenous generation can drop in a given region if transmission is in-bound. Conversely, out-bound transmission can increase the amount of generation in a given region because it's serving its neighbors. So this is a diagram intended to conceptualize the notion that the long-run supply curve has to be the confluence of the five items illustrated in the list, existing capacity, cost reductions and/or capacity increases in existing capacity, retirements and shutdowns of existing capacity, in-bound/out-bound transmission, and new plant entry.

Q Doctor Nesbitt, I want to turn now to some of the parts of your testimony. You begin at Page 13 about talking about a need for -- immediate need for five hundred megawatts of new electric generation capacity in Florida. Do you have a specific type in mind here, sir?

A Yes, indeed. If you note at Line 25, the sentence beginning at Line 23 states: "The Altos North American Regional Electricity Model projects

economically viable and profitable new additions of up to six thousand megawatts of new gas fired combined cycle power plants." The five hundred megawatts of new additions should be gas combined cycle. Those are the most economic, the most cost competitive and the most price reducing plants you can entering the peninsula of Florida market.

Q So the five hundred megawatts is part of the six thousand that you referred to earlier?

A Part of the six thousand, yeah.

Q Now the six thousand is over what time period, sir?

A The six thousand is immediate. The way we set up this model simulation and we ask the question, if there were no time constraints, if you could build as much economic capacity as you wanted whenever you wanted it, up to the point at which the market would quit absorbing it, how much would you build? And the model came back and said I want six gigawatts as soon as I can get them. And the reason it wants it is it wants to replace the old units that are very high in cost and drive down the price in Florida and drive up the reserve margin and drive up the reliability.

Q Okay. Well, you say in the prior sentence that the need is immediate and the need is growing over

time.

A Right.

Q The need for six thousand megawatts is immediate. There is further need beyond that six thousand megawatt?

A Indeed, there is more to come beyond that six thousand megawatts.

Q And how much more is there to come over the course of your projection horizon here?

A Through the year 2014 there is a need for -- correct me if I'm wrong, Mike -- another six thousand, seven thousand say megawatts of combustion turbine, most of that back end loaded in our scenario, and another couple thousand megawatts of combined cycle beginning in approximately the year 2008. To summarize, there is a need for a big increment of capacity right now and then a big increment of capacity initiating in the year 2008, roughly.

Q And all of that capacity would be based on an economic need to offset the cost of preexisting higher cost generating units?

A That's only part of it. The other part of it is there is growth projected in the load here, so the reason for that need is to offset high costs that you don't want to force your ratepayers to have to pay,

plus to have enough capacity to meet energy at peak demands as they are growing in Florida.

Q How much --

A Plus -- Let me add one more thing. Plus, and we haven't quantified it here. Plus to replace plants that are going to shut down because they are at or beyond the end of their economic life. I should point out that we've not included shutdown of old plants just because they get old. So I would argue that we have conservatively stated need.

Q So you're forecasting a need of approximately 15 thousand megawatts of new capacity in Florida through the year 2014?

A I'd like to check that number. That's approximately right. Thirteen to 15 thousand is my recommendation -- or my recollection, excuse me. Yes.

Q And about eight thousand of that being combined cycle, and another seven thousand or so being combustion turbine?

A That's approximately right. Subject to check, yes.

Q Okay. And your model shows that the entry of all of that in the time frames that you've discussed would be economically viable and profitable?

A Yes.

Q The way you've defined "need," it wouldn't be needed unless it were economically viable and profitable?

A That's true. Need, you know, the demand has to be there. If the demand is there, yes, it will not be needed until and unless it's economically profitable and cost competitive.

Q Now your model doesn't discriminate between plants that are built by merchant developers and plants that are built by utilities, does it?

A It does. It doesn't in this scenario, and the way it would and does is utilities typically have fixed cost pass-through and variable cost pass-through. If you want to simulate the world where a utility company is competing against a merchant, you want to look at utility-owned plants, you want to reduce their cost structure to reflect the fixed cost pass-through that is imposed on the ratepayers outside the energy system, compete those against entering merchant plants who have to recoup all their costs through sales in the market and solve that. The configuration that we have put together and the cost structure that we have put together assumes that both the utilities companies and the merchants have to recuperate all their costs at fair market value

prices. It marks the utilities' decisions to market in the same way it does the merchants.

Q So this simulation doesn't distinguish between a utility and a merchant addition?

A No, in that sense it does the same cost structure.

Q Okay. Now you had said that your model was conservative in its projection because it didn't include plant shutdowns that over this course of time would be at the end of their projected useful life?

A That's correct.

Q Okay.

A It does not shut down any of the currently existing plants as of the initial model year or any plant that is built during the horizon by an assumption that its reached the end of its life and has to be shut down and/or replaced. It does not obsolete the plants due to age.

Q Okay. Does your model, however, project the retirement of existing plants?

A Yes, and the way it does it, it doesn't project retirements in the sense that the plants are decommissioned; it simply fails to call on them. They sit idle. So I would say that if a plant always sits idle, my model is telling me that that plant is

retired. My plant fail -- my model fails to draw on uneconomic capacity.

Q All right. So if your model fails to dispatch a plant economically, it should be retired?

A You have to be careful with that. You have to look at the decommissioning costs which are sunk and not in the model. Okay, those are assumed to be sunk costs transferred to whomever has to pay for it outside of the energy market. It's an assumption in the simulation. So the way to say it is, if a plant -- if the market fails to provide a price that is high enough to call on the plant, the plant just doesn't run. Whether and how it is decommissioned is a decision that is made outside the model.

Q And the cost associated with the decommissioning or retirement is a matter that is outside the model?

A It's assumed to be borne external to the energy and capacity markets, which is consistent with the merchant assumption, that if you don't recover the cost through energy sales, you don't do it.

Q Can you tell me, sir, which of the existing generating units in Florida your model shows would fail to dispatch over the planning horizon or some portion of the planning horizon?

A I would have to get into to the model to show you

specifically, but I'd be delighted to show you generally using the supply stack that we have provided. In the supply stack that we've provided for the FRCC, 1998 you'll see plants that are designated, FO1, FO2 and gas out at the right-hand side in the range of 30 to 35 thousand megawatts, the plants at the extreme right-hand side. You'll see where the Duke New Smyrna plant lies; it lies well to the left in the stack. Duke New Smyrna is going to displace one of these oil burning plants. Any other kind combined cycle units that are built are going to displace more and more of these high-cost plants. More and more of them that are built are going to displace these old gas steam turbine units. So the old oil and gas steam turbine, combustion turbine units are the ones that are going displaced out of the system by a much lower cost gas combined cycle units.

Q Okay. Let's mark this as deposition exhibit 1.

(SO MARKED EXHIBIT NUMBER 2)

MR. McGLOTHLIN: The witness has reminded me that not in the room but available to us is a better copy of that that will show it much better, so we'll substitute another copy for that one.

A If you have a color copier, you could make a color copy of that. It's much easier to read.

Q I don't have that capability here.

On your Deposition Exhibit 2, the FRCC 1998 supply stack, are each of the existing generating units in Florida designated on this curve, or are they aggregated in some fashion?

A I believe each is designated.

WITNESS NESBITT: Mike, could you comment on that?

MR. BLAHA: The hydro are aggregated. All of the fossil nuclear units are broken out by prime mover.

MR. GUYTON: Now what do you mean by prime mover?

MR. BLAHA: The technology that converts the other energy source into steam or in a steam plant or into electrical energy through a combustion turbine plant.

MR. GUYTON: Well, if, for instance, we had a steam generating plant that had two four-hundred-megawatt units added, how would it be represented on this supply stack?

MR. BLAHA: You are talking about a 211 configuration to CT to ST combined cycle?

MR. GUYTON: No, I'm just talking about two steam gas fired generating units. Would there be two data entries? Would there be one data entry, or would that be part of a larger data entry?

MR. BLAHA: Let's use an example like Crystal River South which has two coal plants.

MR. GUYTON: Okay.

MR. BLAHA: That would be represented twice.

MR. GUYTON: For each coal unit.

MR. BLAHA: Correct. Crystal River station, which has five plants, four coal and one new, would be represented five times, one for each. In essence, a prime mover is a boiler or a combustion turbine.

MR. GUYTON: Okay. So with the exception of hydro, there should be a data entry on this supply stack for every generating unit in Florida?

MR. BLAHA: Correct.

BY MR. GUYTON (Continuing):

Q Now, Doctor Nesbitt, you were telling me that as new gas fired combined cycle units were added those units would displace units that were around the 35 thousand cumulative megawatt capacity?

A Yes.

Q And would they displace them in descending order from the top of the -- from the top of the graph?

A In the following sense they would, yes. If you add an increment -- let's make it a large increment -- five thousand megawatts of gas combined cycle units at the cost indicated on this diagram for Duke New Smyrna

Beach, you just take the rest of the stack and you push it horizontally by five thousand megawatts, and you insert that traunch of five thousand megawatts here.

To the extent that demand was here, you've de facto pushed the demand curve on the residual plants over to the left by five, and you've swept across the plants that would otherwise have been for marginal but are now beyond the margin and are not going to get dispatched. So the way to think about it is if you add five here, you subtract five from the right. If you add 10 here, you subtract 10 from the right. As long as demand is causative.

So the way that you have to think about this is that this plant doesn't compete with this plant. This plant competes with this plant. The next one competes with this plant. The next one competes with this plant. It's not okay to assume that it's a horse race between existing combined cycle units. What you have to assume is a horse race between existing combined cycle units and the marginal plant that is now pushed out and doesn't have to be called on any more because it's too expensive.

Q Okay. And those plants which would be displaced on this supply stack, the first 1s to be displaced

would be the ones that are farthest to the right and furtherest up?

A Farthest to the right and furthest up. There is one minor caveat to that, and that's some of the peaking units have to be there all the time because they are providing needle peaking service. But if we look at this large traunch of, for example, steam turbine units, okay, these units displace these one for one. In fact, these units are more flexible, and they are lower in cost. So what's going to happen is the entry of this five -- six thousand, excuse me, megawatts of new combined cycle is going to displace six thousand megawatts of these old steam turbines that have these very high costs; and you can see the cost differential on this chart.

Q And the steam turbines being the --

A This traunch.

Q -- traunch that's, say, between 27 five hundred -- 27 thousand five hundred and 32 five hundred?

A It probably goes out a little further. Some of these are probably smaller steam turbine units out here. These are peaking units out here.

MR. BLAHA: If I might add, that traunch is the FO6 fired steam turbines.

Q Okay. The one designated with squares is what we are talking about here, if I understand your

designation correctly.

A Yes, the FO6 is steam turbines, these little guys with the squares; and they will be color coded on your new chart, yes, indeed.

Q Okay.

A Okay. There are some FO2s, I believe, here. Oh, that's the -- subject to checking in the model, I suspect that these are being displaced too.

Q Okay. What I'd like for you to do is check your model, and I would like to know which of the individual units in Florida that you've identified would be -- I don't want to say retired because I don't think you go right that far, but that your model fails to dispatch.

A Right.

Q As a result of the addition of -- and that would be the full six thousand megawatts of combined cycle that you project is needed immediately, correct?

A That's correct. Yeah, let me state what I think you said and see if I've got it right. You'd like to know which units on this supply stack failed to dispatch and are not called upon by the market after the entry of the six thousand megawatts of combined cycle that is predicted by the Altos model?

Q Yes, sir. And I guess I'd like to know -- what

I'd like to know also is when the six thousand megawatts are added to the system and when those specific units begin to fail to dispatch, whether that would be the same time or over an extended period of time.

A Subject to check, I know the answer to that question.

Q Okay.

A It's installing the six gigawatts in the first two years, so by the year 2000, subject to the assumption we let come in, whenever they are economic, they are in; and they are causing these plants out in the supply stack, which I will find you the increments of plants specifically, immediately, by the year 2000. And our objective here was in getting the model to strongly state the substitution it wants to do and, thereby, to conservatively state the prices with respect to the profitability of a new entrant like Duke New Smyrna.

Q And then you also said that your model suggested an additional six to seven thousand of combustion turbine capacity would be added through 2014. When would that capacity be added under your model?

A As I recall, subject to checking, it was in the year 2008 to 2014. Roughly uniformly, as I recall,

across that interval.

Q Fairly even spread over that interval?

A Yeah, that's my recollection. You need peaking capacity then.

Q So about 12 to 15 hundred megawatts a year?

A Yeah, that's my recollection. That's pretty close, and I'd be glad to check that.

Q If you would. Now is this shown on your -- in the output tables that you've provided us?

A Yes, the schedule of new capacity additions is in there, on those disks that I sent you, under -- I think it's called the long.zip. You unzip that and look in Table 21. It's got the detailed schedule of cap adds, we call it, capacity additions by region, by plant, by time; and the user guide gives you the guidance you need to read it.

Q Okay. And you also said around 2008 you believe -- your recollection was the model showed the need for an additional two thousand megawatts of gas fired combined cycle capacity?

A Yeah, that's my recollection. That's right.

Q Okay.

A My recollection was that was added in a -- that was front-end loaded in that interval. In other words, it wasn't uniform over the interval, but it was added in at 2008 to 2012.

Q Okay. Does the addition of either the CT or the subsequent 2000 increment of gas combined cycle have the effect of causing other units on the supply stack not to dispatch?

A I'm going to check that out. I don't know the answer to that question right now, but I'll need to do so. I won't conjecture. Let me look at that and check that out for you. Actually I do know the answer to that. The reason you need the CT as long-term is because of low growth in Southern in Florida. Peak power gets scarce in Southern in Florida, and you've got to start adding peaking capacity. You can't rely on in-bound transmission any more.

Q So that is not going to have the effect of displacing existing units?

A Maybe in Southern. It displaces existing units more broadly than in Florida, but I do need to check that out.

MR. BLAHA: I can answer that now. What you see in the long-term is build requirements required in VCAR, Southern Florida, TVA, California and Wisconsin, which gets severely -- due to growth gets severely constrained.

MR. GUYTON: I'm sorry, would you repeat that?

MR. BLAHA: Basically we are looking at areas

that are short of indigenous capacity. They need to start building in the long-term to meet the actual indigenous demand. The long-term, what happens is, transmission doesn't necessarily want to flow at time of peak because everyone is using gas fired combustion turbines as the marginal source, so each region is trying to build enough capacity to meet its indigenous peak demand.

MR. GUYTON: So the seven thousand CT addition that is forecast for Florida in the model would be to meet indigenous demand growth, if I understand what you're saying?

MR. BLAHA: Indigenous peak, correct.

WITNESS NESBITT: If you refer to DMN Exhibit 12, you can see this already starting in 1998. When you look at the bottom graph which is imports of power from Southern, you'll see in the summer on peak, super peak, imports from Southern are below capacity, but off peak they are at capacity. It's because the price of peak power in Southern has risen high enough on peak that they don't want to sell it here, they want to keep it at home; and as this phenomenon exacerbates over time because of low growth in both Florida and Southern, there is less utilization of the transmission system on peak in each successive year.

When that happens, you've got to bring in peaking capacity. And in the model that starts in the 2008 era where you need lots of peaking capacity to meet the indigenous Florida and Southern peak demands.

BY MR. GUYTON (Continuing):

Q And that's not a function of there being insufficient transmission capacity but insufficient Southern generation?

A That's right, and insufficient price differential across the transmission capacity to induce anybody to want to move it. Southern producers make more money selling in Southern. Why sell in Florida? You just lose the transmission cost.

Q I think we covered this earlier. I want to make sure. Your model doesn't employ a reliability criteria, does it?

A It does in the following sense: There is an equivalent availability assumed for each plant which reflects scheduled and unscheduled downtime, so a thousand megawatt plant may have a 95% availability on peak, so on peak it's capability is 950. So you will have, because of this equivalent availability that is applied to the name plate capacity, more capacity in place in your supply stack than you would need at a hundred percent availability to meet the demand. So

reliability is taking account of in the model by assuming an equivalent availability factor on each unit that reflects the fraction of time that can actually be capable of producing energy.

Q Well, that's just a function that -- that's just a recognition that a plant is not available a hundred percent of the time?

A Yeah, but you can use that to look at building excess plant inventory to meet a given level of demand. If you want to simulate a reliability criteria and allow 15%, set it to .8; and the thing will give you a 15 percent reserve margin.

Q Okay. But you didn't do that in your analysis?

A Did not do that, no. We set them at the scheduled plus unscheduled downtime so that supply and demand equilibrate so that our prices are conservative, so that we get a conservative evaluation of the Duke New Smyrna Beach project.

Q So you have no reserve margin criteria?

A No.

Q You have no loss of load probability?

A Not as such.

Q Okay. Equivalent unserved load?

A Nope.

Q Now I want to make sure that I understand

something, and I'm a bit confused from what I've read in your testimony and your documents and from what I've heard you say today, and please don't hold that against me; that happens all the time.

You speak in your testimony of the fundamental reality that some of the old installed capacity in Florida is higher in cost than the cost that new capacity could be installed for, and I thought I understood from reading your exhibit that when you drew that comparison you were drawing a comparison of the total cost of new generating capacity versus something less than the total cost of existing capacity; that is, the existing capacity, the cost of that would be measured in terms of variable O&M, fuel costs, and some portion of fixed O&M but not the capital cost or the remainder of fixed O&M? Now is my understanding correct?

A Your understanding, yeah, is correct.

Q Okay.

A We look, we compare the -- I call it the forward cost to market of a new plant. What's the forward cost to get into the market of a new plant? It's all the capital costs, all the operating costs, plus all the fuel costs. What's the forward cost to get into the market on an existing plant? It's all the fuel

costs and all the operating costs. One of the big discriminators is heat rate. The heat rate of these old units is far higher than the heat rate of these new units, so they suffer a severe fuel cost disadvantage.

Q Okay. Now when you said the operating costs of existing units, that's all the variable O&M plus some of the fixed costs?

A That's correct, plus the fixed costs marked to market. The marked to market fixed cost on the new units, yes.

Q Okay. When we were discussing the cost that went into the aggregation of the types of units in your model earlier today, and we were talking about some of those units having fixed costs included in them and some not. Were we talking about the same calculation of forward marketing cost?

A Yes.

Q Okay. Those -- yeah, let me state that for you so that I'm clear on that. The costs -- the variable costs and the consumables are always included, okay, with the exception of things like hydro where we just subtract them from demand; but all units have the variable costs included. Okay, the base load plants only have those costs included. The intermediate load

plants grafts on to that the cycling cost. The peaking units graft on to that the preservation costs. And those costs are all forward costs to market. You've got to have those costed repatriated or you don't run the plant.

Q Now what do you mean by forward costs to market?

A Okay. These are costs -- and I think I alluded to just a second ago. Forward costs to market are dollars I have to spend that are not sunk in future to keep my plant around to be capable and to make energy out of it. So it's the dollars I've got to spend going forward in time to make energy; it's not the sunk cost.

Q The sunk cost being capital cost?

A Capital cost, and if I've already decided in the middle of the year that I'm going to continue to maintain it for next year, the maintenance costs are sunk.

Q Now how does one go about differentiating maintenance costs that are sunk and not sunk?

A The way to think about that, and I think it's in Mike's earlier testimony, at least implicitly, if you are -- let's suppose that you are looking at, you know, a monthly market and you've already spent the maintenance dollars to keep your plant around for the

next two years. Those maintenance dollars are sunk. If you keep that plant around for the next year and a half, you may or may not put any incremental maintenance dollars into it, but you've already bought the right to produce with that plant for the next year and a half until the next maintenance cycle hits. In that particular situation, the maintenance costs on that plant are sunk. If you look at the decision that you have to make a year and a half from now whether to sink maintenance dollars into it, that's a forward cost. You can't go beyond a year and a half from now and maintain that capacity in place until and unless you spend the maintenance dollars. So you need the prices to pay your maintenance dollars a year and a half out or you're not going to keep the plant around because you are not going to get those repatriated out of the market sales. The issue is what is sunk with respect to each decision and what is forward, not sunk, you have to spend it in the future to make your product.

MR. BLAHA: If I might --

Q Okay. I understand that, but I understand -- But I guess what I'm asking is how in your modeling do you -- when you sit down and take a look at maintenance costs, do you make a determination of which portion of

those have been sunk and which portion of those are forward-looking?

A It's a hard question the way you've posed it, but let's put it to your car, and we'll come back by analogy. How do you decide whether to change your oil or not? Okay, you can decide to either change your oil or sell the car. You'd usually say, well, it doesn't cost me much to change the oil, I'll change the oil. The next three thousand miles you drive it, the oil change is sunk, you don't care about it. You keep driving the car and you don't give a darn about oil change prices. Three months out you are facing another decision on your car. The answer is what is the maintenance cycle time? Where you are in the maintenance cycle depends on whether the costs are sunk versus forward to market. Well, we have made the assumption in the model that we'll have an amortized maintenance cost, an amortized annual maintenance cost across these maintenance cycles, and each year you are going to have to pay that or you shut the plant down.

Q Okay. Perhaps the amortized maintenance cost assumption in the model goes to what I'm trying -- I mean I understand conceptually how you are distinguishing between sunk and forward-looking costs, but I'm trying to understand how you model that within

the model for a given year. Is that through the amortized maintenance cost?

WITNESS NESBITT: You want to make that, Mike?

MR. BLAHA: The way that we are doing the model right now is the maintenance costs we're assuming are being -- are economic costs. So when the wear and tear occurs, they get placed into the cost factor, not necessarily when dollars are spent because fundamental in that assumption is that we are assuming that the operator of the plant wants this plant to be a going concern over the long-term. I do know of utilities who view some of these steam turbines as not necessarily good long-term investments, so they are in essence wasting the plant with the idea that when it comes time to do the next overhaul they'll look at it and say, is this an investment in the plant to keep it going, or do I just scrap it at that point? What we do is the former. We assume that these plants are going to be going concerns for a long period.

MR. GUYTON: Well, let's, if we can, put this back in the context of a gas combined cycle where we've developed some costs and see maybe if you can help us there.

MR. BLAHA: Right. Right.

MR. GUYTON: I understood that for existing

plants you use a cost, an O&M cost of $4.19 per megawatt hour, correct?

MR. BLAHA: Correct.

WITNESS NESBITT: That's right. In Florida.

MR. GUYTON: And $2.36 of that is consumable, so that's not what we are stalking about here.

MR. BLAHA: Correct.

MR. GUYTON: And another dollar 83 of that is the overhaul or maintenance cost?

MR. BLAHA: Correct.

MR. GUYTON: Okay. Now that's not all the overhaul and maintenance costs that are reflected on the books and records of the units that comprise -- that you use to develop your aggregates for gas combined cycle in Florida?

MR. BLAHA: For a gas combined cycle it's not all, but for combined cycle it's most of them.

MR. GUYTON: Okay. And the only elements that's missing there are the preservation costs?

MR. BLAHA: Let's break out maintenance just a little bit more.

MR. GUYTON: Okay.

MR. BLAHA: There is some maintenance on combined cycle with respect to the structures. There is some maintenance costs if you don't run the plant. If you

don't run your automobile, you are going to incur some maintenance costs just for not running it, and it just -- just the nature of the equipment. But for the most part, preservation costs are not maintenance costs on a combined cycle plant.

MR. GUYTON: Okay. So I'm confusing the matter by introducing preservation costs. Let's take those out right now. Help me understand for purposes of modeling gas combined cycle existing plant in Florida what maintenance costs are included and excluded?

MR. BLAHA: The maintenance costs included in our forward cost to market are the cycling costs, which are the overhaul costs of the combustion turbine and the steam turbine, which are the large dollar items.

MR. GUYTON: The overhaul cost that are associated with the wear and tear that arises from having to cycle the unit on and off?

MR. BLAHA: Correct.

MR. GUYTON: Okay. Now what maintenance costs are excluded for gas combined cycle?

MR. BLAHA: There is going to be some relative to the structures of the building, some maintenance costs with the control systems. Those types of costs which are fairly minor with respect to the entire plant are not included.

MR. GUYTON: Okay. Now the maintenance cost for -- that are included and excluded for your model differ, depending upon the type of unit that we are talking about here?

MR. BLAHA: Differs between the type of technology we are talking about.

MR. GUYTON: Okay.

MR. BLAHA: To give you an example, a nuclear plant is going to have a lot of maintenance to it whether you run the plant or not. That would be a preservation cost.

MR. GUYTON: Well, let's go back and look at your various types of plants. For your base load units, your nuclear, your hydro, and your high efficiency coal, none of the maintenance costs are included?

MR. BLAHA: We have not included them, correct.

MR. GUYTON: Okay.

MR. BLAHA: And the reason why we did not include them is the fact that these units are going to run all the time. If they are running all the time, they don't really have a choice of whether or not they can bid in a different price and try to capture a higher price. They are basically price takers.

WITNESS NESBITT: Let me interject as well, they are always in for marginal, so they don't set the

price, so they are specific cost structure is not very important. Keep in mind: Who sets the price? It's the guy on the margin. If you are a coal plant in for marginal, you are a lot less sensitive to all this stuff that we are talking about here than you are for a steam turbine, a combustion turbine or somebody who is on the margin.

MR. GUYTON: Okay. The intermediate units that you have identified would be steam turbines, combined cycle units and low efficiency coal?

MR. BLAHA: Correct.

MR. GUYTON: Well, we know about the combined cycle units. I won't ask you about that. Steam turbine, they have an element of cost that is variable O&M when you are trying to calculate the forward market cost that would be comprised of -- Let me try this over again.

When you are trying to model the forward market cost for a steam turbine, you are capturing the variable O&M or consumables?

MR. BLAHA: Correct.

WITNESS NESBITT: Right.

MR. GUYTON: The fuel?

WITNESS NESBITT: Right.

MR. GUYTON: And do you include some cycling

costs?

MR. BLAHA: We include the cycling cost.

MR. GUYTON: Okay. And those are, as in the combined cycle unit, the maintenance costs associated with cycling, the overhaul costs associated with the wear and tear of that that occurs to the unit due to the cycling?

MR. BLAHA: The major maintenance due to operating the plant.

MR. GUYTON: Okay. And then what costs are excluded from the maintenance costs for a steam turbine?

MR. BLAHA: Property taxes, insurance, staffing the plant; and for steam turbine you are going to have a larger share of maintenance because you've got boiler scaffolding that has to be attended to. For the oil plants you've got the delivery lines going from the tanks. There is just far more working parts than on a combined cycle plant.

MR. GUYTON: Okay. So this is -- A larger share of maintenance would be included in the forward market price for steam turbines than for gas combined cycles.

MR. BLAHA: I think you have two effects. One, there is more maintenance; and two, there is a larger

share that is in preservation.

MR. GUYTON: Okay. Now when you model this -- well, let me back up. Do you model this, or do you make this decision in your model database, the calculation?

MR. BLAHA: We make the decision of what -- what we model are the bidding behaviors of specific aggregated units. So the cost structure of those, the forward costs to market for those aggregated units are done external to the forward electric pricing model.

MR. GUYTON: So you do it in your database?

MR. BLAHA: We do it -- I don't want to say database because structurally what we have are data bases, and from the databases we distill that into the essence of the information, so there is a series of procedures that we go through to generate the supply and the demand curves that go into the GEMS.

MR. GUYTON: Okay. Now do you --

WITNESS NESBITT: Let me clarify that. It is not done inside the Altos model. It's done prior to the model, and the results are stuck into the model.

BY MR. GUYTON (Continuing):

Q Okay. And that's a judgment exercise that you, as using the model or Mr. Blaha, makes a judgment as to what the appropriate inclusion and exclusion of

maintenance costs would be?

A It's in part judgment, and it's in part an appeal to the historical data and the judgment of others, the professional opinions of others.

MR. GUYTON: Now forgive me, you wouldn't be -- this wouldn't be so simplistic as saying you are going to include 80% of the cost of maintenance? I mean are there measures that you use that are rounded in that fashion?

MR. BLAHA: What we've done is taken the historical estimates from -- reported by the large plant statistics in the FERC Form 1 to determine what that breakdown of plant is.

MR. GUYTON: Okay. And you've taken that large plant history and you've gone through for each year and divided what you think should be included or excluded?

MR. BLAHA: We didn't exclude any costs. We allocated them between variable, cycling and preservation costs.

MR. GUYTON: Okay. Well, I'm trying to go back to the maintenance costs for the steam turbines, and if I understand, some of them are characterized as cycling and included in the forward market price and some are excluded.

MR. McGLOTHLIN: Excuse me. Some units or some costs? I'm sorry.

MR. GUYTON: Some costs, some maintenance costs.

MR. BLAHA: Correct.

MR. GUYTON: Okay. Now if they are excluded, they are not a preservation cost and they are not a cycling cost; they are just excluded, right?

MR. BLAHA: No. Basically, let's go back. The cycling cost, the way we are defining cycling costs are, are there cost associated with the plant if I do not operate the plant? Can I avoid certain things if I decide not to operate the plant? And if I do not operate the plant, I will not suffer the wear and tear on the boiler and the steam turbine.

MR. GUYTON: Okay.

MR. BLAHA: But that doesn't avoid all maintenance. Particularly, when you get into coal plants with a lot more working parts and a lot more caustic materials open to the air, you wind up with a lot more maintenance with respect to the balance of plant, besides the boiler turbine.

MR. GUYTON: Okay. We are obviously not communicating, and I'm afraid that I'm just a little obtuse, but we switched from steam turbine to coal, and I want to go back and focus on steam turbine, if I

can.

MR. BLAHA: Okay.

MR. GUYTON: The components of your forward market price for steam turbine are variable O&M, fuel, and cycling costs?

MR. BLAHA: Correct.

MR. GUYTON: Okay. The cycling costs do not reflect all the maintenance costs for the steam turbines?

MR. BLAHA: Correct.

MR. GUYTON: Okay. They reflect some portion of the maintenance cost for the steam turbines?

MR. BLAHA: Correct.

MR. GUYTON: Okay. Which in your estimation -- which was developed based upon your judgment from looking at historic data?

MR. BLAHA: Correct.

MR. GUYTON: Okay. That historic data would be data from FERC Form 1s for major facilities for ten years; is that --

MR. BLAHA: Correct.

MR. GUYTON: Okay. And did you develop for each year what you thought the portion of the total maintenance costs were for cycling and then average those together, or -- I'll just stop right there.

MR. BLAHA: We took all of the maintenance costs and allocated them to cycling or preservation for each year.

MR. GUYTON: All right. Maybe this is where I'm --

MR. BLAHA: And then we averaged each year to come up with a --

MR. GUYTON: Okay. Take all the maintenance costs and you allocate them to cycling or preservation?

MR. BLAHA: Or preservation.

MR. GUYTON: Okay.

MR. BLAHA: And the reason for it is the cycling cost is where you get the greatest, widest variant because, when you do a major overhaul, that is a lot of dollars being spent in one year.

MR. GUYTON: Preservation costs are not captured in the forward market cost for the steam turbines but the cycling costs are.

MR. BLAHA: Correct?

WITNESS NESBITT: I don't agree with that. That's not the way -- Costs are not captured. Price captures everything. See, I think one of the things to keep in mind, just because you put a cost estimate into the model doesn't mean the market is going to capture it,

okay? Keep in mind that capture, capture of margins, the difference between price and cost. If you don't put it in, you can still capture it because somebody else is on the margin.

BY MR. GUYTON (Continuing):

Q Okay. So what we are -- this is a forward market price for steam turbine generation?

A This is the cost of steam turbine generation, the cost, the bid cost, what the steam turbine generator will bid into play; and if that is less than the market price, he or she wins. If it is more than the market price, he or she doesn't win, and he or she doesn't operate.

MR. GUYTON: So this is what you're -- This is the input price in terms of your model?

MR. BLAHA: I would define it as it's the input forward cost to market of that unit. If the forward cost to market is less than -- is less than the market clearing price, the unit runs. If it is greater than the market clearing price, the unit won't run.

MR. GUYTON: Okay. Low efficiency coal, what were the -- what are the elements that comprise the input forward cost to market for low efficiency coal?

MR. BLAHA: The same as the oil and gas steam turbines, which are fuel, non-fuel consumables, and cycling costs.

MR. GUYTON: Okay. Are the cycling costs greater percentage of total maintenance cost for low efficiency coal than they are for steam turbine?

MR. BLAHA: The cycling costs are less a percentage of total maintenance for low efficiency coal.

MR. GUYTON: Okay. Than they are for steam turbines?

MR. BLAHA: Than they are for steam turbines, oil and gas steam turbines.

BY MR. GUYTON (Continuing):

Q The fuel cost for these units escalates over time depending upon your assumed price of fuel, correct, escalates or decreases depending upon whether --

A It changes, yeah. It changes based upon your projected price of fuel, yes.

Q Okay. The consumables for each of the generating units, do they change over time, their cost?

A My understanding, subject to check, is that they are constant and real over time for each of the units, and that subject to check, with what are those technological change limit parameters for each of those variables that we talked about earlier in the testimony; so they are constant real as I sit here right now.

Q Okay. The cycling costs that are included in some instances, do they change over time, or are they

constant and real?

A Yeah, let me state more precisely. As I testified earlier, the number that goes into the model is the sum total of the relevant non-fuel consumables plus cycling, plus preservation, according to the allocations that you've talked about in your questions, i.e., a low efficiency coal plant, a steam turbine, et cetera. It's the sum total of those two or three or one, depending on the plant type you are talking about. It stays constant in real terms over the modeled horizon. We are not making an assumption of how each incremental or individual element is. We are making an assumption how the sum total of the relevant elements changes through the simulation period. For example, the $4.19 number that you've broken into consumables and cycling, that $4.19 stays constant real. It doesn't say anything about what its composition does. It simply says that the sum total stays constant real.

Q The fuel changes, the other component of price input, stays constant and real?

A That's correct. The O&M component stays constant real subject, as I say, to checking those limits.

MR. GUYTON: This may be a good time for a short break. I may be able to consolidate some notes.

(BRIEF RECESS)

BY MR. GUYTON (Continuing):

Q Doctor Nesbitt, you had said earlier that you would endeavor to go back and take a look at the model and identify the units that were no longer dispatched in the model.

A Right.

Q Are you going to be able to identify those by individual units, or are those going to be by aggregate unit types?

A I would like to do it first by aggregate unit types because that is what is resident within the model.

MR. BLAHA: May I ask one thing here? Which is, what years do you want to look at?

MR. GUYTON: I really want to look at the years of your simulation.

MR. BLAHA: I mean if we look at -- if we do every two years, that could be a substantial amount of work. If we want to do just like a cut, like the beginning and the end or --

BY MR. GUYTON (Continuing):

Q Well, what I'm really trying to find out is at what point which units are no longer dispatched. I don't need -- I mean if -- You tell me. Once they are no longer dispatched, is it conceivable that they will be dispatched at a later date in time?

A No, it's not.

Q Okay. So I guess I don't need to look at the subsequent years as to those units, but I am trying to find out which units are no longer dispatched, which existing units are no longer dispatched in what years under your assumption.

A Okay.

Q And that will be a function of the input price for those units being greater than the market clearing price?

A That's right. By -- I would add by period of load. Sometimes they may be dispatched, sometimes they might not; but in any period of load, yes. If their cost is higher than the price, they don't dispatch. If their cost is lower than the price, they do.

Q Okay. Can you tell me which tables in your output that information is reflected in?

A Yeah. The best place to see the plant dispatch is for the monthly -- for the annual model, Exhibits DMN-12, 11, 10, 9, 8, I believe.

Q I'm sorry, DMN?

A I'll start at the beginning because I'm at the back here. It's DMN-8 through 12, and that's resident, by the way, in the spread sheet that I've provided you on the disk named -- it's named short.xls. I can find out what it is when I see your disk if you've got them. And then I

will give you the counterpart of this for the 20-year forward simulation, and that will show you exactly how the new plants dispatch in each category of load in each forward year. And tacitly, if it doesn't dispatch, then it doesn't dispatch. Okay, in other words you will see the plants that will dispatch. When you know the total capacity in place because of the supply stack, you'll know the plants that won't; and we'll walk you through that.

Q Okay.

A And both of those spread sheets that I just enumerated have been provided to you, and I'll help you find those on your disk.

Q Okay. The problem is our disk is in Miami. I do not have it here.

A In Miami, okay. What you might do --

Q As you may recall, I was limited to making only one copy of it.

A That's right.

Q Do you have the disks here?

A I have the files; I don't have the disks. Yeah, I've got them.

Q Okay. Well, perhaps we can walk that through and you tell me the files, and then I can tell whoever is looking it up on the disk where that is.

A Okay.

Q But that will be tomorrow's exercise.

A Okay.

Q In those outputs we would be looking at a total price that is composed of the various elements that we are talking about, but would it be a total price, or would the outputs show the breakdown of the various elements we have been talking about, the variable O&M, consumables?

A Okay, the output will not show the breakdown of consumables, cycling, et cetera. As I mentioned before, that will give you the total. The analogy of the $4.19 number you saw earlier would show you the $4.19 number. It will show you how much a plant with that cost and the attendant heat rate and fuel prices will dispatch, if at all.

Q So the output will show the total O&M, however that is comprised for that aggregate?

A I mean -- let me take you back to what it will show and maybe use DMN-8 as an example.

Q Okay.

A What that output shows in DMN-8 -- okay, instead of months down the horizontal axis, it will be years beginning in 1998 and going ahead in ten intervals separated by two years. Okay, and it will show you the dispatch of plants in exactly the analogous fashion to what DMN-8 shows. It will show how much hydro, how much nuke,

how much coal and so forth. And you will see in that the combined cycle will be growing rapidly, and following the growth and load over time -- and, in fact, growing slightly more rapidly than the growth and load because it's going to replace some of the old units. So you'll be able to see the incursion of gas combined cycle in Florida, and tacitly, the exit of the high cost capacity that doesn't have to dispatch any more.

So what you see is the results of the simulation. If you want to see the cost structure of the simulation, that's in the database that is on your disks in Miami. My plants dispatch in the real world and in the model when the price is above their cost, and this is the set of plants in these charts for which the price is above the cost.

Q Okay. Where are the forward market prices?

A They are in the same spread sheet in which this is embedded and which it's longer run counterpart are embedded. There is a tab that says electric prices or elec. prices or elec. underscore prices, and that contains the forward prices by load period, by region, by time; and that's true in the spread sheet named "short," which is the direct monthly counterpart of Exhibit DMN-8 and the one that is long, which is the analogy to DMN-8 that goes forward 20 years. So the prices are there and are a rate

in real 1998 dollars forward through time in the appropriate years.

Q Okay. Now which of your exhibits that you filed in this testimony are premised upon your long-term model?

A All of them are premised on both the long- and the short-term model. They have the same data in them. As I said, they are the same model; the only thing that is different is the time frame. For example, the primary element that the long-term model introduces is to predict the rate of capacity additions over time. What the short-run model does is give you a finer level of detail on how you run the system at the state of capacity that it exists in the system in each of the forward years. In other words, it gives you more detail on operation within the year. The long-term model gives you more detail on what catalyzes capacity entry.

Q Both models use the same forward market price?

A Of what? Forward market price of what?

Q Of various generation type.

A Costs.

Q I'm sorry. Thank you.

A Both models are intended to use the same cost estimates for the same plant increments, yes. Okay, the fuel prices are different because the annual model we have to have intra-year price variation as you saw in the PSC

exhibit this morning. Okay, in the long-run model, the prices change over time.

Q Now the model treats the recovery of any undepreciated cost of retired plant as something extraneous to the model, not reflected in the market clearing price?

A That's right. The assumption is that plant decommissioning, site clean up, and so forth is external to the electric or the fuel markets.

Q Okay. So the market doesn't afford recovery of that?

A Not necessarily. We don't calculate whether it does or not. We simply say that any costs that are associated with such clean up are borne outside the energy market and that's an assumption.

Q Okay. When we were discussing the load forecast that you prepared for purposes of your analysis, you spoke of the NERC data from 1996 through the year 2007. Was that --

MR. BLAHA: Five.

Q 2005. Your simulation ran through the year 2014, correct?

A That's correct.

MR. GUYTON: Okay. How did you develop the load forecast for the years 2006 through 2014?

MR. BLAHA: We assumed a growth, whatever was the

last year's growth rate between 2004 and 2005 and just extrapolated forward.

MR. GUYTON: So a constant growth rate, whatever the growth rate was 2004 to 2005?

MR. BLAHA: Correct.

WITNESS NESBITT: To 2006, I think you meant the say. Oh, no, I'm sorry. Cancel that.

MR. GUYTON: And that's the growth in net energy for load that was assumed for Florida in the NERC document?

MR. BLAHA: Correct.

WITNESS NESBITT: For Florida and for everywhere else in the United States.

BY MR. GUYTON (Continuing):

Q Now earlier you spoke of having assembled the hourly reported data for every hour for the past five years for every reporting entity in Florida and the United States as part of your -- Is that part of a compilation or your model data base?

A Yeah, let me ask Mike to tell you exactly how he down loaded the FERC 714s for Florida and elsewhere and how he processed those to calculate those forward load projections.

MR. BLAHA: We have down loaded all five years of 714 information from 1993 through 1997.

MR. GUYTON: And who are the reporting entities

in Florida for purposes of that?

MR. BLAHA: My list may not be totally inclusive, but let me see if -- let me see, Florida Power and Light, Florida Power Corp, TECO. All of the members of Seminole report separately. I can't list all of them.

MR. GUYTON: Sure.

MR. BLAHA: Tallahassee, Gainesville, Orlando, Lakeland. I'm not sure if FMPP, Florida Municipal Power Pool reports. Kissimmee reports, and there are a couple of other smaller cities that I just can't remember at this point.

MR. GUYTON: Most but not all the entities that comprise the peninsula of Florida?

MR. BLAHA: All of the control areas that comprise the peninsula of Florida, plus all of the little co-ops in Seminole.

MR. GUYTON: What do you mean by control area?

MR. BLAHA: Control area is the entity that has the responsibility of instantaneously balancing the demands with the loads.

MR. GUYTON: Do you have a ready list of the reporting entities that comprise Florida?

MR. BLAHA: I did not bring one with me.

MR. GUYTON: Okay. Would you -- Do you have one readily accessible to you that I might request as a

late-filed?

MR. BLAHA: I either have it at home, or the woman who does all this work, we could call her and she could fax me.

MR. GUYTON: Okay. I would like to request that if I might, Joe, as a late-filed exhibit. That's the reporting entities to NERC. Why don't we say the Florida reporting entities to NERC.

WITNESS NESBITT: It's to FERC, I believe, isn't it. It's not reporting to NERC; it's reporting to FERC.

MR. BLAHA: It's the FERC Form 714.

WITNESS NESBITT: Form 714.

MR. GUYTON: I guess what I'm trying to get at here is does this comprise all of the -- do the reporting entities that report to FERC comprise all the entities within the peninsula of Florida?

MR. BLAHA: I think of all of the regions that report that FERC -- or FRCCs has the best response rate; but whether or not it contains every single megawatt of load for any hour, I don't know that they -- it's a hundred percent included.

BY MR. GUYTON (Continuing):

Q At Page 18 of your testimony, between Lines 8 and 16, you talk about in-bound transmission from Southern competing against Duke New Smyrna; and you state that the

model shows indigenous combined cycle capacity in Florida is better to address the Florida winter peak than the in-bound transmission. There you are talking about not Duke New Smyrna per se but the six thousand megawatts of gas combined cycle capacity?

A Let me say it this way, six thousand megawatts of merchant capacity with the cost discipline that merchant capacity typically undergoes so it performs like Duke New Smyrna. Okay, clearly the Duke New Smyrna project at the parameters that I've assumed is better. There may be others, but clearly Duke New Smyrna is better, and I don't want to genericize it.

Q Duke New Smyrna is better than in-bound transmission, but it may be the same as or maybe not quite as effective as or maybe more effective as some of the other gas combined cycle capacity?

A Maybe. My guess is -- or my judgment is it's a commercial unit. Spot from commercial vendors is pretty much the same. It's what other people would build. I doubt it's going to be any worse because it's subject to a lot of cost discipline because Duke has agreed to take all the risk. My guess is it's better.

Q Now you say the Altos model shows this. Where is that shown in the Altos model output?

A What the testimony says, the Altos Model 14 shows

that indigenous combined cycle generation in Florida such as the Duke New Smyrna Beach power project is better. The way it shows that is through the procedure we talked about earlier. It generates market clearing prices in Florida. The Duke New Smyrna Beach project and combined cycle projects like it displace high cost sources off the back end of the supply stack we talked about, generate price reductions and cost savings as a result of so doing; and that's better than transmission from somewhere else. And the way the Altos model shows that is it doesn't bring transmission in from somewhere else to knock the Duke New Smyrna unit and units like it out.

Q All right. Where is the dispatch of the -- of this gas combined cycle capacity instead of the in-bound transmission shown in the output of the model?

A If you'll refer -- one place it's shown -- to DMN-8, you'll see a base load application that in-bound transmission is not flowing at capacity except for about four months, which means in-bound transmission is on the margin for base load for those other eight months, which means that if New Smyrna is dispatching it's beating it. Okay, in this particular case in base load that does not appear to be the case. If we turn --

Q That would be because we are not showing a combined cycle dispatch in the winter months?

A That's right. You are showing -- in base load off peak, you are showing combined cycle dispatch June through September, and you are showing, co-incidentally through that dispatch, that the Southern to Florida capacity is flowing at capacity during those months. So both of those are at the margin it turns out.

We'll move to high load factor intermediate. Now we see, in this particular case for the year 1998, okay, we see the combined cycle units in DMN-9, okay, dispatching all year. We see the Southern system flowing full, and we see these steam turbines running a little bit in April and a lot in May through October, and a little bit in November, which tells us that those steam turbines are on the margin, which means that both in-bound Southern transmission and indigenous combined cycle generation is are inframarginal, they are beating the margin; and the steam turbines are at the margin, or setting the price for everybody.

Q So this one doesn't show us that gas combined cycle is superior to the in-bound transmission, just that both of them are being dispatched?

A Okay, that's right, in this case. Now if you remember from my testimony, I asked the question, okay, what if we double, roughly speaking, to seven thousand megawatts the in-bound transmission capability from Southern and we maintain the same wheeling process? Okay,

I haven't shown that in the testimony; I've simply articulated it in the testimony. And in that particular case, as I recall, you don't completely fill up the in-bound Southern transmission. You'd rather build combined cycle facilities in Florida, which means that it beats it.

Q So your testimony at Page 18, lines 8 through 16 is based upon your sensitivity where you ran additional in-bound transmission capability?

MR. McGLOTHLIN: Let me have that reference again, please, Charlie.

MR. GUYTON: It's testimony at Page 18, Lines 8 through 16 where he states that the Altos model shows that the indigenous combined cycle generation in Florida is better than the in-bound transmission from Southern.

A In part, yes, but let me refer you over to the specific discussion of that sensitivity on Page 26, lines approximately 7 -- line approximately 7.

BY MR. GUYTON (Continuing):

Q Bear with me just a minute. Page what?

A 26, line approximately 7, and this amplifies and explains I think the previous result you alluded to. And it simply says in a nutshell that if you open up the transmission from Southern to Florida, once you've exhausted what I'll call excess low cost coal capacity in

Southern, you don't want to move power from Southern into Florida. You are better off to build it in Florida.

Q So there is some more coal to be exhausted in Southern?

A During certain points of time, yes. I'd have to check that in the model, but Southern is exporting coal-fired -- coal-generated energy to Florida, particularly in those off-peak months.

Q The Florida system was planned with that in mind, was it not?

A I don't know what it was planned with, but it's certainly -- it's happening, and it's projected to happen in the model for a while.

Q Let me get you to turn back to Page 18 of your testimony, and at Lines 16 through 19, you refer to Exhibit DMN-3, and you say that it's unlikely that there will be summer energy or capacity available to be imported into peninsula Florida from points north. How is it that you draw that conclusion from a load duration curve or a series of load duration curves, or are you, in fact, relying on other information other than DMN-3?

A Give me a moment if I might.

Q Certainly.

A Let me summarize the analysis. The answer to your question is it depends on more than what is in DMN-3.

It depends on the previous discussion in the testimony and a look at DMN-3, 4, 5, 6. I believe it's 5, 6. I'll summarize fairly quickly for you. DMN-3 shows with monthly load duration curves that the peak occurs -- Florida is fairly strong in summer peak, but it has a local peak in the winter. Okay, so the way I characterized it is it's a dual peaked system vis a vis the seasons.

Let me flip over to DMN-4, DMN-4 which characterizes Southern's load duration curve shows quite a different situation. It shows a strong summer peak, but it doesn't show the same degree of peakedness in the winter, if you will. In other words, the heights of the winter load duration curves are lower, relatively speaking, than the heights of the summer load duration curve in DMN-4 than they are in DMN-3. The thought that occurred to me was, well, Southern may have excess capacity in the winter -- that's the conjecture -- and excess energy such that they could push power into Florida in the winter and beat whatever else is in Florida.

Now what the model suggests and what the capacities that are resident within DMN-5 and 6 suggest are that the -- particularly in Southern -- the amount of what I would call base load capacity, if you look at the 24 thousandish -- Where is that capacity? There is capability in 19 -- 24,970, or 25, you still have a peak

in the winter -- Excuse me, indigenous demand in Southern commands most of the base load capacity in the winter so that there is not the residual exportability of energy or capacity, if you will, from Southern to Florida in the winter and that that -- So then to meet the peak load demand in the winter in Southern requires a gas technology. As soon as you observe that it requires a gas technology, then you know you are not going to have economic incentive to move that peak load energy in the winter from Southern to Florida. You are better off to generate in the winter using an indigenous Florida generation facility, such as Duke New Smyrna Beach.

In other words, any excess generation capacity that would occur on peak in the winter in Southern would be gas, and so you are better off to build the New Smyrna Beach project in Florida and capture the winter peak market in Florida with an indigenous Florida generator. That is what the testimony attempts to say.

Q All other things being equal, gas in Florida is better than gas imported from Southern?

A When you have to pay transmission cost to move gas from Southern to Florida, gas indigenously generated in Florida is better than gas indigenously generated in Southern by approximately the transmission charge.

Q That assumes that the coal capacity and other

base load capacity in Southern is committed to serve Southern's indigenous load?

A Committed to serve the market as it exists in Southern. The price in Southern will reflect the supply demand situation in Southern. The price in Florida will reflect the supply demand situation in Florida. The differential between those two markets will dictate whether any transmission is economic.

Now what these load duration curves suggest is when you are looking at the margin during peak in the winter, there is no economic incentive to move power from Southern to Florida. The economic incentive is to build plant and equipment in Florida to meet that demand in the lowest cost fashion, which is the Duke New Smyrna Beach combined cycle type unit.

Q Let's go back. I think you were saying that you thought looking at the base load in Southern in the winter that their indigenous -- that their base load capacity would be committed to their indigenous load?

A It would be committed to the market in Southern.

Q Okay. And that would be -- To find -- Let's see, the value for that for winter would be -- Probably the best value of that for winter would be to look at your load duration curves for January?

A January, February, December, those areas; and we

can see that 24, 25 megawatt horizontal cut point -- 25 thousand megawatt, excuse me.

Q Okay. There is roughly peak demand in Southern of as much as 30 thousand megawatts in January of '98?

A Correct.

Q And there's what, 33, 34 thousand megawatts of base load capacity in the Southern system?

A Not of base load capacity. I see about 24 thousand -- Oh, wait, excuse me.

Q I'm sorry, I thought you had defined base load as nuclear, hydro, coal.

A Yeah, excuse me, excuse me, you're right. Yeah, there is about 35 thousand, you're correct.

Q So there may be some, even in the winter months, some base load capacity available for transport to Florida, at least in 1998?

A There may be, but the model is telling us that that's not where it wants to go. The model is telling us that there are other more valuable uses for that.

Q Okay. So I guess I'm getting back to the question I posed originally now. We can't discern that from DMN-3 or even DMN-3 through 6. Instead, you're now relying on what the model tells you. Where in the model would the output be that would show that indigenous combined cycle generation in Florida such as the Duke New

Smyrna power project is better for meeting the Florida winter peak deficit than in-bound transmission from Southern?

A You will see that in the spread sheet named long.zip which has got all of the inputs and all of the outputs and all the market clearing prices for Florida and for Georgia and shows the magnitude of transmission flow and the magnitude of indigenous generation. So you have the spread sheet that shows that.

Q Okay. Which -- I mean there are a number of spread sheets within long.zip. Which spread sheet are we talking about now?

A You will need to look at the ones titled FL for Florida.

Q Okay.

A You will need to look at the one that is titled SOU for Southern.

Q And that will just show that --

A It will show that the market is building combined cycle units to serve the Florida market, rather than importing energy from Southern, either retired existing capacity or augment load.

Q Okay. So the Florida spread sheet will show the dispatch of combined cycle instead of in-bound transmission?

A It will show the absolute dispatch of everything, and you will see that it is building the six gigawatts of combined cycle in preference to increasing any in-bound transmission from Southern.

Q And then the Southern will show that -- will show the disposition of its base load capacity in some fashion other than transport or sale to Florida?

A Yes, and the way it will show that, is it will show that the on-peak prices during the winter season are roughly the same between Georgia and Florida so that you have reduced incentive for power transshipment.

Q And it's just a spread sheet labeled "FL" and "SOU"?

A Yeah, there are what we call spinners in there, little arrows. When you pull up the spread sheets that say -- I'd have to check, the one on the far left that says "Dispatch," or I'll tell you what it says. That brings up a spread sheet that has a spinner on it. A spinner is a little set of up/down arrows. When you touch that, it opens the window and shows you all the regions and, touch Florida or touch SOU, and it will open the dispatch of Florida or SOU Southern respectively.

Q I knew I wanted to have my consultant here today. I'm sorry, I don't want to alarm you. My consultant being somebody internal to FPL.

Going on on that page, you say that the exhibit further suggests that prices will be firm for a substantial portion of the summer and winter but not necessarily during the spring and fall months. That's really not what DMN-3 suggests, is it, but instead what DMN-3 through 6 may reflect as well as your model?

A Yeah, but I would suggest that DMN-3 alone and DMN-4 alone would suggest that. I mean if you look at the magnitude of variation in peak demand between the season, say G, the peak in January is pretty high, but the peak in the summer is higher, so we are going to move farther up that supply stack that is Exhibit 2; and, therefore, our prices during those peak hot summer months are going to be higher than the peak prices in those cooler winter months on average, subject to these curves.

What I'm trying to say in the testimony is the obvious in some sense. There is a pretty large seasonal variation in electricity demand in Florida and Southern, and structurally that causes prices to be higher during the peak summer season than during the off-peak winter season. And these load duration curves in DMN-3 and 4 certainly support that.

Q Okay. And then the model verifies that fact as well, but the model also verifies that the fall and spring prices aren't low enough to knock the project out of the

mix. By the mix you mean out of the dispatch?

A Yeah, out of the mix means the prices don't fall below the production cost of the facility for very many hours. By knocking it out of the mix means don't run it.

Q Okay. So essentially your 82% capacity factor for the Duke New Smyrna unit for the first year of your simulation would suggest that that's running not only the winter and the summer, but also a good part of the spring and the fall?

A It's running on peak in the spring and fall, not off peak, to some degree. You will have to look at the prices and the production cost to see exactly when it's running, but that's right. And it's running all the time in the summer, as you can see in DMN-8 through 12, okay? And it's running a lot in the summer as well as non-summer months in every category of load save base.

Q Okay. And that's really true of all six thousand megawatts of the combined cycle that you, your models introduced into Florida?

A Yes, you can see that in the long-run spread sheet, but the combined cycles that are built run a lot of ours during the winter and the summer peaks and run lesser hours during the shoulder months. All of the six thousand megawatts that are added, yes.

Q Okay. In terms of your model and the capacity

factors that you show for the Duke New Smyrna unit would be the same capacity factors as for the remaining 55 hundred megawatts of gas combined cycle that you introduced, would they not?

A No, not exactly the same, and I haven't done that simulation. If you push enough capacity in here so that the last plant is just barely profitable, i.e. the present value of future margins from the very last megawatt that is added equals the present value to the fixed cost to add it, you'll find it's not running as much as the most inframarginal plant because the addition of six thousand megawatts is described as spark spread and created less run incentives for the last guy, the marginal guy in the combined cycle portion of the supply stack.

Q Okay. Have you assumed that the Duke New Smyrna unit is the first five hundred megawatt increment of that six thousand megawatts?

A We've assumed -- No, we haven't. What we have ---

Q Have you assumed it has any particular place in the addition of units?

A No, let me tell you what we have assumed. We have calculated the market clearing price assuming economically optimum addition in the sense that we have talked about earlier in the testimony of capacity, and then

we asked the question: How much will that plant run at the market clearing prices that are calculated with that amount of new capacity addition? And the Duke New Smyrna plant runs at the levels reported. So we run the Duke New Smyrna plant based on the market prices of gas and the power in Florida as calculated by the electric model, assuming the new capacity additions that it assumes.

Q All six thousand megawatts?

A Yeah.

Q Of the gas combined cycle?

(WITNESS NODDED HEAD AFFIRMATIVELY)

Q Okay. Then you take that to your operating data model and you ask it to dispatch Duke New Smyrna, correct?

A We take the prices from the Altos North American model, the market clearing prices, which have the new capacity additions in there resident within those prices that the model calculates. We take the prices out of that model and we stick it into the operating model. We stick the plant cost and performance parameters for the Duke New Smyrna plant into that model and predict its operation on that basis, so it's a two-step process.

Q All right. Now what, which -- What plant cost and performance data do you have for Duke New Smyrna plant that you use the specific for the plant operating data model?

A Those are the parameters that are articulated in my testimony, the 6,831 heat rate. Subject to check, the $2.30 fully commodotized all-in O&M cost, and the roughly 160 odd million dollars worth of investment.

Q So you don't use those in the Altos regional model, but you do use those in the plant operating data model?

A That's right. The ones that we use in the Altos model are the ones that were reported earlier.

Q Okay. And the source of those three elements of data that you use for Duke New Smyrna is what, the 6,832 heat rate?

A I think Mr. Blaha talked about that earlier, but it's experience with a number of different customers that we have. It is bids that we have seen by vendors to customers for plant performance. It's reading trade publications, such as the Avery (phonetics) Technology Assessment Guide which gives some general parameters. I would say it's the aggregate of Altos's experience and discussions with Duke. There have been some informal discussions with a lot of different companies including Duke, and these numbers appear in our judgment, and Mr. Blaha's judgment I think in particular, and he should speak for himself, to be very reasonable, very representative for a plant like that.

Q Okay. The 2.3 O&M cost, the 2.3 cents per kwh O&M cost; is that --

A Did I say that wrong? It's 2.3 dollars per megawatt hours.

Q Okay. 2.3 dollars per megawatt hour. Thank you. You probably said it right.

A I probably didn't.

WITNESS NESBITT: Mike, do you have anything to add to that?

MR. BLAHA: No.

MR. GUYTON: What other plant-specific operating data for the Duke New Smyrna unit do you use in the plant operating model besides the heat rate, the O&M, and the 160 million dollars that you show for capital costs?

MR. BLAHA: And about five million dollars I believe in preservation costs.

MR. GUYTON: Is that an up-front cost, or is that an annual cost?

MR. BLAHA: That's annual.

BY MR. GUYTON (Continuing):

Q Is the fuel cost in the $2.30 per megawatt hour?

A No, it's not.

Q Okay. What fuel cost do you use, the same one you use in your regional model?

A No, the fuel cost is equal, as we testified

earlier to the assumed heat rate, 6,831 times the fuel price that pertains in a given year, or the given month of the year.

Q So the fuel price is from your earlier fuel forecast from your NARG model?

A Right, the ones that have been -- let me put it this way: It's the fuel prices that are resident within the electric model of which you have a copy of the database. They were intended to be taken from the NARG model, that's right, but the fuel prices that that model uses are the fuel prices that are in those spread sheets and have been delivered to you.

Q Okay. Are they different than the fuel prices that were in a document that was handed out at your deposition by staff this morning?

A They are not for the year 2000, no. Those are the fuel prices that are used in the annual model for the year 2000, subject to check. No, they are not different.

Q Okay. Now where in the output tables would I find that fuel price?

A The fuel prices are in the two spread sheets that we talked about earlier, the one named long.zip and the one named short.zip that are on your disks. When you look at the model itself -- Let me think for a moment where the fuel price forecasts are. I'll have to check which tables

they are in those large databases I dumped for you. I'll have to find out where those are. They are articulated in the user guide. I don't remember right off the top of my head where we put them.

Q Okay.

A But they are in that database.

Q Part of the difficulty we are having is that I don't think they are as user friendly to us as they are to you because of your familiarity with them, and so I'm simply trying to find a way to locate them.

A I understand that.

Q Doctor Nesbitt, I want to ask you a few questions about your testimony at Pages 19 and 20 where you talk about breaking your monthly load duration curves into five discrete blocks, and you use that to divide your annual load into 60 time increments which you model.

A I have the position in the testimony.

Q Okay. You characterize base load as the 40% of hours in the month with the lowest average load, correct?

A Uh-huh. That's correct.

Q And this is the -- these are the 40% of hours with the average monthly -- with the lowest average monthly load duration curve for the years 1993 through 1997?

A Let me clarify those. 40% of the hours with the lowest average hourly load. Okay, I think the relevant

insight is the last sentence. This represents the zero to the 40th percentile of load, average hourly load over the historical period that Mr. Blaha used to calculate those averages. And then on Number 2, it's the 40th percentile to the 60th percentile of hourly load within the month and so forth.

What we are doing here is simply lining up the average historical monthly loads from highest to lowest -- excuse me, from lowest to highest, and then we're placing the fractile break points 40, 65, 80, 95 and 100 in the curve. And those represent the discrete points at which we divide the curve.

Q Now you -- The first break point is for base load at the 40th percentile of load?

A That's right.

Q Now you characterize that as base load. Does that correspond to any particular type of unit, or you just use base load for -- Why do you characterize it as base load?

A It doesn't -- It is not intended to correspond to a given unit. In other words, every unit -- no unit is precluded for competing -- precluded from competing for demand in that block of hours, okay? Those are simply the lowest average demand, 40% block of hours. Now as it so happens, when you do the simulation, it's the low fuel

cost, low O&M plants, plants that people typically term base load plants that actually win that competitive battle and get those hours.

Okay. So base load, the name is simply -- this is the lowest category of load. It persists for 40 percentile of the hours, and de facto persists for all the rest as well. So it's the lowest increment of load that we are representing in the model.

Q And it's there throughout the other periods as well? It underlies, and the other periods are hours of load that you are building on top of that?

A Yes, in the sense of the diagrams that we just referred to for load duration curves, and let me refer to the appropriate diagrams in my testimony. As an example, in DMN-3, if we refer to the June monthly load duration curve which starts up at around 35 megawatts and drops down to around 15.

Q Yes, sir.

A Okay, we ask where does the 40% of the hours break point occur? It's about 40% of the way from the right side of the June vertical line to the left side of the June vertical line.

Q So it's about 22?

A 22ish, something like that, yeah.

Q Okay.

A So that 22 megawatts of load in the model, okay, not actually that. That's the left most point. That's the highest of the 40% fractile hours. 15 is the lowest of the 40% fractile hours. The average of those hours is somewhere around, shall we say, 18? And so what the model does is it assumes that load is 18 megawatts for all 40% of those hours. It makes a discrete stair step approximation to that continuously declining curve. So that continuously declining curve is represented by a discrete stair step approximation that has five increments to it.

Q Okay. And you do that for every month of the year, you divide that load duration curve into five elements with the five stair steps?

A Exactly, five categories of hours, five stair steps for each month independently. In other words, you do it afresh for each month.

Q And then once you have divided the load up and identified the load in that fashion, then you calculate the market clearing price of the units that your model dispatches to serve that load?

A That's correct, and let me say how we do that. In that particular example, which we've used loosely that the average of those 40% of the hours in June would be 18 megawatts --

Q Okay.

A -- we compete all the units on the supply stack that were in Exhibit 2 and all the in-bound transmission minus all the out-bound transmission for that 18 megawatts of indigenous load. So the aggregate of all supplies minus the aggregate of all out, bound transmission, plus the aggregate of all in-bound transmission has to meet that 18 megawatts approximately of June base load.

Q Okay.

A And that moves you up the indigenous supply stack to a certain level. Then we do a parallel calculation in each of the five categories of load that were articulated on Page 19 and 20. There are five categories as you noted.

Q Okay. I've been meaning to ask you this, and I've forgotten a couple of times: How do you model out-of-state capacity if it's owned by a Florida utility?

A The answer is we model it correctly, and we model it correctly by recognizing that it sells commodity into its local market, and as it sells commodity into its local market, it's another commodity supplier into its local market. It affects the supply in its local market. It affects the price, okay? And either that physical commodity that's delivered into the local market is consumed there or it's transported into a contiguous market, okay?

The way we model it, and the reason I said

correctly, I don't mean to be flippant, is that if capacity owned by a utility in Region A or a company in Region A operates in Region B, it's selling its product at the market clearing price in Region B. Okay, and if there any arbitrage possibilities, they will be exercised. In other words, if it's better for the owner of the plant who resides in Region A to arbitrage it into his or her own region, he will do it at the differentials of the market clearing prices that are calculated by the model.

We want the model to give us the physical supply demand equilibrium and to eliminate all arbitrage possibilities and to eliminate all non-economic decisions that might be by the owner of a plant in Region A who uneconomically dispatches capacity in Region B and transports it to himself. Every region and every plant in every region is marked to market in the physical region where it resides.

Q So it would be treated as -- A resource that was in the Southern region but owned by a Florida utility would be treated as a Southern region generating asset?

A It would mark its product to market at the market price in Southern, and the market price in Southern would be related to the market price in Florida in a way that is consistent with the supply/demand balance in all the regions of North America. It's a no arbitrage possibility.

You mark your plant to market wherever the market your plant accesses resides. That's the assumption that is resident within the model.

Q The market clearing price that you -- let's go back to the example of the base load and the 18 thousand megawatts -- that would be calculated for the base load in June of 1998 would be the cost of the margin to serve 18 thousand megawatts? It wouldn't be the average cost of generation?

A That's correct. The supply stack cuts through 18 thousand megawatts at some point, the marginal plant, where the supply stack is not just generation; it's in-bound less outbound transmission as well. Whoever is at the margin, he or she sets the price to everybody in that region, and it's his or her cost that dictates the price in that region.

Q Okay. But in that particular example where we said that the demand ran from 15 thousand to 22 thousand megawatts, but you developed an average of 18 thousand?

A Correct.

Q It would be whatever -- the market clearing price would be for the marginal generation at 18 thousand megawatts and not at 22 thousand megawatts?

A That's right. That's right.

Q Now I think probably I skipped over this, and I

probably ought to ask you to go back and explain to me how you develop the average load for each of your five divisions of load. You take -- well, let's just use the base load as an example. How do you develop the average load for your base load which is comprised of the 40th lowest average hours that range from 15 thousand to 22 thousand?

A Okay, the way I understand that -- Actually, Mike, you want to talk about how you average the historical FERC 714 down loads to make the average historical LDC, load duration curve? Because that is really what happens.

Q You don't average the load, instead you average the historical load duration curve?

A Let me ask Mike to address exactly how we get it.

Q Okay.

MR. BLAHA: Each hourly load duration curve in essence has a histogram, and we cut through that histogram for each hour until we get the bottom 40% of the loads, so we have to iterate through. We pull at one point, see if we are high or low, and then we either have to start adding more hours or decreasing hours until we get 40% of the hours for that period.

MR. GUYTON: Now which period are we talking about here?

MR. BLAHA: For, say, the monthly.

MR. GUYTON: Okay.

MR. BLAHA: So for January it's 40% of 744 hours. For February it would be 40% of 672 hours. Once we do those histograms, we now have a histogram basically for the bottom 40% of the hours, and we estimate the mean of that histogram. The mean is the average, arithmetic average.

MR. GUYTON: So you just sum the load for each of those 40 hours and divide by 40? I'm sorry, that's wrong. It's not 40 hours. You just sum the load for each of the hours that comprise your 40 percentile of lowest load.

MR. BLAHA: Correct.

MR. GUYTON: And then divide by whatever the total number of hours are.

MR. BLAHA: Correct. That's right.

MR. McGLOTHLIN: Charlie, let's go off the record and talk about logistics for a minute if we can.

(WHEREUPON, THE DEPOSITION WAS ADJOURNED UNTIL 9:00 A.M. NOVEMBER 11, 1998)

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ERRATA SHEET

DOCKET NUMBER 981042-EM
DALE M. NESBITT
NOVEMBER 10, 1998

p 6 l 5 september not december

p 6 l 7 september not december

p 14 l 15 terms

p 15 l 3 would, not we'd

p 15 l 11-12 delete "right across that."

p 17 l 11 replace "to apply the new" with "to apply to new"

p 25 l 4 observed

p 26 l 16 replace "is, is" with "is"

p 26 l 22 replace capturable with captured

p 27 l 18 strike the word "Different,"

p 31 l 11 things

p 33 l 11 insert the word "not" at the very end of the line

p 42 l 13 Balkanize

p 42 l 15 "it is not a good idea to assume"

p 54 l 11 change the to to

p 58 l 17 megawatt hour

p 79 l 18 prospective

p 83 l 5 basin is replaced by base and

p 96 l 15 It is comprised

p 98 l 6 can have entering

p 107 l 8 delete "for" before "marginal" and insert "infra"

p 124 l 25 in for marginal should read inframarginal

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that DALE M. NESBITT personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 14th day of November, 1998.

NANCY S. METZKE
Notary Public - State of Florida

Nancy S. Metzke
MY COMMISSION # CC677518 EXPIRES
September 13, 2001
BONDED THRU TROY FAIN INSURANCE, INC.

CERTIFICATE OF DEPONENT

This is to certify that I, DALE M. NESBITT, have read the foregoing transcription of my testimony, Page 1 through 173, given on November 10, 1998 in Docket Number 981042-EM, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the errata sheet attached hereto.

DALE M. NESBITT

Sworn to and subscribed before me this 2nd day of December, 1998

Patricia J. Wilcox
NOTARY PUBLIC
State of
My Commission Expires:

Patricia J. Wilcox
MY COMMISSION # CC652104 EXPIRES
March 23, 2001
BONDED THRU TROY FAIN INSURANCE, INC.

☐ Personally Known (OR)
☑ Produced Identification
Type of Identification Produced: Florida Drivers License

REPORTER'S DEPOSITION CERTIFICATE

STATE OF FLORIDA)
COUNTY OF LEON)

I, NANCY S. METZKE, Certified Shorthand Reporter and Registered Professional Reporter, certify that I was authorized to and did stenographically report the deposition of DALE M. NESBITT; that a review of the transcript was requested; and that the transcript is a true and complete record of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 10th day of November, 1998.

NANCY S. METZKE, RPR, CCR

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