AUSLEY & MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW
227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

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August 16, 1999

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Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Generic Investigation into Aggregate Electric Utility Reserve margins Planned for Peninsular Florida; FPSC Docket No. 981890-EI

Dear Ms. Bayo:

Enclosed for filing in this docket, on behalf of Tampa Electric Company. are the original and fifteen (15) copies of Prepared Direct Testimony of Mark D. Ward and accompanying Exhibit (MDW-1)

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

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Sincerely,

James D. Beasley

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Prepared Direct Testimony and Exhibit of Mark D. Ward, filed on behalf of Tampa Electric Company, has been served by U. S. Mail or hand delivery(*) on this 16th date of August 1999 to the following:

Mr. Robert V. Elias*
Ms. Leslie Paugh*
Staff Counsel
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Mr. Paul Sexton
Mr. Thorton J. Williams
Thorton Williams & Associates
P. O. Box 10109
Tallahassee, FL 32302

Mr. Robert Scheffel Wright
Mr. John T. LaVia III
Landers and Parsons, P.A.
P. O. Box 271
Tallahassee, FL 32302

Mr. Jeffrey A. Stone
Beggs & Lane
P. O. Box 12950
Pensacola, FL 32756-2950

Ms. Michelle Hershel
Florida Electric Cooperative Association
P. O. Box 590
Tallahassee, FL 32302

Mr. Richard A. Zambo
598 S.W. Hidden River Avenue
Palm City, FL 34990

Mr. Jon Moyle
Moyle, Flanigan, Katz, Kolins,
Raymond & Sheehan, P.A.
The Perkins House
118 North Gadsden Street
Tallahassee, FL 32301

Ms. Gail Kamaras
Ms. Debra Swim
Legal Environmental Association
Foundation, Inc.
1114 Thomasville Road – Suite E
Tallahassee, FL 32303-6290

Mr. John Roger Howe
Office of Public Counsel
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

Mr. Matthew M. Childs
Steel Hector & Davis
215 South Monroe Street, Suite 601
Tallahassee, FL 32301-1804

Mr. James A. McGee
Florida Power Corporation
P. O. Box 14042
St. Petersburg, FL 33733

Mr. Joseph A. McGlothlin
Ms. Vicki Gordon Kaufman
McWhirter, Reeves, McGlothlin, Davidson,
Decker, Kaufman, Arnold & Steen, P.A.
117 S. Gadsden Street
Tallahassee, FL 32301

Mr. John W. McWhirter, Jr.
McWhirter, Reeves, McGlothlin, Davidson,
Decker, Kaufman, Arnold & Steen, P.A.
Post Office Box 3350
Tampa, FL 33601-3350

Mr. Frederick M. Bryant
General Counsel
Florida Municipal Power Agency
2010 Delta Boulevard
Tallahassee, FL 32315

Mr. Ken Wiley
Florida Reliability Coordinating Council
405 Reo Street, Suite 100
Tampa, FL 33609

Mr. James Swartz
City of Homestead
675 N. Flagler Street
Homestead, FL 33030

Mr. Gary Lawrence
City of Lakeland
501 East Lemon Street
Lakeland, FL 33801

Mr. J. Paul Wetzel
City of St. Cloud
1300 Ninth Street
St. Cloud, FL 34769

Mr. Rex Taylor
City of Vero Beach
P. O. Box 1389
Vero Beach, FL 32961

Mr. Thomas W. Richards
Fort Pierce Utilities
P. O. Box 3191
Ft. Pierce, FL 34948

Mr. Raymond O. Manasco, Jr.
Gainesville Regional Utilities
P. O. Box 147117
Station A-138
Gainesville, FL 32614

Mr. Ben Sharma
Kissimmee Utility Authority
Post Office Box 423219
Kissimmee, FL 34742

Mr. Timothy Woodbury
Seminole Electric Cooperative
Post Office Box 272000
Tampa, FL 33688

Mr. Harvey Wildschuetz
City of Lake Worth Utilities
1900 Second Avenue, North
Lake Worth, FL 33461

Mr. Dean Shaw
City of Ocala
Post Office Box 1270
Ocala, FL 34478

Mr. Richard G. Feldman
City of Tallahassee
300 South Adams Street
Tallahassee, FL 32301

Mr. Charles A. Russell
Florida Keys Electric Cooperative
Post Office Box 377
Tavernier, FL 33070

Ms. Tracy E. Danese
Jacksonville Electric Authority
21 West Church Street T-16
Jacksonville, FL 32202

Mr. T. B. Tart
Orlando Utilities Commission
Post Office Box 3193
Orlando, FL 32802

Mr. Larry J. Thompson
Utility Board of the City of Key West
Post Office Drawer 6100
Key West, FL 33041

Mr. Gary Sasso
Carlton, Fields, Ward,
Emmanuel, Smith & Cutler
Post Office Box 2861
St. Petersburg, FL 33731

ATTORNEY

ORIGINAL

TAMPA ELECTRIC

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 981890-EU

TESTIMONY
AND EXHIBIT OF

MARK D. WARD

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

Mark D. Ward

Q. Please state your name, address, occupation and employer.

A. My name is Mark D. Ward. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") in the position of Manager, Resource Planning.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Mechanical Engineering in 1984 from the University of Alabama in Huntsville. Prior to my employment with Tampa Electric, I held a number of engineering positions with various aerospace companies and the Department of Defense. In 1996, I began my employment as a Consulting Engineer with Tampa Electric's Generation Planning department. In February 1997, I was promoted to Manager - Resource Planning. I am responsible for managing Tampa Electric's resource planning activities that include generation expansion, fuel burn projections and system reliability. As manager of Resource Planning, I have also served on the Florida Reliability Coordinating Council's (FRCC) Resource Working Group (RWG) since 1997.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address the issues identified in Order No. PSC-99-1274-PCO-EU issued in this proceeding on July 1, 1999 and to explain Tampa Electric's position regarding the appropriate methodology for calculating and evaluating reserve margins.

Tampa Electric believes that it is important for the FRCC to adopt planning reserve margin criteria for the Peninsular Florida region that are evaluated on an aggregate basis. These criteria are indicators of regional reliability for generation planning purposes. The planning criteria most appropriate for aggregate Peninsular Florida are minimum seasonal firm reserve margins. Tampa Electric believes that as long as these criteria are met by the projected aggregate Peninsular Florida resources, the Florida Public Service Commission ("Commission") should find that the Peninsular Florida system is reliable for planning purposes.

On an individual utility basis, Tampa Electric believes that each utility may utilize the same or similar reserve margin methodologies for developing planning criteria as are used for the aggregate Peninsular Florida region. However, using the same or similar methodologies may result in reserve margin criteria that will vary from utility to utility. These variations can result from the fact that individual systems have unique characteristics in both resources and system demand and energy requirements. The design and operation of the individual systems can produce different reserve margin criteria even though the same methodology is used.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, my Exhibit No. ____ (MDW-1) consisting of 10 documents was prepared under my direction and supervision.

Aggregate Peninsular Florida

Q. Are aggregate Peninsular Florida planning reserve margins needed?

A. Yes. Tampa Electric believes that aggregate Peninsular Florida seasonal reserve margins are necessary to ensure a reliable grid. Generally, the higher the reserve margin the more reliable the system. Aggregate Peninsular Florida reserve margins are also needed as a means to simplify the annual review process of Peninsular Florida's reliability and reduce the costs of annual workshops. The reserve margin is an analytical benchmark used in system planning to quantitatively assess the reliability of a specified electrical system by comparing available system energy resources with expected system demand requirements. The calculation of an aggregate Peninsular Florida reserve margin is an appropriate method for the Commission to use in assessing the reliability of the Peninsular Florida aggregate system.

The reserve margin is an indication of energy resources in excess of the planned seasonal firm peak demand. These additional resources are needed to ensure Peninsular Florida has sufficient electric generating resources to reliably serve its firm customers during conditions of temporary seasonal weather extremes that may increase system demand requirements and/or the unexpected loss of generating resource capacity at the time of system peak.

The seasonal Peninsular Florida reserve margins should consist of an appropriate mix of supply-side resources and contributions from Commission-approved demand-side management programs. The mix of supply-side and demand-side resources is a function of economics, customer acceptability, and system operating requirements.

Q. What are appropriate planning aggregate reserve margin criteria?

A. Tampa Electric maintains a position consistent with the FRCC. It recommends seasonal minimum firm reserve margins for winter and summer as the appropriate planning criteria for Peninsular Florida. This recommendation is based on the collective operating experience of the FRCC utilities and is consistent with many other reliability councils' planning criteria.

Tampa Electric supports the FRCC aggregate 15 percent minimum firm reserve margin standard for Peninsular Florida's winter and summer forecasted non-coincident firm peak demands. These criteria are tested on an annual basis using the FRCC reserve margin methodology and assumptions.

Q. What is the methodology for determining the appropriate seasonal minimum firm reserve margin criteria for Peninsular Florida?

A. Tampa Electric supports FRCC's approach which is used to test the reserve margin criteria against historical performance levels as well as against certain contingencies. The information produced by this analysis can then be used in combination with appropriate engineering and economic judgement, and experience to adjust, if necessary, the reserve margin criteria.

The approach utilized by the FRCC is based on examining how accurately the utilities have been able to project the component values of the reserve margin calculation. In order to calculate this level of accuracy, the utilities' projections over the most recent years are compared to the actual values for these years. The results of this comparison are used to develop "certainty factors" for each component of the reserve margin calculation. A certainty factor is an average value based on historical variances between projected and actual values of the components used in the reserve margin equation. A detailed description of this equation is included in Document 1 of my exhibit entitled the "FRCC 1999 Reserve Margin Analyses."

Q. How should the Peninsular Florida planning reserve criteria be used?

A. When the FRCC completes its reliability assessment and its Regional Load and Resource Plan, the FRCC should evaluate the ten-year projected planning reserves for Peninsular Florida using the adopted planning reserve criteria. The evaluation should consist of the FRCC comparing projected regional reserves with the minimum seasonal firm reserve margin criteria. This evaluation should be conducted on an annual basis with the results provided to the Commission. The FRCC 1999 Regional Load and Resource Plan is provided in Document 2 of my exhibit.

Q. How should the minimum firm reserve margins for the Peninsular Florida region be calculated?

A. The firm reserve margins should be calculated using the industry accepted formula for projected winter and summer aggregate resources and system requirements applied to Peninsular Florida. The formula calculates the firm reserve margins as the projected total firm supply-side resource capacity minus the projected seasonal non-coincident firm peak demand and planned unit outages divided by the projected seasonal non-coincident firm peak demand. The formula is presented in more detail in Document 3 of my exhibit entitled "Firm Reserve Margin

Calculation."

Q. What are the components of the firm reserve margin calculation?

A. The components of the firm reserve margin calculation may be classified as firm supply-side resources and seasonal firm peak demand.

Firm supply-side resources include the aggregated firm installed and planned generating capacity of the Peninsular Florida utilities less planned outages less firm contracted capacity exports plus firm contracted capacity from non-utility generating and qualifying facilities plus firm contracted imported capacity from outside Peninsular Florida.

The aggregate non-coincident firm peak demand includes all customers within the Peninsular Florida region except for those participating in Commission-approved, demand-side management programs and customers on interruptible or non-firm tariffs. The non-coincident firm peak is the aggregate forecasted seasonal firm peaks of all load-serving utilities in Peninsular Florida.

Q. Should the FRCC aggregate Peninsular Florida utilities' supply-side and demand data?

A. Yes. Aggregation of supply-side and demand-side data for the purposes of projecting Peninsular Florida's minimum firm reserve margins is the responsibility of the FRCC RWG. The RWG should aggregate Peninsular Florida firm capacity as resources that are contracted or owned by those utilities that have an obligation to serve Peninsular Florida customers. In addition, as-available supply-side resources are also aggregated and are accounted for in the Peninsular Florida region. The FRCC should also aggregate projected firm and non-firm loads. Non-firm loads include load management and interruptible loads. The aggregation of the data ensures that double counting of load and supply-side resources is avoided.

The projected reserve margins and data should be calculated for ten years and published in the "FRCC 1999 Regional Annual Load and Resource Plan."

Q. What if the FRCC evaluation shows that Peninsular Florida projected planning reserves fail the reserve criteria?

A. If the regional reserve margin criteria is violated in any peak period, the FRCC Reliability Assessment Group would assess the data and provide an explanation to the FRCC Executive Board and the Commission. Assessment of individual operating entities within the region should be conducted by the Commission at its discretion.

Individual Utilities

Q. Should the Commission establish one set of generation reserve margin standards or criteria to be applied to all of the individual Peninsular Florida Utilities?

A. No. It would be inappropriate for the Commission to establish the same criteria values for each Peninsular Florida utility because "one size does not fit all." System reliability should be assessed on a utility specific basis because each system has unique characteristics in both resources and system demand and energy requirements. The design and operation of each system would likely result in different reserve margin criteria being appropriate even if the same methodology for determining criteria is used. Individual utilities should establish appropriate reserve margin criteria that will ensure their customers are served reliably but those criteria should be developed to meet each utility's unique characteristics.

Q. What is the purpose of individual utility reliability criteria or standards?

A. Planning reserve margin criteria are designed to assure that an individual utility can meet its firm peak demand requirements under certain contingencies. These contingencies include reasonably anticipated temperature extremes, unexpected losses of generating resources, and variations in the timing and magnitude of regional load growth. Such contingencies may vary from utility to utility.

Q. What reserve margin criteria are appropriate for Tampa Electric?

A. A 15 percent minimum firm reserve margin criterion has been determined to provide Tampa Electric adequate energy resources during reasonably anticipated planning contingencies for both the winter and summer firm peak demands. In addition, Tampa Electric will adopt a 7 percent minimum summer supply-side reserve margin criterion. A supply-side reserve margin standard establishes a balance of resources by requiring a minimum level of supply-side reserves while not limiting the contributions of demand-side management programs.

Maintaining this balance of resources is a primary concern during summer months when supply-side resources are required to operate at high capacity factors while also experiencing capacity derations, thus reducing the amount of supply-side resources available for capacity reserves. Please refer to Document 4 of my exhibit entitled "1998 Daily Peak Demand." Document 4 shows that typical daily summer peaks vary little from day to day and are relatively close to the level of the summer firm peak demand.

Q. What methodology should be used to develop an appropriate minimum reserve margin criterion for Tampa Electric Company?

A. Tampa Electric has adopted a methodology similar to that used by the FRCC. This methodology is used to test the firm reserve margin criteria against historical performance levels as well as certain contingencies. The result of this analysis is used with appropriate engineering judgement and experience to adopt the reserve margin criterion or, if necessary, adjust the criterion to an appropriate level.

The method used by Tampa Electric is based on the Company's historical and projected supply-side and firm peak values of the reserve margin calculation. In order to calculate this accurately, certainty factors are developed from ratios of actual and projected supply-side resources and for actual and projected firm peak demands. The ratio of the firm peak certainty factor and supply-side certainty factor is used to test the company's 15 percent minimum firm reserve margin standard. This concept is presented in more detail in Document 5 of my exhibit entitled "Firm Reserve Margin Criteria." Winter and summer minimum firm reserve margins for average and average absolute firm peak certainly factors provided a range of values from 10 percent to 14 percent, thus supporting Tampa Electric's 15 percent minimum firm reserve margin criteria.

The supply-side certainty factor is the average value of the historical variances between planned and actual supply-side capacity resources available at the time of the seasonal firm peak demand. Please refer to Document 6 of my exhibit entitled "Projected and Actual Supply-Side Resources at Time of Peak Demand." This document illustrates the development of Tampa Electric's supply-side certainty factor using 14 years of projected and actual data.

The firm peak certainty factor is derived from the average value of historical variances between planned and actual firm peak demands. In this case, the projected firm peak demands used in the certainty factor are those made five years prior to the year that the actual firm peak occurred. Firm peak projections five years earlier than the actual peak were used to account for the estimated time required to plan, permit, procure and construct new capacity resources. Please refer to Document 7 of my exhibit entitled "Summer Load Forecast Comparison and Winter Load Forecast Comparison." Document 7 provides 19 years of projected and actual data firm peak data used to develop Tampa Electric's firm peak certainty factor.

Q. What methodology should be used to develop an appropriate minimum summer supply-side reserve margin criterion for Tampa Electric Company?

A. The minimum summer supply-side reserve margin should be based on the summer supply-side certainty factor used to test the minimum firm summer reserve margin. The result of subtracting the supply-side certainty factor from one provides a value by which the minimum supply-side reserve margin can be tested.

The results of this analysis are used with engineering judgement and experience to adopt the criterion or, if necessary, adjust the criterion to an appropriate level. Please refer to Document 8 of my exhibit entitled "Minimum Summer Supply-Side Reserve Margin Criterion," which provides the derivation for testing the criterion.

Q. How should the minimum firm reserve margin and minimum summer supply-side reserve margin criteria be used by Tampa Electric?

A. Tampa Electric proposes to use seasonal minimum firm reserve margins and minimum summer supply-side reserve margin criteria for future planning purposes. In its planning process, the Company will apply the dual criteria to determine the timing, size and type of resources required to reliably serve its customers. The resulting ten-year expansion plan, based upon the dual reserve margin criteria, will be filed with the Commission in April of 2000 as part of the annual Ten-Year Site Plan.

Q. How should Tampa Electric's firm reserve margin be calculated?

A. Like the FRCC, Tampa Electric calculates seasonal firm reserve margins using the industry accepted reserve margin formula. It should be calculated for Tampa Electric's winter and summer projected hourly integrated firm peak demands. Tampa Electric's ten-year projected firm reserve margins should be included in the annual Ten-Year Site Plan filed with the Commission.

Q. How should Tampa Electric calculate summer supply-side reserve margins?

A. The summer supply-side reserve margin should be calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the summer firm peak demand, and interruptible and load management loads. The summer supply-side reserve margin formula and its components are provided in Document 9 of my exhibit entitled "Summer Supply-Side Reserve Margin Calculation."

Q. How should the Commission evaluate Tampa Electric Company's reliability?

A. The Commission may evaluate Tampa Electric's system reliability on an annual basis using the Company's annual Ten-Year Site Plan. If the FRCC projected firm reserve margins meet the Peninsular Florida planning criteria, the Commission may not need to conduct a detailed review of Tampa Electric's specific reliability indicators. This would simplify the annual review process and reduce the costs of annual workshops.

Should the Commission choose to evaluate Tampa Electric's system reliability, it should do so by comparing projected firm and summer supply-side reserve margins to the Company's minimum firm and summer supply-side reserve margin criteria. If the projected reserves meet or exceed the planning criteria, then the Commission should determine that Tampa Electric's system and associated Ten-Year Site Plan are suitable and reasonable.

Q. Do you support Tampa Electric's positions on the detailed list of issues attached to the July 1, 1999 Order Clarifying Scope of Proceeding; Docket Procedures, and Establishing Issues?

A. Yes. While my testimony focuses on what Tampa Electric considers to be the key issues to be resolved in this proceeding, I have also prepared Tampa Electric's positions on the specific issues attached to the Commission's July 1 Order. I adopt those positions as if fully set forth in my testimony. Those issues and Tampa Electric's positions are set forth in Document 10 of my exhibit.

Q. Please summarize your testimony.

A. Tampa Electric supports the FRCC aggregate Peninsular Florida 15 percent minimum firm reserve margin for both winter and summer non-coincident firm peak demands. This criterion should be based on the historical availability of firm supply-side resources and account for historical variations in forecasted peak demands. The firm reserve margin criteria is necessary to ensure a reliable grid for Peninsular Florida.

The FRCC has the responsibility to evaluate and establish the Peninsular Florida reserve criteria and to aggregate Peninsular Florida supply-side resources and forecasted loads and calculate projected firm reserve margins. Peninsular Florida's planning reserve criteria should be a product of the FRCC's annual reliability assessment_and the region's aggregate projected firm and supply-side reserve margins should be reported in the FRCC's annual load and resource plan.

The FRCC should also evaluate projected reserve margins based on the planning criterion and report its findings to the Commission. The Commission should investigate individual utilities' reserves only if the projected aggregate Peninsular Florida reserves fall below the planning criteria.

Tampa Electric does not support the concept of a universal reserve margin standard or criterion for all Peninsular Florida utilities because each utility's generation system and demand and energy requirements differ. These differences between utilities require different criteria.

As a Peninsular Florida utility that has an obligation to serve, Tampa Electric has adopted minimum firm reserve margin and a minimum summer supply-side reserve margin criteria that are appropriate for ensuring adequate system reliability. Tampa Electric plans to maintain a 15 percent minimum firm reserve margin for both winter and summer firm peaks as well as a 7 percent minimum supply-side reserve margin for the summer firm peak. These criteria will be used by Tampa Electric in its annual resource planning process. Resulting resource plans will be included in the annual Ten-Year Site Plan filed with the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY

DOCKET NO. 981890-EU

INDEX TO

TAMPA ELECTRIC COMPANY'S

EXHIBIT NO. ___ (MDW-1) DOCUMENTS 1 - 10

Mark D. Ward
Manager, Resource Planning
Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

DOCUMENT 1

1999
Reserve Margin Analyses

Prepared By:
The Resource Working Group

Florida Reliability Coordinating Council

August, 1999

FRCC
1999 Reserve Margin Analyses

Table of Contents

Executive Summary

The Florida Reliability Coordinating Council (FRCC) conducts a review of the reliability of the Region on an annual basis in compliance with North American Electric Reliability Council (NERC) Standards. The FRCC analyzes its members' load and resources plans and submits its findings to the Florida Public Service Commission. For 1999, the FRCC conducted both reserve margin and loss-of-load-probability (LOLP) analyses of the load and resources projected for Peninsular Florida's utilities. However, because the results of the 1999 LOLP work were very similar to the results of the 1998 LOLP work, i.e., LOLP values for the peninsula are projected to be significantly lower than the generally accepted 0.1 day/year standard, the FRCC chose to primarily focus its 1999 work on analyzing the projected reserve margin levels for the peninsula. A description of the work carried out as part of this reserve margin analysis, plus the results of the analysis, are presented in this document.

The reserve margin analyses used projections of resources and demands which are found in the FRCC's 1999 Regional Load & Resource Plan, submitted to the Florida Public Service Commission on July 1, 1999. The FRCC analyses were directed towards determining whether the peninsula's composite reserve margin met the FRCC's 15% reserve margin criterion and towards confirming the continued adequacy of that standard. The FRCC used as its basis reserve margin analyses it had undertaken in 1998, considered the availability of additional data, and made improvements in its analysis techniques where warranted.

Based on this analysis of projected reserve margins for the peninsula, plus the results of the 1999 LOLP work, it is clear that: (1) the FRCC's current projected reserve margin levels do meet and/or exceed the 15% standard; and (2) the FRCC concludes that the existing and planned resources for the peninsula will reliably meet the expected needs of the peninsula's electricity consumers over the 1999 through 2008 study period. In addition, the analysis confirmed that the FRCC's 15% reserve margin criterion continues to be suitable for planning purposes.

Finally, due to the fact that most of the planned generating resource additions for the peninsula for the 1999 through 2008 time period are projected to burn natural gas, a letter from the Florida Gas Transmission (FGT) Company has been included (as Exhibit I) in this document to present the FGT's most current view of natural gas availability for the peninsula during this time frame.

I. Introduction

In September 1997, the North American Electric Reliability Council (NERC) adopted a new set of NERC Planning Standards. The NERC Planning Standards include a requirement to review and assess the overall reliability of the (NERC) Regions' electric systems to ensure that the Regions conform to their own Regional planning criteria and to the NERC Planning Standards. In 1998, the Florida Reliability Coordinating Council (FRCC) formally adopted a generation resource adequacy standard for reserve capacity. It is as follows: "The FRCC generation resource adequacy standard for reserve capacity shall be a 15% regional reserve margin based on firm load. Each year the FRCC composite Ten Year Load and Resource Plan shall be assessed to ensure that this resource adequacy standard of 15% regional reserve margin is maintained over the peak periods. Any peak period which does not meet this regional reserve margin standard shall be thoroughly assessed by the RAG (Reliability Assessment Group), and such assessment shall be forwarded to the FRCC Executive Board and to the Florida Public Service Commission."

The FRCC conducted analyses of the projected composite reserve margins for peninsular Florida during its 1999 work. A technical sub-group of the FRCC, known as the Resource Working Group (RWG), focused on two objectives. The first objective was to determine if the peninsula's composite reserve margin met the FRCC's 15% reserve margin generation resource adequacy standard. The second objective was to take a look at whether this 15% standard still appeared to be adequate. Supplemental work on loss-of-load (LOLP) was also performed and determined not to be a driving factor in reserve adequacy.

In regard to the first objective, the FRCC's work clearly showed that the composite reserve margin for the peninsula met the 15% standard. This fact has already been presented in the FRCC's 1999 Regional Load & Resource Plan which was submitted to the Florida Public Service Commission (FPSC) on July 1, 1999. Consequently, this document focuses on the second objective: analyzing whether the 15% standard still appears to be adequate. These analyses were based on similar reserve margin analyses which were performed in the FRCC's 1998 Reliability Assessment. The results of the 1998 analyses supported both the 15% standard and the 1998 projected reserve margin levels for the peninsula.

II. Methodology Used in the Analyses

A. The Reserve Margin Concept

When calculating a utility's reserve margin, five separate component values are used:

1) Amount of capacity (MW) available at the peak hour from the utility's own generating units.
2) Amount of capacity (MW) available at the peak hour from qualifying facilities (QFs) with which the utility has a firm capacity contract.
3) Amount of capacity (MW) available at the peak hour resulting from the utility's firm import capacity contracts.
4) Peak hour load served by the utility (MW) before the effects of any demand side management programs (DSM) sponsored by the utility. (DSM encompasses incremental conservation, load management, and interruptible rate programs.)
5) Capability (MW) of the utility's DSM programs at the peak hour.

When a utility projects a reserve margin, it is forecasting or projecting what each of these five component values will be at a peak hour in a given year in the future. These component values are then used to calculate reserve margin using the following formula:

$$\text{Reserve margin (\%)} = \frac{\text{(Total firm capacity – Firm seasonal peak load)}}{\text{(Firm seasonal peak load)}} * 100$$

Where: Total firm capacity = Utility generation capacity + firm QF capacity + firm import capacity

and Firm seasonal peak load = Peak load served by the utility minus DSM MW.

Utilities maintain reserves (i.e., capacity resources over and above the exact MW amount that is projected to be needed for a given year) because they recognize that it is impossible to exactly predict the load which customers may require in the future, to know exactly when a generating unit may break and have to be taken out of service for repairs, etc. A utility maintains reserves in recognition of this inability to perfectly forecast all of these factors and to thus ensure that adequate generating resources will exist to cover uncertainties and allow the utility to reliably provide electric service.

B. Deciding What Reserve Margin Level to Maintain

The utility industry "standard" for reserve margin levels in the United States has been approximately 15% for some time. Years of operating experience have shown utilities that a 15% level of reserves "works". In other words, this level of reserves enables utilities to reliably maintain the ability to provide electricity service to its customers while keeping electricity rates at a reasonable level. Providing higher levels of reserves means providing higher levels of firm capacity and/or of DSM. This results in a utility either purchasing more firm capacity through purchase contracts, building new generating units, and/or implementing more DSM, all of which have an impact on electricity rates.

For its 1999 work of assessing the continued suitability of its 15% reserve margin standard, the FRCC chose an approach which combines the current projected reserve margins for the peninsula with a look at historical performance levels of the utilities.

C. The FRCC's Approach to Analyzing Reserve Margin Levels

It should be understood that the FRCC's approach to examining reserve margins is not an approach that necessarily determines an appropriate reserve margin level: rather it is an approach which can be used to test a particular reserve level against historical performance levels as well as against certain contingencies. The information produced by this analysis can then be used in combination with appropriate engineering / economic judgement and experience to adjust, if necessary, a predetermined reserve margin level.

The approach utilized by the FRCC is based on examining how accurately the utilities have been able to project the component values of a reserve margin calculation. In order to calculate this level of accuracy, the utilities' most recent projections are compared to the actual values for these years. The results of this comparison are used to develop "certainty factors" for each component of a reserve margin calculation. Then these "certainty factors" are applied to the current projected reserve margins for the peninsula in order to determine the effect of these variables on both a 15% reserve margin criterion and on the current projected reserve margins.

The following four steps are used in these analyses:

1) For each utility, the projection accuracy (i.e., a Certainty Factor) for each component of a reserve margin calculation is separately calculated:

a) Utility installed generation, firm QF capacity, and firm import capacity (i.e., the first three component values identified in Section II.A. above): From previous years' reserve margin projections by each utility (such as those reported in Ten Year Site Plans, etc.), the projected values for utility installed generation, firm QF capacity, and net imports which are all expected to be available at the seasonal peak hour were extracted. These values are the utilities' historical projections of what they expected to have available.

Then, from each utility's database, the actual amount of installed generation, firm QF capacity, and net imports which were available for each of these seasonal peak hours is extracted.

A historical "Certainty Factor" for each of these capacity components of reserve margin is then developed by dividing the actual value for a given year by the historical projection for that year. For example, assume that the original projection for a given year called for 100 MW of installed utility generation to be available on the Summer peak hour, but only 94 MW were actually available that peak hour. In this case, a "Certainty Factor" of 94% (94 actual MW divided by 100 projected MW) for this component of reserve margin would be calculated.

Since utilities do not plan to take their generating units out for planned maintenance during the time around seasonal peak hours, the 6% by which the utility in the example "missed" its projection is most likely due to a forced outage. A utility may experience either an abnormally small or an abnormally large amount of forced outages on the peak hour of any one year. Consequently, it is advisable to look at more than one year's data when developing a Certainty Factor in order to determine what level of certainty is really historically representative for the utility. For its 1999 analyses, the FRCC used comparisons of projections versus actuals for the last 6 years in developing Certainty Factors for installed generation, firm QF capacity, and firm import capacity. The Certainty Factors for each were arithmetic averages of the 6 years' results of comparing projections versus actuals.

b) Load forecasts (i.e., the fourth component value identified in Section II.A. above): Certainty factors for load forecasts were also developed in a similar fashion to the approach explained above for developing certainty factors for the three capacity components of reserve margins calculations. However, unlike the averaging approach used to calculate one overall Certainty Factor for each of the capacity components, a separate Certainty Factor was developed for forecasts looking ahead 2 years, another

Certainty Factor was developed for forecasts looking ahead 3 years, etc. This is based on the premise that a projection of load only 2 years out should be more accurate than a projection of load made 3 years (or more) out. In other words, the further out one tries to forecast the less accurate one can expect the forecast to be. Therefore, the further out the forecast is, the greater the expected deviation from 1.00 in the associated Certainty Factor.

Consequently, a series of Certainty Factors was developed for the load forecast component of reserve margin calculations.

c) DSM capability (i.e., the fifth component value identified in Section II.A. above): When considering the total projected DSM capability for peninsular Florida, it is apparent that the majority of this capability is made up of the utilities' load management programs. As a result, the FRCC's approach focused on developing a Certainty Factor for load management. This was also based upon historical information. Each utility which offers load management reexamined both their confidence in being able to sign up and retain the required number of load management program participants to achieve the projected load management MW reduction values, as well as their confidence in the kw reduction/participant value they apply to the projected number of participants. (These reduction values are generally derived from past field monitoring and/or engineering estimates.) By combining these two confidence values, a load management Certainty Factor for each utility was developed.

2) **These individual utility Certainty Factors are combined into a composite, peninsular Certainty Factor for each component of the reserve margin calculation:**

For the three capacity components, and the load forecast component, this was done by first adding up all of the individual utilities' projected values to get a projected total. Then the individual utilities' actual values were added up to get an actual total.

Dividing the actual total by the projected total results in a composite peninsular Certainty Factor for each of these four reserve margin components.

The load management Certainty Factors developed by each utility for the FRCC's 1999 work were then combined to form a composite value. Each utility's total load management capability was divided by the total sum of all utilities' load management capability to derive a "weighting" of each utility's contribution to the peninsula's total load management capability. Then each utility's individual load management Certainty Factor was multiplied by this weighting factor and the resulting weighted Certainty Factors from each utility were added together to form the composite load management Certainty Factor for the peninsula.

3) A "coincidence factor" for the composite load forecast was developed:

The FRCC's current projection of reserve margins, as shown in the FRCC's <u>1999 Regional Load & Resource Plan,</u> simply takes all of the components of a reserve margin calculation (utility installed generation, load forecast, etc.) for each utility and adds the components together. This approach is fine for four of the components: utility installed generation, firm QF capacity, firm import capacity, and load management capability, since all of these components for individual utilities can, and frequently do, operate at the same time.

However, this approach tends to <u>overstate</u> the forecasted load which the peninsula will experience. This is because the various utilities tend to peak at different times of the day and/or days of the month. Consequently, a more accurate way to project a composite, total forecasted load for the peninsula is to address the fact that this load will be somewhat less than the sum of each utility's individual load. The FRCC did <u>not</u> address this in its 1998 analyses of the 15% standard. However, the FRCC decided to make this improvement to its analysis approach in its 1999 work. The different timing of individual utility loads was addressed through the application of a <u>non-coincidence</u> adjustment factor which accounts, through the use of historical data, for the timing of individual utility peaks. For its 1999 work, non-coincidence adjustment factors of 98.4% and 98.3% were used for Summer reserve margin and Winter reserve margin calculations, respectively. The application of these non-coincidence adjustment factors serves to properly lower the composite total forecasted load for the peninsula in its reserve margin calculations. This approach is consistent with the way that individual utilities plan their systems since they project their customers' peak loads on a coincident basis. Thus, when projecting peak loads for utilities in the aggregate, it is appropriate to also do so on a coincident basis.

4) The composite certainty and non-coincidence adjustment factors are applied to the current projection of peninsula reserve margins:

The current projection of reserve margins for the peninsula (as shown in the FRCC's 1999 Regional Load & Resource Plan) is used as the starting point for applying the composite Certainty Factors and non-coincidence adjustment factors described above. The basic approach is to first apply the non-coincidence adjustment factor to more accurately reflect the total load for the peninsula. This results in a revised reserve margin projection. Then the individual Certainty Factors are applied, one at a time, to this revised reserve margin projection which results in a series of revised reserve margin projections. For example, assume that the current projection of utility installed generation capacity is 30,000 MW for a given year and the calculated Certainty Factor is 0.90 for this component. The resulting revised utility installed generation capacity value would now be 27,000 MW (30,000 MW x 0.90 = 27,000 MW). Applying this revised component in the reserve margin calculation would yield a revised reserve margin.

Once all of these factors have been applied, the final revised reserve margin projection is then compared to the original projection. In almost all cases, the final revised reserve margin projection is lower than the original projection of reserve margins. This is because the original reserve margin projection basically assumes that the values for all components of the reserve margin calculation are known with 100% certainty. (The application of the non-coincidence adjustment factor first results in a lowering of the forecasted load and a corresponding increase in the revised reserve margin. However, the subsequent application of each of the various Certainty Factors generally serves to lower the values of each of the components, thus considerably lowering the revised reserve margin.) A common outcome of this method is for an original reserve margin projection in the 15% - to- 20% range to be revised down to a final value in the 1% - to - 5% range after all of the factors have been applied. The meaning of such an outcome is discussed below.

The difference between the original projection and the final revised projection represents the reserve margin level that could be "needed" based on the utilities' most recent projected versus actual values.

For example, assume that the FRCC's original reserve margin projection for the peninsula is 16% for a given year. Now assume that after each of the factors have been applied, the original projected 16% reserve margin level drops to a revised level of 2%. The difference of 16% - 2% = 14% indicates that a 14% reserve margin level could, based on the utilities' most recent ability to project loads and have resources available to meet them, be sufficient to maintain reliable electric service during the peak hours of that year.

This conclusion is drawn by the fact that if the original reserve margin projection had been 14%, the application of the factors would have resulted in a final revised reserve margin of 0%; i.e., the peninsula's resources would have been exactly equal to the peninsula's load after accounting for the uncertainties of all of the components. The 2% reserve margin value that is "left over" in this example, would be an additional reserve margin "cushion" over what the "needed" reserve margin is. Consequently, electric service during the peak hour should be maintained.

Also in this example, note that both the FRCC's 15% reserve margin planning criterion and the peninsula's projected 16% reserve margin could be deemed sufficient to maintain reliable electric service.

On the other hand, assume again that the FRCC's original projected reserve margin for a given year was 16%, but now assume that the revised reserve margin level drops to –1% after all of the certainty factors have been applied. In this example, the difference of 16% - (-1%) = 17% shows that a 17% reserve margin level could be "needed" to meet loads at seasonal peaks. In this example, the peninsular Florida utilities would want to examine whether any actions were necessary to correct or minimize the associated uncertainties to maintain reliable electric service at reasonable cost.

D. The FRCC's 1998 and 1999 Analyses

As mentioned above, the FRCC began using this basic approach to analyze the suitability of its current 15% reserve margin planning criterion in its 1998 work. In that effort, two decisions regarding the data to be used were made:

1) The actual and projected values for the three capacity components (utility installed generation, firm QF, & firm imports) would be taken from 1993 through 1997.
2) The projected values for load forecasts would start with the 1988 forecast projections for future years.

These decisions were largely based on the recognition that utility methodologies and practices tend to change over time as new methods are developed, priorities change, etc. Therefore, it was important not to go back in time too far to extract data to work with. In 1998, it was felt that the (then) most recent 5 years worth of data covering the period of 1993 through 1997 was sufficient to address the actual-versus-projected performance of utility generators, firm QF capacity, and firm imports at peak hours.

However, since it may take approximately 3-to-6 years to bring new power plants in-service from the time a need to add capacity is recognized, it was necessary to look at load forecasts going further back in time than 1993 in order to capture as many 3-to-6 years ahead forecasts as possible, as long as these forecasts were deemed applicable.

The decision was made that forecasts from 1988-forward were applicable. The selection of the year 1988 as the starting point for forecast analyses was made primarily due to the fact that the current load forecasting methodology for the peninsula's largest utility, FPL, were first in place in 1988. The selection of a 1988 starting point also enabled the FRCC to look at forecasts of future load as much as 9 years out.

For its 1999 work, another year (1998) of actual load, generation, etc. was available for use in the analysis. The FRCC faced the question of whether to drop the oldest year of data from its previous year's work and replace it with 1998 data, or to add this additional year's data to its previously developed database without any corresponding omission of older data. The decision was made to do the latter for the 1999 FRCC work but with the recognition that, in future years, it may be appropriate to drop off older data.

For its 1999 work, new Load Management Certainty Factors were developed. These factors were not directly based on the factors used in the 1998 work. Instead, each utility was asked to place a new, "from scratch" certainty value on their projected load management capabilities using any new monitoring data available and their 1998 experience with load management.

In addition to these, there were two changes in the FRCC's 1999 analysis approach compared to the analysis approach used in its 1998 work. Both changes represent needed improvements to the approach used in 1998 which were recognized while reviewing the 1998 work. The first of these, the inclusion of a non-coincidence adjustment factor to more accurately compile a composite forecasted load for the peninsula, has already been discussed. The second improvement was to drop the 1993 Winter values for utility installed generation from the calculation of an installed generation Certainty Factor for Winter.

In the Winter of 1993, the Winter seasonal peak load actually occurred very late (in March). This peak occurred after various utilities had assumed that the peak load for that

Winter had already been experienced. Consequently, these utilities allowed generating units to come off-line for maintenance that had been planned for several weeks later in order to be better prepared for the upcoming Summer loads. These units were thus not available when this unexpectedly late Winter load was experienced. Since the installed generation Certainty Factor is designed to test "breakage" (or forced outages) of units that are expected to be in-service during all peak periods, it was felt that continuing to include the effects of this "unforced" maintenance experienced in 1993 was incorrect. Therefore, the actual and projected values for Winter 1993 were discarded in the FRCC's 1999 analyses (except the analysis of one scenario which was included solely to provide a comparison to the 1998 work).

III. Results of the 1999 FRCC Analyses

A. Description of the Cases Analyzed

The FRCC's 1999 reserve margin analysis work ultimately resulted in an examination of five cases. These cases are described in Table 1.

The Base Case is the case which the FRCC believes is the most meaningful case analyzed. It was constructed by adding the actual and projected 1998 values to the database used in last year's analyses. In other words, one more year of data has been added to the database and the expanded database is then used to develop new Certainty Factors for: utility installed generation, firm QF's, firm imports, and load forecast. The 1999 Load Management Certainty Factors also replaced the factors used in the 1998 work. Then the effects of two improvements (which have been previously discussed) to the analysis approach were incorporated: the inclusion of a non-coincidence adjustment factor for load forecasts and the removal of the 1993 Winter data for utility installed generation.

Table 1

Description of Cases in FRCC's 1999 Reserve Margin Analysis

Name of Case	Description of Cases
Base Case	Most meaningful case. Contains 1998 actuals and projections added to last year's database, the new 1999 Load Management Certainty Factor, and 2 improvements to last year's approach: (1) addition of a non-coincidence adjustment factor for load forecasts, and (2) removal of Winter 1993 actual and projected data for utility installed generation.
Scenario 1	For comparison with last year's work only. Contains 1998 actuals added to last year's database, and the new 1999 Load Management Certainty Factor, with no changes/improvements to last year's approach.
Scenario 2	Base Case with worst value for utility installed generation availability applied every year.
Scenario 3	Base Case with worst values for load forecast accuracy applied to each corresponding forecast year (i.e., worst value for 5-year out forecast applied to current 5-year out forecast, etc.).
Scenario 4	Base Case with combination of worst values for utility installed generation availability and load forecast accuracy applied.

The FRCC believes the Base Case is the most meaningful case because of these two improvements to the approach and because of the fact that it captures a truly representative set of values (i.e., a range of values including accurate to not-so-accurate projections) of the peninsular utilities' recent unit and firm purchase availability, load forecast accuracy, and the most current view of load management capability.

In addition to the Base Case analysis, four other scenarios were analyzed. Scenario 1 is a "stand alone" analysis while Scenarios 2, 3, and 4 use the Base Case as a starting point. Scenario 1 is offered solely to provide a point-of-reference comparison to last year's FRCC work. In Scenario 1, neither of the two improvements to last year's analysis approach have been included. The only change to last year's results is the inclusion of the 1998 actual and projected values to last year's database, which result in the development of new Certainty Factors for four of the five components, and the use of the new-for-1999 Load Management Certainty Factor

Scenarios 2, 3, and 4 are best characterized as "worst case every year" analyses which focus on the two biggest "drivers" of the amount of reserve margin "needed": utility installed generation availability at peak hours and load forecast accuracy.

Scenario 2 returns to the Base Case and uses its results as a starting point. Then the worst annual value for the availability of utility installed generation at the peak hour is extracted and inserted as the utility installed generation Certainty Factor for all years. This "worst case every year" scenario thus assumes that unit availability at the peak hour degrades to the worst value experienced during the last 6 years and remains at this low level with no remedial action by the utilities to improve the situation.

Scenario 3 also uses the Base Case results as a starting point. In this scenario, the worst values for load forecast accuracy for 2-years out, 3-years out, etc., are extracted and inserted for the corresponding load forecast Certainty Factor. For example, assume that the worst case of load forecast accuracy for a 3-years out forecast was 12% too low while the multi-year average for a 3-year out forecast was 5% low. In Scenario 3, a "worst case" Certainty Factor of 1.12 is substituted in place of the 1.05 Certainty Factor value for a 3-year out forecast used in the Base Case. Similar Certainty Factor substitutions occur for all other "years out" of the load forecast. This "worst case every year" scenario assumes that <u>all</u> of the worst levels of load forecast accuracy are now applied to the current peninsular composite forecast and that the utilities take no remedial action to improve the situation. Note that the extraction of the worst accuracy level <u>for each year</u> from forecasts done over multiple years is an even more damaging (and a less probable) assumption than the worst case utility installed generation availability assumption made in Scenario 2.

Finally, Scenario 4 once again returns to the Base Case but now combines the "worst case" Certainty Factors for utility installed generation availability <u>and</u> load forecast accuracy from Scenarios 2 and 3. This most extreme "worst case every year" scenario basically assumes that the utilities simultaneously allow unit availability at peak hours, and the accuracy of their load forecasts, to significantly degrade without taking remedial action. This scenario should be considered very unlikely.

B. Results of the Analyses

The results of the FRCC's 1999 reserve margin analyses are presented in Tables 2 through 5. Tables 2 and 3 focus on the results as they pertain to Summer reserve margins while the results presented in Tables 4 and 5 pertain to Winter reserve margins.

These tables first present the FRCC's reserve margin planning criterion (15%) and then present the FRCC's current projections of annual reserve margins for the peninsula in the columns marked "FRCC's Current Projected Reserve Margin (%)". The values in these columns have been previously reported in the FRCC's 1999 Regional Load & Resource Plan.

Following these columns come the actual results of the analyses: the "needed" level of reserve margins as calculated for the Base Case and for Scenarios 1 through 4. In addition, two questions are addressed in Tables 3 and 5. The first of these questions is "Does the FRCC's 15% minimum reserve margin planning criterion meet or exceed the calculated level of "needed" reserve margins for a given case?" If the answer is "Yes", then the 15% minimum criterion can be considered adequate to maintain reliable electric service during peak hours. The second question is "Do the FRCC's current projected reserve margins meet or exceed the calculated level of "needed" reserve margins for a given case?" If the answer is "Yes", then the peninsula's projected reserve margins can be considered adequate to maintain reliable electric service during peak hours.

Since the peninsula's projected reserve margins are typically greater than the planning criterion of a minimum of 15%, a possible outcome is one in which the "needed" reserve margin is greater than 15% but less than or equal to the projected reserve margins. With such an outcome, the projected reserve margins would still be considered adequate.

Another possible outcome is one in which the "needed" reserve margin level is greater than both the minimum 15% criterion and the peninsula's projected reserve margin for one or more years. Taken at face value, one might interpret this to indicate that neither the FRCC's planning criterion nor their projected reserve margins are adequate. However, this is not necessarily correct. Other factors need to be taken into consideration before reaching such a conclusion.

First, when (for what year) does such a result appear? If this result appears for seven or more years out in the future, the utilities have sufficient time to adjust their capacity plans accordingly. Conversely, if such a result occurs prior to three years out, relatively little from a utility capacity planning perspective can be done due to the short lead time available. Consequently, the key time frame which this analysis approach focuses on is the 3rd through the 6th year out period.

Second, how likely is it that the assumptions behind the analysis case in question will come to pass? If the answer is that the assumptions are not likely, then the potential concern is minimized or eliminated. Only if the assumptions are considered likely, and if the time frame in question is reasonably close at hand (i.e., in the 3-to-6 years out range), is it prudent to be concerned with the results of this particular analysis.

Finally, it is important to recognize that utilities have a significant amount of additional MW's available to them in the form of operational measures (e.g. public appeals, voltage reductions, load control "scram", etc.) that are not included in these reserve margin calculations but which are already in place. These measures offer a significant safety factor at little or no cost to customers compared to construction or purchase alternatives.

(1) Results Regarding Summer Reserve Margins

The results of the FRCC's 1999 reserve margin analyses in regard to Summer reserve margins are summarized in Tables 2 and 3. Table 2 presents the 15% reserve margin standard, the current projection of the peninsular Summer reserve margins, and the "needed" Summer reserve margin levels from the analysis of the Base Case.

Table 2

Results of 1999 FRCC Analysis of Summer Reserve Margins

Year	FRCC's Planning Criterion	FRCC's Current Projected Reserve Margin (%)	"Needed" Reserve Margin (%) for: Base Case
1999	15	17	6
2000	15	16	8
2001	15	18	9
2002	15	20	10
2003	15	20	11
2004	15	19	10
2005	15	18	12
2006	15	17	13
2007	15	18	13
2008	15	17	13

As shown in Table 2, the results for the FRCC's Base Case show that the "needed" Summer reserve margin is 13% or less each year. This result indicates that both the FRCC's reserve margin planning criterion of a 15% minimum level, and the FRCC's higher-than-15% projected reserve margins for each year, are more than adequate to maintain system reliability during Summer peak hours.

Table 3 presents an expanded version of Table 2. In addition to the information presented in Table 2, the results of the Summer reserve margin analyses of Scenarios 1 through 4, plus a summary of comparisons of the results to the 15% standard and to the projected reserve margin, are added.

Table 3

Results of 1999 FRCC Analysis of Summer Reserve Margins (w/Scenarios)

Year	FRCC's Reserve Margin (%) Planning Criterion	FRCC's Current Projected Reserve Margin (%)	"Needed" Reserve Margin (%) for : Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1999	15	17	6	8	9	6	9
2000	15	16	8	9	11	12	15
2001	15	18	9	11	12	13	16
2002	15	20	10	12	13	12	15
2003	15	20	11	13	14	18	20
2004	15	19	10	12	13	16	19
2005	15	18	12	14	15	18	20
2006	15	17	13	15	16	18	21
2007	15	18	13	15	16	18	21
2008	15	17	13	15	16	18	21

	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
(1) Does 15% planning criterion meet/ exceed "needed" reserve margins?	Yes	Yes	No for last 3 yrs	No for last 6 yrs	No for 7 of 10 yrs
(2) Do current projected reserve margins meet/exceed "needed" reserve margins?	Yes	Yes	Yes	No for 8th& 10th yr.	No for last 4 yrs

The results for Scenario 1 are similar to those for the Base Case. In this scenario, the projected "needed" reserve margin is 1-to-2% higher than in the Base Case (due to Scenario 1's omission of the non-coincidence adjustment factor for load forecasts). Nevertheless, the resulting "needed" reserve margin is 15% or lower each year, which again means that both the planning reserve margin of a 15% minimum level and the higher-than-15% projected reserve margins are adequate for maintaining system reliability.

Only in the three "worst case every year" scenarios do the results change at all. In Scenario 2 (which is the Base Case, but with the worst case of utility installed generation availability at the peak hour assumed to occur every year), the results show that the 15% minimum reserve margin planning criterion is adequate for all except the 8th, 9th, and 10th years of the projection. However, the FRCC's projected reserve margins for all years still satisfy the "needed" reserve margin levels for this scenario.

In Scenario 3 (which is the Base Case but with the worst cases of load forecast accuracy assumed to occur every year), the 15% minimum reserve margin planning criterion could be insufficient for the last 6 years. However, the FRCC's projected reserve margins still satisfy the "needed" reserve margins in all years except the 8th and 10th years of the projection.

Finally, in Scenario 4 (which is a combination of Scenarios 2 and 3 in which the Base Case is modified to include both the worst cases of utility generation availability and load forecast accuracy every year), the 15% minimum reserve margin planning criterion could be insufficient for 7 of the 10 years and the FRCC's projected reserve margins could be insufficient for the last 4 years of the projection period (i.e., the 7th, 8th, 9th, and 10th years). However, even in this very extreme scenario, the FRCC's projected reserve margins meet the "needed" reserve margin levels for the key 3-to-6 years out time period.

Conclusion Regarding Summer Reserve Margin Analyses:

The FRCC concludes from this analysis of Summer reserve margins that its reserve margin planning criterion of a 15% minimum level, and its projected annual reserve margin levels, are adequate for maintaining reliable electric service during Summer peak hours for years 1999 through 2008.

The minimum 15% reserve margin planning criterion, and the FRCC's projection of annual reserve margins, meet or exceed the "needed" reserve margin levels calculated in both the Base Case and Scenario 1. Although the results from the remaining three "worst case every year" scenarios show that the minimum 15% reserve margin planning criterion could be insufficient for some of the years, it is unrealistic to believe that utility generation availability and load forecasting practices would remain unchanged if a trend of occurrences such as those depicted in these scenarios were to appear.

Furthermore, the FRCC's projected annual reserve margins are sufficient to "cover" all years in Scenario 2, are sufficient for all but the 8th and 10th years in Scenario 3, and are sufficient for all but the 7th through 10th years in Scenario 4. The fact that all years are "covered" even in these "worst case every year" analysis until, at the earliest, 7 years out means that the utilities have more than enough time to alter their capacity addition plans if circumstances reflected in these scenarios begin to emerge. In addition, as previously mentioned, there are operational measures available which are not included in reserve margin calculations that would alleviate the effects of these uncertainties were they to occur.

(2) Results Regarding Winter Reserve Margins

The results of the FRCC's 1999 reserve margin analyses in regard to Winter reserve margins are summarized in Table 4 and 5. Tables 4 and 5 are identical in format to Tables 2 and 3, respectively. Table 4 presents the 15% reserve margin standard, the current projection of peninsular Winter reserve margins, and the "needed" Winter reserve margin levels from the analysis of the Base Case.

Table 4

Results of 1999 FRCC Analysis of Winter Reserve Margins

Year	FRCC's Reserve Margin (%) Planning Criterion	FRCC's Current Projected Reserve Margin (%)	"Needed" Reserve Margin (%) for: Base Case
---------	---------	---------	---------
1999/00	15	16	5
2000/01	15	18	-2
2001/02	15	20	-2
2002/03	15	21	-2
2003/04	15	19	-3
2004/05	15	19	-3
2005/06	15	18	0
2006/07	15	18	-1
2007/08	15	18	-1
2008/09	15	15	-1

As shown in Table 4, the results from the Base Case show that the "needed" Winter reserve margin are not only significantly less than 15% each year, they are negative for most years. This is primarily due to the fact that forecasted very cold temperatures do <u>not</u> occur in Florida every year, but that the FRCC's projected reserve margins for the peninsula <u>do</u> assume that they occur each year. Consequently, the Winter load forecast Certainty Factors for each year (approximately 94%) in the Base Case are substantially less than the corresponding Summer load forecast Certainty Factors each year (approximately 104%). This results in the projected load being lowered to the point in the Base Case where the "needed" reserve margin is negative for most years. Obviously, both the 15% minimum reserve margin planning criterion and the FRCC's projected annual reserve margins are more than adequate to maintain system reliability during Winter peak hours under the assumptions analyzed.

Table 5 presents an expanded version of Table 4. In addition to the information presented in Table 4, the results of the Winter reserve margin analyses of Scenarios 1 through 4, plus a summary of comparisons of the results to the 15% standard and to the projected reserve margins, are also presented.

Table 5

Results of 1999 FRCC Analysis of Winter Reserve Margins (w/Scenarios)

Year	FRCC's Reserve Margin (%) Planning Criterion	FRCC's Current Projected Reserve Margin (%)	"Needed" Reserve Margin (%) for : Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1999/00	15	16	5	9	10	5	10
2000/01	15	18	-2	1	3	20	24
2001/02	15	20	-2	1	2	20	24
2002/03	15	21	-2	1	3	18	22
2003/04	15	19	-3	0	2	15	19
2004/05	15	19	-3	1	2	15	19
2005/06	15	18	0	4	5	16	20
2006/07	15	18	-1	2	4	18	22
2007/08	15	18	-1	2	4	18	22
2008/09	15	15	-1	2	4	18	22

	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
(1) Does 15% planning criterion meet/ exceed "needed" reserve margins?	Yes	Yes	Yes	No for 7 of 10 yrs	No for 9 of 10 yrs
(2) Do current projected reserve margins meet/exceed "needed" reserve margins?	Yes	Yes	Yes	No for 2nd & 10th yrs	No for 7 of 10 yrs

The results for Scenario 1 are very similar to those for the Base Case (although the values are not negative). This same result is also reflected in the first of the "worst case every year" analyses, Scenario 2, in which the worst case utility generation availability at peak hour is assumed to take place every year.

Only in the two "worst case every year" scenarios (Scenarios 3 and 4) in which the worst case of load forecast accuracy is assumed to occur every year do these results change. Both of these cases assume that very cold temperatures <u>will</u> occur every year. In Scenario 3, the minimum 15% reserve margin planning criterion could be insufficient for 7 of the 10 years. However, the FRCC's projected annual reserve margins would still be adequate for all but 2 of the 10 years (i.e., the 2^{nd} and 10^{th} years). This means that for the key period, years 3-to-6, are still "covered" by the FRCC's projected reserve margin. Finally, in the most extreme scenario (Scenario 4) in which both the worst cases of load forecast accuracy and utility installed generation availability are assumed, the results indicate that the minimum 15% reserve margin planning criterion could be insufficient for 9 of the 10 years and the FRCC's projected annual reserve margins could be insufficient for 7 of the 10 years.

<u>Conclusions Regarding Winter Reserve Margin Analyses:</u>

The FRCC concludes from this analysis of Winter reserve margin that its reserve margin planning criterion of a 15% minimum level, and its projected annual reserve margin levels, are adequate for maintaining reliable electric service during Winter peak hours.

The minimum 15% reserve margin planning criterion, and the FRCC's projection of annual reserve margins, meet or exceed the "needed" reserve margin levels calculated in the Base Case, in Scenario 1, and in one of the "worst case every year" cases, Scenario 2.

Even though the results from the "worst load forecast accuracy every year" Scenario 3, indicate that the minimum 15% reserve margin planning criterion could be insufficient, the FRCC's projected annual reserve margins would still "cover" these circumstances for all but 2 years. One of those years is in the last (10^{th}) year of the projection and is, therefore, subject to at least several years of changed assumptions and new projections before that year is close enough to the present to be of real concern from a planning perspective. The other year for which the FRCC's projected reserve margins could be deemed insufficient in this scenario (i.e., the 2^{nd} year) is obviously much closer. In fact, it is too close to fall into the 3^{rd} through the 6^{th} year time frame for which this analysis approach is really designed. Furthermore, the analysis does not take into account either the fact that very high Winter peaks do not occur every year or utilities' operational capabilities (load control program scram operation, etc.) which would effectively increase utility reserves.

The key point of the results of this scenario is that for the key years (i.e., the 3^{rd} through the 6^{th} years) for which new capacity could realistically be added if a need was identified, no additional capacity over and above what is shown in the FRCC's projected annual reserve margins is needed even assuming, unlikely as it may be, that the worst case load forecast accuracy occurs for each of these years.

Finally, the results from Scenario 4 are driven by the very unlikely assumption that the worst case utility generation availability and the load forecast accuracy occur in combination each year, and that the utilities do not alter their forecasting or power plant maintenance processes (or their capacity plans) in response to these circumstances. This fact, plus the facts that very cold winter temperatures do not occur every year and the utilities' operational capabilities are again not accounted for in the analysis, serve to significantly discount the significance that should be applied to the results of this most extreme of the "worst case" scenarios.

IV. Summary

The FRCC's 1999 work regarding reserve margins for the peninsula had two objectives: (1) to determine if the current projected reserve margin for the peninsula met the FRCC's 15% reserve margin generation resource adequacy standard; and, (2) to take a look at whether this 15% standard still appeared to be adequate.

In regard to the first objective, the FRCC's current projected reserve margin levels do meet and/or exceed the 15% standard. This fact is demonstrated in the FRCC's 1999 Regional Load & Resource Plan.

As for the second objective, an analysis of the continued suitability of the 15% standard was carried out. The results of that analysis showed that this minimum 15% criterion continues to appear suitable for planning purposes based on an examination of past projected-versus-actual performance levels.

DOCUMENT 2

1999 Regional Load & Resource Plan

July, 1999

FLORIDA RELIABILITY COORDINATING COUNCIL

1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

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HISTORY AND FORECAST

(1)	(2)	(6)	(7)	(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 (%)
1989	26,608	1989 / 90	29,170	1989	141,021	60.07%
1990	27,238	1990 / 91	24,978	1990	142,490	55.76%
1991	27,662	1991 / 92	28,179	1991	146,786	60.58%
1992	28,930	1992 / 93	27,215	1992	147,728	58.29%
1993	29,748	1993 / 94	28,149	1993	153,269	58.82%
1994	29,321	1994 / 95	32,618	1994	159,353	62.04%
1995	31,801	1995 / 96	34,552	1995	168,982	59.14%
1996	32,315	1996 / 97	34,762	1996	173,327	57.26%
1997	32,924	1997 / 98	30,932	1997	175,534	57.64%
1998	37,153	1998 / 99	35,907	1998	187,868	57.72%

(1) YEAR	(2) TOTAL PEAK DEMAND (MW)	(3) INTER-RUPTIBLE LOAD (MW)	(4) LOAD MANAGE-MENT (MW)	(5) FIRM PEAK DEMAND (MW)	(6) YEAR	(7) TOTAL PEAK DEMAND (MW)	(8) INTER-RUPTIBLE LOAD (MW)	(9) LOAD MANAGE-MENT (MW)	(10) FIRM PEAK DEMAND (MW)	(11) YEAR	(12) NET ENERGY FOR LOAD (GWH)	(13) LOAD FACTOR (%)
1999	36,788	1,225	1,540	34,023	1999 / 00	39,989	1,173	2,839	35,977	1999	186,374	59.25%
2000	37,541	1,247	1,591	34,703	2000 / 01	40,928	1,184	2,925	36,819	2000	190,955	60.59%
2001	38,223	1,265	1,578	35,380	2001 / 02	41,865	1,178	2,894	37,793	2001	195,687	60.67%
2002	38,959	1,265	1,537	36,157	2002 / 03	42,808	1,193	2,866	38,749	2002	200,060	60.43%
2003	39,781	1,284	1,509	36,988	2003 / 04	43,726	1,200	2,863	39,663	2003	204,884	60.36%
2004	40,593	1,296	1,493	37,804	2004 / 05	44,651	1,215	2,870	40,566	2004	209,492	60.29%
2005	41,433	1,317	1,478	38,638	2005 / 06	45,553	1,226	2,877	41,450	2005	214,094	60.25%
2006	42,398	1,334	1,467	39,597	2006 / 07	46,600	1,239	2,885	42,476	2006	218,611	60.21%
2007	43,252	1,352	1,457	40,443	2007 / 08	47,502	1,233	2,895	43,374	2007	223,179	59.98%
2008	44,066	1,348	1,452	41,266	2008 / 09	48,441	1,248	2,907	44,286	2008	227,645	59.91%

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

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FRCC REGION
HISTORY AND FORECAST
ENERGY USE BY CUSTOMER TYPE - GWH
AS OF JANUARY 1, 1999

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		RURAL & RESIDENTIAL			COMMERCIAL			INDUSTRIAL			STREET & HIGHWAY LIGHTING	OTHER SALES	TOTAL SALES	RESALE	UTILITY USE & LOSSES	NEL
	YEAR	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	GWH	GWH	GWH	GWH	GWH
	1989	62,263	5,191,812	11,993	43,237	618,010	69,962	16,633	26,681	623,384	501	3,503	126,137	0	14,884	141,021
	1990	65,022	5,354,736	12,143	44,819	633,799	70,715	16,676	26,065	639,761	506	3,576	130,600	0	11,890	142,490
	1991	66,787	5,484,780	12,177	45,796	645,580	70,938	16,650	25,020	665,471	538	3,736	133,508	0	13,276	146,766
	1992	67,008	5,584,026	12,000	45,888	660,642	69,459	16,646	24,690	674,190	552	3,796	133,890	0	13,838	147,728
	1993	70,488	5,709,685	12,345	48,080	676,150	71,109	16,524	24,962	661,962	535	3,877	139,503	0	13,766	153,269
	1994	74,128	5,833,171	12,708	50,454	691,625	72,951	17,025	25,964	655,718	562	4,007	146,177	0	13,176	159,353
	1995	78,667	5,955,574	13,209	52,100	705,921	73,804	17,687	25,660	689,293	586	4,165	153,205	0	15,777	168,982
	1996	81,047	6,066,709	13,359	53,086	720,371	73,693	18,338	25,523	718,516	600	4,278	157,349	0	15,978	173,327
	1997	80,727	6,185,747	13,051	55,643	737,205	75,478	18,707	25,936	721,263	620	4,536	160,233	0	15,301	175,534
	1998	88,200	6,309,119	13,980	59,052	755,690	78,143	19,560	26,994	724,593	614	4,503	172,029	0	15,839	187,868
89-1998	**% AAGR**	3.95%	2.19%	1.72%	3.52%	2.26%	1.24%	1.82%	0.13%	1.69%	2.29%	3.08%	3.51%	0.00%	0.69%	3.24%
	1999	86,784	6,432,939	13,491	58,626	772,370	75,904	19,259	26,993	713,322	639	4,665	169,973	0	16,400	186,374
	2000	89,141	6,559,408	13,590	60,320	788,526	76,497	19,639	27,187	722,367	658	4,769	174,546	0	16,409	190,955
	2001	91,402	6,685,699	13,671	62,041	804,892	77,080	19,894	27,428	725,339	677	4,919	178,933	0	16,754	195,687
	2002	93,708	6,809,302	13,762	63,708	820,982	77,600	20,128	27,678	727,220	697	5,045	183,286	0	16,774	200,060
	2003	96,033	6,930,494	13,857	65,301	836,863	78,030	20,502	27,806	737,325	718	5,169	187,724	0	17,160	204,884
	2004	98,337	7,049,891	13,949	66,900	852,392	78,485	20,818	27,919	745,671	739	5,305	192,099	0	17,393	209,492
	2005	100,623	7,165,968	14,040	66,448	867,633	78,891	21,193	28,046	755,626	760	5,438	196,461	0	17,632	214,094
	2006	102,921	7,283,304	14,131	69,992	882,695	79,294	21,550	28,145	765,673	782	5,564	200,810	0	17,801	218,611
	2007	105,160	7,399,732	14,211	71,551	897,811	79,695	21,930	28,338	773,864	804	5,692	205,136	0	18,043	223,179
	2008	107,460	7,515,636	14,296	73,133	912,927	80,108	22,138	28,536	775,793	828	5,823	209,382	0	18,264	227,645
99-2008	**% AAGR**	2.40%	1.74%	0.65%	2.49%	1.88%	0.60%	1.56%	0.62%	0.94%	2.92%	2.49%	2.34%	0.00%	1.20%	2.25%

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SUMMARY OF LOAD MANAGEMENT / INTERRUPTIBLE LOAD - MW
(SUMMER)

YEAR	FKE	FMP		FPC		FPL		JEA		KUA	LAK		NSB	OEU	OUC		SEC		TEC		TOTALS LM	TOTALS INT	TOTAL LM + INT
1999	4	4	0	502	324	727	417	0	146	12	22	5	6	2	0	1	136	110	125	222	1,540	1,225	2,765
2000	4	4	0	498	313	775	433	0	150	12	22	5	6	2	0	1	140	112	128	233	1,591	1,247	2,838
2001	5	4	0	453	301	799	456	0	154	12	23	5	6	2	0	1	144	115	130	233	1,578	1,265	2,843
2002	5	5	0	394	298	808	467	0	158	12	23	5	6	2	0	1	149	117	133	219	1,537	1,265	2,802
2003	5	5	0	353	300	814	477	0	162	12	24	5	6	3	0	1	154	119	134	220	1,509	1,284	2,793
2004	6	5	0	321	297	820	487	0	166	13	25	5	6	3	0	1	158	121	136	219	1,493	1,296	2,789
2005	6	5	0	293	299	826	497	0	170	13	25	5	6	3	0	1	163	124	138	221	1,478	1,317	2,795
2006	6	5	0	269	301	831	505	0	174	13	26	5	6	3	0	1	168	126	140	222	1,467	1,334	2,801
2007	6	5	0	248	303	836	514	0	178	13	26	5	6	3	0	1	172	129	142	222	1,457	1,352	2,809
2008	7	5	0	230	305	841	522	0	183	13	27	5	6	3	0	1	177	131	143	201	1,452	1,348	2,800

SUMMARY OF LOAD MANAGEMENT / INTERRUPTIBLE LOAD - MW
(WINTER)

YEAR	FKE	FMP		FPC		FPL		JEA		KUA	LAK		NSB	OEU	OUC		SEC		TEC		TOTALS LM	TOTALS INT	TOTAL LM + INT
1999 / 00	0	7	0	1,003	312	1,293	432	0	102	12	52	5	8	3	0	1	198	109	263	212	2,839	1,173	4,012
2000 / 01	0	7	0	1,003	300	1,366	450	0	105	12	53	5	8	4	0	1	205	111	267	212	2,925	1,184	4,109
2001 / 02	0	8	0	932	297	1,394	456	0	107	12	54	5	8	4	0	1	212	113	271	199	2,894	1,178	4,072
2002 / 03	0	8	0	883	299	1,404	462	0	110	12	55	5	8	4	0	1	218	116	274	200	2,866	1,193	4,059
2003 / 04	0	8	0	857	296	1,415	468	0	113	12	57	5	8	4	0	1	225	118	277	199	2,863	1,200	4,063
2004 / 05	0	9	0	840	298	1,426	474	0	116	13	58	5	8	4	0	1	231	120	281	201	2,870	1,215	4,085
2005 / 06	0	9	0	826	300	1,437	479	0	118	13	59	5	8	4	0	1	238	122	283	201	2,877	1,226	4,103
2006 / 07	0	9	0	814	302	1,446	484	0	121	13	60	5	8	5	0	1	245	124	286	202	2,885	1,239	4,124
2007 / 08	0	9	0	805	304	1,455	489	0	124	13	61	5	8	5	0	1	251	127	288	183	2,895	1,233	4,128
2008 / 09	0	9	0	798	306	1,464	494	0	128	13	62	6	8	5	0	1	258	129	290	184	2,907	1,248	4,155

NOTE: A SINGLE NUMBER DENOTES LOAD MANAGEMENT.

1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF EXISTING CAPACITY
AS OF JANUARY 1, 1999

UTILITY	NET CAPABILITY - MW SUMMER	WINTER
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOCIATION, INC.	22	22
FLORIDA MUNICIPAL POWER AGENCY	453	478
FLORIDA POWER CORPORATION	6,962	7,727
FLORIDA POWER & LIGHT COMPANY	16,326	16,783
FORT PIERCE UTILITIES AUTHORITY	119	119
GAINESVILLE REGIONAL UTILITIES	550	563
CITY OF HOMESTEAD	60	60
JEA	2,628	2,733
UTILITY BOARD OF THE CITY OF KEY WEST	52	52
KISSIMMEE UTILITY AUTHORITY	172	189
CITY OF LAKELAND	625	660
CITY OF LAKE WORTH UTILITIES	95	105
UTILITIES COMMISSION OF NEW SMYRNA BEACH	24	24
OCALA ELECTRIC UTILITY	11	11
ORLANDO UTILITIES COMMISSION	1,632	1,689
REEDY CREEK IMPROVEMENT DISTRICT	48	49
SEMINOLE ELECTRIC COOPERATIVE, INC.	1,291	1,345
CITY OF ST. CLOUD	22	21
CITY OF TALLAHASSEE	490	508
TAMPA ELECTRIC COMPANY	3,433	3,587
CITY OF VERO BEACH	150	155
TOTALS:		
FRCC EXISTING CAPACITY:	35,165	36,880
NON-UTILITY GENERATING FACILITIES (FIRM):	2,076	2,129
TOTAL FRCC EXISTING:	**37,241**	**39,009**

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LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOCIATION, INC.															
MARATHON	3	MONROE	D	LO	TK	HO	TK	6	1955	---	---	3,000	3	3	
MARATHON	4	MONROE	D	LO	TK	HO	TK	6	1957	---	---	3,000	3	3	
MARATHON	5	MONROE	D	LO	TK	HO	TK	6	1959	---	---	3,000	3	3	
MARATHON	6	MONROE	D	LO	TK	HO	TK	6	1973	---	---	2,500	3	3	
MARATHON	7	MONROE	D	LO	TK	HO	TK	6	1973	---	---	2,500	3	3	
MARATHON	8	MONROE	D	LO	TK	HO	TK	6	1988	---	---	2,000	2	2	
MARATHON	9	MONROE	D	LO	TK	HO	TK	6	1988	---	---	2,000	2	2	
MARATHON	10	MONROE	D	LO	TK	HO	TK	1	1998	---	---	3,500	3	3	
TOTAL:													22	22	
FLORIDA MUNICIPAL POWER AGENCY															
ST. LUCIE (839/853)	2	ST. LUCIE	N	N	TK	--	--	8	1983	---	---	839,000	74	75	
STANTON ENERGY CENTER (438/440)	1	ORANGE	FS	C	RR	--	--	7	1987	---	---	464,580	115	115	
STANTON ENERGY CENTER (441/441)	2	ORANGE	FS	C	RR	--	--	7	1987	---	---	464,580	122	122	
INDIAN RIVER(74/94) CT	A,B	BREVARD	CT	NG	PL	LO	TK	7	1989	---	---	82,800	29	37	
INDIAN RIVER(214/254) CT	C,D	BREVARD	CT	NG	PL	LO	TK	8	1992	---	---	260,000	44	54	
CANE ISLAND(30/35)	1	OSCEOLA	CT	NG	PL	LO	TK	11	1994	---	---	42,000	15	15	
CANE ISLAND(68/80)	2	OSCEOLA	CCT	NG	PL	LO	TK	6	1995	---	---	80,000	34	40	
CANE ISLAND(40/40)	2	OSCEOLA	CCW	NG	PL	LO	TK	6	1995	---	---	40,000	20	20	
TOTAL:													453	478	
FLORIDA POWER CORPORATION															
AVON PARK	P1	HIGHLANDS	CT	NG	PL	LO	TK	12	1968	12	2004	33,790	29	32	
AVON PARK	P2	HIGHLANDS	CT	LO	TK	---	---	12	1968	12	2004	33,790	29	32	
BAYBORO	P1	PINELLAS	CT	LO	WA,TK	---	---	4	1973	---	---	56,700	47	58	
BAYBORO	P2	PINELLAS	CT	LO	WA,TK	---	---	4	1973	---	---	56,700	47	58	
BAYBORO	P3	PINELLAS	CT	LO	WA,TK	---	---	4	1973	---	---	56,700	47	58	
BAYBORO	P4	PINELLAS	CT	LO	WA,TK	---	---	4	1973	---	---	56,700	47	58	
CRYSTAL RIVER	1	CITRUS	FS	C	WA,RR	---	---	10	1966	---	---	440,550	369	373	
CRYSTAL RIVER	2	CITRUS	FS	C	WA,RR	---	---	11	1969	---	---	523,800	464	469	

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1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
CRYSTAL RIVER(814/836)	3	CITRUS	N	N	TK	---	---	3	1977	---	---	890,460	734	755	
CRYSTAL RIVER	4	CITRUS	FS	C	WA,RR	---	---	12	1982	---	---	739,260	697	717	
CRYSTAL RIVER	5	CITRUS	FS	C	WA,RR	---	---	10	1984	---	---	739,260	697	717	
TURNER	P1	VOLUSIA	CT	LO	TK	---	---	10	1970	12	2004	19,290	15	18	
TURNER	P2	VOLUSIA	CT	LO	TK	---	---	10	1970	12	2004	19,290	15	18	
TURNER	P3	VOLUSIA	CT	LO	TK	---	---	8	1974	---	---	71,200	65	82	
TURNER	P4	VOLUSIA	CT	LO	TK	---	---	8	1974	---	---	71,200	65	82	
HIGGINS	P1	PINELLAS	CT	NG	PL	LO	TK	3	1969	12	2003	33,790	29	32	
HIGGINS	P2	PINELLAS	CT	NG	PL	LO	TK	4	1969	12	2003	33,790	29	32	
HIGGINS	P3	PINELLAS	CT	NG	PL	LO	TK	12	1970	12	2003	42,925	35	42	
HIGGINS	P4	PINELLAS	CT	NG	PL	LO	TK	1	1971	12	2003	42,925	35	42	
BARTOW	1	PINELLAS	FS	HO	WA	---	---	9	1958	---	---	127,500	115	117	
BARTOW	2	PINELLAS	FS	HO	WA	---	---	8	1961	---	---	127,500	117	119	
BARTOW	3	PINELLAS	FS	NG	PL	HO	WA	7	1963	---	---	239,360	208	213	
BARTOW	P1	PINELLAS	CT	LO	WA	---	---	5	1972	---	---	55,700	46	53	
BARTOW	P2	PINELLAS	CT	NG	PL	LO	WA	6	1972	---	---	55,700	46	53	
BARTOW	P3	PINELLAS	CT	LO	WA	---	---	6	1972	---	---	55,700	46	53	
BARTOW	P4	PINELLAS	CT	NG	PL	LO	WA	6	1972	---	---	55,700	49	58	
RIO PINAR	P1	ORANGE	CT	LO	TK	---	---	11	1970	12	2003	19,290	15	18	
SUWANNEE RIVER	1	SUWANNEE	FS	NG	PL	HO	TK	11	1953	12	2001	34,500	33	34	
SUWANNEE RIVER	2	SUWANNEE	FS	NG	PL	HO	TK	11	1954	12	2001	37,500	32	33	
SUWANNEE RIVER	3	SUWANNEE	FS	NG	PL	HO	TK	10	1956	12	2001	75,000	80	80	
SUWANNEE RIVER	P1	SUWANNEE	CT	NG	PL	LO	TK	10	1980	---	---	61,200	54	67	
SUWANNEE RIVER	P2	SUWANNEE	CT	LO	TK	---	---	10	1980	---	---	61,200	54	67	
SUWANNEE RIVER	P3	SUWANNEE	CT	NG	PL	LO	TK	11	1980	---	---	61,200	54	67	
DEBARY	P1	VOLUSIA	CT	LO	TK,RR	---	---	2	1976	---	---	66,870	54	65	
DEBARY	P2	VOLUSIA	CT	LO	TK,RR	---	---	3	1976	---	---	66,870	54	65	
DEBARY	P3	VOLUSIA	CT	LO	TK,RR	---	---	12	1975	---	---	66,870	54	65	
DEBARY	P4	VOLUSIA	CT	LO	TK,RR	---	---	4	1976	---	---	66,870	54	65	
DEBARY	P5	VOLUSIA	CT	LO	TK,RR	---	---	12	1975	---	---	66,870	54	65	
DEBARY	P6	VOLUSIA	CT	LO	TK,RR	---	---	4	1976	---	---	66,870	54	65	
DEBARY	P7	VOLUSIA	CT	NG	PL	LO	TK,RR	10	1992	---	---	115,000	83	99	
DEBARY	P8	VOLUSIA	CT	LO	TK,RR	---	---	10	1992	---	---	115,000	83	99	
DEBARY	P9	VOLUSIA	CT	NG	PL	LO	TK,RR	10	1992	---	---	115,000	83	99	
DEBARY	P10	VOLUSIA	CT	LO	TK,RR	---	---	10	1992	---	---	115,000	83	99	
UNIV. OF FLORIDA	P1	ALACHUA	CT	NG	PL	---	---	1	1994	---	---	43,000	36	42	
ANCLOTE	1	PASCO	FS	HO	PL	---	---	10	1974	---	---	556,200	503	517	

LOAD AND RESOURCE PLAN
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EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1) PLANT NAME AND UNIT NO.	(2)	(3) LOCATION	(4) UNIT TYPE	(5) PRIMARY FUEL: FUEL TYPE	(6) PRIMARY FUEL: TRANSP. METHOD	(7) ALTERNATE FUEL: FUEL TYPE	(8) ALTERNATE FUEL: TRANSP. METHOD	(9) COM'L IN-SERVICE MO.	COM'L IN-SERVICE YEAR	(10) EXPTD RTRMNT MO.	EXPTD RTRMNT YEAR	(11) GEN MAX NAMEPLATE kW	(12) NET CAPABILITY - MW SUMMER	(13) NET CAPABILITY - MW WINTER	(14) STATUS
ANCLOTE	2	PASCO	FS	HO	PL	NG	PL	10	1978	---	---	556,200	503	517	
INTERCESSION	P1	OSCEOLA	CT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58	
INTERCESSION	P2	OSCEOLA	CT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58	
INTERCESSION	P3	OSCEOLA	CT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58	
INTERCESSION	P4	OSCEOLA	CT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58	
INTERCESSION	P5	OSCEOLA	CT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58	
INTERCESSION	P6	OSCEOLA	CT	LO	PL,TK	---	---	5	1974	---	---	56,700	47	58	
INTERCESSION	P7	OSCEOLA	CT	NG	PL	LO	PL,TK	10	1993	---	---	115,000	83	99	
INTERCESSION	P8	OSCEOLA	CT	NG	PL	LO	PL,TK	10	1993	---	---	115,000	83	99	
INTERCESSION	P9	OSCEOLA	CT	NG	PL	LO	PL,TK	10	1993	---	---	115,000	83	99	
INTERCESSION	P10	OSCEOLA	CT	NG	PL	LO	PL,TK	10	1993	---	---	115,000	83	99	
INTERCESSION	P11	OSCEOLA	CT	LO	PL,TK	---	---	1	1997	---	---	165,000	0	168	
TIGER BAY	1	POLK	CC	NG	PL	---	---	8	1997	---	---	233,000	206	246	
TOTAL:													6,962	7,727	
FLORIDA POWER & LIGHT COMPANY															
TURKEY POINT	ST1	DADE	FS	HO	WA	NG	PL	4	1967	---	---	402,050	410	411	
TURKEY POINT	ST2	DADE	FS	HO	WA	NG	PL	4	1968	---	---	402,050	400	403	
TURKEY POINT	3	DADE	N	N	TK	---	---	12	1972	---	---	760,000	693	717	
TURKEY POINT	4	DADE	N	N	TK	---	---	9	1973	---	---	760,000	693	717	
TURKEY POINT	IC1	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	3	3	
TURKEY POINT	IC2	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	3	3	
TURKEY POINT	IC3	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	2	2	
TURKEY POINT	IC4	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	2	2	
TURKEY POINT	5	DADE	D	LO	TK	---	---	4	1968	---	---	2,750	2	2	
CUTLER	5	DADE	FS	NG	PL	---	---	11	1954	---	---	745,000	71	72	
CUTLER	6	DADE	FS	NG	PL	---	---	7	1955	---	---	162,000	144	145	
LAUDERDALE	4ST	BROWARD	CCW	WH	---	---	---	10	1957	---	---	151,250	430	452	
LAUDERDALE	4CT1	BROWARD	CCT	NG	PL	LO	TK	5	1993	---	---	185,000			
LAUDERDALE	4CT2	BROWARD	CCT	NG	PL	LO	TK	5	1993	---	---	185,000			
LAUDERDALE	5ST	BROWARD	CCW	WH	---	---	---	4	1958	---	---	151,250	430	452	
LAUDERDALE	5CT1	BROWARD	CCT	NG	PL	LO	TK	6	1993	---	---	185,000			
LAUDERDALE	5CT2	BROWARD	CCT	NG	PL	LO	TK	6	1993	---	---	185,000			
LAUDERDALE	1	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	2	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
LAUDERDALE	3	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	GT4	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	GT5	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	6	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	7	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	8	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	9	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	10	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	11	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	38	
LAUDERDALE	12	BROWARD	CT	NG	PL	LO	TK	8	1970	---	---	34,228	35	39	
LAUDERDALE	13	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	14	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	15	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	16	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	17	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	18	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	19	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	20	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	21	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	22	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	23	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	38	
LAUDERDALE	24	BROWARD	CT	NG	PL	LO	TK	8	1972	---	---	34,228	35	39	
PORT EVERGLADES	ST1	BROWARD	FS	HO	WA	NG	PL	6	1960	---	---	225,250	221	222	
PORT EVERGLADES	ST2	BROWARD	FS	HO	WA	NG	PL	4	1961	---	---	225,250	221	222	
PORT EVERGLADES	ST3	BROWARD	FS	HO	WA	NG	PL	7	1964	---	---	402,050	389	391	
PORT EVERGLADES	ST4	BROWARD	FS	HO	WA	NG	PL	4	1965	---	---	402,050	410	410	
PORT EVERGLADES	GT1	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	GT2	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	GT3	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	GT4	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	GT5	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	6	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	7	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	8	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	9	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
PORT EVERGLADES	10	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	11	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	38	
PORT EVERGLADES	12	BROWARD	CT	NG	PL	LO	WA	8	1971	---	---	34,228	35	39	
RIVIERA	3	PALM BEACH	FS	HO	WA	NG	PL	6	1962	---	---	310,420	290	292	
RIVIERA	4	PALM BEACH	FS	HO	WA	NG	PL	3	1963	---	---	310,420	290	292	
MARTIN	1	MARTIN	FS	NG	PL	HO	PL	12	1980	---	---	863,300	814	821	
MARTIN	2	MARTIN	FS	NG	PL	HO	PL	6	1981	---	---	863,300	816	833	
MARTIN	3ST	MARTIN	CCW	WH	---	---	---	2	1994	---	---	204,000	440	465	
MARTIN	3CT1	MARTIN	CCT	NG	PL	LO	TK	2	1994	---	---	204,000			
MARTIN	3CT2	MARTIN	CCT	NG	PL	LO	TK	2	1994	---	---	204,000			
MARTIN	4ST	MARTIN	CCW	WH	---	---	---	4	1994	---	---	204,000	435	465	
MARTIN	4CT1	MARTIN	CCT	NG	PL	LO	TK	4	1994	---	---	204,000			
MARTIN	4CT2	MARTIN	CCT	NG	PL	LO	TK	4	1994	---	---	204,000			
ST. LUCIE	1	ST. LUCIE	N	N	TK	---	---	5	1976	---	---	850,000	839	853	
ST. LUCIE (839/853)	2	ST. LUCIE	N	N	TK	---	---	6	1983	---	---	839,000	714	726	
CAPE CANAVERAL	1	BREVARD	FS	HO	WA	NG	PL	4	1965	---	---	402,050	395	399	
CAPE CANAVERAL	2	BREVARD	FS	HO	WA	NG	PL	5	1969	---	---	402,050	405	408	
SANFORD	3	VOLUSIA	FS	HO	WA	NG	PL	5	1959	---	---	156,250	153	155	
SANFORD	4	VOLUSIA	FS	HO	WA	NG	PL	7	1969	---	---	436,100	390	394	
SANFORD	5	VOLUSIA	FS	HO	WA	NG	PL	5	1974	---	---	436,100	390	394	
SCHERER	4	MONROE, GA.	FS	C	RR	---	---	7	1991	---	---	891,000	667	667	
ST. JOHNS RIVER (640/640)	1	DUVAL	FS	LO	PL	C	CV	3	1986	---	---	679,600	130	130	
ST. JOHNS RIVER (640/640)	2	DUVAL	FS	LO	PL	C	CV	5	1988	---	---	679,600	130	130	
PUTNAM	1ST	PUTNAM	CCW	WH	---	NG	PL	4	1978	---	---	120,000	249	260	
PUTNAM	1GT1	PUTNAM	CCT	NG	PL	LO	WA	4	1978	---	---	85,000			
PUTNAM	1GT2	PUTNAM	CCT	NG	PL	LO	WA	4	1978	---	---	85,000			
PUTNAM	2ST	PUTNAM	CCW	WH	---	NG	PL	8	1977	---	---	120,000	249	260	
PUTNAM	2GT1	PUTNAM	CCT	NG	PL	LO	WA	8	1977	---	---	85,000			
PUTNAM	2GT2	PUTNAM	CCT	NG	PL	LO	WA	8	1977	---	---	85,000			
FT. MYERS	ST1	LEE	FS	HO	WA	---	---	11	1958	---	---	156,250	147	148	
FT. MYERS	ST2	LEE	FS	HO	WA	---	---	7	1969	---	---	402,050	397	400	
FT. MYERS	GT1	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	58	
FT. MYERS	GT2	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	58	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
FT. MYERS	GT3	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	58	
FT. MYERS	GT4	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	58	
FT. MYERS	GT5	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	58	
FT. MYERS	GT6	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	58	
FT. MYERS	GT7	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	57	
FT. MYERS	GT8	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	57	
FT. MYERS	GT9	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	57	
FT. MYERS	GT10	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	57	
FT. MYERS	GT11	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	57	
FT. MYERS	GT12	LEE	CT	LO	WA	---	---	5	1974	---	---	62,000	51	57	
MANATEE	1	MANATEE	FS	HO	WA	---	---	10	1976	---	---	863,300	798	805	
MANATEE	2	MANATEE	FS	HO	WA	---	---	12	1977	---	---	863,300	792	799	
TOTAL:													16,326	16,783	
FORT PIERCE UTILITIES AUTHORITY															
H. D. KING	5	ST. LUCIE	CCW	WH	---	---	---	1	1953	---	---	8,375	8	8	
H. D. KING	6	ST. LUCIE	FS	NG	PL	HO	TK	12	1958	---	---	16,500	17	17	M
H. D. KING	7	ST. LUCIE	FS	NG	PL	HO	TK	1	1964	---	---	33,000	32	32	
H. D. KING	8	ST. LUCIE	FS	NG	PL	HO	TK	5	1976	---	---	56,116	50	50	
H. D. KING	9	ST. LUCIE	CCT	NG	PL	LO	TK	5	1990	---	---	22,520	23	23	
H. D. KING	D1	ST. LUCIE	D	LO	TK	---	---	4	1970	---	---	2,750	3	3	
H. D. KING	D2	ST. LUCIE	D	LO	TK	---	---	4	1970	---	---	2,750	3	3	
TOTAL:													119	119	
GAINESVILLE REGIONAL UTILITIES															
CRYSTAL RIVER(814/836)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	11	11	
DEERHAVEN	1	ALACHUA	FS	NG	PL	HO	TK	8	1972	---	---	75,000	85	85	
DEERHAVEN	2	ALACHUA	FS	C	RR	---	---	10	1981	---	---	250,750	228	228	
DEERHAVEN	GT1	ALACHUA	CT	NG	PL	LO	TK	7	1976	---	---	24,600	18	20	
DEERHAVEN	GT2	ALACHUA	CT	NG	PL	LO	TK	8	1976	---	---	24,600	18	20	
DEERHAVEN	GT3	ALACHUA	CT	NG	PL	LO	TK	1	1996	---	---	96,140	75	81	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
J. R. KELLY	7	ALACHUA	FS	NG	PL	HO	TK	8	1961	---	---	25,000	23	23	
J. R. KELLY	8	ALACHUA	FS	NG	PL	HO	TK	4	1965	---	---	50,000	50	50	
J. R. KELLY	GT1	ALACHUA	CT	NG	PL	LO	TK	2	1968	--	---	16,320	14	15	
J. R. KELLY	GT2	ALACHUA	CT	NG	PL	LO	TK	2	1968	---	---	16,320	14	15	
J. R. KELLY	GT3	ALACHUA	CT	NG	PL	LO	TK	2	1969	---	---	16,320	14	15	
TOTAL:													550	563	
CITY OF HOMESTEAD															
G. W. IVEY	8	DADE	D	NG	PL	LO	TK	1	1954	1	2008	2,500	3	3	
G. W. IVEY	2-3	DADE	D	NG	PL	LO	TK	3	1970	---	---	4,140	4	4	
G. W. IVEY	9-10	DADE	D	NG	PL	LO	TK	1	1958	1	2008	5,000	5	5	
G. W. IVEY	11-12	DADE	D	NG	PL	LO	TK	1	1965	1	2008	6,540	7	7	
G. W. IVEY	13-17	DADE	D	NG	PL	LO	TK	11	1972	---	---	10,350	10	10	
G. W. IVEY	18-19	DADE	D	NG	PL	LO	TK	4	1975	---	---	17,600	18	18	
G. W. IVEY	20-21	DADE	D	NG	PL	LO	TK	5	1981	---	---	12,970	13	13	
TOTAL:													60	60	
JEA															
ST. JOHNS RIVER (640/640)	1	DUVAL	FS	C	RR/WA	---	---	3	1987	3	2027	679,600	510	510	
ST. JOHNS RIVER (640/640)	2	DUVAL	FS	C	RR/WA	---	---	5	1988	5	2028	679,600	510	510	
SCHERER	4	MONROE, GA.	FS	C	RR	---	---	7	1991	2	2029	416,000	200	200	
GIRVIN LANDFILL	1-4	DUVAL	IC	NG	PL	---	---	6	1997	---	---	3,000	3	3	
KENNEDY	8	DUVAL	FS	HO	PL	---	---	7	1955	---	---	50,000	43	43	M
KENNEDY	9	DUVAL	FS	HO	PL	---	---	1	1958	---	---	50,000	43	43	M
KENNEDY	10	DUVAL	FS	HO	PL	NG	PL	12	1961	3	2000	149,600	97	97	
KENNEDY	3	DUVAL	CT	LO	PL	---	---	5	1973	---	---	56,200	45	63	
KENNEDY	4	DUVAL	CT	LO	PL	---	---	8	1973	---	---	56,200	48	63	
KENNEDY	5	DUVAL	CT	LO	PL	---	---	7	1973	---	---	56,200	48	63	
NORTHSIDE	1	DUVAL	FS	HO	PL	NG	PL	11	1966	---	---	297,500	262	262	
NORTHSIDE	2	DUVAL	FS	HO	PL	---	---	3	1972	---	---	297,500	262	262	M

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(1)	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
NORTHSIDE	3	DUVAL	FS	HO	PL	NG	PL	6	1977	---	---	563,700	505	505	
NORTHSIDE	3	DUVAL	CT	LO	PL	---	---	2	1975	---	---	62,100	47	62	
NORTHSIDE	4	DUVAL	CT	LO	PL	---	---	1	1975	---	---	62,100	47	62	
NORTHSIDE	5	DUVAL	CT	LO	PL	---	---	12	1974	---	---	62,100	47	62	
NORTHSIDE	6	DUVAL	CT	LO	PL	---	---	12	1974	---	---	62,100	47	62	
SOUTHSIDE	4	DUVAL	FS	HO	PL	NG	PL	11	1958	10	2001	75,000	67	67	
SOUTHSIDE	5	DUVAL	FS	HO	PL	NG	PL	9	1964	10	2001	156,600	142	142	
TOTAL:													2,628	2,733	
KEY WEST UTILITY BOARD															
BIG PINE	1	MONROE	D	LO	TK	---	---	2	1969	---	---	2,750	3	3	
CUDJOE	2	MONROE	D	LO	TK	---	---	8	1968	---	---	2,750	3	3	
CUDJOE	3	MONROE	D	LO	TK	---	---	8	1968	---	---	2,300	2	2	
STOCK ISLAND	GT1	MONROE	CT	LO	WA	---	---	11	1978	---	---	23,450	20	20	
STOCK ISLAND	IC1	MONROE	D	LO	WA	---	---	1	1965	---	---	2,500	2	2	
STOCK ISLAND	IC2	MONROE	D	LO	WA	---	---	1	1965	---	---	2,500	2	2	
STOCK ISLAND	IC3	MONROE	D	LO	WA	---	---	1	1965	---	---	2,500	2	2	
MEDIUM SPEED DIESEL	IC4	MONROE	D	LO	WA	---	---	6	1991	---	---	9,600	9	9	
MEDIUM SPEED DIESEL	IC5	MONROE	D	LO	WA	---	---	6	1991	---	---	9,600	9	9	
TOTAL:													52	52	
KISSIMMEE UTILITY AUTHORITY															
CRYSTAL RIVER(814/836)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	6	6	
CANE ISLAND(30/35)	1	OSCEOLA	CT	NG	PL	LO	TK	11	1994	---	---	42,000	15	20	
CANE ISLAND(68/80)	2	OSCEOLA	CCT	NG	PL	LO	TK	6	1995	---	---	80,000	34	40	
CANE ISLAND(40/40)	2	OSCEOLA	CCW	NG	PL	LO	TK	6	1995	---	---	40,000	20	20	
HANSEL	8	OSCEOLA	D	NG	PL	LO	TK	2	1959	1	1998	3,000	3	3	
HANSEL	14	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2	
HANSEL	15	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2	
HANSEL	16	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2	

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EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
HANSEL	17	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2	
HANSEL	18	OSCEOLA	D	NG	PL	LO	TK	2	1972	1	2002	2,070	2	2	
HANSEL	19	OSCEOLA	D	LO	TK	---	---	2	1983	1	2013	2,500	3	3	
HANSEL	20	OSCEOLA	D	LO	TK	---	---	2	1983	1	2013	2,500	3	3	
HANSEL	21	OSCEOLA	CCT	NG	PL	LO	TK	2	1983	1	2013	35,000	28	32	
HANSEL	22	OSCEOLA	CCW	WH	---	---	---	11	1983	1	2013	10,000	10	10	
HANSEL	23	OSCEOLA	CCW	WH	---	---	---	11	1983	1	2013	10,000	10	10	
INDIAN RIVER(74/94) CT	A,B	BREVARD	CT	NG	PL	LO	TK	7	1989	---	---	82,800	9	11	
STANTON ENERGY CENTER (438/440)	1	ORANGE	FS	C	RR	---	---	7	1987	---	---	464,580	21	21	
TOTAL:													172	189	
CITY OF LAKELAND															
LARSEN	2	POLK	CT	NG	PL	LO	TK	11	1962	---	---	11,250	10	14	
LARSEN	3	POLK	CT	NG	PL	LO	TK	12	1962	---	---	11,250	10	14	
LARSEN	5	POLK	CCW	WH	---	---	---	4	1956	---	---	25,000	29	31	
LARSEN	6	POLK	FS	NG	PL	HO	TK	12	1959	7	1999	25,000	25	27	
LARSEN	7	POLK	FS	NG	PL	HO	TK	2	1966	2	2001	50,000	50	50	
LARSEN	8	POLK	CC	NG	PL	LO	TK	7	1992	---	---	101,520	73	93	
MCINTOSH(338/341)	3	POLK	FS	C	RR	REF	TK	9	1982	---	---	363,870	205	205	
MCINTOSH	GT1	POLK	CT	NG	PL	LO	TK	---	1973	---	---	26,640	17	20	
MCINTOSH	IC1	POLK	D	LO	TK	---	---	---	1970	---	---	2,500	3	3	
MCINTOSH	IC2	POLK	D	NG	PL	---	---	---	1970	---	---	2,500	3	3	
MCINTOSH	ST1	POLK	FS	NG	PL	HO	TK	2	1971	10	2002	103,000	87	87	
MCINTOSH	ST2	POLK	FS	NG	PL	HO	TK	6	1976	7	2004	126,000	113	113	
TOTAL:													625	660	
CITY OF LAKE WORTH UTILITIES															
TOM G. SMITH	S-1	PALM BEACH	FS	NG	PL	HO	TK	1	1961	---	---	7,500	7	8	
TOM G. SMITH	S-3	PALM BEACH	FS	NG	PL	HO	TK	11	1967	---	---	26,500	22	24	
TOM G. SMITH	S-4	PALM BEACH	FS	NG	PL	HO	TK	8	1971	---	---	32,580	32	33	M

EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
TOM G. SMITH	MU1	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2	
TOM G. SMITH	MU2	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2	
TOM G. SMITH	MU3	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2	
TOM G. SMITH	MU4	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2	
TOM G. SMITH	MU5	PALM BEACH	D	LO	TK	---	---	12	1965	---	---	2,000	2	2	
TOM G. SMITH	GT-1	PALM BEACH	CT	LO	TK	---	---	12	1976	---	---	30,800	26	31	
TOM G. SMITH	GT-2	PALM BEACH	CCT	NG	PL	LO	TK	3	1978	---	---	21,410	21	23	
TOM G. SMITH	S-5	PALM BEACH	CCW	WH		---	---	3	1978	---	---	10,000	9	9	
TOTAL:													95	105	
UTILITIES COMMISSION OF NEW SMYRNA BEACH															
CRYSTAL RIVER(814/836)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	4	4	
GLENCOE	1	VOLUSIA	D	LO	TK	---	---	2	1982	---	---	750	1	1	
NORTH CAUSEWAY	1	VOLUSIA	D	LO	TK	---	---	7	1981	---	---	750	1	1	
SMITH	3	VOLUSIA	D	LO	TK	---	---	1	1946	---	---	840	1	1	
SMITH	4	VOLUSIA	D	LO	TK	---	---	1	1950	---	---	1,000	1	1	
SMITH	6	VOLUSIA	D	LO	TK	---	---	1	1955	---	---	1,800	2	2	
SMITH	7	VOLUSIA	D	LO	TK	---	---	1	1956	---	---	1,800	2	2	
SMITH	8	VOLUSIA	D	LO	TK	---	---	1	1960	---	---	1,100	1	1	
SMITH	9	VOLUSIA	D	LO	TK	---	---	1	1967	---	---	2,000	2	2	
SMITH	10	VOLUSIA	D	LO	TK	---	---	1	1967	---	---	2,000	2	2	
SMITH	11	VOLUSIA	D	LO	TK	---	---	1	1967	---	---	2,000	2	2	
SWOOPE STATION	2	VOLUSIA	D	NG	PL	LO	TK	11	1981	---	---	910	1	1	
SWOOPE STATION	3	VOLUSIA	D	NG	PL	LO	TK	12	1982	---	---	2,050	2	2	
SWOOPE STATION	4	VOLUSIA	D	NG	PL	LO	TK	12	1982	---	---	2,275	2	2	
TOTAL:													24	24	
OCALA ELECTRIC UTILITY															
CRYSTAL RIVER(814/836)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	11	11	

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EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
ORLANDO UTILITIES COMMISSION															
CRYSTAL RIVER(814/836)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,463	13	13	
INDIAN RIVER	1	BREVARD	FS	NG	PL	HO	WA	2	1960	---	---	86,700	88	90	
INDIAN RIVER	2	BREVARD	FS	NG	PL	HO	WA	12	1964	---	---	207,600	201	205	
INDIAN RIVER	3	BREVARD	FS	NG	PL	HO	WA	2	1974	---	---	344,500	319	324	
INDIAN RIVER(74/94) CT	A,B	BREVARD	CT	NG	PL	LO	TK	7	1989	---	---	82,800	36	46	
INDIAN RIVER(214/254) CT	C,D	BREVARD	CT	NG	PL	LO	TK	8	1992	---	---	260,000	170	200	
MCINTOSH(338/341)	3	POLK	FS	C	RR	REF	TK	9	1982	---	---	363,870	133	136	
ST. LUCIE (839/853)	2	ST. LUCIE	N	N	TK	---	---	6	1983	---	---	839,000	51	52	
STANTON ENERGY CENTER (438/440)	1	ORANGE	FS	C	RR	---	---	7	1987	---	---	464,580	302	304	
STANTON ENERGY CENTER (441/441)	2	ORANGE	FS	C	RR	---	---	6	1996	---	---	464,580	319	319	
TOTAL:													1,632	1,689	
REEDY CREEK IMPROVEMENT DISTRICT															
CENTRAL ENERGY PLANT	1	ORANGE	CC	NG	PL	---	---	1	1988	1	2018	43,000	39	40	
REEDY CREEK DIESEL	D1-D2	ORANGE	D	LO	TK	---	---	---	---	1	2010	5,000	5	5	
REEDY CREEK THERMAL	1	ORANGE	OT	WA	---	---	---	1	1998	1	2010	4,000	4	4	
TOTAL:													48	49	
SEMINOLE ELECTRIC COOPERATIVE, INC.															
CRYSTAL RIVER(814/836)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,463	15	15	
SEMINOLE	1	PUTNAM	FS	C	RR	---	---	2	1984	---	---	714,600	633	665	
SEMINOLE	2	PUTNAM	FS	C	RR	---	---	1	1985	---	---	714,600	633	665	
TOTAL:													1,291	1,345	

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EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
CITY OF ST. CLOUD															
ST. CLOUD	1	OSCEOLA	IC	NG	PL	LO	TK	7	1982	---	---	2,000	2	2	
ST. CLOUD	2	OSCEOLA	IC	NG	PL	LO	TK	12	1974	---	---	5,850	6	5	
ST. CLOUD	3	OSCEOLA	IC	NG	PL	LO	TK	9	1982	---	---	2,000	2	2	
ST. CLOUD	4	OSCEOLA	IC	NG	PL	LO	TK	8	1961	---	---	3,750	3	3	
ST. CLOUD	6	OSCEOLA	IC	NG	PL	LO	TK	3	1967	---	---	3,750	3	3	
ST. CLOUD	7	OSCEOLA	IC	NG	PL	LO	TK	9	1982	---	---	6,300	6	6	
ST. CLOUD	8	OSCEOLA	IC	NG	PL	LO	TK	4	1977	---	---	6,445	6	6	M
TOTAL:													22	21	
CITY OF TALLAHASSEE															
CRYSTAL RIVER(814/836)	3	CITRUS	N	N	---	---	---	3	1977	---	---	890,460	11	11	
HOPKINS	1	LEON	FS	NG	PL	HO	TK	5	1971	3	2016	75,000	76	80	
HOPKINS	2	LEON	FS	NG	PL	HO	TK	10	1977	3	2022	259,250	238	248	
HOPKINS	GT1	LEON	CT	NG	PL	LO	TK	2	1970	3	2015	16,320	12	14	
HOPKINS	GT2	LEON	CT	NG	PL	LO	TK	9	1972	3	2017	27,000	24	26	
PURDOM	5	WAKULLA	FS	NG	PL	HO	WA	4	1958	9	1999	25,000	24	24	
PURDOM	6	WAKULLA	FS	NG	PL	HO	WA	1	1961	9	1999	25,000	24	24	
PURDOM	7	WAKULLA	FS	NG	PL	HO	WA	6	1966	3	2011	50,000	50	50	
PURDOM	GT1	WAKULLA	CT	NG	PL	LO	TK	12	1963	3	2008	15,000	10	10	
PURDOM	GT2	WAKULLA	CT	NG	PL	LO	TK	5	1964	3	2009	15,000	10	10	
C. H. CORN HYDRO	1	LEON/	HY	WAT	WA	---	---	9	1985	---	---	4,000	4	4	
C. H. CORN HYDRO	2	GADSEN/	HY	WAT	WA	---	---	8	1985	---	---	4,000	4	4	
C. H. CORN HYDRO	3	LIBERTY	HY	WAT	WA	---	---	1	1986	---	---	3,000	3	3	
TOTAL:													490	508	
TAMPA ELECTRIC COMPANY															
BIG BEND	ST1	HILLSBOROUGH	FS	C	WA	---		10	1970	---	---	445,500	421	431	
BIG BEND	ST2	HILLSBOROUGH	FS	C	WA	---	---	4	1973	---	---	445,500	421	431	
BIG BEND	ST3	HILLSBOROUGH	FS	C	WA	---	---	5	1976	---	---	445,500	428	438	
BIG BEND	ST4	HILLSBOROUGH	FS	C	WA	---	---	2	1985	---	---	486,000	442	447	

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EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
				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
BIG BEND	GT1	HILLSBOROUGH	CT	LO	WA	---	TK	2	1969	---	---	18,000	12	17	
BIG BEND	GT2	HILLSBOROUGH	CT	LO	WA	---	TK	11	1974	---	---	78,750	57	60	
BIG BEND	GT3	HILLSBOROUGH	CT	LO	WA	---	TK	11	1974	---	---	78,750	57	80	
DINNER LAKE	1	HIGHLANDS	FS	NG	PL	HO	TK	12	1966	---	---	12,650	11	11	M
GANNON	1	HILLSBOROUGH	FS	C	WA	---	RR	9	1957	---	---	125,000	99	99	
GANNON	2	HILLSBOROUGH	FS	C	WA	---	RR	11	1958	---	---	125,000	93	93	
GANNON	3	HILLSBOROUGH	FS	C	WA	---	RR	10	1960	---	---	179,520	145	155	
GANNON	4	HILLSBOROUGH	FS	C	WA	---	RR	11	1963	---	---	187,500	169	179	
GANNON	5	HILLSBOROUGH	FS	C	WA	---	RR	11	1965	---	---	239,360	227	232	
GANNON	6	HILLSBOROUGH	FS	C	WA	---	RR	10	1967	---	---	445,500	362	392	
GANNON	GT1	HILLSBOROUGH	CT	LO	WA	---	TK	3	1969	---	---	18,000	12	17	
HOOKERS POINT	1	HILLSBOROUGH	FS	HO	WA	---	---	7	1948	1	2003	33,000	32	34	
HOOKERS POINT	2	HILLSBOROUGH	FS	HO	WA	---	---	6	1950	1	2003	34,500	32	34	
HOOKERS POINT	3	HILLSBOROUGH	FS	HO	WA	---	---	8	1950	1	2003	34,500	32	34	
HOOKERS POINT	4	HILLSBOROUGH	FS	HO	WA	---	---	10	1953	1	2003	49,000	41	43	
HOOKERS POINT	5	HILLSBOROUGH	FS	HO	WA	---	---	5	1955	1	2003	81,600	67	67	
PHILLIPS PLANT	3	HIGHLANDS	HRSG	WH	---	---	---	6	1983	---	---	3,600	3	3	M
PHILLIPS PLANT	IC1	HIGHLANDS	D	HO	TK	LO	---	6	1983	---	---	19,215	17	17	
PHILLIPS PLANT	IC2	HIGHLANDS	D	HO	TK	LO	---	6	1983	---	---	19,215	17	17	
PHILLIPS PLANT	IC5	HIGHLANDS	D	LO	---	---	---	1	1956	---	---	600	1	1	M
POLK	1	POLK	IGCC	C	TK	LO	---	9	1996	---	---	326,229	250	250	
TOTAL:													3,433	3,587	
CITY OF VERO BEACH															
MUNICIPAL PLANT	1	INDIAN RIVER	FS	NG	PL	HO	TK	11	1961	---	---	12,500	13	13	
MUNICIPAL PLANT	2	INDIAN RIVER	CCW	NG	PL	HO	TK	8	1964	---	---	16,500	13	13	
MUNICIPAL PLANT	3	INDIAN RIVER	FS	NG	PL	HO	TK	9	1971	---	---	33,000	33	33	
MUNICIPAL PLANT	4	INDIAN RIVER	FS	NG	PL	HO	TK	8	1976	---	---	55,000	56	56	
MUNICIPAL PLANT	5	INDIAN RIVER	CCT	NG	PL	LO	TK	12	1992	---	---	41,400	35	40	
TOTAL:													150	155	

TOTAL FRCC EXISTING: 35,165 36,880

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FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES, AND REMOVALS
(JANUARY 1,1999 THROUGH DECEMBER 31, 2008)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					FUEL		FUEL TRANSPORATION		COMMERCIAL	GENERATOR MAXIMUM	NET CAPABILITY (MW)		
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALTERNATE	PRIMARY	ALTERNATE	IN-SERVICE (MO/YR)	NAMEPLATE kW	SUMMER	WINTER	STATUS
	1999												
FPL	PORT EVERGLADES GT's		BROWARD	CT	LO	---	WA	---	1 / 1999	---	18	7	A
FPL	LAUDERDALE GT's		BROWARD	CT	LO	---	WA	---	1 / 1999	---	18	7	A
FPL	LAUDERDALE GT's		BROWARD	CT	LO	---	WA	---	1 / 1999	---	18	7	A
FPL	FT. MYERS GT's		LEE	CT	LO	---	WA	---	1 / 1999	---	14	10	A
FPL	PORT EVERGLADES	2	BROWARD	FS	HO	NG	WA	---	1 / 1999	---	1	1	A
FPL	PORT EVERGLADES	4	BROWARD	FS	HO	NG	WA	---	1 / 1999	---	(2)	1	A
FPL	CAPE CANAVERAL	1	BREVARD	FS	HO	NG	WA	---	1 / 1999	---	10	9	A
FPL	MANATEE	1	MANATEE	FS	HO	---	WA	---	1 / 1999	863,300	21	21	A
FPL	MANATEE	2	MANATEE	FS	HO	---	WA	---	1 / 1999	863,300	27	27	A
FPL	MARTIN	3	MARTIN	CC	NG	LO	PL	---	1 / 1999	204,000	40	(5)	A
FPL	MARTIN	4	MARTIN	CC	NG	LO	PL	---	1 / 1999	204,000	32	(5)	A
FPL	PUTNAM	1	PUTNAM	CC	NG	LO	PL	---	1 / 1999	---	14	0	A
FPL	PUTNAM	2	PUTNAM	CC	NG	LO	PL	---	1 / 1999	---	14	0	A
FPC	HINES ENERGY COMPLEX	1	POLK	CC	NG	LO	PL	TK	4 / 1999	---	470	505	V
FPC	CRYSTAL RIVER	3	CITRUS	N	N	---	TK	---	5 / 1999	890,460	20	16	A
FPC	CRYSTAL RIVER	5	CITRUS	FS	C	---	WA,RR	---	5 / 1999	739,260	17	17	A
FPC	ANCLOTE	1	PASCO	FS	HO	NG	PL	PL	5 / 1999	556,200	0	0	CA
FPC	DEBARY	P8	VOLUSIA	CT	NG	LO	PL	TK,RR	6 / 1999	115,000	0	0	CA
FMP	STOCK ISLAND	CT2	MONROE	CT	LO	---	WA	---	6 / 1999	19,770	18	18	W
FMP	STOCK ISLAND	CT3	MONROE	CT	LO	---	WA	---	6 / 1999	19,770	18	18	W
LAK	MCINTOSH	5	POLK	CT	NG	LO	PL	TK	6 / 1999	249,090	217	264	V
LAK	LARSEN	6	POLK	FS	NG	HO	PL	TK	7 / 1999	25,000	(25)	(27)	R
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
	2000												
FPL	FT. MYERS GT's		LEE	CT	LO	---	WA	---	1 / 2000	---	39	0	A
FPL	PORT EVERGLADES	3	BROWARD	FS	HO	NG	WA	---	1 / 2000	402,050	14	15	A
FPL	CAPE CANAVERAL	2	BREVARD	FS	HO	NG	WA	---	1 / 2000	402,050	3	0	A
FPL	MARTIN	3	MARTIN	CCW	NG	LO	PL	---	1 / 2000	204,000	10	30	A
FPL	MARTIN	4	MARTIN	CCW	NG	LO	PL	---	1 / 2000	204,000	23	30	A
TEC	BIG BEND	ST1	HILLSBOROUGH	FS	C	---	WA	---	1 / 2000	445,500	(5)	(5)	D
TEC	BIG BEND	ST2	HILLSBOROUGH	FS	C	---	WA	---	1 / 2000	445,500	(5)	(5)	D
TEC	GANNON	1	HILLSBOROUGH	FS	C	---	WA	RR	1 / 2000	125,000	20	20	A
TEC	GANNON	2	HILLSBOROUGH	FS	C	---	WA	RR	1 / 2000	125,000	25	25	A
TEC	GANNON	5	HILLSBOROUGH	FS	C	---	WA	RR	1 / 2000	239,350	(9)	(10)	D
TEC	GANNON	6	HILLSBOROUGH	FS	C	---	WA	RR	1 / 2000	445,500	0	(20)	D
JEA	KENNEDY	10	DUVAL	FS	HO	NG	WA	PL	3 / 2000	149,600	(97)	(97)	R
FPC	CRYSTAL RIVER	4	CITRUS	FS	C	---	WA,RR	---	4 / 2000	739,250	17	17	A
FPC	CRYSTAL RIVER	2	CITRUS	FS	C	---	WA,RR	---	4 / 2000	523,800	24	24	A
TAL	PURDOM	8	WAKULLA	CC	NG	LO	PL	TK	5 / 2000	259,800	233	260	U

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FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES, AND REMOVALS
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
										GENERATOR			
									COMMERCIAL	MAXIMUM			
		UNIT		UNIT	FUEL		FUEL TRANSPORATION		IN-SERVICE	NAMEPLATE	NET CAPABILITY (MW)		
UTILITY	POWER PLANT NAME	NO.	LOCATION	TYPE	PRIMARY	ALTERNATE	PRIMARY	ALTERNATE	(MO/YR)	kW	SUMMER	WINTER	STATUS
JEA	KENNEDY	GT7	DUVAL	CT	NG	LO	PL	WA	5 / 2000	185,000	149	186	U
GRU	J. R. KELLY	8	ALACHUA	FS	NG	HO	PL	TK	11 / 2000	(50,000)	(50)	(50)	R
SEC	UNKNOWN	GT1	UNKNOWN	CT	NG	LO	PL	TK	11 / 2000	160,000	150	150	P
SEC	UNKNOWN	GT2	UNKNOWN	CT	NG	LO	PL	TK	11 / 2000	160,000	150	150	P
FPC	INTERCESSION CITY	P12	OSCEOLA	CT	NG	LO	PL	PL,TK	12 / 2000	---	83	99	U
FPC	INTERCESSION CITY	P13	OSCEOLA	CT	NG	LO	PL	PL,TK	12 / 2000	---	83	99	U
FPC	INTERCESSION CITY	P14	OSCEOLA	CT	NG	LO	PL	PL,TK	12 / 2000	---	83	99	U
	2001												
FPL	FT. MYERS EXPANSION /1	CT1	LEE	CCW	NG	—	WA	—	1 / 2001	---	149	182	P
FPL	CAPE CANAVERAL	2	BREVARD	FS	HO	NG	WA	—	1 / 2001	402,050	0	3	A
FPL	LAUDERDALE	4	BROWARD	CCW	NG	LO	PL	—	1 / 2001	34,228	10	10	A
FPL	LAUDERDALE	5	BROWARD	CCW	NG	LO	PL	—	1 / 2001	34,228	10	10	A
JEA	BRANDY BRANCH PLANT	GT1	DUVAL	CT	NG	LO	PL	TK	1 / 2001	185,000	149	186	P
JEA	BRANDY BRANCH PLANT	GT2	DUVAL	CT	NG	LO	PL	TK	1 / 2001	185,000	149	186	P
TEC	POLK	2	POLK	CT	NG	LO	PL	TK	1 / 2001	---	155	180	P
GRU	J. R. KELLY	CT4	ALACHUA	CCT	NG	LO	PL	TK	2 / 2001	96,140	70	70	L
GRU	J. R. KELLY	FS8	ALACHUA	CCW	WH	--	—	—	2 / 2001	50,000	40	40	RP
LAK	LARSEN	7	POLK	FS	NG	HO	PL	TK	3 / 2001	50,000	(50)	(50)	R
FPC	SUWANNEE RIVER	P2	SUWANNEE	CT	NG	LO	PL	TK	5 / 2001	---	0	0	CA
FPL	FT. MYERS EXPANSION /1		LEE	CCW	NG	---	WA	---	6 / 2001	---	52	180	P
FKE	MARATHON		MONROE	D	LO	HO	TK	TK	6 / 2001	3,500	4	4	P
KUA/FMP	CANE ISLAND	3	OSCEOLA	CC	NG	LO	PL	TK	6 / 2001	250,000	240	250	P
JEA	SOUTHSIDE	4	DUVAL	FS	HO	NG	WA	PL	10 / 2001	75,000	(67)	(67)	R
JEA	SOUTHSIDE	5	DUVAL	FS	HO	NG	WA	PL	10 / 2001	155,600	(142)	(142)	R
SEC	PAYNE CREEK		HARDEE	CC	NG	LO	PL	TK	11 / 2001	587,000	488	572	T
JEA	BRANDY BRANCH PLANT	GT3	DUVAL	CT	NG	LO	PL	TK	12 / 2001	185,000	149	186	P
FPC	CRYSTAL RIVER	1	CITRUS	FS	C	---	WA,RR	---	12 / 2001	440,550	17	17	A
FPC	SUWANNEE RIVER	1	SUWANNEE	FS	HO	NG	TK	PL	12 / 2001	34,500	(33)	(34)	R
FPC	SUWANNEE RIVER	2	SUWANNEE	FS	HO	NG	TK	PL	12 / 2001	37,500	(32)	(33)	R
FPC	SUWANNEE RIVER	3	SUWANNEE	FS	HO	NG	TK	PL	12 / 2001	75,000	(80)	(80)	R
	2002												
FPL	FT. MYERS EXPANSION /1		LEE	CCW	NG	---	WA	---	1 / 2002	---	725	740	A
FPL	FT. MYERS GT's		LEE	CT	LO	---	WA	---	1 / 2002	---	0	30	A
FPL	SANFORD EXPANSION /2	CT1	VOLUSIA	CCW	NG	---	WA	---	1 / 2002	---	149	182	P
KUA	HANSEL	8	OSCEOLA	IC	NG	LO	PL	TK	1 / 2002	3,000	(3)	(3)	R
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

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					FUEL		FUEL TRANSPORATION		COMMERCIAL IN-SERVICE	GENERATOR MAXIMUM NAMEPLATE	NET CAPABILITY (MW)		
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALTERNATE	PRIMARY	ALTERNATE	(MO/YR)	kW	SUMMER	WINTER	STATUS
KUA	HANSEL	18	OSCEOLA	IC	NG	LO	PL	TK	1 / 2002	2,070	(2)	(2)	R
LAK	MCINTOSH	5	POLK	CCW	WH	—	—	—	1 / 2002	120,000	120	120	P
JEA	NORTHSIDE	2	DUVAL	FS	PET	C	RR	RR	4 / 2002	297,500	269	269	RP,CA
JEA	NORTHSIDE	1	DUVAL	FS	PET	C	RR	RR	4 / 2002	297,500	7	7	RP,CA
FPL	SANFORD EXPANSION /2		VOLUSIA	CCW	NG	—	WA	—	6 / 2002	---	53	179	P
LAK	MCINTOSH	ST1	POLK	FS	NG	HO	PL	TK	10 / 2002	103,000	(87)	(87)	R
SEC	UNKNOWN	GT3	UNKNOWN	CT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
SEC	UNKNOWN	GT4	UNKNOWN	CT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
SEC	UNKNOWN	GT5	UNKNOWN	CT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
SEC	UNKNOWN	GT6	UNKNOWN	CT	NG	LO	PL	TK	11 / 2002	180,000	150	150	P
	2003												
FPL	SANFORD EXPANSION /2		VOLUSIA	CCW	NG	—	WA	—	1 / 2003	---	725	740	A
TEC	HOOKERS POINT	1	HILLSBOROUGH	FS	HO	---	WA	---	1 / 2003	33,000	(32)	(34)	R
TEC	HOOKERS POINT	2	HILLSBOROUGH	FS	HO	—	WA	—	1 / 2003	34,500	(32)	(34)	R
TEC	HOOKERS POINT	3	HILLSBOROUGH	FS	HO	--	WA	—	1 / 2003	34,500	(32)	(34)	R
TEC	HOOKERS POINT	4	HILLSBOROUGH	FS	HO	--	WA	--	1 / 2003	49,000	(41)	(43)	R
TEC	HOOKERS POINT	5	HILLSBOROUGH	FS	HO	—	WA	—	1 / 2003	81,600	(67)	(67)	R
TEC	POLK	3	POLK	CT	NG	LO	PL	TK	1 / 2003	---	155	180	P
SEC	UNKNOWN	GT7	UNKNOWN	CT	NG	LO	PL	TK	11 / 2003	180,000	150	150	P
SEC	UNKNOWN	GT8	UNKNOWN	CT	NG	LO	PL	TK	11 / 2003	180,000	150	150	P
FPC	HIGGINS	P1	PINELLAS	CT	LO	NG	TK	PL	12 / 2003	33,790	(29)	(32)	R
FPC	HIGGINS	P2	PINELLAS	CT	LO	NG	TK	PL	12 / 2003	33,790	(29)	(32)	R
FPC	HIGGINS	P3	PINELLAS	CT	LO	NG	TK	PL	12 / 2003	42,925	(35)	(42)	R
FPC	HIGGINS	P4	PINELLAS	CT	LO	NG	TK	PL	12 / 2003	42,925	(35)	(42)	R
FPC	RIO PINAR	P1	ORANGE	CT	LO	—	TK	—	12 / 2003	19,290	(15)	(18)	R
	2004												
TEC	POLK	4	POLK	CT	NG	LO	PL	TK	1 / 2004	---	155	180	P
LAK	MCINTOSH	4	POLK	PB	C	—	RR	—	5 / 2004	238,000	238	238	P
LAK	MCINTOSH	ST2	POLK	FS	NG	HO	PL	TK	7 / 2004	126,000	(113)	(113)	R
FPC	HINES ENERGY COMPLEX	2	POLK	CC	NG	LO	PL	TK	11 / 2004	---	495	567	P
SEC	UNKNOWN	GT9	UNKNOWN	CT	NG	LO	PL	TK	11 / 2004	180,000	150	150	P
FPC	AVON PARK	P1	HIGHLANDS	CT	LO	NG	TK	PL	12 / 2004	33,790	(29)	(32)	R
FPC	AVON PARK	P2	HIGHLANDS	CT	LO	—	TK	—	12 / 2004	33,790	(29)	(32)	R
FPC	TURNER	P1	VOLUSIA	CT	LO	—	TK	—	12 / 2004	19,290	(15)	(18)	R
FPC	TURNER	P2	VOLUSIA	CT	LO	---	TK	---	12 / 2004	19,290	(15)	(18)	R

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FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES, AND REMOVALS
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(1) UTILITY	(2) POWER PLANT NAME	(3) UNIT NO.	(4) LOCATION	(5) UNIT TYPE	(6) FUEL PRIMARY	(7) FUEL ALTERNATE	(8) FUEL TRANSPORATION PRIMARY	(9) FUEL TRANSPORATION ALTERNATE	(10) COMMERCIAL IN-SERVICE (MO/YR)	(11) GENERATOR MAXIMUM NAMEPLATE kW	(12) NET CAPABILITY (MW) SUMMER	(13) NET CAPABILITY (MW) WINTER	(14) STATUS
	2005												
TEC	POLK	5	POLK	CT	NG	LO	PL	TK	1 / 2005	---	155	180	P
JEA	BRANDY BRANCH PLANT	CC	DUVAL	CC	NG	LO	PL	TK	6 / 2005	585,840	149	186	P,A
SEC	UNKNOWN	GT10	UNKNOWN	CT	NG	LO	PL	TK	11 / 2005	180,000	150	150	P
	2006												
FPL	MARTIN	5	MARTIN	CC	NG	LO	PL	---	1 / 2006	---	419	448	P
FPC	HINES ENERGY COMPLEX	3	POLK	CC	NG	LO	PL	TK	11 / 2006	---	495	567	P
SEC	UNKNOWN	GT11	UNKNOWN	CT	NG	LO	PL	TK	11 / 2006	180,000	150	150	P
	2007												
FMP	CANE ISLAND	4	OSCEOLA	CT	NG	LO	PL	TK	1 / 2007	80,000	80	80	P
FPL	MARTIN	6	MARTIN	CC	NG	LO	PL	—	1 / 2007	---	419	448	P
TEC	POLK	6	POLK	CT	NG	LO	PL	TK	1 / 2007	---	155	180	P
JEA	UNSITED CT	CT	UNKNOWN	CT	NG	LO	PL	TK	6 / 2007	195,280	149	186	P
SEC	UNKNOWN	GT12	UNKNOWN	CT	NG	LO	PL	TK	11 / 2007	180,000	150	150	P
	2008												
FPL	UNSITED CC		UNKNOWN	CC	NG	LO	PL	---	1 / 2008	---	419	448	P
TEC	POLK	7	POLK	CT	NG	LO	PL	TK	1 / 2008	---	155	180	P
TAL	PURDOM	GT1	WAKULLA	CT	NG	LO	PL	TK	3 / 2008	15,000	(10)	(10)	R
									FRCC FUTURE TOTAL:		9,658	10,664	

/1 The Ft. Myers Expansion project includes the initial operation of five 149/182 MW CT's as part of the repowering of Ft. Myers 1 & 2 over the course of one year.
/2 The Sanford Expansion project includes the initial operation of five 149/182 MW CT's as part of the repowering of Sanford 3 & 4 over the course of one year.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
						RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT.			RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT.	
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)	(MW)	% OF PEAK	FIRM PEAK DEMAND (MW)	(MW)	% OF PEAK
1999	36,125	1,640	2,076	39,841	36,788	3,053	8%	34,023	5,818	17%
2000	36,518	1,755	2,076	40,349	37,541	2,808	7%	34,703	5,646	16%
2001	38,065	1,682	2,076	41,823	38,223	3,600	9%	35,380	6,443	18%
2002	39,675	1,658	2,055	43,387	38,959	4,428	11%	36,157	7,230	20%
2003	40,864	1,566	2,055	44,484	39,781	4,703	12%	36,988	7,496	20%
2004	41,301	1,566	2,055	44,921	40,593	4,328	11%	37,804	7,117	19%
2005	42,162	1,566	2,045	45,772	41,433	4,339	10%	38,638	7,134	18%
2006	42,731	1,566	1,912	46,208	42,398	3,810	9%	39,597	6,611	17%
2007	44,179	1,566	1,906	47,651	43,252	4,399	10%	40,443	7,208	18%
2008	44,893	1,566	1,891	48,350	44,066	4,284	10%	41,266	7,084	17%

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

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
						RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT.			RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT.	
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)	(MW)	% OF PEAK	FIRM PEAK DEMAND (MW)	(MW)	% OF PEAK
1999 / 00	37,803	1,772	2,129	41,704	39,989	1,715	4%	35,977	5,727	16%
2000 / 01	39,497	1,694	2,129	43,320	40,928	2,392	6%	36,819	6,501	18%
2001 / 02	41,549	1,671	2,129	45,349	41,865	3,484	8%	37,793	7,556	20%
2002 / 03	43,225	1,566	2,108	46,899	42,808	4,091	10%	38,749	8,150	21%
2003 / 04	43,539	1,566	2,108	47,213	43,726	3,487	8%	39,663	7,550	19%
2004 / 05	44,461	1,566	2,098	48,125	44,651	3,474	8%	40,566	7,559	19%
2005 / 06	45,245	1,566	1,965	48,776	45,553	3,223	7%	41,450	7,326	18%
2006 / 07	46,670	1,566	1,959	50,195	46,600	3,595	8%	42,476	7,719	18%
2007 / 08	47,634	1,566	1,944	51,144	47,502	3,642	8%	43,374	7,770	18%
2008 / 09	47,624	1,566	1,944	51,134	48,441	2,693	6%	44,286	6,848	15%

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

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1999 LOAD & RESOURCE PLAN - FRCC REGION

SCHEDULE OF CONTRACTED IMPORTS BY UTILITY - MW

	SUMMER					
	FIRM					
YEAR	[1] FPC	FPL	GRU	JEA	TAL	TOTAL
1999	445	921	32	460	104	1,962
2000	445	921	0	364	25	1,755
2001	445	921	0	291	25	1,682
2002	445	921	0	292	0	1,658
2003	445	921	0	200	0	1,566
2004	445	921	0	200	0	1,566
2005	445	921	0	200	0	1,566
2006	445	921	0	200	0	1,566
2007	445	921	0	200	0	1,566
2008	445	921	0	200	0	1,566

	WINTER					
	FIRM					
YEAR	[1] FPC	FPL	GRU	JEA	TAL	TOTAL
1999/00	445	921	0	302	104	1,772
2000/01	445	921	0	303	25	1,694
2001/02	445	921	0	280	25	1,671
2002/03	445	921	0	200	0	1,566
2003/04	445	921	0	200	0	1,566
2004/05	445	921	0	200	0	1,566
2005/06	445	921	0	200	0	1,566
2006/07	445	921	0	200	0	1,566
2007/08	445	921	0	200	0	1,566
2008/09	445	921	0	200	0	1,566

[1] FPC includes 36 MW from SEPA in their import that is distributed to other companies.

1999 LOAD & RESOURCE PLAN - FRCC REGION

SCHEDULE OF CONTRACTED EXPORTS BY UTILITY - MW

	SUMMER					
	FIRM					
YEAR	FPC	FPL	GRU	JEA	TAL	TOTAL
1999	275	0	47	0	0	322
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0

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	WINTER					
	FIRM					
YEAR	FPC	FPL	GRU	JEA	TAL	TOTAL
1999/00	0	0	0	0	0	0
2000/01	0	0	0	0	0	0
2001/02	0	0	0	0	0	0
2002/03	0	0	0	0	0	0
2003/04	0	0	0	0	0	0
2004/05	0	0	0	0	0	0
2005/06	0	0	0	0	0	0
2006/07	0	0	0	0	0	0
2007/08	0	0	0	0	0	0
2008/09	0	0	0	0	0	0

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EXISTING NON-UTILITY GENERATING FACILITIES AS OF JANUARY 1, 1999

(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)		
		UNIT			FUEL TYPE		COMMERCIAL IN-SERVICE	FIRM		AS-AVAILABLE						
UTIL	FACILITY NAME	NO.	LOCATION	TYPE	PRI	ALT	(MO/YR)	SUM	WIN	SUM	WIN	SUM	WIN	SUM	WIN	STATUS
JEA																
	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
	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	0.6	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					
SEMINOLE ELECTRIC COOPERATIVE, INC.																
	HARDEE POWER STATION /8	1	HARDEE	CC	NG	LO	01/93	221.0	269.0	0.0	0.0	0.0	0.0	224.0	259.0	C
	HARDEE POWER STATION /8	2	HARDEE	GT	NG	LO	01/93	74.0	93.0	0.0	0.0	0.0	0.0	74.0	93.0	C
	TOTAL:							298.0	362.0	0.0	0.0					
TAMPA ELECTRIC COMPANY																
	C. F. INDUSTRIES	1	HILLSBOROUGH	COG	WH	—	12/88	0.0	0.0	0.9	0.9	25.7	25.7	26.6	26.8	NC
	CITY OF TAMPA REFUSE	1	HILLSBOROUGH	SPP	REF	—	06/85	13.8	2.8	0.0	0.0	2.3	0.5	16.1	3.3	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
	CUTRALE CITRUS JUICES USA	1-3	POLK	COG	NG/WH	LO	12/87	0.0	0.0	0.0	0.0	6.9	6.9	6.9	6.9	NC
	FARMLAND HYDRO	1	POLK	COG	WH	—	10/90	0.0	0.0	1.4	1.4	24.4	24.4	25.8	25.8	NC
	HILLS. COUNTY REFUSE	1	HILLSBOROUGH	SPP	REF	—	04/87	26.1	26.1	0.0	0.0	3.1	3.1	29.2	29.2	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	1.4	1.4	34.1	34.1	35.5	35.5	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	21.9	21.9	0.0	0.0	—	—	21.9	21.9	C
	ST. JOSEPH'S HOSPITAL	1	HILLSBOROUGH	COG	NG	—	04/93	0.0	0.0	0.0	0.0	0.7	0.7	0.7	0.7	NC
	TOTAL:							61.8	50.8	3.8	3.8					
							TOTAL FRCC REGION:	2,076.4	2,139.4	97.4	119.4					

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

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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)		
		UNIT			FUEL TYPE		COMMERCIAL IN-SERVICE	FIRM		AS-AVAILABLE				
UTIL	FACILITY NAME	NO.	LOCATION	TYPE	PRI.	ALT.	(MO/YR)	SUM	WIN	SUM	WIN	SUM	WIN	STATUS
	1999													
	2000													
	2001													
	2002													
FPL	ROYSTER CO. - MULBERRY	1	POLK	COG	WH	—	03/02	(9.0)	(9.0)	0.0	0.0	—	—	NC
FPC	TIMBER ENERGY	1	LIBERTY	SPP	BIO	—	04/02	(12.8)	(12.6)	0.0	0.0	0.0	0.0	NC
	2003													
	2004													
	2005													
FPL	BIO-ENERGY PARTNERS	1	BROWARD	SPP	LG	—	01/05	(10.0)	(10.0)	0.0	0.0	—	—	NC
FPL	FLORIDA CRUSHED STONE	1	HERNANDO	COG	C	—	11/05	(133.0)	(133.0)	0.0	0.0	—	—	NC
	2006													
	2007													
FPC	US AGRICHEM	1	POLK	COG	WH	—	01/07	(5.6)	(5.6)	(10.0)	(10.0)	28.5	28.5	NC
	2008													
FPC	CARGILL	2	POLK	COG	WH	NG	01/08	(15.0)	(15.0)	0.0	0.0	0.0	0.0	NC

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1999
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)
1999	2,076.4	97.4	1999/00	2,129.4	119.4
2000	2,076.4	97.4	2000/01	2,129.4	119.4
2001	2,076.4	97.4	2001/02	2,129.4	119.4
2002	2,054.6	97.4	2002/03	2,107.6	119.4
2003	2,054.6	97.4	2003/04	2,107.6	119.4
2004	2,054.6	97.4	2004/05	2,097.6	119.4
2005	2,044.6	97.4	2005/06	1,964.6	119.4
2006	1,911.6	97.4	2006/07	1,959.0	109.4
2007	1,906.0	87.4	2007/08	1,944.0	109.4
2008	1,891.0	87.4	2008/09	1,944.0	109.4

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1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1) PURCHASING UTILITY	(2) SELLING UTILITY	(3) CONTRACT TERM FROM (MO/YR)	(4) CONTRACT TERM TO (MO/YR)	(5) NET CAPABILITY - MW SUMMER	(6) NET CAPABILITY - MW WINTER	(7) DESCRIPTION
ENRON POWER MARKETING						
	OUC	06/96	05/00	18	18	SCHEDULE D
FLORIDA MUNICIPAL POWER AGENCY						
	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	UPS
	LWU	01/98	12/00	15	15	SCHEDULE D
	TEC	12/98	12/99	105	105	SCHEDULE D
	TEC	12/99	03/01	150	150	SCHEDULE D
	LAK	12/00	05/01	50	50	FIRM - SYSTEM POWER PURCHASES
	LAK	06/01	12/01	90	90	FIRM - SYSTEM POWER PURCHASES
	LAK	01/02	09/10	100	100	FIRM - SYSTEM POWER PURCHASES
	GRU	01/99	12/99	10	10	SCHEDULE D
	GRU	10/97	12/03	3	3	SCHEDULE D
	VER	06/97	------	150	155	EXISTING UNIT PURCHASE
	FTP	01/93	------	118	118	EXISTING UNIT PURCHASE
	KEY	04/98	------	50.4	50.4	EXISTING UNIT PURCHASE
	LWU	01/00	------	94	105	EXISTING UNIT PURCHASE
FLORIDA POWER CORPORATION						
	SOU	01/94	06/10	204	204	UPS #1
	SOU	01/95	06/10	205	205	UPS #2
	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	
FLORIDA POWER & LIGHT COMPANY						
	SOU (1)	06/93	05/10	921	921	UNIT POWER SALES
	JEA (2)	03/87	09/21	388	388	UNIT POWER SALES

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1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1) PURCHASING UTILITY	(2) SELLING UTILITY	(3) CONTRACT TERM FROM (MO/YR)	(4) CONTRACT TERM TO (MO/YR)	(5) NET CAPABILITY - MW SUMMER	(6) NET CAPABILITY - MW WINTER	(7) DESCRIPTION
CITY OF FT. MEADE						
	TEC	01/97	12/13	12	13	PARTIAL REQUIREMENTS
GAINESVILLE REGIONAL UTILITIES						
	LPM	03/93	03/99	31	31	SCHEDULE D
	EPP	03/99	01/00	32	32	SCHEDULE D
GEORGIA POWER COMPANY						
	FPC	06/99	09/99	200	0	FIRM
JEA						
	SOU	06/95	05/10	200	200	UNIT POWER SALE - 1988 AGREEMENT
	PEC	06/99	10/99	67	0	FIRM
	ENR	01/99	12/99	88	76	FIRM
	ENR	01/00	12/00	89	77	FIRM
	ENR	01/01	12/01	91	78	FIRM
	ENR	01/02	12/02	92	80	FIRM
	TEA	03/99	02/01	25	25	FIRM
	TEA	05/99	09/99	50	0	FIRM
	TEA	06/99	08/99	30	0	FIRM
	TEA	12/99	03/00	0	250	FIRM
	TEA	06/00	09/00	175	0	FIRM
	TEA	06/08	09/08	50	0	FIRM
UTILITY BOARD OF THE CITY OF KEY WEST						
	FPL	06/93	05/13	45	45	FIRM INTERCHANGE

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1999
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
KISSIMMEE UTILITY AUTHORITY						
	FMP	06/82	ONGOING	7	7	UPS, ST. LUCIE
	FMP	06/96	ONGOING	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 LAKE WORTH UTILITIES						
	FPL	LIFE TIME OF UNIT		17	17	UPS - ST. LUCIE
	OUC	LIFE TIME OF UNIT		10	10	UPS - STANTON #1
MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA						
	FPC	05/99	09/99	75	0	FIRM
UTILITIES COMMISSION OF NEW SMYRNA BEACH						
	FPC	06/92	12/02	24	24	PARTIAL REQUIREMENTS
	FPC	03/96	12/02	6	6	STRATIFIED PEAKING
	TEC	06/92	02/00	14	14	BIG BEND UNIT PURCHASE
	TEC	06/96	09/99	5	0	BIG BEND UNIT PURCHASE
	TEC	03/97	09/99	10	0	SCHEDULE J
	ENR	06/96	05/00	10	25	SCHEDULE OS
	DUK	01/02	12/12	35	40	UNIT PURCHASE
	DUK	01/02	12/12	35	40	UNIT PURCHASE
PECO ENERGY						
	GRU	06/98	09/99	47	0	SCHEDULE D
	OUC	06/96	12/99	100	100	50% STANTON;50% INDIAN RIVER

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

(1) PURCHASING UTILITY	(2) SELLING UTILITY	(3) CONTRACT TERM FROM (MO/YR)	(4) CONTRACT TERM TO (MO/YR)	(5) NET CAPABILITY - MW SUMMER	(6) NET CAPABILITY - MW WINTER	(7) DESCRIPTION
REEDY CREEK IMPROVEMENT DISTRICT						
	OUC	01/99	12/99	12	12	UPS STANTON UNIT #1
	OUC	09/89	RENEWED ANNUALLY	57	57	PARTIAL REQUIREMENTS
	FPC	09/89	RENEWED ANNUALLY	20	20	PARTIAL REQUIREMENTS
	TEC	09/89	RENEWED ANNUALLY	15	15	PARTIAL REQUIREMENTS
	TEC	01/98	12/17	20-30	20-30	PARTIAL REQUIREMENTS
SEMINOLE ELECTRIC COOPERATIVE, INC.						
	TPS	01/93	12/02	145	145	UNIT POWER PURCHASE TEC BIG BEND #4
	JEA	01/95	05/04	54	63	CAPACITY PURCHASES OF CTs
	OUC	01/96	05/04	75	75	UNIT POWER PURCHASE
	OUC	01/97	12/00	50	50	UNIT POWER PURCHASE
	GRU	01/99	02/99	0	75	SEASONAL UNIT POWER PURCHASE
	TAL	01/99	03/99	0	25	SEASONAL UNIT POWER PURCHASE
	MOR	01/99	03/99	0	30	SEASONAL UNIT POWER PURCHASE
	PEC	01/99	03/99	0	20	SEASONAL UNIT POWER PURCHASE
	TEA	01/99	03/99	0	30	SEASONAL UNIT POWER PURCHASE
	FPC	01/99	12/01	300	300	STRUCTURED SYSTEM CAPACITY PURCHASE
	FPC	01/99	12/01	155	155	SYSTEM PEAKING CAPACITY PURCHASE
	FPC	01/99	12/13	150	150	SYSTEM INTERMEDIATE CAPACITY PURCHASE
	UNSPECIFIED	12/99	02/00	0	200	SEASONAL UNIT POWER PURCHASE
	FPC	01/00	12/02	150	150	SYSTEM PEAKING CAPACITY PURCHASE
	UNSPECIFIED	06/00	08/00	90	0	SEASONAL UNIT POWER PURCHASE
	FPC	01/01	12/02	150	150	SYSTEM PEAKING CAPACITY PURCHASE
CITY OF ST. CLOUD						
	TEC	01/99	12/12	15	15	PARTIAL REQUIREMENTS

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LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1) PURCHASING UTILITY	(2) SELLING UTILITY	(3) CONTRACT TERM FROM (MO/YR)	(4) CONTRACT TERM TO (MO/YR)	(5) NET CAPABILITY - MW SUMMER	(6) NET CAPABILITY - MW WINTER	(7) DESCRIPTION
CITY OF TALLAHASSEE						
	ENT	03/96	03/02	25	25	FIRM CAPACITY & ENERGY
	SOU	10/96	05/00	79	79	UPS
TAMPA ELECTRIC COMPANY						
	FPC	01/99	01/00	25 / 50	25 / 50	ON / OFF PEAK SALE
	PEC	03/98	12/99	25 / 55	25 / 55	PURCHASE FOR RESALE
	TPS (3)	01/93	12/12	298	360	HARDEE POWER STATION SALE
TECO POWER SERVICES						
	TEC	01/93	12/02	145	145	BIG BEND UNIT 4 SALE
CITY OF WAUCHULA						
	TEC	01/97	12/13	17	20	PARTIAL REQUIREMENTS

NOTES:

1) 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.

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

3) 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.

1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

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

		ACTUAL											
TYPE		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
INTERCHANGE	GWH	11,739	9,452	14,577	15,056	15,183	13,814	13,825	14,393	14,438	14,594	15,077	15,075
NUCLEAR	GWH	23,426	31,723	30,161	30,490	30,105	30,806	30,503	30,083	30,896	30,072	30,323	30,713
COAL	GWH	68,819	65,324	55,634	66,598	67,139	68,638	70,095	71,116	71,250	71,760	70,653	72,800
OIL - TOT	GWH	24,001	37,398	34,856	32,627	28,955	21,322	15,338	16,932	15,149	14,658	12,200	10,697
STEAM	GWH	23,451	36,266	34,265	32,101	28,416	20,996	15,066	16,586	14,920	14,376	11,942	10,459
CC	GWH	53	92	51	69	63	65	90	96	105	119	125	117
CT	GWH	497	1,040	540	457	476	261	182	250	124	163	132	121
NG - TOT	GWH	33,556	31,576	26,896	31,922	39,848	51,538	61,883	63,524	68,887	75,117	82,505	86,072
STEAM	GWH	13,748	10,831	3,387	4,316	8,914	6.031	6,006	6,159	9,653	13,333	18,551	22,027
CC	GWH	18,316	18,837	21,177	25,172	27,193	42,922	52,950	53,620	55,929	57,861	60,093	59,665
CT	GWH	1,492	1,908	2,332	2,434	3,741	2,585	2,927	3,745	3,305	3,923	3,855	4,380
HYDRO	GWH	29	17	25	25	25	25	25	25	25	25	25	25
NUG	GWH	13,964	12,378	14,225	14,237	14,432	13,917	13,215	13,419	13,449	12,385	12,394	12,263
NEL	GWH	175,534	187,868	186,374	190,955	195,687	200,060	204,884	209,492	214,094	218,511	223,179	227,645

1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

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

TYPE		ACTUAL 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
INTERCHANGE	%	6.7%	5.0%	7.8%	7.9%	7.8%	6.9%	6.7%	6.9%	6.7%	6.7%	6.8%	6.6%
NUCLEAR	%	13.3%	16.9%	16.2%	16.0%	15.4%	15.4%	14.9%	14.4%	14.4%	13.8%	13.6%	13.5%
COAL	%	39.2%	34.8%	35.2%	34.9%	34.3%	34.3%	34.2%	33.9%	33.3%	32.8%	31.7%	32.0%
OIL - TOT	%	13.7%	19.9%	18.7%	17.1%	14.8%	10.7%	7.5%	8.1%	7.1%	6.7%	5.5%	4.7%
STEAM	%	13.4%	19.3%	18.4%	16.8%	14.5%	10.5%	7.4%	7.9%	7.0%	6.6%	5.4%	4.6%
CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
CT	%	0.3%	0.6%	0.3%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
NG - TOT	%	19.1%	16.8%	14.4%	16.7%	20.4%	25.8%	30.2%	30.3%	32.2%	34.4%	37.0%	37.8%
STEAM	%	7.8%	5.8%	1.8%	2.3%	4.6%	3.0%	2.9%	2.9%	4.5%	6.1%	8.3%	9.7%
CC	%	10.4%	10.0%	11.4%	13.2%	13.9%	21.5%	25.8%	25.6%	26.1%	26.5%	26.9%	26.2%
CT	%	0.8%	1.0%	1.3%	1.3%	1.9%	1.3%	1.4%	1.8%	1.5%	1.8%	1.7%	1.9%
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	%	8.0%	6.6%	7.6%	7.5%	7.4%	7.0%	6.5%	6.4%	6.3%	5.7%	5.6%	5.4%
NEL	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

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1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

HISTORY AND FORECAST: FUEL REQUIREMENTS

TYPE		ACTUAL 1997	ACTUAL 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
NUCLEAR	10E12 BTU	246	333	317	320	316	323	320	316	324	316	318	322
COAL	10E3 TON	26,045	28,264	27,969	28,163	28,234	28,625	29,265	29,795	30,078	30,317	29,791	30,790
OIL - TOT	10E3 BBL	39,097	62,524	55,688	52,252	46,922	34,962	25,317	28,313	27,035	26,693	23,131	20,847
STEAM	10E3 BBL	36,817	58,854	53,198	49,860	44,264	32,862	23,400	26,049	23,223	22,400	18,695	16,415
CC	10E3 BBL	338	380	321	368	359	362	404	412	1,928	2,875	2,945	2,907
CT	10E3 BBL	1,942	3,290	2,169	2,024	2,299	1,738	1,513	1,852	1,884	1,418	1,491	1,525
NG - TOT	10E6 CF	291,086	274,808	232,481	274,734	353,371	412,664	473,142	490,119	513,550	556,158	607,221	631,904
STEAM	10E6 CF	136,390	104,549	39,649	51,585	98,437	67,779	66,564	68,205	87,263	117,169	155,502	177,872
CC	10E6 CF	135,278	143,430	161,090	191,903	208,146	314,126	373,919	380,005	392,714	398,842	414,467	411,447
CT	10E6 CF	19,418	26,829	31,742	31,246	46,788	30,759	32,659	41,909	33,573	40,147	37,252	42,585

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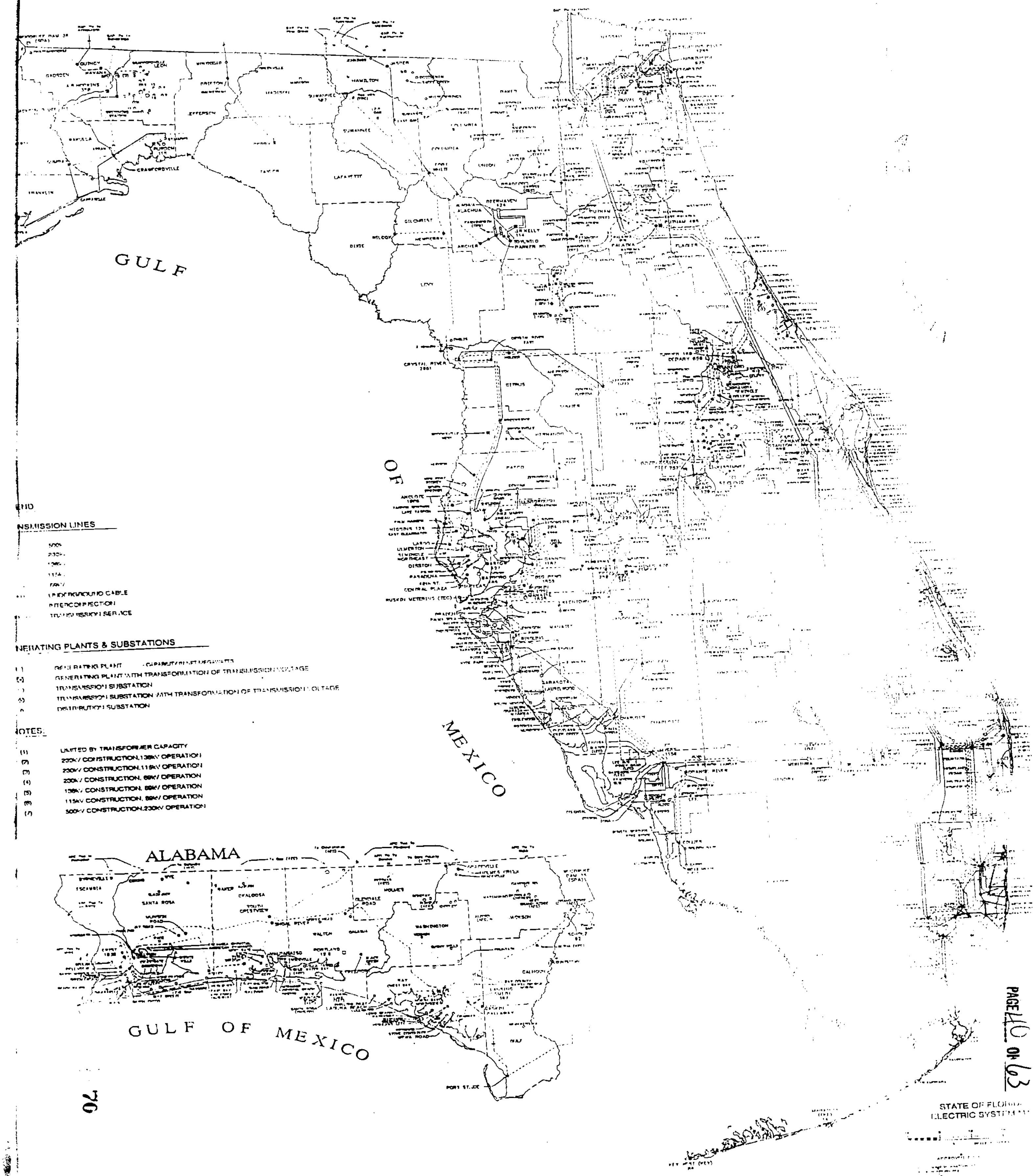
GULF OF MEXICO
ALABAMA
GULF OF MEXICO
TRANSMISSION LINES
UNDERGROUND CABLE
INTERCONNECTION
GENERATING PLANTS & SUBSTATIONS
GENERATING PLANT
GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION
TRANSMISSION SUBSTATION WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
DISTRIBUTION SUBSTATION
NOTES:
(1) LIMITED BY TRANSFORMER CAPACITY
(2) 230KV CONSTRUCTION, 138KV OPERATION
(3) 230KV CONSTRUCTION, 115KV OPERATION
(4) 230KV CONSTRUCTION, 69KV OPERATION
(5) 138KV CONSTRUCTION, 69KV OPERATION
(6) 115KV CONSTRUCTION, 69KV OPERATION
(7) 500KV CONSTRUCTION, 230KV OPERATION
CRYSTAL RIVER
ALACHUA
ANCLOTE
PORT ST. JOE
STATE OF FLORIDA
ELECTRIC SYSTEM

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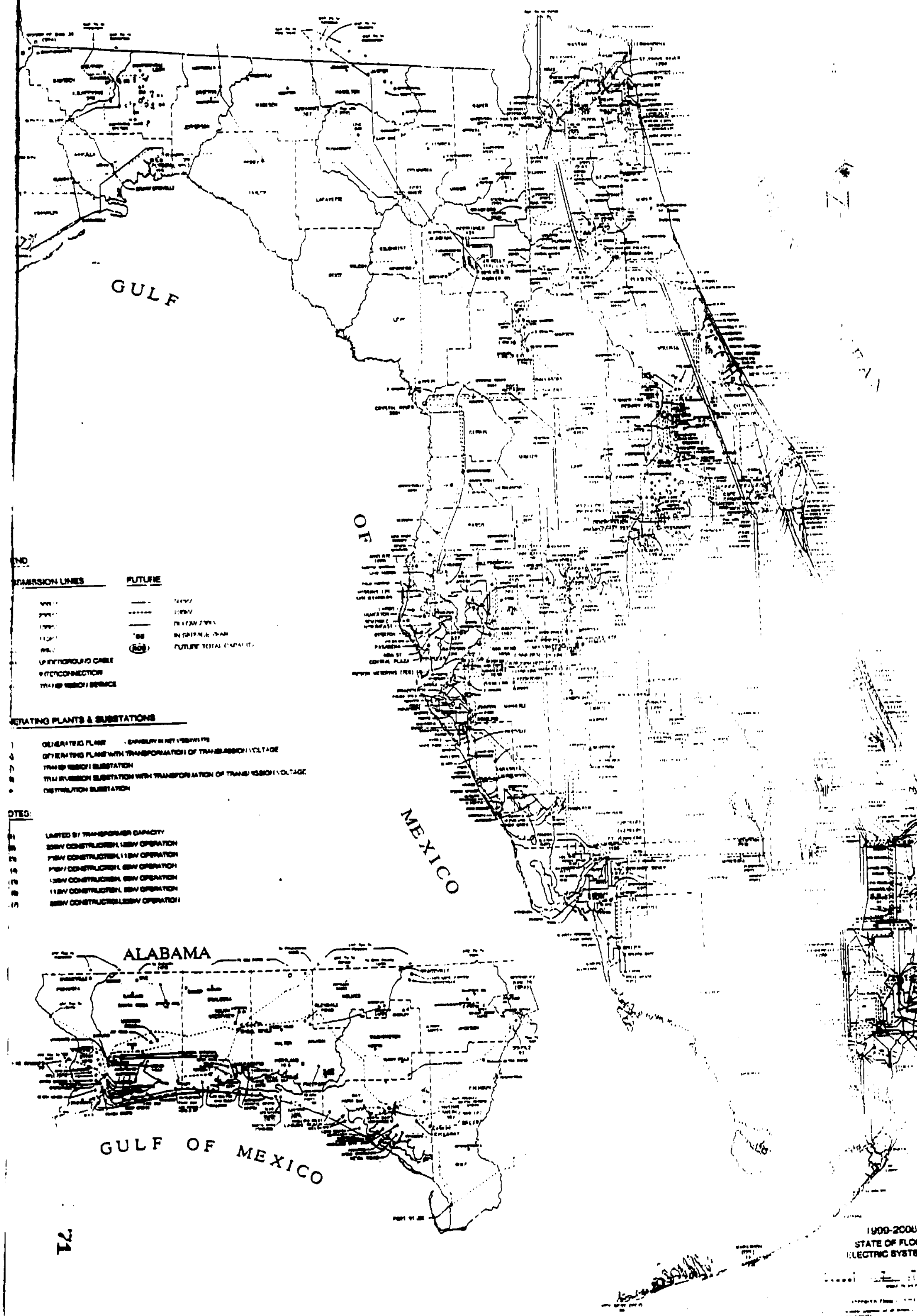

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1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

PROPOSED TRANSMISSION LINES
1999-2008

(1) LINE OWNERSHIP LIST	(2) TERMINALS		(3) LINE LENGTH CKT. MILES	(4) COMMERCIAL IN-SERVICE DATE(YR/MO)		(5) NOMINAL VOLTAGE IN kV OPER.	DESIGN
FPL	BROWARD	YAMATO	3	1999	6	230	230
FPL / OUC	CAPE	INDIAN RIVER	2	1999	6	230	230
FPL	GREYNOLDS	LAUDANIA	3	1999	6	230	230
FPL	ANDYTOWN	PENNSUCO	9	1999	8	230	230
FPL	DADE	LEVEE	3	1999	11	230	230
FPL	COLLIER	ORANGE RIVER	36	1999	12	230	230
FPL	BROWARD	RANCH	5	2000	6	230	230
FPL	FLAGAMI	TURKEY POINT	2	2000	6	230	230
FPL	SANFORD	VOLUSIA	6	2000	6	230	230
OUC	STANTON	CURRY FORD	6	2000	6	230	230
FPC	LAKE BRYAN	INTERCESSION CITY	10	2000	10	230	230
FPL	CALUSA	FT. MYERS	2	2000	10	230	230
JEA	DUVAL	BRANDY RANCH CKT 1	2	2001	1	230	230
JEA	BRANDY RANCH	NORMANDY CKT 1	10	2001	1	230	230
JEA	DUVAL	BRANDY RANCH CKT 2	2	2001	1	230	230
JEA	BRANDY RANCH	NORMANDY CKT 1	10	2001	1	230	230
FPL	FT. MYERS	ORANGE RIVER	3	2001	5	230	230
FMP / KUA	CANE ISLAND (FMPA/KUA)	INTERCESSION CITY (FPC)	3	2001	6	230	230
FPL	BROWARD	CORBETT	2	2001	6	230	230
FPL	GRYENOLDS	LAUDANIA	7	2001	6	230	230
LAK	EATON PARK	CREWS LAKE	10	2001	6	230	230
TEC	BARCOLA	PEBBLEDALE	3	2001	6	230	230
JEA	CENTER PARK	FORREST	5	2001	11	230	230
JEA	FORREST	GREENLAND	8	2001	11	230	230

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1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

PROPOSED TRANSMISSION LINES
1999-2008

(1) LINE OWNERSHIP LIST	(2) TERMINALS		(3) LINE LENGTH CKT. MILES	(4) COMMERCIAL IN-SERVICE DATE(YR/MO)		(5) NOMINAL VOLTAGE IN kV OPER.	DESIGN
JEA	CENTER PARK	NORTHSIDE	11	2001	11	230	230
FPL	POINSETT	SANFORD	45	2002	6	230	230
FPL	POINSETT	SANFORD	45	2002	6	230	230
FPC	TAYLOR CREEK	HOLOPAW	1	2002	11	230	230
FPL	BROWARD	CORBETT	11	2003	6	230	230
TEC	POLK	LITHIA	28	2003	6	230	230
TEC	LITHIA	WHEELER	11	2003	6	230	230
FPC	LAKE BRYAN	WINDERMERE	10	2003	12	230	230
FPC	BARCOLA #2	HINES ENERGY COMPLEX	3	2004	5	230	230
FPL	YULEE	ONEIL	7	2004	6	230	230
TEC	POLK	LITHIA	28	2004	6	230	230
TEC	DAVIS	DALE MABRY	13	2004	6	230	230
JEA	CENTER PARK	S. KERNAN	6	2004	11	230	230
JEA	S. KERNAN	GREENLAND	6	2004	11	230	230
FPC	CENTRAL FLORIDA	SILVER SPRINGS	3	2005	5	230	230
TEC	WHEELER	DAVIS	12	2005	6	230	230
FPC	WEST LAKE WALES	HINES ENERGY COMPLEX	21	2006	5	230	230
FPL	CONSERVATION	LEVEE	36	2007	6	500	500
TEC	LITHIA	DAVIS	23	2008	6	230	230

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1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

ABBREVIATIONS

ELECTRIC MARKET PARTICIPANTS

DUK - Duke Energy
ENR - Enron Power Marketing
ENT - Entergy Power Marketing Corp.
EPP - El Paso Power Sales
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 - JEA
KEY - Key West, City of
KUA - Kissimmee Utility Authority
LAK - Lakeland, City of
LPM - LGEC Power Markrting
LWU - Lake Worth Utilities, City of
MOR - Morgan Stanley Capital Group
NOR - NorAm Energy Services, Inc.
NSB - Utilities Commission of New Smyrna Beach
OEU - Ocala Electric Utility
OPC - Oglethorpe Power Corporation
OUC - Orlando Utilities Commission
PEC - PECO Energy Company
RCI - Reedy Creek Improvement District
STC - St. Cloud, City of
SEC - Seminole Electric Cooperative, Inc.
SEPA - Southeastern Power Administration
SOU - Southern Company
TAL - Tallahassee, City of
TEA - The Energy Authority
TEC - Tampa Electric Company
TPS - TECO Power Services
VER - Vero Beach, City of
WAU - Wauchula, City of

OTHER

FRCC - 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)

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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
W	--	Construction complete; but not in commercial operation

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

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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

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1999
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

1999
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
- July 1 through September 30 of each year being studied.

WINTER
- January through March 31.

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

STATE OF FLORIDA SUPPLEMENT

TO THE

1999

FLORIDA RELIABILITY COORDINATING COUNCIL

LOAD & RESOURCE PLAN

1999
STATE OF FLORIDA
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 (%)
1989	28,488				1989 / 90	31,224				1989	150,119	60.15%
1990	29,232				1990 / 91	26,869				1990	151,945	55.55%
1991	29,619				1991 / 92	30,107				1991	156,352	60.26%
1992	30,983				1992 / 93	28,986				1992	157,460	58.02%
1993	31,662				1993 / 94	30,158				1993	163,304	58.47%
1994	31,343				1994 / 95	34,581				1994	169,291	61.66%
1995	34,112				1995 / 96	36,964				1995	179,512	59.26%
1996	34,551				1996 / 97	36,930				1996	184,142	56.87%
1997	35,254				1997 / 98	32,896				1997	186,603	57.68%
1998	38,526				1998 / 99	38,281				1998	199,550	59.13%

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 (%)
1999	39,303	1,254	1,540	36,509	1999 / 00	42,448	1,201	2,839	38,408	1999	198,332	59.14%
2000	40,102	1,276	1,591	37,235	2000 / 01	43,418	1,212	2,925	39,281	2000	203,356	60.44%
2001	40,823	1,294	1,578	37,951	2001 / 02	44,381	1,206	2,894	40,281	2001	208,361	60.55%
2002	41,601	1,294	1,537	38,770	2002 / 03	45,340	1,221	2,866	41,253	2002	212,987	60.36%
2003	42,449	1,313	1,509	39,627	2003 / 04	46,283	1,228	2,863	42,192	2003	218,048	60.34%
2004	43,301	1,325	1,493	40,483	2004 / 05	47,244	1,243	2,870	43,131	2004	222,893	60.31%
2005	44,190	1,346	1,478	41,366	2005 / 06	48,179	1,254	2,877	44,048	2005	227,748	60.28%
2006	45,202	1,363	1,467	42,372	2006 / 07	49,268	1,267	2,885	45,116	2006	232,513	60.26%
2007	46,109	1,381	1,457	43,271	2007 / 08	50,205	1,257	2,895	46,053	2007	237,339	60.05%
2008	46,971	1,373	1,452	44,146	2008 / 09	51,193	1,272	2,907	47,014	2008	242,046	60.00%

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

STATE OF FLORIDA
HISTORY AND FORECAST
ENERGY USE BY CUSTOMER TYPE - GWH
AS OF JANUARY 1, 1999

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		RURAL & RESIDENTIAL			COMMERCIAL			INDUSTRIAL			STREET & HIGHWAY LIGHTING	OTHER SALES	TOTAL SALES	RESALE	UTILITY USE & LOSSES	NEL
	YEAR	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	GWH	GWH	GWH	GWH	GWH
	1989	65,557	5,441,850	12,047	45,407	651,510	69,695	18,727	26,910	695,918	516	4,298	134,505	0	15,614	150,119
	1990	68,382	5,609,865	12,190	47,037	667,756	70,440	18,853	26,312	716,525	525	4,406	139,204	0	12,741	151,945
	1991	70,242	5,744,175	12,223	48,069	679,952	70,695	18,768	25,280	742,384	554	4,604	142,237	0	14,115	156,352
	1992	70,605	5,849,400	12,070	48,257	696,651	69,270	18,825	24,952	754,455	566	4,696	142,951	0	14,509	157,460
	1993	74,201	5,981,279	12,405	50,514	714,627	70,665	18,554	25,230	735,387	551	4,853	148,672	0	14,632	163,304
	1994	77,879	6,111,386	12,743	53,003	731,614	72,447	18,672	26,244	719,104	579	4,993	155,327	0	13,964	169,291
	1995	82,681	6,239,291	13,252	54,808	746,928	73,378	19,482	25,936	751,163	602	5,257	162,830	0	16,682	179,512
	1996	85,207	6,354,461	13,409	55,895	762,752	73,280	20,146	25,804	780,763	617	5,432	167,297	0	16,845	184,142
	1997	84,847	6,482,244	13,089	58,541	781,160	74,941	20,610	26,213	786,241	638	5,718	170,353	0	16,250	186,603
	1998	92,637	6,613,532	14,007	62,164	801,200	77,589	21,393	27,257	784,871	632	4,603	181,430	0	18,120	199,550
89-1998	% AAGR	3.92%	2.19%	1.69%	3.55%	2.32%	1.20%	1.49%	0.14%	1.35%	2.27%	0.77%	3.38%	0.00%	1.67%	3.21%
	1999	91,342	6,745,418	13,541	61,773	818,984	75,427	21,197	27,263	776,919	657	4,665	179,635	0	18,697	198,332
	2000	93,833	6,879,482	13,639	63,593	836,676	76,007	21,669	27,481	788,487	676	4,789	184,559	0	18,797	203,356
	2001	96,173	7,011,817	13,716	65,387	854,239	75,545	21,970	27,725	792,438	696	4,919	189,146	0	19,215	208,361
	2002	98,572	7,141,233	13,803	67,127	871,276	77,044	22,223	27,978	794,292	716	5,045	193,682	0	19,305	212,987
	2003	100,991	7,268,278	13,895	68,797	888,071	77,458	22,595	28,109	803,840	737	5,169	198,290	0	19,758	218,048
	2004	103,394	7,393,552	13,984	70,472	904,522	77,911	22,909	28,225	811,670	758	5,305	202,838	0	20,055	222,893
	2005	105,792	7,516,441	14,075	72,099	920,692	78,309	23,280	28,355	820,989	779	5,438	207,387	0	20,361	227,748
	2006	108,194	7,638,606	14,164	73,717	936,673	78,701	23,641	28,457	830,774	802	5,564	211,918	0	20,595	232,513
	2007	110,541	7,760,904	14,243	75,355	952,715	79,095	24,024	28,653	838,447	823	5,692	216,436	0	20,903	237,339
	2008	112,963	7,683,552	14,329	77,014	968,763	79,497	24,208	28,854	839,006	848	5,823	220,856	0	21,190	242,046
99-2008	% AAGR	2.39%	1.75%	0.63%	2.48%	1.88%	0.59%	1.49%	0.62%	0.86%	2.67%	2.49%	2.32%	0.00%	1.40%	2.24%

SUMMARY OF LOAD MANAGEMENT / INTERRUPTIBLE LOAD - MW
(SUMMER)

YEAR	GPC		FRCC TOTALS LM	FRCC TOTALS INT	STATE TOTALS LM	STATE TOTALS INT	STATE TOTAL LM + INT
1999	0	29	1,540	1,225	1,540	1,254	2,794
2000	0	29	1,591	1,247	1,591	1,276	2,867
2001	0	29	1,578	1,265	1,578	1,294	2,872
2002	0	29	1,537	1,265	1,537	1,294	2,831
2003	0	29	1,509	1,284	1,509	1,313	2,822
2004	0	29	1,493	1,296	1,493	1,325	2,818
2005	0	29	1,478	1,317	1,478	1,346	2,824
2006	0	29	1,467	1,334	1,467	1,363	2,830
2007	0	29	1,457	1,352	1,457	1,381	2,838
2008	0	25	1,452	1,348	1,452	1,373	2,825

SUMMARY OF LOAD MANAGEMENT / INTERRUPTIBLE LOAD - MW
(WINTER)

YEAR	GPC		FRCC TOTALS LM	FRCC TOTALS INT	STATE TOTALS LM	STATE TOTALS INT	STATE TOTAL LM + INT
1999 / 00	0	28	2,839	1,173	2,839	1,201	4,040
2000 / 01	0	28	2,925	1,184	2,925	1,212	4,137
2001 / 02	0	28	2,894	1,178	2,894	1,206	4,100
2002 / 03	0	28	2,865	1,193	2,866	1,221	4,087
2003 / 04	0	28	2,863	1,200	2,863	1,228	4,091
2004 / 05	0	28	2,870	1,215	2,870	1,243	4,113
2005 / 06	0	28	2,877	1,226	2,877	1,254	4,131
2006 / 07	0	28	2,885	1,239	2,885	1,267	4,152
2007 / 08	0	24	2,895	1,233	2,895	1,257	4,152
2008 / 09	0	24	2,907	1,248	2,907	1,272	4,179

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1999
STATE OF FLORIDA
SUMMARY OF EXISTING CAPACITY
AS OF JANUARY 1, 1999

UTILITY	NET CAPABILITY - MW	
	SUMMER	WINTER
ALABAMA ELECTRIC COOPERATIVE, INC.	1,044	1,085
GULF POWER COMPANY	2,232	2,240
TOTALS:		
FRCC REGION:	35,165	36,880
STATE OF FLORIDA:	38,441	40,205
FRCC NON-UTILITY GENERATING FACILITIES:	2,076	2,129
TOTAL STATE NON-UTILITY GENERATING FACILITIES:	2,095	2,148
TOTAL FRCC REGION:	**37,241**	**39,009**
TOTAL STATE OF FLORIDA:	**40,536**	**42,353**

1999
STATE OF FLORIDA
EXISTING GENERATING FACILITIES AS OF JANUARY 1, 1999

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)		(11)	(12)	(13)	(14)
					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
ALABAMA ELECTRIC COOPERATIVE, INC.																
GANTT		3	ALABAMA	HY	WAT	—	—	—		1926	—	—	1,200	1	1	
GANTT		4	ALABAMA	HY	WAT	—	—	—	2	1985	—	—	1,800	2	2	
POINT "A"		1	ALABAMA	HY	WAT	—	—	—		1925	—	—	1,600	2	2	
POINT "A"		2	ALABAMA	HY	WAT	—	—	—		1925	—	—	1,600	2	2	
POINT "A"		3	ALABAMA	HY	WAT	—	—	—		1949	—	—	2,000	2	2	
CHARLES R. LOWMAN		1	ALABAMA	FS	C	WA	—	—	6	1969	—	—	66,000	71	78	
CHARLES R. LOWMAN		2	ALABAMA	FS	C	WA	—	—	6	1978	—	—	236,000	232	235	
CHARLES R. LOWMAN		3	ALABAMA	FS	C	WA	—	—	6	1980	—	—	236,000	238	240	
MCWILLIAMS		1	ALABAMA	CCW	WH	—	—	—	12	1954	—	—	7,500	10	10	
MCWILLIAMS		2	ALABAMA	CCW	WH	—	—	—	12	1954	—	—	7,500	10	10	
MCWILLIAMS		3	ALABAMA	CCW	WH	—	—	—	8	1959	—	—	25,000	23	23	
MCWILLIAMS		4	ALABAMA	CCT	NG	PL	—	—	12	1996	—	—	107,000	102	117	
PORTLAND		1	WALTON, FL	GT	LO	TK	—	—	3	1964	—	—	11000	11	11	
MCINTOSH		2	ALABAMA	GT	NG	PL	LO	TK	6	1998	—	—	113,000	113	120	
MCINTOSH		3	ALABAMA	GT	NG	PL	LO	TK	6	1998	—	—	113,000	113	120	
JAMES H. MILLER, JR. (686/686)		1	ALABAMA	FS	C	WA	—	—	6	1992	—	—	—	55	56	
JAMES H. MILLER, JR. (686/686)		2	ALABAMA	FS	C	WA	—	—	6	1992	—	—	—	56	56	
TOTAL:														1,044	1,085	
GULF POWER COMPANY																
CRIST		1	ESCAMBIA	FS	NG	PL	HO	TK	1	1945	12	2011	28,125	24	24	
CRIST		2	ESCAMBIA	FS	NG	PL	HO	TK	6	1949	12	2011	28,125	24	24	
CRIST		3	ESCAMBIA	FS	NG	PL	HO	TK	9	1952	12	2011	37,500	35	35	
CRIST		4	ESCAMBIA	FS	C	WA	NG	PL	7	1959	12	2014	93,750	73	79	
CRIST		5	ESCAMBIA	FS	C	WA	NG	PL	6	1961	12	2016	93,750	60	80	
CRIST		6	ESCAMBIA	FS	C	WA	NG	PL	5	1970	12	2015	369,750	302	302	
CRIST		7	ESCAMBIA	FS	C	WA	NG	PL	8	1973	12	2018	578,000	495	495	
SCHOLZ		1	JACKSON	FS	C	RR/WA	—	—	3	1953	12	2011	49,000	46	46	
SCHOLZ		2	JACKSON	FS	C	RR/WA	—	—	10	1953	12	2011	49,000	46	46	
LANSING SMITH		1	BAY	FS	C	WA	—	—	6	1965	12	2015	149,600	162	162	
LANSING SMITH		2	BAY	FS	C	WA	—	—	6	1967	12	2017	190,400	192	192	
LANSING SMITH		A	BAY	GT	LO	TK	—	—	5	1971	12	2006	41,850	32	40	
DANIEL		1	JACKSON, MS	FS	C	RR	HO	TK	9	1977	12	2027	274,125	239	239	
DANIEL		2	JACKSON, MS	FS	C	RR	HO	TK	6	1981	12	2031	274,125	239	239	
SCHERER		3	MONROE, GA	FS	C	RR	—	—	1	1987	12	2042	222,750	223	223	
PEA RIDGE		1	SANTA ROSA	GT	NG	PL	—	—	5	1998	—	—	4,750	5	5	
PEA RIDGE		2	SANTA ROSA	GT	NG	PL	—	—	5	1998	—	—	4,750	5	5	
PEA RIDGE		3	SANTA ROSA	GT	NG	PL	—	—	5	1998	—	—	4,750	5	5	
TOTAL:														2,232	2,240	
												FRCC TOTAL:		35,165	36,880	
												STATE TOTAL:		38,441	40,205	

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1999
STATE OF FLORIDA

FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES, AND REMOVALS
(JANUARY 1,1999 THROUGH DECEMBER 31, 2008)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					FUEL		FUEL TRANSPORTATION		COMMERCIAL	GENERATOR MAXIMUM	NET CAPABILITY (MW)		
UTILITY	POWER PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALTERNATE	PRIMARY	ALTERNATE	IN-SERVICE (MO/YR)	NAMEPLATE kW	SUMMER	WINTER	STATUS
	1999												
	2000												
	2001												
	2002												
AEC	FUTURE CC	1	UNKNOWN	CC	NG	—	PL	—	1 / 2002	235,000	235	260	P
GPC	LANSING SMITH	3	BAY	CC	NG	—	PL	—	6 / 2002	—	540	540	L
	2003												
AEC	FUTURE CC	2	UNKNOWN	CC	NG	—	PL	—	6 / 2003	235,000	235	260	P
	2004												
	2005												
	2006												
AEC	FUTURE CC	3	UNKNOWN	CC	NG	—	PL	—	1 / 2006	235,000	235	260	P
GPC	LANSING SMITH	A	BAY	GT	LO	—	TK	—	12 / 2006	41,850	(32)	(40)	
	2007												
GPC	CRIST	1,2,3	ESCAMBIA	CC	NG	—	PL	—	6 / 2007	—	180	180	RP
	2008												

FRCC FUTURE TOTAL:	9,658	10,664
STATE FUTURE TOTAL:	11,051	12,124

1999
STATE OF FLORIDA
SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF SUMMER PEAK

(1) YEAR	(2) INSTALLED CAPACITY (MW)	(3) CAPACITY IMPORT PEN FL (MW)	(4) CAPACITY IMPORT GPC&AEC (MW)	(5) CONTRACTED FIRM NET TO GRID FROM NUG (MW)	(6) TOTAL AVAILABLE CAPACITY (MW)	(7) TOTAL PEAK DEMAND (MW)	(8) RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT. (MW)	(9) RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT. % OF PEAK	(10) FIRM PEAK DEMAND (MW)	(11) RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT. (MW)	(12) RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT. % OF PEAK
1999	39,401	1,640	(16)	2,095	43,120	39,303	3,817	10%	36,509	6,611	18%
2000	39,794	1,755	(71)	2,095	43,573	40,102	3,471	9%	37,235	6,338	17%
2001	41,341	1,682	(71)	2,095	45,047	40,823	4,224	10%	37,951	7,096	19%
2002	43,726	1,658	(214)	2,074	47,243	41,601	5,642	14%	38,770	8,473	22%
2003	45,150	1,566	(214)	2,074	48,575	42,449	6,126	14%	39,627	8,948	23%
2004	45,587	1,566	(214)	2,074	49,012	43,301	5,711	13%	40,483	8,529	21%
2005	46,448	1,566	(214)	2,064	49,863	44,190	5,673	13%	41,366	8,497	21%
2006	47,252	1,566	(214)	1,931	50,534	45,202	5,332	12%	42,372	8,162	19%
2007	48,848	1,566	(214)	1,925	52,125	46,109	6,016	13%	43,271	8,854	20%
2008	49,562	1,566	(214)	1,910	52,824	46,971	5,853	12%	44,146	8,678	20%

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

(1) YEAR	(2) INSTALLED CAPACITY (MW)	(3) CAPACITY IMPORT PEN FL (MW)	(4) CAPACITY IMPORT GPC&AEC (MW)	(5) CONTRACTED FIRM NET TO GRID FROM NUG (MW)	(6) TOTAL AVAILABLE CAPACITY (MW)	(7) TOTAL PEAK DEMAND (MW)	(8) RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT. (MW)	(9) RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT. % OF PEAK	(10) FIRM PEAK DEMAND (MW)	(11) RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT. (MW)	(12) RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT. % OF PEAK
1999 / 00	41,128	1,772	(36)	2,148	45,012	42,448	2,564	6%	38,408	6,604	17%
2000 / 01	42,822	1,694	(71)	2,148	46,593	43,418	3,175	7%	39,281	7,312	19%
2001 / 02	45,134	1,671	(71)	2,148	48,862	44,361	4,501	10%	40,281	8,601	21%
2002 / 03	47,350	1,566	(214)	2,127	50,829	45,340	5,489	12%	41,253	9,576	23%
2003 / 04	47,924	1,566	(214)	2,127	51,403	46,283	5,120	11%	42,192	9,211	22%
2004 / 05	48,846	1,566	(214)	2,117	52,315	47,244	5,071	11%	43,131	9,184	21%
2005 / 06	49,890	1,566	(214)	1,934	53,226	48,179	5,047	10%	44,048	9,178	21%
2006 / 07	51,275	1,566	(214)	1,978	54,605	49,268	5,337	11%	45,116	9,489	21%
2007 / 08	52,419	1,566	(214)	1,963	55,734	50,205	5,529	11%	46,053	9,681	21%
2008 / 09	52,409	1,566	(214)	1,963	55,724	51,193	4,531	9%	47,014	8,710	19%

COLUMN 10:"FIRM PEAK DEMAND" = TOTAL PEAK DEMAND - INTERRUPTIBLE LOAD - LOAD MANAGEMENT.
ONLY 10 MW OF AEC's GENERATION IS LOCATED IN THE STATE OF FLORIDA.

1999
STATE OF FLORIDA
NET TO GRID FROM NON-UTILITY GENERATING FACILITIES

	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)
1999	2,095.4	127.4	1999/00	2,148.4	149.4
2000	2,095.4	127.4	2000/01	2,148.4	149.4
2001	2,095.4	127.4	2001/02	2,148.4	149.4
2002	2,073.6	127.4	2002/03	2,126.6	149.4
2003	2,073.6	127.4	2003/04	2,126.6	149.4
2004	2,073.6	127.4	2004/05	2,116.6	149.4
2005	2,063.6	127.4	2005/06	1,983.6	149.4
2006	1,930.6	127.4	2006/07	1,978.0	139.4
2007	1,925.0	117.4	2007/08	1,963.0	139.4
2008	1,910.0	117.4	2008/09	1,963.0	139.4

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1999
STATE OF FLORIDA

EXISTING NON-UTILITY GENERATING FACILITIES AS OF JANUARY 1, 1999

(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)		
		UNIT			FUEL TYPE		COMMERCIAL IN-SERVICE	FIRM		AS-AVAILABLE						
UTIL	FACILITY NAME	NO.	LOCATION	TYPE	PRI	ALT	(MO/YR)	SUM	WIN	SUM	WIN	SUM	WIN	SUM	WIN	STATUS
GULF POWER COMPANY																
	BAY RES. MANAGEMENT FACILITY	1	BAY	SPP	REF	—	2/87	0.0	0.0	11.0	11.0	0.0	0.0	12.5	12.5	NC
	CHAMPION	1	ESCAMBIA	COG	WD/COL	NG	5/83	0.0	0.0	0.0	0.0	37.4	37.4	37.4	37.4	NC
	CHAMPION	2	ESCAMBIA	COG	WD/COL	NG	5/83	0.0	0.0	0.0	0.0	40.8	40.8	40.8	40.8	NC
	MONSANTO	1	ESCAMBIA	COG	NG	LO	1954	0.0	0.0	0.0	0.0	4.0	4.0	5.0	5.0	NC
	MONSANTO	2	ESCAMBIA	COG	NG	LO	1954	0.0	0.0	0.0	0.0	4.0	4.0	5.0	5.0	NC
	MONSANTO	3	ESCAMBIA	COG	NG	LO	1954	0.0	0.0	0.0	0.0	4.0	4.0	6.0	6.0	NC
	MONSANTO /1	4	ESCAMBIA	COG/SPP	NG	—	9/93	19.0	19.0	19.0	19.0	63.0	63.0	86.0	86.0	C
	PENSACOLA CHRISTIAN COLLEGE	1	ESCAMBIA	COG	NG	—	4/88	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	NC
	PENSACOLA CHRISTIAN COLLEGE	2	ESCAMBIA	COG	NG	—	4/88	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	NC
	PENSACOLA CHRISTIAN COLLEGE	3	ESCAMBIA	COG	NG	—	4/88	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	NC
	STONE CONTAINER	1	BAY	COG	WD/HO/LO	NG/COL	1960	0.0	0.0	0.0	0.0	4.0	4.0	4.0	4.0	NC
	STONE CONTAINER	2	BAY	COG	WD/HO/LO	NG/COL	1960	0.0	0.0	0.0	0.0	5.0	5.0	5.0	5.0	NC
	STONE CONTAINER	3	BAY	COG	WD/HO/LO	NG/COL	1960	0.0	0.0	0.0	0.0	10.0	10.0	10.0	10.0	NC
	STONE CONTAINER	4	BAY	COG	WD/HO/LO	NG/COL	1960	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	NC
	TOTAL:							19.0	19.0	30.0	30.0					
	FRCC REGION TOTAL:							2076.4	2129.4	97.4	119.4					
	STATE TOTAL:							2095.4	2148.4	127.4	149.4					

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NOTES:

/1 FIRM CONTRACT CAPACITY TERM - 6/1/96-5/31/05

1999
STATE OF FLORIDA
SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		CONTRACT TERM				
PURCHASING UTILITY	SELLING UTILITY	FROM (MO/YR)	TO (MO/YR)	NET CAPABILITY - MW SUMMER	WINTER	DESCRIPTION
ALABAMA ELECTRIC COOPERATIVE, INC.						
	DUK	01/99	12/99	80	80	SCHEDULE D
	DUK	01/00	12/01	100	100	SCHEDULE D
	ENR	01/99	12/99	50	50	SCHEDULE D
	ENR	01/00	12/00	0	50	SCHEDULE D
	ENR	01/01	12/01	100	50	SCHEDULE D
	OPC	06/98	12/05	100	100	SCHEDULE D
	ENT	06/98	12/99	50	100	SCHEDULE D
	ENT	01/00	05/03	70	140	SCHEDULE D
	NOR	01/00	12/00	60	65	SCHEDULE D
	NOR	01/01	12/01	58	63	SCHEDULE D
	NOR	01/02	12/02	56	61	SCHEDULE D
	TEA	01/99	12/00	38	38	SCHEDULE D

1999
STATE OF FLORIDA
PROPOSED TRANSMISSION LINES
1999-2008

(1) LINE OWNERSHIP LIST	(2) TERMINALS		(3) LINE LENGTH CKT. MILES	(4) COMMERCIAL IN-SERVICE DATE(YR/MO)		(5) NOMINAL VOLTAGE IN kV	
						OPER.	DESIGN
GPC	BRENTWOOD	SILVERHILL	14	2000	5	230	230

1999
STATE OF FLORIDA
HISTORY AND FORECAST: INTERCHANGE AND GENERATION BY FUEL TYPE - GWH

TYPE		ACTUAL 1997	ACTUAL 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
INTERCHANGE	GWH	8,817	5,667	9,639	11,239	12,014	11,580	12,472	13,900	13,600	14,074	14,598	14,326
NUCLEAR	GWH	23,426	31,723	30,161	30,490	30,105	30,806	30,503	30,083	30,896	30,072	30,328	30,713
COAL	GWH	82,650	80,564	82,322	82,635	82,762	83,701	84,505	85,010	85,742	86,182	85,289	87,950
OIL - TOT	GWH	24,001	37,398	34,856	32,627	28,955	21,322	15,338	16,932	15,149	14,658	12,200	10,697
STEAM	GWH	23,451	36,266	34,265	32,101	28,416	20,996	15,066	16,586	14,920	14,376	11,942	10,459
CC	GWH	53	92	51	69	63	65	90	96	105	119	126	117
CT	GWH	500	1,059	541	458	477	262	182	250	124	163	132	121
NG - TOT	GWH	33,556	31,576	26,896	31,922	39,848	51,538	61,883	63,524	68,887	75,117	82,505	86,072
STEAM	GWH	13,792	11,003	3,484	4,369	8,979	6,081	6,006	6,159	9,653	13,333	18,551	22,027
CC	GWH	18,457	19,200	21,568	29,667	34,635	50,941	62,429	53,620	55,929	57,861	60,098	59,665
CT	GWH	1,492	2,234	2,775	2,675	3,969	2,778	3,155	3,745	3,305	3,923	3,856	4,380
HYDRO	GWH	91	96	129	105	123	123	132	25	25	25	25	25
NUG	GWH	14,062	12,526	14,329	14,338	14,534	13,917	13,215	13,419	13,449	12,365	12,394	12,263
NEL	GWH	186,603	199,550	198,332	203,356	208,361	212,987	218,046	222,893	227,748	232,513	237,339	242,046

1999
STATE OF FLORIDA
HISTORY AND FORECAST: INTERCHANGE AND GENERATION BY FUEL TYPE - % GWH

TYPE		ACTUAL 1997	ACTUAL 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
INTERCHANGE	%	4.7%	2.8%	4.9%	5.5%	5.8%	5.4%	5.7%	6.2%	6.0%	6.1%	6.2%	5.9%
NUCLEAR	%	12.6%	15.9%	15.2%	15.0%	14.4%	14.5%	14.0%	13.5%	13.6%	12.9%	12.8%	12.7%
COAL	%	44.3%	40.4%	41.5%	40.6%	39.7%	39.3%	38.8%	38.1%	37.6%	37.1%	35.9%	36.3%
OIL - TOT	%	12.9%	18.7%	17.6%	16.0%	13.9%	10.0%	7.0%	7.6%	6.7%	6.3%	5.1%	4.4%
STEAM	%	12.6%	18.2%	17.3%	15.8%	13.6%	9.9%	6.9%	7.4%	6.6%	6.2%	5.0%	4.3%
CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
CT	%	0.3%	0.5%	0.3%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%
NG - TOT	%	18.0%	15.8%	13.6%	15.7%	19.1%	24.2%	28.4%	28.5%	30.2%	32.3%	34.8%	35.6%
STEAM	%	7.4%	5.5%	1.8%	2.1%	4.3%	2.9%	2.8%	2.8%	4.2%	5.7%	7.8%	9.1%
CC	%	9.9%	9.6%	10.9%	14.6%	16.6%	23.9%	28.6%	24.1%	24.6%	24.9%	25.3%	24.7%
CT	%	0.8%	1.1%	1.4%	1.3%	1.9%	1.3%	1.4%	1.7%	1.5%	1.7%	1.6%	1.8%
HYDRO	%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
NUG	%	7.5%	6.3%	7.2%	7.1%	7.0%	6.5%	6.1%	6.0%	5.9%	5.3%	5.2%	5.1%
NEL	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

1999
STATE OF FLORIDA
HISTORY AND FORECAST: FUEL REQUIREMENTS

TYPE		ACTUAL 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
NUCLEAR	10E12 BTU	246	333	317	320	316	323	320	316	324	316	318	322
COAL	10E3 TON	32,569	35,361	35,455	35,231	35,091	35,269	35,627	35,948	36,496	36,699	36,266	37,510
OIL - TOT	10E3 BBL	39,135	62,609	55,837	52,396	47,078	35,222	25,681	28,706	27,436	27,174	23,620	21,342
STEAM	10E3 BBL	36,846	58,876	53,217	49,879	44,283	32,882	23,422	26,070	23,245	22,421	18,718	16,443
CC	10E3 BBL	340	380	388	427	425	575	728	759	2,277	3,317	3,390	3,350
CT	10E3 BBL	1,949	3,353	2,232	2,090	2,370	1,765	1,531	1,877	1,914	1,436	1,512	1,549
NG - TOT	10E6 CF	293,560	283,334	243,002	284,916	363,876	447,306	525,188	545,057	568,713	614,827	673,952	701,271
STEAM	10E6 CF	137,345	107,332	41,160	53,077	99,320	68,605	67,427	69,202	88,068	117,957	155,502	177,872
CC	10E6 CF	136,797	146,861	165,725	195,985	212,750	346,037	423,874	432,268	445,032	455,510	479,720	479,156
CT	10E6 CF	19,418	29,141	36,117	35,854	51,806	32,664	33,887	43,587	35,613	41,360	38,730	44,243

DOCUMENT 3

Firm Reserve Margin Calculation

FRM = (SSR - FPD)/(FPD)

SSR = (IC + PC + FI +FQF - FE - PO)

FPD = (FR + FW)

Where:

FRM: Firm Reserve Margin

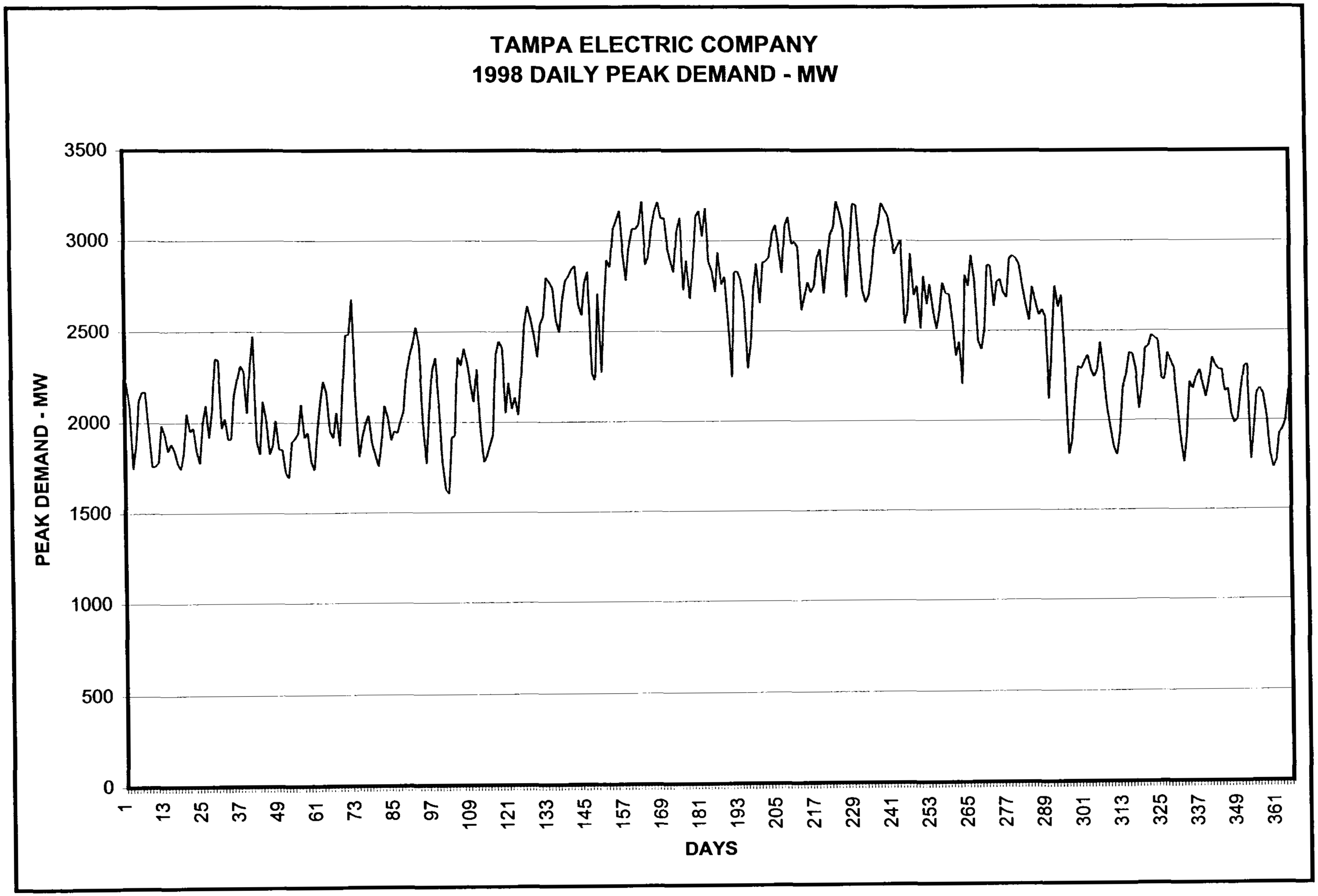
SSR: Supply-Side Resources

IC: Installed Capacity
PC: Planned Capacity
FI: Firm Imports
FQF: Firm QF
FE: Firm Exports
PO: Planned Outages

FPD: Firm Peak Demand

FR: Firm Retail Demand
FW: Firm Wholesale Demand

DOCUMENT 4


TAMPA ELECTRIC COMPANY
1998 DAILY PEAK DEMAND - MW
PEAK DEMAND - MW
3500
3000
2500
2000
1500
1000
500
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
289
301
313
325
337
349
361
DAYS

96

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DOCUMENT 5

Firm Reserve Margin Criteria

$$FRM = (SSR - FPD)/ FPD$$

$$FRM = (SSR/FPD) - 1$$

$$(SSR/FPD) = FRM +1$$

Minimum Requirement for a Reliable System

$$SSR(SSCF) = FPD(FPCF)$$

$$(SSR/FPD) = (FPCF/SSCF)$$

$$(FPCF/SSCF) = FRM + 1$$

MFRM Criterion is

$$\boxed{\mathbf{MFRM_{CRITERION} \geq (FPCF/SSCF) - 1}}$$

Winter Minimum Firm Reserve Margin Criteria:

AVG (SSCF)	AVG (FPCF)	AVG ABS (FPCF)	MFRM	MFRM Criterion
0.93	1.03	-	11%	
0.93	-	1.06	14%	**15%**

Summer Minimum Firm Reserve Margin Criteria:

AVG (SSCF)	AVG (FPCF)	AVG ABS (FPCF)	MFRM	MFRM Criterion
0.93	1.02	-	10%	
0.93	-	1.04	12%	**15%**

AVG: AVERAGE
AVG ABS: AVERAGE ABSOLUTE

Where:

FRM: Firm Reserve Margin

SSR: Supply-Side Resources

FPD: Firm Peak Demand

SSCF: (Actual SSR @ FPD)/(Projected SSR), Supply-Side Certainty Factor

FPCF: (Actual Peak/Projected Peak 5 Years Earlier), Firm Peak Certainty Factor

MFRM: Minimum Firm Reserve Margin

DOCUMENT 6

Projected and Actual Supply Side Resources at Time of Peak Demand

Winter Projected TYSP SSR	Total	Summer Projected TYSP SSR	Total
1985	2835	1985	2744
1986	2676	1986	2569
1987	2675	1987	2811
1988	2801	1988	2801
1989	2917	1989	2917
1990	2932	1990	2949
1991	3232	1991	3237
1992	3306	1992	3239
1993	3525	1993	3483
1994	3477	1994	3435
1995	3665	1995	3482
1996	3656	1996	3477
1997	3878	1997	3688
1998	3776	1998	3590

Winter Actual per Interrogatory 3	Total	Summer Actual per Interrogatory 3	Total
1985	2626	1985	2235
1986	2631	1986	2621
1987	2698	1987	2662
1988	3093	1988	2660
1989	2523	1989	3041
1990	2322	1990	2737
1991	3151	1991	2730
1992	3846	1992	2680
1993	2297	1993	3308
1994	3121	1994	3312
1995	3284	1995	3200
1996	3594	1996	3250
1997	3566	1997	3263
1998	3309	1998	3487

	Wtr Proj/Wtr Act		Sum Proj/Sum Act
1985.00	0.93	1985.00	0.81
1986.00	0.98	1986.00	1.02
1987.00	1.01	1987.00	0.95
1988.00	1.10	1988.00	0.95
1989.00	0.86	1989.00	1.04
1990.00	0.79	1990.00	0.93
1991.00	0.97	1991.00	0.84
1992.00	1.16	1992.00	0.83
1993.00	0.65	1993.00	0.95
1994.00	0.90	1994.00	0.96
1995.00	0.90	1995.00	0.92
1996.00	0.98	1996.00	0.93
1997.00	0.92	1997.00	0.88
1998.00	0.88	1998.00	0.97
Wtr Supply-Side Certainty Factor	**0.93**	**Sum Supply-Side Certainty Facto**	**0.93**

DOCUMENT 7

Firm Peak Certainty Factors

Summer Load Forecast Comparison
Actual Firm Peak Occurs 5 Years After the Forecast Year

Forecast Year		
1975	FORECAST	1984
	ACTUAL	1753
	VARIANCE	-11.64%
1976	FORECAST	1718
	ACTUAL	1808
	VARIANCE	5.24%
1977	FORECAST	1819
	ACTUAL	1787
	VARIANCE	-1.76%
1978	FORECAST	1868
	ACTUAL	1842
	VARIANCE	-1.39%
1979	FORECAST	1899
	ACTUAL	1931
	VARIANCE	1.69%
1980	FORECAST	1910
	ACTUAL	2012
	VARIANCE	5.34%
1981	FORECAST	1932
	ACTUAL	2096
	VARIANCE	8.49%
1982	FORECAST	1910
	ACTUAL	2042
	VARIANCE	6.91%
1983	FORECAST	2034
	ACTUAL	2118
	VARIANCE	4.13%
1984	FORECAST	2024
	ACTUAL	2134
	VARIANCE	5.43%
1985	FORECAST	2183
	ACTUAL	2282
	VARIANCE	4.54%
1986	FORECAST	2156
	ACTUAL	2300
	VARIANCE	6.68%
1987	FORECAST	2297
	ACTUAL	2349
	VARIANCE	2.26%
1988	FORECAST	2428
	ACTUAL	2390
	VARIANCE	-1.57%
1989	FORECAST	2522
	ACTUAL	2471
	VARIANCE	-2.02%
1990	FORECAST	2611
	ACTUAL	2597
	VARIANCE	-0.54%
1991	FORECAST	2636
	ACTUAL	2557
	VARIANCE	-3.00%
1992	FORECAST	2709
	ACTUAL	2779
	VARIANCE	2.58%
1993	FORECAST	2725
	ACTUAL	2784
	VARIANCE	2.17%

Winter Load Forecast Comparison
Actual Firm Peak Occurs 5 Years After the Forecast Year

Forecast Year		
1975	FORECAST	1755
	ACTUAL	1900
	VARIANCE	8.26%
1976	FORECAST	1705
	ACTUAL	1990
	VARIANCE	16.72%
1977	FORECAST	1987
	ACTUAL	1960
	VARIANCE	-1.36%
1978	FORECAST	2016
	ACTUAL	2031
	VARIANCE	0.74%
1979	FORECAST	2087
	ACTUAL	2178
	VARIANCE	4.36%
1980	FORECAST	2185
	ACTUAL	2380
	VARIANCE	8.92%
1981	FORECAST	2197
	ACTUAL	2231
	VARIANCE	1.55%
1982	FORECAST	2161
	ACTUAL	2310
	VARIANCE	6.89%
1983	FORECAST	2241
	ACTUAL	2480
	VARIANCE	10.66%
1984	FORECAST	2308
	ACTUAL	2437
	VARIANCE	5.59%
1985	FORECAST	2389
	ACTUAL	2874
	VARIANCE	20.30%
1986	FORECAST	2407
	ACTUAL	2334
	VARIANCE	-3.03%
1987	FORECAST	2498
	ACTUAL	2597
	VARIANCE	3.96%
1988	FORECAST	2674
	ACTUAL	2627
	VARIANCE	-1.76%
1989	FORECAST	2749
	ACTUAL	2567
	VARIANCE	-6.62%
1990	FORECAST	2850
	ACTUAL	2604
	VARIANCE	-8.63%
1991	FORECAST	2853
	ACTUAL	2710
	VARIANCE	-5.01%
1992	FORECAST	2923
	ACTUAL	3020
	VARIANCE	3.32%
1993	FORECAST	2932
	ACTUAL	2842
	VARIANCE	-3.07%

	Summer	Winter
Average Firm Peak Certainty Factor	1.02	1.03
Average Absolute Certainty Factor	1.04	1.06

DOCUMENT 8

Minimum Summer Supply-Side Reserve Margin Criterion

MSSR = SSR - SSR(SSCF)

MSSR = SSR(1-(SSCF))

$\boxed{\mathbf{MSSRM_{CRITERION} \geq 1 - (SSCF)}}$

$$SSCF = \frac{(\text{Actual SSR @ Peak})}{(\text{Projected SSR Available @ Peak})}$$

MSSRM (SSCF) $_{1985\text{-}1998}$ ***= 0.93***

MSSRM $_{Criterion}$ = 0.07

Where:

MSSR: Minimum Supply-Side Resources

SSR: Supply-Side Resources

SSCF: Supply-Side Certainty Factor

MSSRM: Minimum Summer Supply-Side Reserve Margin

DOCUMENT 9

Summer Supply-Side Reserve Margin Calculation

SSRM= (SSR - FPD - DSM) / (FPD)

SSRM = (IC + PC + FI + FQF - FE - PO)

FPD = (FR + FW)

DSM = (INT + LM)

Where:

SSRM: Summer Supply-Side Reserve Margin

SSR: Supply-Side Resources
IC: Installed Capacity
PC: Planned Capacity
FI: Firm Imports
FQF: Firm QF
FE: Firm Exports
PO: Planned Outages

FPD: Firm Peak Demand

FR: Firm Retail Demand
FW: Firm Wholesale Demand

DSM: Demand-Side Resources

INT: Interruptible Load
LM: Load Management

DOCUMENT 10

Generic Investigation into	)	**TAMPA ELECTRIC COMPANY**
Aggregate Electric Utility	)	**DOCKET NO. 981890-EU**
Reserve Margins Planned for	)	**WITNESS: WARD**
Peninsular Florida	)	**EXHIBIT NO. _____ (MDW-1)**
		DOCUMENT 10
		PAGE 2 OF 7
		FILED: AUGUST 16, 1999

Tampa Electric Company's
List of Issues in Response to Staff's List of Positions

Issue 1: What is the appropriate methodology, for planning purposes, for calculating reserve margins for individual utilities and for Peninsular Florida?

The Florida Reliability Coordinating Council ("FRCC") should be responsible for aggregating capacity and load data from Peninsular Florida utilities and calculating the projected reserve margins for the region. The FRCC's load and capacity aggregation process should eliminate double counting of generating resources and loads. The projected reserve margins are calculated for ten year periods and are published annually in the FRCC Load and Resource Plan, which is filed with the Florida Public Service Commission ("FPSC" or "Commission").

The firm reserve margin should be calculated using the accepted industry formula for projected winter and summer firm non-coincident peak demands. The formula calculates the firm reserve margin as the total firm supply-side resources minus the non-coincident seasonal firm peak demand divided by the projected non-coincident seasonal firm peak demand.

Issue 2: What is the appropriate methodology, for planning purposes, for evaluating reserve margins for individual utilities and for Peninsular Florida?

This evaluation should be conducted by the FRCC on an annual basis using the results of the FRCC reliability assessment and the FRCC Load and Resource Plan. The FRCC Load and Resource Plan should be assessed to ensure that projected aggregate Peninsular Florida seasonal firm reserve margins meet or exceed the regional generation adequacy standard. Reserve margins that meet or exceed the reserve margin criterion would indicate that, for planning purposes, the FRCC aggregate system resource plan provides adequate reliability for the region. If the regional criterion is violated in any peak period, the FRCC Reliability Assessment Group ("RAG") would assess the data and provide an explanation to the FRCC Executive Board and the Commission. Assessment of individual operating entities within the region should be conducted by the Commission.

Issue 3: **How should the individual components of an individual or Peninsular Florida percent reserve margin planning criteria be defined:**

A. Capacity available at time of peak (Ex. QF capacity, firm and non-firm purchases and non-committed capacity). Should equipment delays be taken into account?

B. Seasonal firm peak demand. Over what period should the seasonal firm peak demand be determined? What is the proper method for accounting for diversity of the individual utilities' seasonal firm peak demands and load uncertainty? Is sufficient load uncertainty load data available and being used? How are interruptible, curtailable, load management and wholesale loads treated at the end of their tariff or contract period? How should demand and/or energy use reduction options be evaluated and included in planning and setting reserve margins?

C. Should percent reserve margin planning criterion be determined on an annual, seasonal, monthly, daily, or hourly basis?

A. The components of the firm reserve margin calculation may be classified as firm supply-side resources available at time of firm peak and seasonal firm peak demand.

Firm supply-side resources include all FRCC firm installed generating capacity less the capacity of planned unit outages during the projected seasonal peak less firm contracted exports plus firm contracted capacity from non-utility generating and qualifying facilities plus firm contracted imported capacity from outside the Peninsular Florida.

The aggregate non-coincident firm peak demand includes all customers within Peninsular Florida region except to the extent those participating in Commission-approved demand-side management programs. The non-coincident firm peak is the aggregate firm peak of all load serving utilities in Peninsular Florida.

The projected in-service date of planned capacity should be adjusted to reflect equipment delays as they occur. These adjustments should be included in the reserve margin calculation when they become known.

B. For Peninsular Florida planning purposes, the seasonal firm peaks should include December through February for the winter season and June through August for the summer season. Tampa Electric ("Tampa Electric" or "Company") supports the FRCC's approach to calculating load diversity and developing load forecast certainty factors.

The FRCC aggregation process includes all projected firm loads regardless of contractual commitments. Included in the FRCC aggregation process is the accounting of non-firm loads in Peninsular Florida. This data is provided in the FRCC Load and Resource Plan.

The actual and projected demand and energy reductions from conservation programs are captured in the FRCC methodology for testing its 15 percent minimum firm reserve margin standard for the seasonal non-coincidental peaks.

C. The firm reserve margin should be calculated on a seasonal basis that includes the non-coincident winter and summer firm peaks. The winter period should include December through February while the summer months should be defined as June through August. Tampa Electric calculates its supply-side reserve margin for the summer firm peak. This is during the period that generating units experience the highest capacity factors.

Issue 4: How should generating units be rated (MW) for inclusion in a percent reserve margin planning criteria calculation?

If the unit is not scheduled for an outage at the time of the projected peak demand, then the generating resource's maximum net capability should be used to calculate both the firm reserve margin and supply-side reserve margin.

Issue 5: How should individual utility reserve margins be integrated into the aggregated reserve margin for Peninsular Florida?

On an aggregate basis individual utility reserve margins are not additive since individual systems vary in demand and energy requirements. Planning reserves should be based on each individual utility's resources and system demand and energy.

An aggregate reserve margin should be calculated for Peninsular Florida using the region's firm existing and planned installed capacity, and firm contracted capacity to serve Peninsular Florida's projected aggregate non-coincident firm seasonal peaks. This integration should be conducted by the FRCC and is explained in Tampa Electric's position on Issue 2.

Issue 6: **Should there be a limit on the ratio of non-firm load to MW reserves? If so, what should that ratio be?**

No.

Issue 7: **Should there be a minimum of supply-side resource when determining reserve margins? If so, what is the appropriate minimum level?**

Yes. A minimum supply-side reserve margin is necessary to ensure a balance of resources for reserve purposes. The minimum supply-side reserve margin establishes a minimum level of supply-side reserves while not limiting the contributions of the Commission-approved, demand-side management programs. Maintaining this balance is a primary concern during summer months when supply-side resources are required to operate at high capacity factors while also experiencing derations due to high seasonal temperatures.

Considering its supply-side resources and demand and energy requirements, Tampa Electric believes that a 7 percent minimum summer supply-side reserve margin criterion along with a 15 percent minimum seasonal firm reserve margin criteria provides adequate system reliability.

Issue 8: **What if any planning criteria should be used to assess the generation adequacy of individual utilities.**

It would be inappropriate to establish the same planning criteria for each Peninsular Florida utility because "one size does not fit all." System reliability should be assessed on a "utility by utility" basis because each system has unique characteristics in both resources and system demand, and energy requirements. Individual utilities should establish appropriate reserve margin criteria that will ensure its customers are reliably served but those criteria should be developed to meet the utility's unique characteristics.

Issue 9: **Should the import capability of Peninsular Florida be accounted for in measuring and evaluating reserve margins and other reliability criteria, both for individual utilities and for peninsular Florida.**

Only firm contracted import and export capacity should be accounted for in measuring and evaluating reserve margins. All import and export capability that is not tied to firm contracted capacity should not be considered in these calculations and evaluations.

Issue 10: **Do the following utilities appropriately account for historical winter and summer temperatures when forecasting seasonal peak loads for purposes of establishing reserve margin planning criteria.**

Yes. Tampa Electric uses historical National Oceanic and Atmospheric Administration temperature profiles to forecast seasonal peak loads. The temperature profiles are based on 30 years of historical data along with an examination of the temperatures on peak days during the period of 1970 - 1998. The forecasted seasonal firm peak demands are used in testing the Company's minimum firm reserve margin criteria.

Issue 11: **Has the FRCC's 15 percent reserve margin planning criteria, or any other proposed reserve margin criterion, been adequately tested to warrant using it as planning criterion for the review of generation adequacy on a peninsular Florida basis? If the answer is no, what planning criteria should be used.**

Yes. The FRCC 15 percent minimum firm reserve margin criterion for Peninsular Florida has been based on the collective planning and operating experience of the FRCC utilities and is consistent with reliability standards adopted by other regional reliability coordinating councils. It has also been tested using the FRCC methodology and found to provide adequate planning reserves for Peninsular Florida.

Issue 12: **What percent reserve margin is currently planned for Tampa Electric and is it sufficient to provide an adequate and reliable source of energy for operational and emergency purposes?**

Tampa Electric currently plans for a 15 percent minimum firm reserve margin for both winter and summer and proposes minimum summer supply-side reserve margin of 7 percent. Tampa Electric's historical availability of supply-side resources and average load forecast errors at the time of the firm peak demand indicate that the 15 percent minimum firm reserve margin and 7 percent minimum supply-side reserve margin will provide adequate and reliable energy for operational and emergency purposes.

Issue 13: How does the reliability criteria adopted by the FRCC compare to the reliability criteria adopted by other reliability councils?

Tampa Electric supports the conclusions drawn from the FRCC research provided in its FRCC prefiled testimony.

Issue 14: Should the Commission adopt a reserve margin standard for individual utilities in Florida? If so, what should be the appropriate reserve margin criteria for individual utilities in Florida. Should there be a transition period for utilities to meet that standard?

No. See response to issue 8.

Issue 15: Should the commission adopt a reserve margin standard for Peninsular Florida? If so, what should be the appropriate reserve margin criteria for Peninsular Florida?

Yes. The Commission should recognize the FRCC 15 percent minimum firm reserve margin criteria for both summer and winter non-coincident firm peak demands.

Issue 16: Should the Commission adopt a maximum reserve margin criterion or other reliability criterion for planning purposes: e.g., level of reserves necessary to avoid interrupting firm load during weather conditions like those experienced on the following dates: 01/08/70, 01/17/77, 01/13/81, 12/19/81, 12/25/83, 01/21/86, 12/23/89?

No. The Commission should adopt minimum reserve margin criteria that will ensure capacity reserve levels adequate for reasonably anticipated winter and summer temperature extremes, unplanned unit outages and variations in load growth

Issue 17: What percent reserve margin is currently planned for Peninsular Florida and is it sufficient to provide an adequate and reliable source of energy for operational and emergency purposes in Peninsular Florida?

The FRCC currently plans for a minimum firm reserve margin of 15 percent for both summer and winter non-coincident firm peak demands. Historical availability of supply-side resources and accuracy of peak load forecasts indicate that a 15 percent minimum firm reserve margin will provide adequate and reliable energy for operational and emergency purposes.

Issue 18: **Can out-of-Peninsular Florida power sales interfere with the availability of Peninsular Florida reserve capacity to serve Peninsular Florida customers during a capacity shortage? If so, how should sales be accounted for in establishing a reserve margin standard?**

No. Peninsular Florida utilities plan a minimum winter and summer firm reserve margin level of 15 percent on an aggregate Peninsular Florida basis. This minimum firm reserve margin of 15 percent is made available to Peninsular Florida utilities on a first call basis to serve firm customers during emergency conditions.

Issue 19: **Based on the resolution of issues 1 through 18, what follow-up action, if any, should the commission pursue?**

Tampa Electric is not aware of the need for any incremental action by the Commission at this time, over and above the Commission's traditional role of insuring adequate and reliable electric service throughout Florida.