ORIGINAL

OKEECHOBEE GENERATING COMPANY, L.L.C.

PETITION FOR DETERMINATION OF NEED

FOR THE

OKEECHOBEE GENERATING PROJECT

EXHIBITS

SEPTEMBER 24, 1999

PETITION FOR DETERMINATION OF NEED
FOR THE OKEECHOBEE GENERATING PROJECT

EXHIBITS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

General Description of the Okeechobee Generating Project

Okeechobee Generating Company, L.L.C. ("OGC"), a public utility subject to the jurisdiction of the Federal Energy Regulatory Commission under the Federal Power Act, and an electric utility under Section 366.02(2), Florida Statutes, applies for the Commission's determination of need for the Okeechobee Generating Project ("Project"), a nominal 550 megawatt ("MW") (at ISO temperature (59F°) and relative humidity (60% R.H.)) natural gas-fired combined cycle generating plant that will be located in Okeechobee County, Florida. The Project is expected to commence commercial operation in April 2003, and its capacity and energy will be made available for sale, at wholesale, to other utilities and power marketers for use in Peninsular Florida. Virtually all of the Project's output is expected to be sold to other Peninsular Florida utilities and power marketers for use in Peninsular Florida.

The Project will include two advanced technology combustion turbine generators, two heat recovery steam generators, and two steam turbine generators. The Project is expected to have a heat rate of approximately 6,775 Btu per kWh (based on the Higher Heating Value ("HHV") of natural gas) at ambient site conditions. The Project will meet or exceed all applicable environmental requirements. The Project's primary source of makeup water to the cooling towers will be supplied by surface water from the South Florida Water Management District channelized canal C-59 at Taylor Creek/Nubbin Slough.

OGC's current projections indicate that the Project will operate approximately 8,150 hours per year, with projected generation of approximately 4.3 million MWH per year.

The Project will be interconnected to the Peninsular Florida transmission grid by looping the 230 kV Florida Power & Light Company ("FP&L") Sherman-Martin transmission line into the switchyard of the Project. The Project will be fueled primarily by natural gas, which will be delivered through a new trans-Florida pipeline to be constructed by Gulfstream Natural Gas System, L.L.C. ("Gulfstream") pursuant to a 20-year firm gas transportation agreement. The natural gas pipeline is planned to traverse the southern portion of the site.

Ownership and Management

The Okeechobee Generating Project will be developed by PG&E Generating Company, L.L.C. ("PG&E Generating") and Okeechobee Generating Company, L.L.C. will own the Project. OGC is a wholly-owned indirect affiliate of PG&E Generating. PG&E Generating is the competitive power generation affiliate of PG&E Corporation. Engineering and construction of the Project will be performed and overseen by PG&E Generating. The Project will be managed by PG&E Generating pursuant to a management service contract between PG&E Generating and OGC. In addition, OGC expects to sign a contract with PG&E Operating Services Company for operation and maintenance of the Project. Power produced by the Project will be sold at wholesale to other utilities and power marketers for use in Peninsular Florida.

Site Description and Location

The Project will be located north-northeast of Lake Okeechobee, in a rural area approximately five miles southeast of the City of Okeechobee in Okeechobee County, Florida. The facility will be located on approximately 40 acres of an approximately 771 acre site situated to the west of Nubbin Slough, approximately one half mile north of State Route 710. An access road will be constructed to the site from State Route 710. The property is zoned for power plant development and is consistent with the Okeechobee County Comprehensive Plan designation.

Description of the Power Plant and Related Facilities

The power plant will consist of two advanced technology combustion turbine generators ("CTGs") (ABB GT24 or equivalent) with two heat recovery steam generators ("HRSGs"). Steam from both HRSGs will feed into two steam turbine generators ("STGs"). The total electrical output of the plant will be 550 MW (nominal) at

ISO temperature (59°F.) and relative humidity (60% R.H.). The facility will utilize state-of-the-art dry low-NO_x[1] combustion technology and selective catalytic reduction ("SCR") to minimize NO_x emissions when firing natural gas. (When firing oil, the Project will use SCR and water injection to control NO_x emissions.)

The Project's primary source of makeup water to the cooling towers will be surface water from the South Florida Water Management District channelized canal C-59 at Taylor Creek/Nubbin Slough. On-site groundwater wells are expected to provide back-up water supply during extreme drought conditions, if needed.

The Project will be electrically interconnected to the transmission grid by looping the 230 kV Sherman-Martin transmission line into the switchyard of the Project.

Fuel Supply

The Project will be fueled primarily by natural gas which will be delivered over the Gulfstream Natural Gas System by a 30-inch trans-Florida pipeline to be constructed by Gulfstream. The natural gas will be supplied to Gulfstream pipeline receipt points by natural gas marketing companies and producers. A back-up fuel supply of distillate fuel oil will be maintained at the Project site with onsite storage capacity sufficient for the plant to

---

[1]"NO_x" is used to refer generically to the oxides of nitrogen produced in the combustion process.

generate at the maximum daily output for 24 hours without refilling storage.

Project Costs and Financing

The Project's direct construction cost, is expected to be approximately $190 million, reflecting a cost of approximately $345 per kW of installed capacity. The Project will be constructed and brought into commercial service with a combination of equity and debt that will be used to pay construction and development costs.

I. INTRODUCTION

The purpose of the Petition for Determination of Need submitted by Okeechobee Generating Company, L.L.C. is to obtain the Florida Public Service Commission's ("FPSC" or "Commission") affirmative determination of need for the Okeechobee Generating Project, a nominal 550 MW (ISO temperature and humidity conditions) natural gas-fired combined cycle generating plant that will be located in Okeechobee County, Florida.

The Commission's determination of need pursuant to Section 403.519, Florida Statutes, is part of the comprehensive permitting process for the Project under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, Florida Statutes ("the Siting Act"). Under Section 403.519, the Commission is to consider the following factors when making its decision whether to grant a determination of need for a power plant subject to the Siting Act:

1. The need for electric system reliability and integrity;
2. The need for adequate electricity at a reasonable cost;
3. Whether the proposed plant is the most cost-effective alternative available for serving an identified need for power;
4. Conservation measures taken by, or reasonably available to, the affected utility or utilities which might mitigate the need for the proposed plant; and

5. Other matters within the Commission's jurisdiction that the Commission deems relevant to its determination.

In these Exhibits, OGC demonstrates that the Okeechobee Generating Project satisfies all relevant criteria under Section 403.519. In addition, these Exhibits demonstrate that the Project satisfies all relevant criteria under Rule 25-22.081, Florida Administrative Code. The Project will provide a power supply resource with proven, reliable, highly efficient, highly available, and environmentally favorable technology. As a wholesale power plant offering capacity and energy to other utilities and power marketers in Peninsular Florida at negotiated, market-based prices, the output of which no utility is obligated to buy, the Project also provides a cost-effective power supply alternative for meeting the needs of other utilities and power marketers in Peninsular Florida.

The Project will contribute meaningfully to the reliability of the power supply system in Peninsular Florida, to lower the cost of electricity generation, to enhance efficiency in electricity generation in Peninsular Florida, and to improve the environmental profile of power generation in Florida.

Section II of these Exhibits provides a description of the applicant and primarily affected utility, OGC. Section III describes the Project, including the site, generating technology, operational reliability and related information, major systems, associated facilities, fuel supply, and the schedules for permitting and constructing the Project. Section IV describes OGC's and Peninsular Florida's need for the Project. Section V describes the cost-effectiveness of the Project, and Section VI addresses the adverse consequences on power supply reliability, on power supply costs, and on Florida's environment of delaying the construction and operation of the Okeechobee Generating Project.

II. THE APPLICANT

The applicant and primarily affected utility for the Commission's determination of need is Okeechobee Generating Company, L.L.C. This section of the Exhibits describes the organization and ownership structure of the Project and of the applicant.

A. Overview and Project Structure.

Okeechobee Generating Company, L.L.C. will be the owner of the Okeechobee Generating Project. OGC is a FERC-jurisdictional, FERC-regulated wholesale public utility (as well as an electric utility under Section 366.02(2), Florida Statutes) that will sell the Project's capacity and energy at wholesale to other utilities and power marketers. PG&E Generating is the developer and manager of the Project, and in that role will negotiate the various contracts and perform other activities necessary for the Project's development, construction, and operation. The Project will be constructed and brought into commercial service solely with funds arranged by PG&E Generating and its affiliates. It is anticipated that the Project will be financed with a combination of debt and equity that will be used to pay development and construction costs. Earth Tech, Incorporated has been retained by OGC to provide environmental licensing and permitting services for the Project. The natural gas fuel supply for the Project will be provided by natural gas marketing companies or producers to receipt points on a new, trans-Florida natural gas pipeline to be constructed by Gulfstream.

B. Okeechobee Generating Company, L.L.C.

Okeechobee Generating Company, L.L.C., a Delaware Corporation, is a wholly-owned indirect subsidiary of PG&E Generating, a Delaware corporation. See Figure 1.

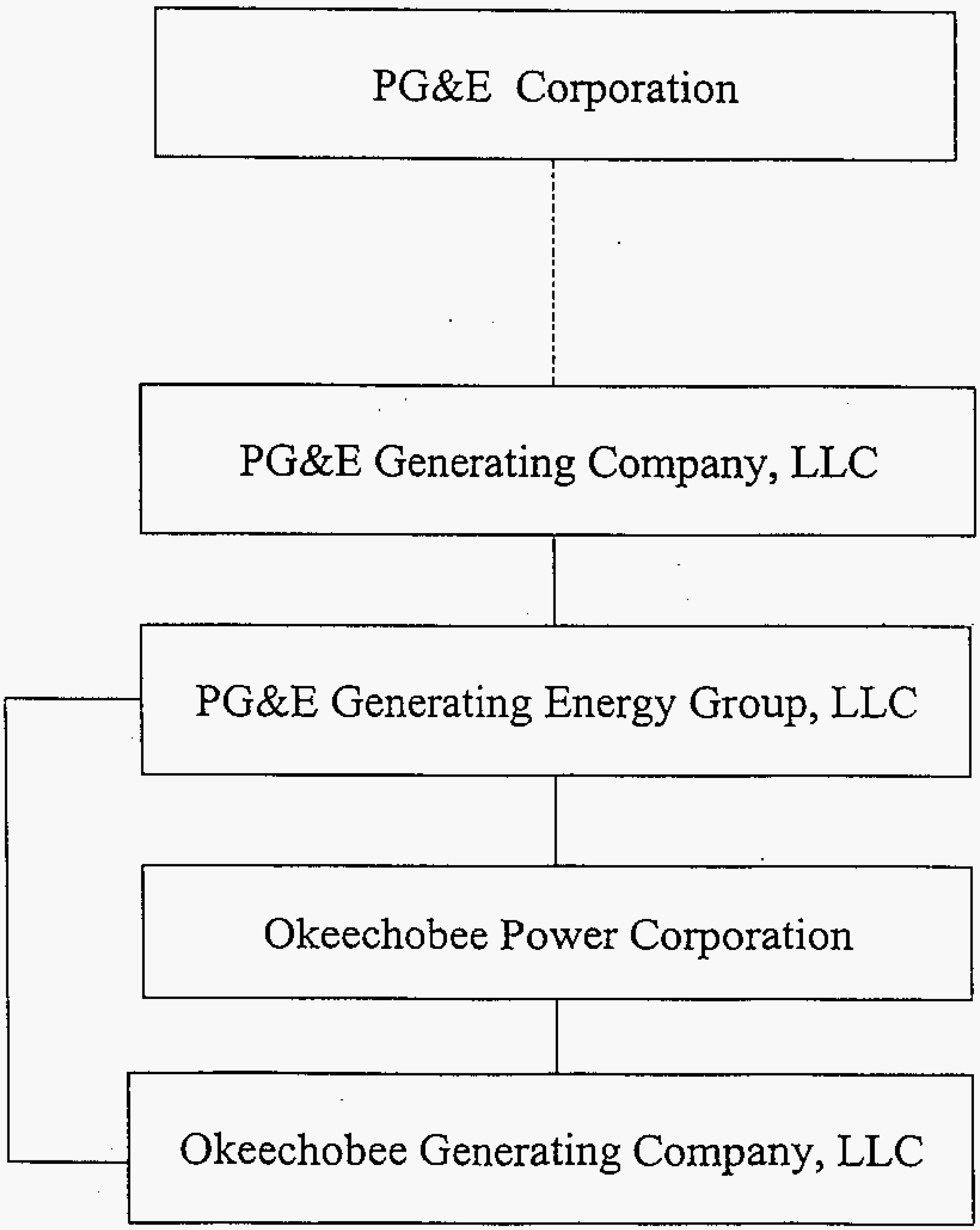
OGC is a public utility under Section 201 of the Federal Power Act. 16 USCA §824(b)(1)&(e)(1994). By its order issued on September 15, 1999, the Federal Energy Regulatory Commission ("FERC") approved OGC's tariff to sell wholesale power at market-based rates. 88 FERC ¶61,219. Pursuant to a FERC order issued on August 24, 1999, OGC is also an Exempt Wholesale Generator ("EWG"). 88 FERC ¶62,177. Copies of these orders are included in the Appendix to these Exhibits.

C. PG&E Generating.

PG&E Generating is a wholly-owned indirect subsidiary of PG&E Corporation. PG&E Generating is the competitive power generation affiliate of PG&E Corporation. Affiliates of PG&E Generating own, manage, operate or control more than 7,300 MW of electricity generation across the United States, including 580 MW of electricity originating from existing facilities located in the State of Florida. Nationally, PG&E Generating has more than 1,162

FIGURE 1

Okeechobee Generating Company, LLC Ownership Structure



MW under construction and more than 8,500 MW in active development. Approximately 4,000 MW of PG&E Generating's total operating capacity is merchant power, in which the electricity is sold into competitive wholesale power markets. Figure 2 presents a listing of electric generation facilities owned or managed by affiliates of PG&E Generating.

PG&E Generating is the developer of the Okeechobee Generating Project. In that role, PG&E Generating is arranging for the permitting of the Project, for the engineering, procurement, and construction of the Project, for the Project's fuel supply, and for other services necessary to bring the Project to commercial operation.

D. **PG&E Corporation**.

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California that markets energy services throughout North America. PG&E Corporation has five wholly-owned subsidiaries. The wholly-owned subsidiaries of PG&E Corporation are PG&E Energy Services, PG&E Energy Trading, PG&E Gas Transmission, PG&E Generating and Pacific Gas and Electric Company. Pacific Gas and Electric Company, is a gas and electric utility regulated by the State of California.

Figure 2
PG&E Generating Portfolio of Generating Assets

Operating Plants -- PG&E Gen Management

Plant		MWs	Fuel	Location	Commercial Service	Electricity Customers	Steam Customer	O&M
Bear Swamp Facility	Pumped Storage 2 Units	588	Water	Massachusetts	1974	Standard Offer; Merchant Market	N/A	PG&E Gen
	Fife Brook	10	Water		1974	Standard Offer; Merchant Market	N/A	PG&E Gen
Brayton Point Station	Unit Nos. 1, 2 and 3	1,130	Coal	Massachusetts	1963, '64, '69	Standard Offer; Merchant Market	N/A	PG&E Gen
	Unit No. 4	446	Oil/Gas		1974	Standard Offer; Merchant Market	N/A	PG&E Gen
	Diesel Generators	10	Diesel Oil		N/A	Standard Offer; Merchant Market	N/A	PG&E Gen
Carneys Point		260	Coal	New Jersey	1994	Conectiv DuPont PG&E Energy Trading-Power	DuPont	PG&E Gen
Cedar Bay		250	Coal	Florida	1994	Florida Power & Light	Smurfit Stone	PG&E Gen
Connecticut River	Hydroelectric 6 Units	484	Water	New Hampshire/Vermont	1909-1957	Standard Offer; Merchant Market	N/A	PG&E Gen
Deerfield River	Hydroelectric 7 Units	84	Water	Massachusetts/Vermont	1912-1927	Standard Offer; Merchant Market	N/A	PG&E Gen
Hermiston		474	Natural Gas	Oregon	1996	PacifiCorp	Lamb-Weston	PG&E Gen
Indiantown		330	Coal	Florida	1995	Florida Power & Light	Caulkins Citrus	PG&E Gen
Logan		225	Coal	New Jersey	1994	Conectiv PG&E Energy Trading-Power	Solutia	PG&E Gen
Manchester St. Station	3 Combined Cycle Units	495	Natural Gas	Rhode Island	1995	Standard Offer; Merchant Market	N/A	PG&E Gen
MASSPOWER		240	Natural Gas	Massachusetts	1993	Boston Edison, Commonwealth Electric, W. Mass. Electric, Mass. Muni Wholesale Electric PG&E Energy Trading-Power	Solutia	GE
Northampton		110	Waste Coal	Pennsylvania	1995	GPU Energy PG&E Energy Trading-Power	Ponderosa Fibres	PG&E Gen
Pittsfield		165	Natural Gas	Massachusetts	1990	New England Power, Comm. Electric, Cambridge Electric	General Electric	PG&E Gen
Salem Harbor Station	Unit Nos. 1, 2 and 3	314	Coal	Massachusetts	1952, '52, '58	Standard Offer; Merchant Market	N/A	PG&E Gen
	Unit No. 4	400	Oil		1972	Standard Offer; Merchant Market	N/A	PG&E Gen
Scrubgrass		83	Waste Coal	Pennsylvania	1993	GPU Energy	None	PG&E Gen
Selkirk		345	Natural Gas	New York	1992 1994	Niagara Mohawk Consolidated Edison PG&E Energy Trading-Power	General Electric	GE
MWs/Operating Plants		6,443						

FIGURE 2 (continued)

Operating Plants -- PG&E Gen Affiliate Investment

Plant	MWs	Fuel	Location	Commercial Service	Electricity Customers	Steam Customer	O&M
Colstrip	37	Waste Coal	Montana	1990	Montana Power	None	UCOS
Panther Creek	83	Waste Coal	Pennsylvania	1992	GPU Energy	None	UCOS
MWs from Investments	120						
Total MWs in Operation	6,563						

Power Contracts--Marketing Control

	MWs						
MWs from Contracts	789				Standard Offer; Merchant Market	N/A	
Total MW Ops & Contracts	7,352						

In Construction

Plant	MWs	Fuel	Location	Commercial Service	Electricity Customers	Steam Customer	O&M
Lake Road	792	Natural Gas	Connecticut	2001	Merchant Market	N/A	PG&E Gen
Millennium	370	Natural Gas	Massachusetts	2000	Merchant Market	N/A	PG&E Gen
MWs (in construction)	1,162						
Total Financed MWs	8,514						

In Development

Plant	MWs	Fuel	Location	Commercial Service	Electricity Customers	Steam Customer	O&M
Athens	1,080	Natural Gas	New York	projected 2001	Merchant Market	N/A	PG&E Gen
Badger	1,022	Natural Gas	Wisconsin	projected 2002	Merchant Market	N/A	PG&E Gen
Brayton Point V	477	Natural Gas	Massachusetts	projected 2002	Merchant Market	N/A	PG&E Gen
Covert	1,022	Natural Gas	Michigan	projected 2002	Merchant Market	N/A	PG&E Gen
Harquahala	1,000	Natural Gas	Arizona	projected 2003	Merchant Market	N/A	PG&E Gen
La Paloma	1,020	Natural Gas	California	projected 2001	Merchant Market	N/A	PG&E Gen
Liberty	1,080	Natural Gas	New Jersey	projected 2002	Merchant Market	N/A	PG&E Gen
Mantua Creek	800	Natural Gas	New Jersey	projected 2001	Merchant Market	N/A	PG&E Gen
Okeechobee	550	Natural Gas	Florida	projected 2003	Merchant Market	N/A	PG&E Gen
Otay Mesa	516	Natural Gas	California	projected 2002	Merchant Market	N/A	PG&E Gen
MWs (in development)	8,567						
Grand Total	17,081						

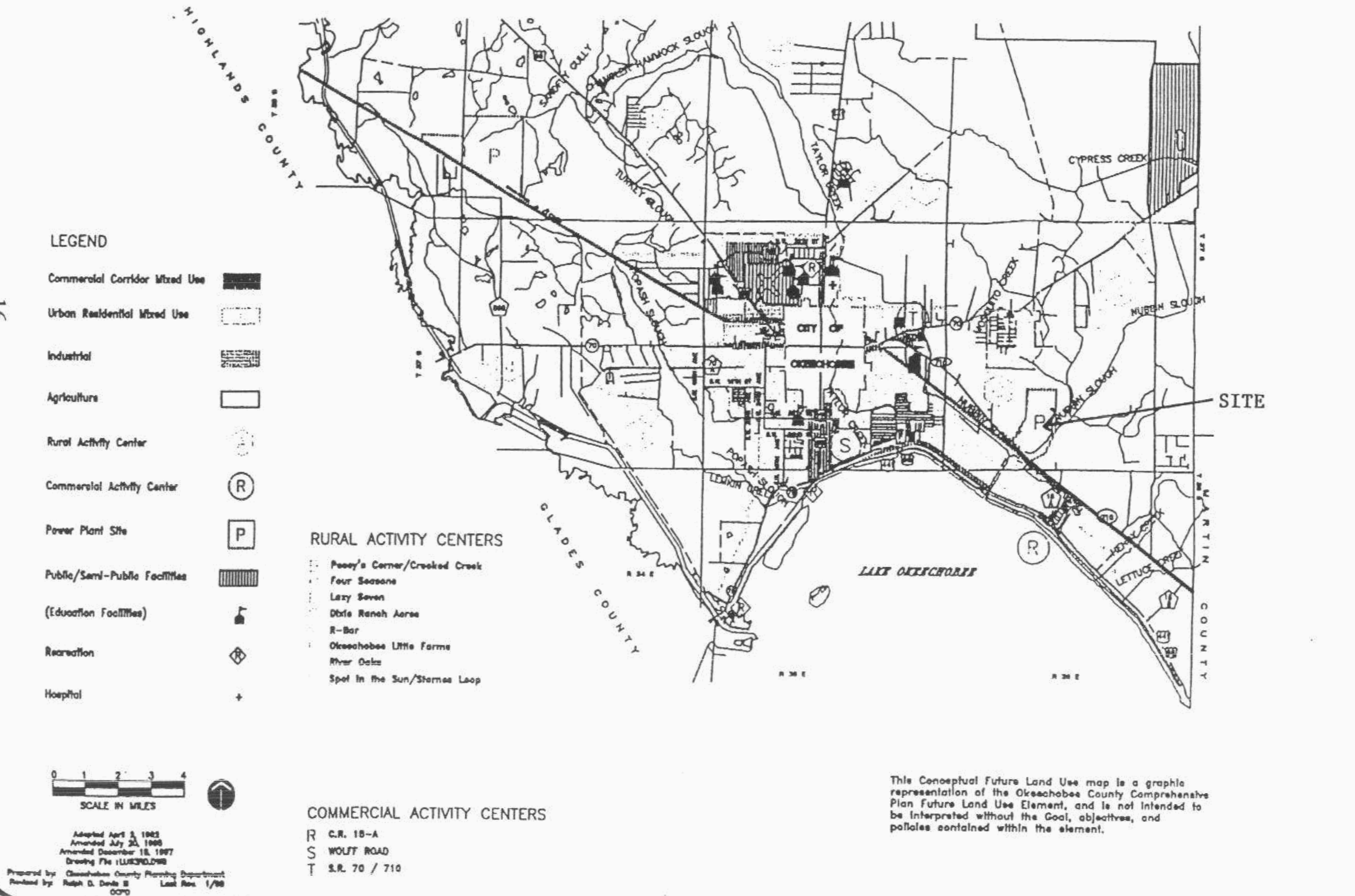
III. DESCRIPTION OF THE OKEECHOBEE GENERATING PROJECT

This section of the Exhibits describes the Okeechobee Generating Project, including the Project's location, site arrangement, major systems and facilities, associated facilities, capital costs and financing, fuel supply, operational reliability, construction and permitting schedules, and operation and maintenance plan.

A. Site Location and Land Use Designation.

The Project will be located north-northeast of Lake Okeechobee, in a rural area approximately five miles southeast of the City of Okeechobee, in Okeechobee County, Florida. The facility will be located on approximately 40 acres of an approximately 771 acre site west of Nubbin Slough on the north side of State Route 710. The site is cleared and situated on fairly level ground. An access road will be constructed to the site from State Route 710. The Project is consistent with the zoning and comprehensive plan designation for the area in which the Project will be located. The site is zoned specifically for power plants. OGC anticipates that it will successfully obtain all required environmental permits for the Project in a timely manner. A map of the site location is included here as Figure 3.

FIGURE 3
OKEECHOBEE GENERATING PROJECT SITE LOCATION RELATIVE TO LOCAL LANDMARKS AND ZONING DESIGNATIONS



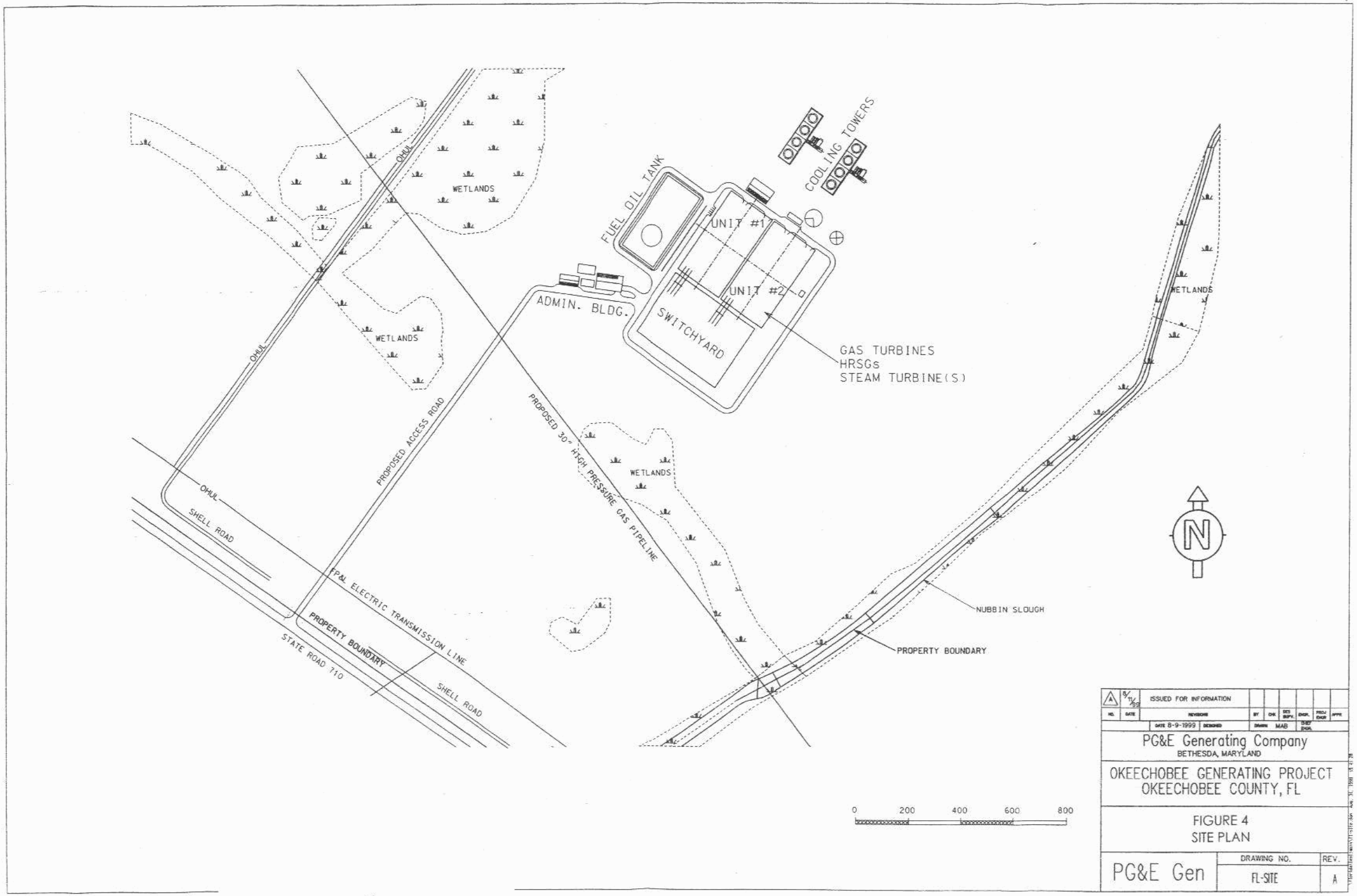
B. **Site Arrangement**.

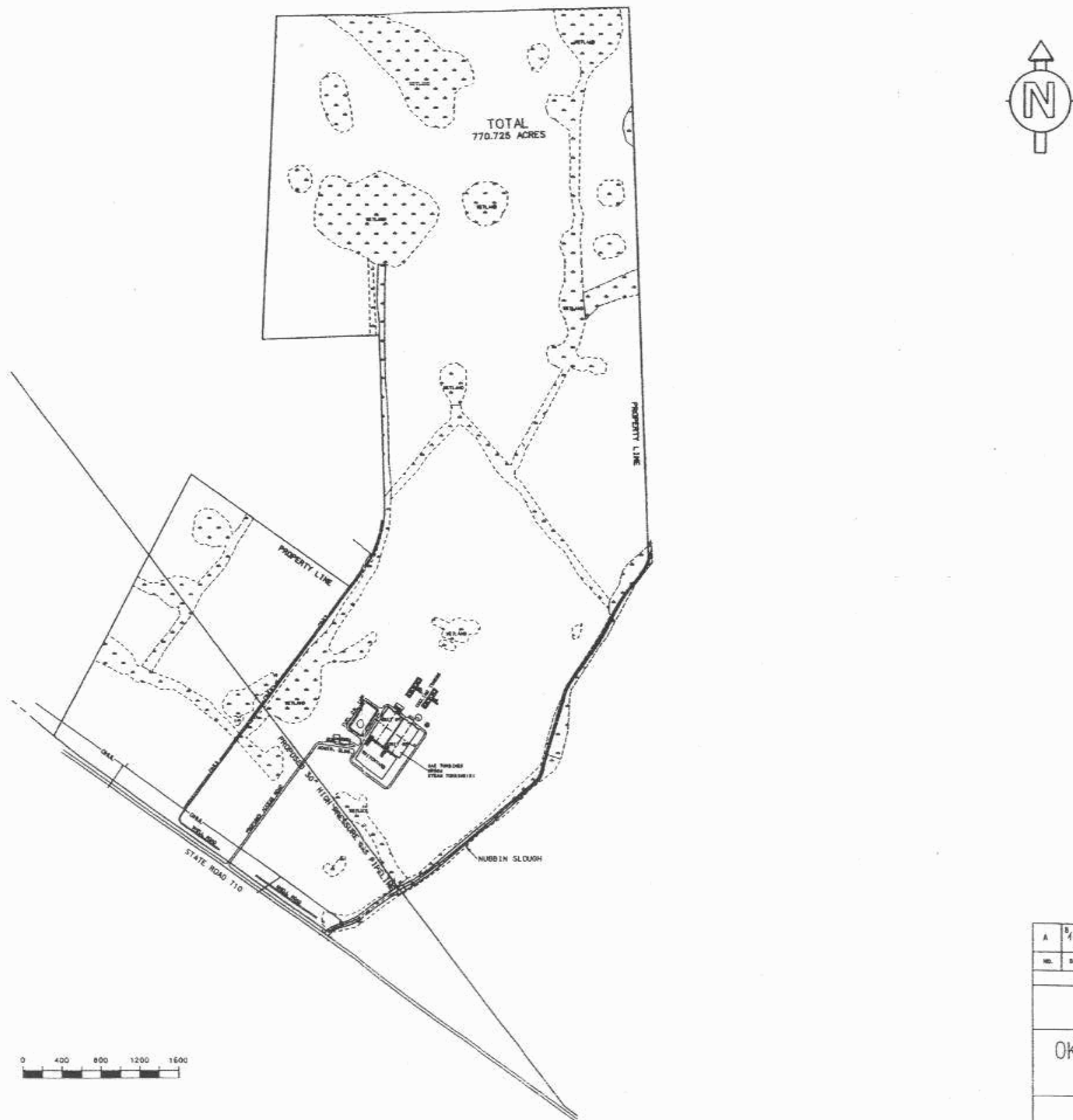
A drawing of the expected layout of the actual generators, cooling towers, water processing and storage facilities and switchyard is shown in Figure 4, the site plan for the Project. The general arrangement of the power plant and switchyard on the Project site is shown in Figure 5, the plot plan for the Project.

C. **Description of Major Systems and Facilities**.

The Project will have 550 MW (nominal) of capacity at ISO temperature and relative humidity; the Project is rated at 514.3 MW for summer operation and 561.3 MW for winter operation. The power block will consist of two advanced technology combustion turbines, two heat recovery steam generators, and two steam turbine generators. Figure 6 presents a one-line electrical diagram for the Project. The Project will be interconnected to the Peninsular Florida bulk transmission grid by looping the 230 kv Sherman Martin transmission line into the Project's switchyard.

The Project's primary source of makeup water to the cooling towers will be supplied by surface water from the South Florida Water Management District channelized canal C-59 at Taylor Creek/Nubbin Slough. On-site groundwater wells are expected to provide back-up water supply during extreme drought conditions, if needed. Approximately, 5.3 million gallons per day of water (at


COOLING TOWERS
FUEL OIL TANK
WETLANDS
OHUL
UNIT #1
UNIT #2
ADMIN. BLDG.
SWITCHYARD
GAS TURBINES
HRSGs
STEAM TURBINE(S)
PROPOSED ACCESS ROAD
PROPOSED 30" HIGH PRESSURE GAS PIPELINE
SHELL ROAD
FP&L ELECTRIC TRANSMISSION LINE
PROPERTY BOUNDARY
STATE ROAD 710
NUBBIN SLOUGH
N
0 200 400 600 800
ISSUED FOR INFORMATION
DATE 8-9-1999
MAB
PG&E Generating Company
BETHESDA, MARYLAND
OKEECHOBEE GENERATING PROJECT
OKEECHOBEE COUNTY, FL
FIGURE 4
SITE PLAN
PG&E Gen
DRAWING NO.
FL-SITE
REV.
A



A	8/10/99	ISSUED FOR INFORMATION
NO.	DATE	REVISIONS

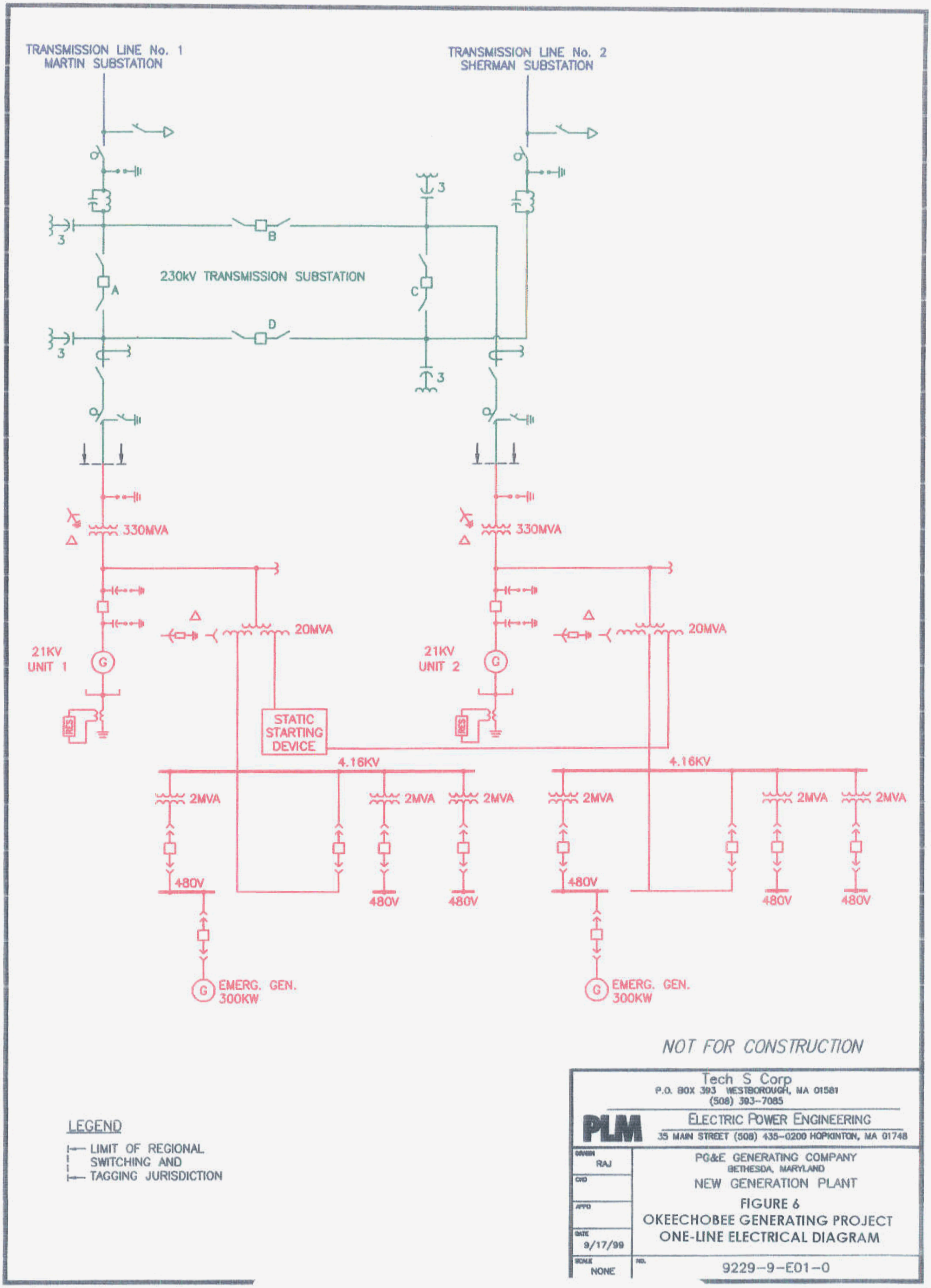
DATE 8/10/1999 DRAWN MAB

PG&E Generating Company
BETHESDA, MARYLAND

OKEECHOBEE GENERATING PROJECT
OKEECHOBEE COUNTY, FL

FIGURE 5
PLOT PLAN

PG&E Gen	DRAWING NO. FL-PLOT	REV. A

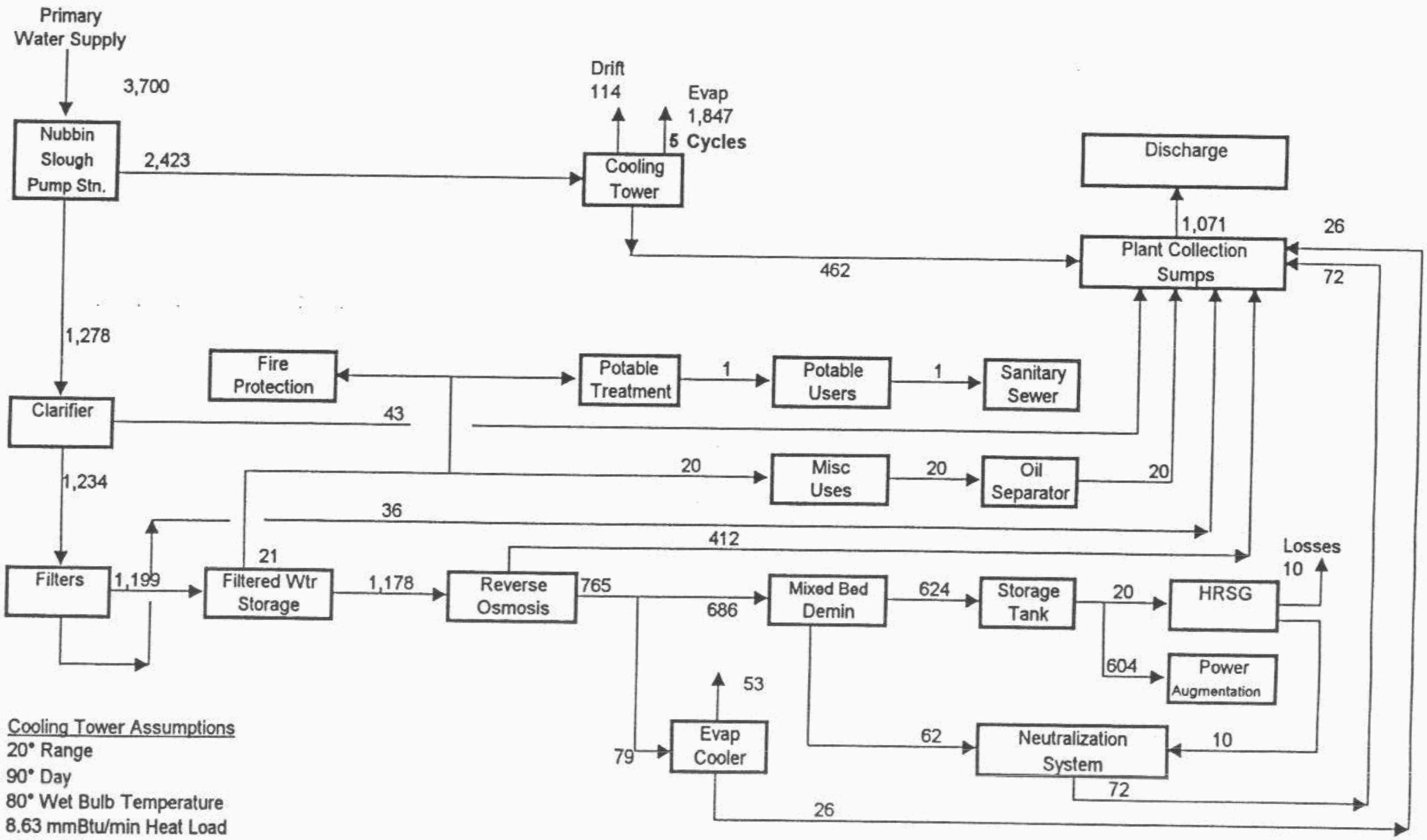

TRANSMISSION LINE No. 1
MARTIN SUBSTATION
TRANSMISSION LINE No. 2
SHERMAN SUBSTATION
230kV TRANSMISSION SUBSTATION
A
B
C
D
3
330MVA
20MVA
21KV
UNIT 1
21KV
UNIT 2
STATIC STARTING DEVICE
4.16KV
2MVA
480V
EMERG. GEN.
300KW
NOT FOR CONSTRUCTION
LEGEND
LIMIT OF REGIONAL SWITCHING AND TAGGING JURISDICTION
Tech S Corp
P.O. BOX 393 WESTBOROUGH, MA 01581
(508) 393-7085
PLM
ELECTRIC POWER ENGINEERING
35 MAIN STREET (508) 435-0200 HOPKINTON, MA 01748
DRAWN RAJ
CHD
APPD
DATE 9/17/99
SCALE NONE
NO.
PG&E GENERATING COMPANY
BETHESDA, MARYLAND
NEW GENERATION PLANT
FIGURE 6
OKEECHOBEE GENERATING PROJECT
ONE-LINE ELECTRICAL DIAGRAM
9229-9-E01-0

peak summer conditions) will be required for the Project. The Project's preliminary water balances are shown in Figure 7.

The Project is expected to have an equivalent availability factor of 93 percent, and an average capacity factor of approximately 93 percent in each year from 2004 to 2013. The Project's actual capacity factor will be greater in years when only minor maintenance outages occur, and less in those years when a major overhaul is performed. The Project's direct construction cost is projected to be approximately \$190 million, or approximately \$345 per kW of nominal capacity.

The Project has been designed with careful consideration of environmental issues and has a favorable environmental profile. The facility will be designed to control NO_x emissions using Best Available Control Technology ("BACT") measures, including state-of-the-art dry low-NO_x combustion technology and selective catalytic reduction ("SCR") to control NO_x emissions when firing natural gas. The Project will use water injection and SCR for NO_x control when firing distillate oil. The Project will meet NO_x emission levels no greater than 2.5 ppmvd when firing natural gas. Both the use of clean-burning natural gas and good combustion practice will minimize sulfur dioxide, carbon monoxide, and volatile organic compound emissions. <u>See</u> Table 1 of these Exhibits.

FIGURE 7
Okeechobee Generating Project
Preliminary Water Balance
(Peak Summer Day)



Cooling Tower Assumptions
20° Range
90° Day
80° Wet Bulb Temperature
8.63 mmBtu/min Heat Load
Natural Gas
Summer Peak Conditions

TABLE 1

OKEECHOBEE GENERATING PROJECT
PROJECT PROFILE

Expected Plant Capacity:

a.	Nominal rating:	550 MW
b.	Annual average (73F°,82% R.H.):	528.2 MW
c.	Summer (95F°,95% R.H.):	514.3 MW
d.	Winter (40F°, 38% R.H.):	561.3 MW
e.	ISO temperature and Humidity (59F°, 60% R.H.):	550 MW

Project Energy Production: Approximately 4,300,000 MWH/year

Technology Type: Two Advanced Firing Temperature Technology Combustion Turbines, Two Heat Recovery Steam Generators, and Two Steam Turbine Generators in Combined Cycle Configuration

Anticipated Construction Schedule:

a.	Project release date:	October 2001
b.	Construction mobilization date:	October 2001
c.	Commercial in-service date:	April 2003

Fuel Use: Approximately 90 Million Standard Cubic Feet of Natural Gas/day, annual average (73F°, 82% R.H.), full load

Air Pollution Control Strategy: Dry Low NO_x Burners and SCR (for natural gas operation); Water Injection and SCR (for oil operation)

Cooling Method: Wet Cooling Tower

Total Site Area: 40 acres of 771 acre site (approximate)

Construction Status: Planned

Certification Status: Need Determination application filed, anticipate filing Site Certification Application June 2000

Status with Federal Agencies:
EWG Status certified by FERC; market-based rates authorized by FERC

TABLE 1

OKEECHOBEE GENERATING PROJECT
PROJECT PROFILE
(CONTINUED)

Projected Unit Performance Data:

Planned Outage Factor (POF):	5%
Forced Outage Factor (FOF):	2%
Equivalent Availability Factor (EAF):	93%
Resulting Capacity Factor (%):	93% (first 10 years)
Average Net Operating Heat Rate (ANOHR):	6775 Btu/kWh(HHV) (73F°,82% R.H.) expected

Project Unit Financial Data (per PG&E Generating):

Book Life (years):	30 years
Direct Construction Cost (Actual):	$190 Million
AFUDC Amount:	Not applicable
Escalation ($/kW)	Not applicable
Fixed O&M ($/kW per year):	Proprietary
Variable O&M ($/MWH):	Proprietary
K-Factor:	Not applicable
Project Life:	30 years

Expected Plant Air Emissions: No_x: 2.5 ppmvd @ 15% 0_2
SO_2: 19.4 lbs./hour

Transmission Lines Required: Loop to FP&L 230 kV Sherman-Martin transmission line

Gas Pipeline Required: 200' (approximate) direct connection to Gulfstream pipeline

Water Requirments: Approx. 5.33 MGD, summer peak conditions (90F°, 60% R.H.), at full load

Wastewater Discharge: 1.54 MGD summer peak conditions

More detailed plant performance and emissions data are shown in Table 2 of these Exhibits. An overall process flow schematic diagram is presented in Figure 8.

D. **Transmission Facilities**.

The Project will be electrically interconnected to the Peninsular Florida transmission system by looping the 230 kV Sherman-Martin transmission line, which traverses the Project site, into the switchyard of the Project. The interconnection facilities are illustrated, schematically, on the electric interconnection schematic diagrams included here as Figures 9 and 10. System impact studies prepared for OGC indicate that no significant transmission additions or upgrades will be necessary to facilitate and support power deliveries from the Project to other Peninsular Florida utilities. The Project will be electrically interconnected to the Peninsular Florida bulk transmission grid by looping the 230 kV FP&L Sherman-Martin transmission line into the switchyard of the Project. Transmission system impact studies prepared for OGC included power flow contingency studies, voltage instability studies, dynamic stability studies, and short circuit studies. These studies indicate that the proposed interconnection, and the existing Peninsular Florida transmission grid, will generally accommodate the delivery of the net output of the Project, regardless which utilities purchase and receive the Project's

TABLE 2

Okeechobee Generating Project
Estimated Plant Performance (Per Unit Values)
Combined Cycle Generating Facility
Two ABB GT24 Combustion Turbine Generators
Two Unfired Heat Recovery Steam Generators
Two Condensing Steam Turbine Generators

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13
Conditions													
Load %	100	100	100	100	100	75	75	75	75	50	50	50	50
Amb. Temp. (°F)	40	59	73	95	95	40	59	73	95	40	59	73	95
W.B. Temp.(°F)	32	51.5	69	77	77	32	51.5	69	77	32	51.5	69	77
Relative Humidity (%)	38%	60%	82%	45%	45%	38%	60%	82%	45%	38%	60%	82%	0.447563
Steam Inj.	Off	Off	Off	Off	On	Off	Off	Off	Off	Off	Off	Off	Off
Evap. Cooler	Off	On	On	On	Off	Off	Off	Off	Off	Off	Off	Off	Off
Location Cond.													
CIT (°F)	40	52.625	69.6	79.7	95	40	59	73	95	40	59	73	95
Elevation (ft above sea level)	25	25	25	25	25	25	25	25	25	25	25	25	25
Pressure (psia)	14.67	14.67	14.67	14.67	14.67	14.67	14.67	14.67	14.67	14.67	14.67	14.67	14.67
Unit Performance													
Exhaust Flow (kip/hr)	3,216	3,154	3,052	2,984	3,036	2,634	2,554	2,479	2,346	2,160	2,095	2,031	1915.575
Steam Injection	0	0	0	0	1	0	0	0	0	0	0	0	0
Gross Output (kW)	285,667	280,000	269,076	262,163	267,386	223,894	214,088	204,564	186,972	162,255	153,842	145,997	133138.8
Heat Input (MMBtu/hr HHV)	1,907	1,865	1,789	1,739	1,777	1,487	1,430	1,376	1,279	1,145	1,098	1,052	969.1373
Gross Heat Rate (BTU/kWhr HHV)	6,676	6,668	6,649	6,635	6,645	6,644	6,678	6,725	6,842	7,059	7,138	7,207	7279.153
Auxiliary Load (kW)	5,000	5,000	5,000	5,000	5,000	4,500	4,500	4,500	4,500	3,900	3,900	3,900	3900
Net Output (kW)	280,667	275,000	264,076	257,163	262,386	219,394	209,588	200,064	182,472	158,355	149,942	142,097	129238.8
Net Heat Rate (Btu/kWhr HHV)	6,795	6,782	6,775	6,764	6,772	6,780	6,822	6,876	7,011	7,233	7,324	7,405	7498.813
Plant Output													
Net Plant Output (kW)	561334	550000	528152	514325	524773	438787	419175	400129	364944	316711	299884	284194	258477.5
Stack Emissions per Unit													
NOx, ppmvd @15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
NOx, lb/hr	18.9	18.5	17.8	17.4	17.7	14.9	14.4	13.9	13.1	11.3	12.3	11.9	10.15423
SO2, lb/hr	9.9	9.7	9.3	9.1	9.3	7.8	7.5	7.2	6.7	6.0	5.7	5.5	5.1

Natual gas sulfur 2 gr/100 SCF
Perfromance new and clean

Figure 8

Okeechobee Generating Project
Process Flow Schematic

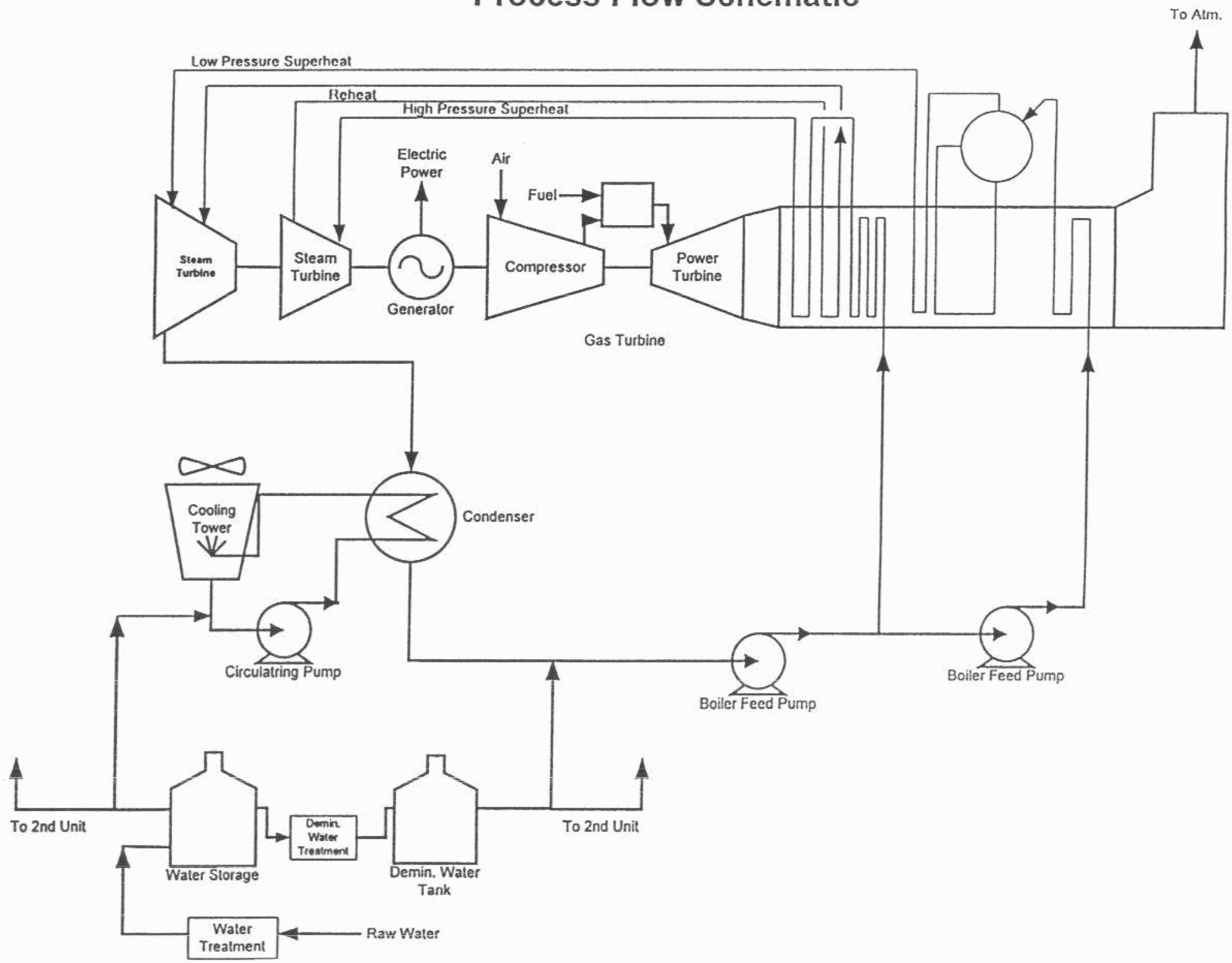
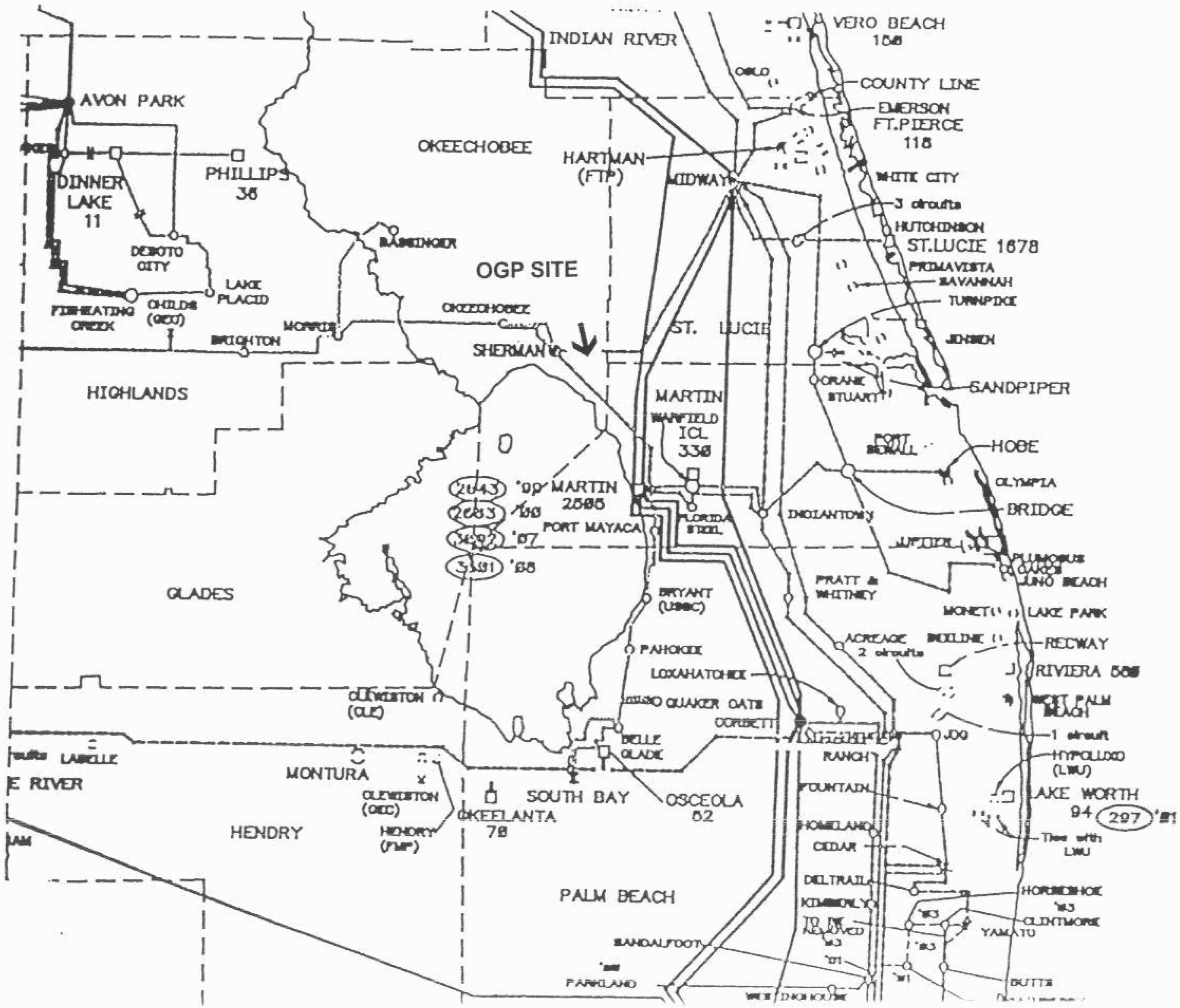
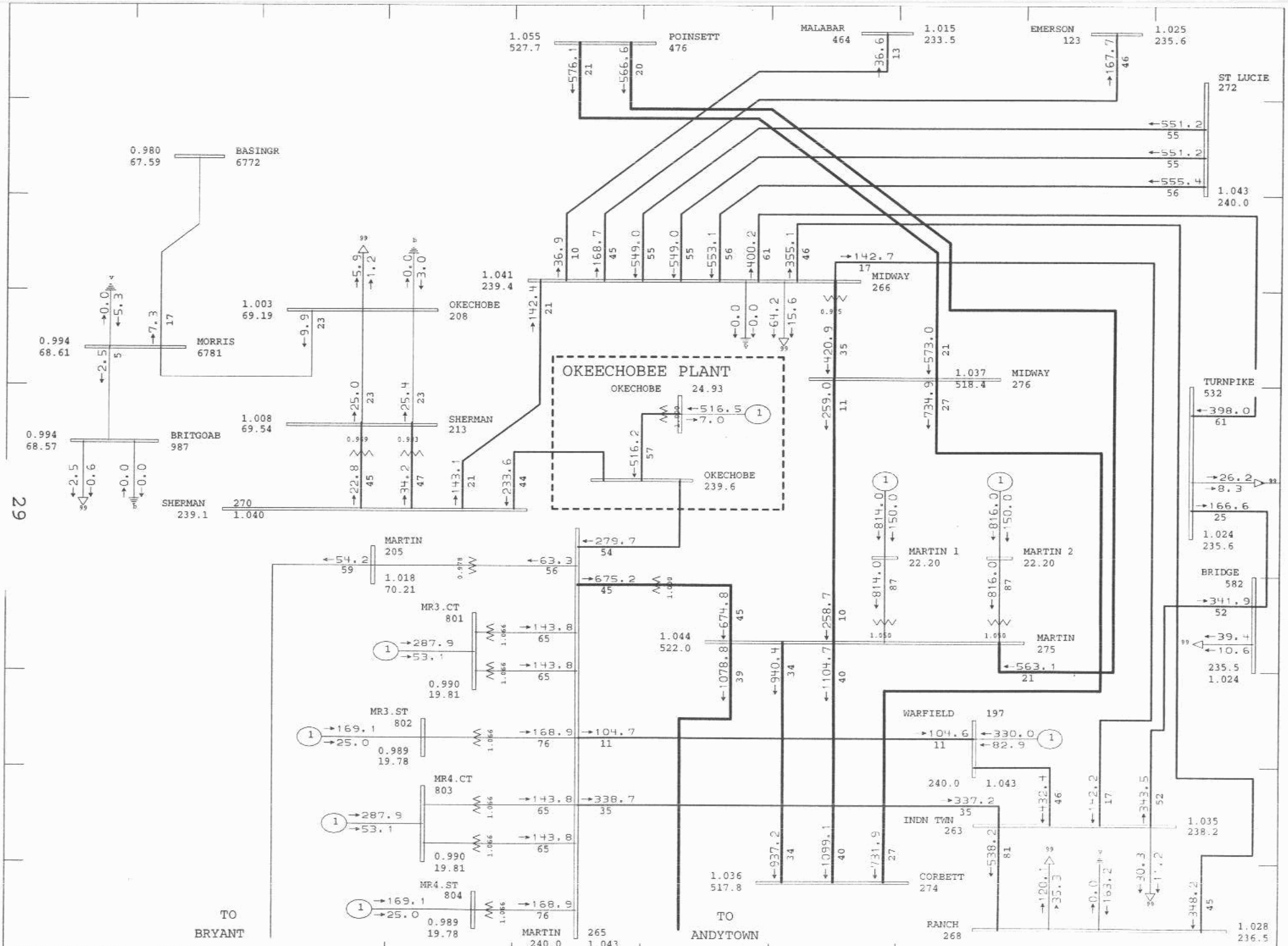


FIGURE 9
Okeechobee Generating Project
Regional Transmission Map





General Electric Company PSLF Program

FIGURE 10
OKEECHOBEE INTERCONNECTION STUDIES

BKJ 9/18/99

2003 SUMMER BASE CASE - FY 1998 - REVISION 5
CASE 503-A: 516.5 MW FROM OKEECHOBEE PLANT DISPATCHED TO TEC

MW/Pct Mon Sep 20 09:48:17 1999
d:\ok03-3\jako.drw
s03-a.sav
Rating = 1

output. The power system impact studies also indicate that, under normal conditions, the Project will not burden the transmission system or violate any transmission constraints or contingencies in Peninsular Florida. The transmission studies indicate that, under two contingency conditions (outage of Project switchyard to Sherman, outage of Project switchyard to Martin), there are apparent marginal exceedences (approximately 8%) of the winter seasonal ratings of the 230 kV Sherman-Project switchyard and Project switchyard-Martin lines. In addition, there are three other apparent marginal exceedences (3-5%) of winter seasonal ratings on transmission lines operating at 138 kV. If these apparent marginal exceedences prove to represent significant concerns, they can be remedied. OGC expects to be represented on the Florida Reliability Coordinating Council ("FRCC").

E. **Associated Facilities**.

Natural gas will be provided to the Project through the Gulfstream Natural Gas System. (The Gulfstream pipeline will be permitted separately by Gulfstream.) The natural gas pipeline is planned to traverse the southern portion of the site as illustrated in Figure 11, a total Gulfstream system map, and Figure 12, a map of the Gulfstream pipeline's route in the vicinity of the Project. The diameter of the Gulfstream pipeline directly servicing the Project will be 30 inches. The pipeline pressure at the OGC site

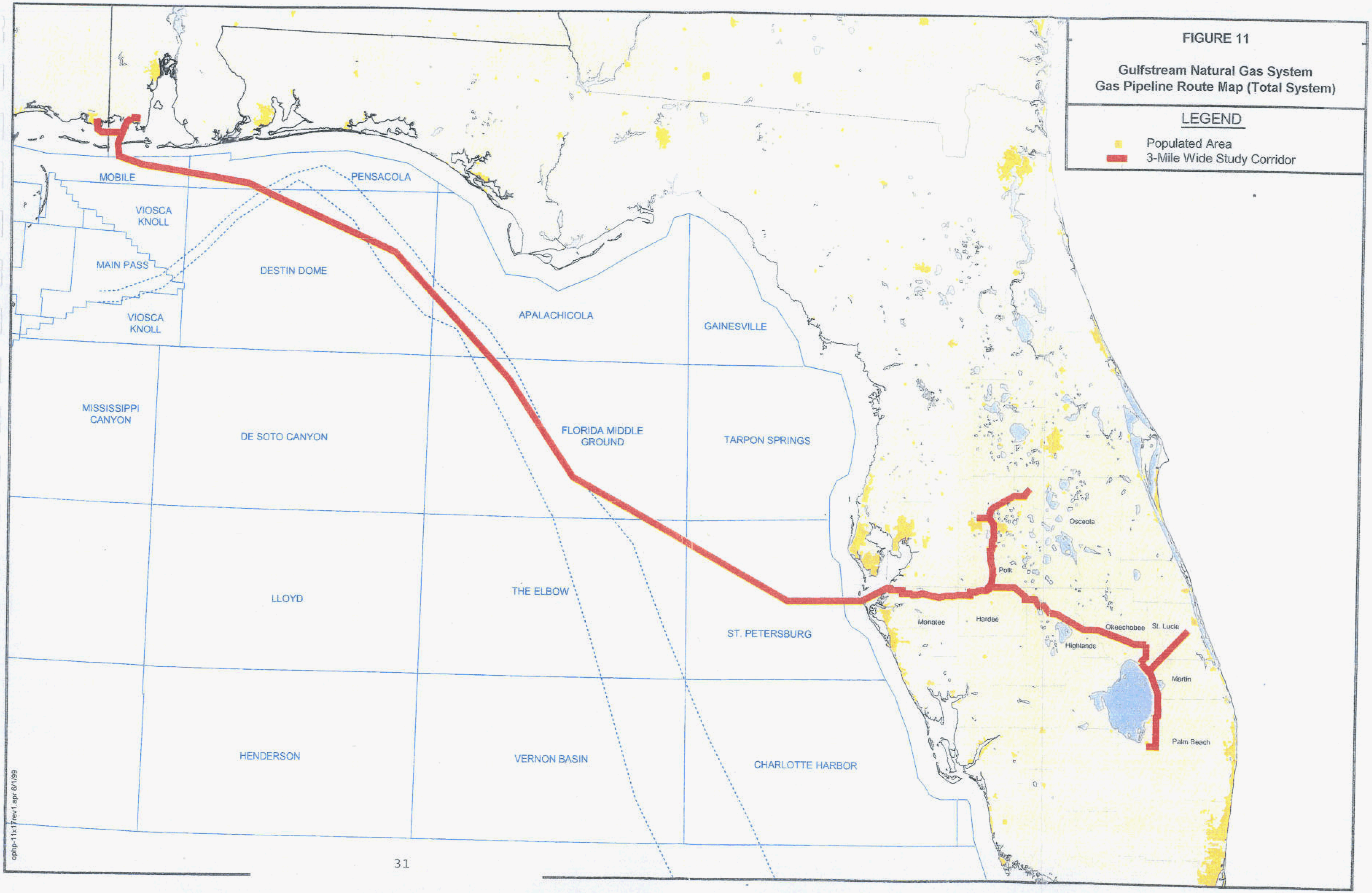


FIGURE 11
Gulfstream Natural Gas System
Gas Pipeline Route Map (Total System)
LEGEND
Populated Area
3-Mile Wide Study Corridor
MOBILE
PENSACOLA
VIOSCA KNOLL
MAIN PASS
DESTIN DOME
VIOSCA KNOLL
APALACHICOLA
GAINESVILLE
MISSISSIPPI CANYON
DE SOTO CANYON
FLORIDA MIDDLE GROUND
TARPON SPRINGS
LLOYD
THE ELBOW
ST. PETERSBURG
HENDERSON
VERNON BASIN
CHARLOTTE HARBOR
Osceola
Polk
Manatee
Hardee
Highlands
Okeechobee
St. Lucie
Martin
Palm Beach
ophp-11x17rev1.apr 6/1/99

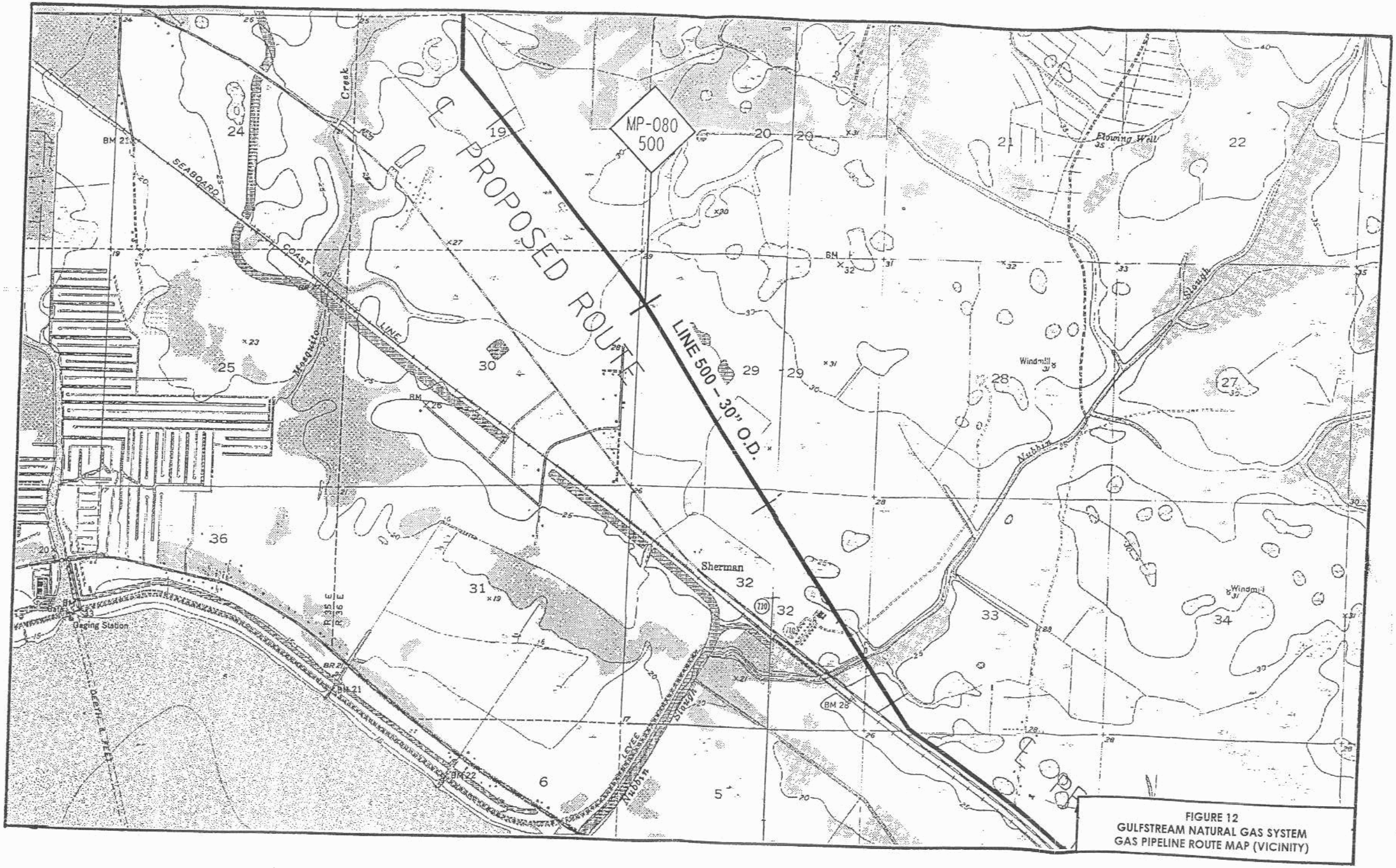


FIGURE 12
GULFSTREAM NATURAL GAS SYSTEM
GAS PIPELINE ROUTE MAP (VICINITY)

is guaranteed by Gulfstream to be 725 psig.[2] Gas transportation will be pursuant to a Precedent Agreement between OGC and Gulfstream. Pursuant to the Precedent Agreement, Gulfstream has committed to provide firm gas transportation service to operate the Project at full capacity for a term of 20 years; thereafter, the gas transportation service agreement may be renewed on a year-to-year basis. The route of the planned new trans-Florida pipeline is shown in Figure 11 of these Exhibits.

F. <u>Capital Cost of the Okeechobee Generating Project</u>.

The direct construction cost of the Okeechobee Generating Project is expected to be approximately $190 million, including the direct construction costs of the electrical switchyard and interconnection. (The pipeline will be constructed by Gulfstream at its expense.)

G. <u>Project Financing</u>.

The Project will be constructed and brought into commercial service with a combination of debt and equity funding that will be used to pay construction and development costs. For planning purposes, it is assumed that 50 percent of the Project cost will be funded through equity investment, with the remaining 50 percent

---

[2]Details of the natural gas transportation arrangements are provided for informational purposes only. Permitting of the pipeline will be sought by Gulfstream in a separate proceeding.

being obtained in the debt market. Regardless of the ultimate financial structure of the Okeechobee Generating Project, no retail ratepayers will be placed at risk.

H. **Fuel Supply**.

The primary fuel for the Project will be natural gas. Natural gas fuel supply for the Project will be provided to Gulfstream receipt points by natural gas marketing companies or producers, through an optimized combination of short-term contract purchases, long-term contract purchases, and spot market purchases. Specifically, the Project will purchase natural gas from producers and marketing companies that have access to those natural gas treatment plants, processing plants, and interstate natural gas transmission systems with supply located in the vicinity of Mobile Bay, Alabama, and Pascagoula, Mississippi. In addition, Gulfstream proposes interconnections with the Mobile Bay Pipeline (Koch), the Destin Plant, the Dauphin Island Gathering System plant, the Williams Plant and the Mobil Mary Ann Plant. The ultimate capacity of the proposed Gulfstream system will be more than one billion cubic feet per day. The natural gas sellers will be responsible for delivery into the Gulfstream pipeline system.

I. **Back-up Fuel**.

A back-up supply of distillate fuel oil will be maintained at the Project site to ensure continued operation of the plant in the event that natural gas is not available. The Project will have on-site fuel oil storage capacity sufficient to provide the maximum daily fuel quantity required by the plant to generate at its maximum capacity for 24 hours without refilling storage. The on-site oil storage facility will be designed to hold approximately 650,000 gallons of fuel oil, equivalent to 90,000 MMBtu of natural gas, the maximum daily quantity of natural gas required for the Project. As the fuel oil storage starts to be drawn down, local suppliers will commence refilling the on-site oil storage facility. This arrangement provides a high level of assurance that the Project will be able to maintain its full output during any reasonably foreseeable gas supply interruption.

J. **Projected Operational Reliability.**

The combined cycle generating unit is projected to have high efficiency and availability. With a heat rate of 6,775 Btu per kWh (based on the Higher Heating Value of natural gas) at ambient site conditions, the net thermal efficiency is expected to be approximately 50.4 percent. The Project is expected to have an Equivalent Availability Factor of 93 percent, a Forced Outage Rate of 2 percent and a Planned Outage Rate of 5 percent. The Project is expected to operate at Capacity Factors of approximately 93 percent from 2004 through 2013. Basic operational reliability information for the Project is shown on the Project Profile included here as Table 1.

K. **Project Schedule**.

Conceptual engineering for the Project is complete. A preliminary site review has been completed. The on-site wetlands in the vicinity of the power-block footprint have been delineated and topographic mapping of the site has also been completed. Preliminary engineering is scheduled to begin in July 2001, and detailed design and engineering are scheduled to begin in October 2001. Full release of the long-lead-time components -- the combustion turbines, heat recovery steam generators, and steam turbine generators -- is projected to be issued, and construction is expected to begin, immediately following issuance of the site certification. The Project is scheduled to achieve commercial in-service status in phased construction with the first unit commencing commercial operation in April 2003, and the second unit in June 2003. The Project engineering and construction schedule is depicted in Figure 13.

L. **Regulatory and Permitting Schedules**.

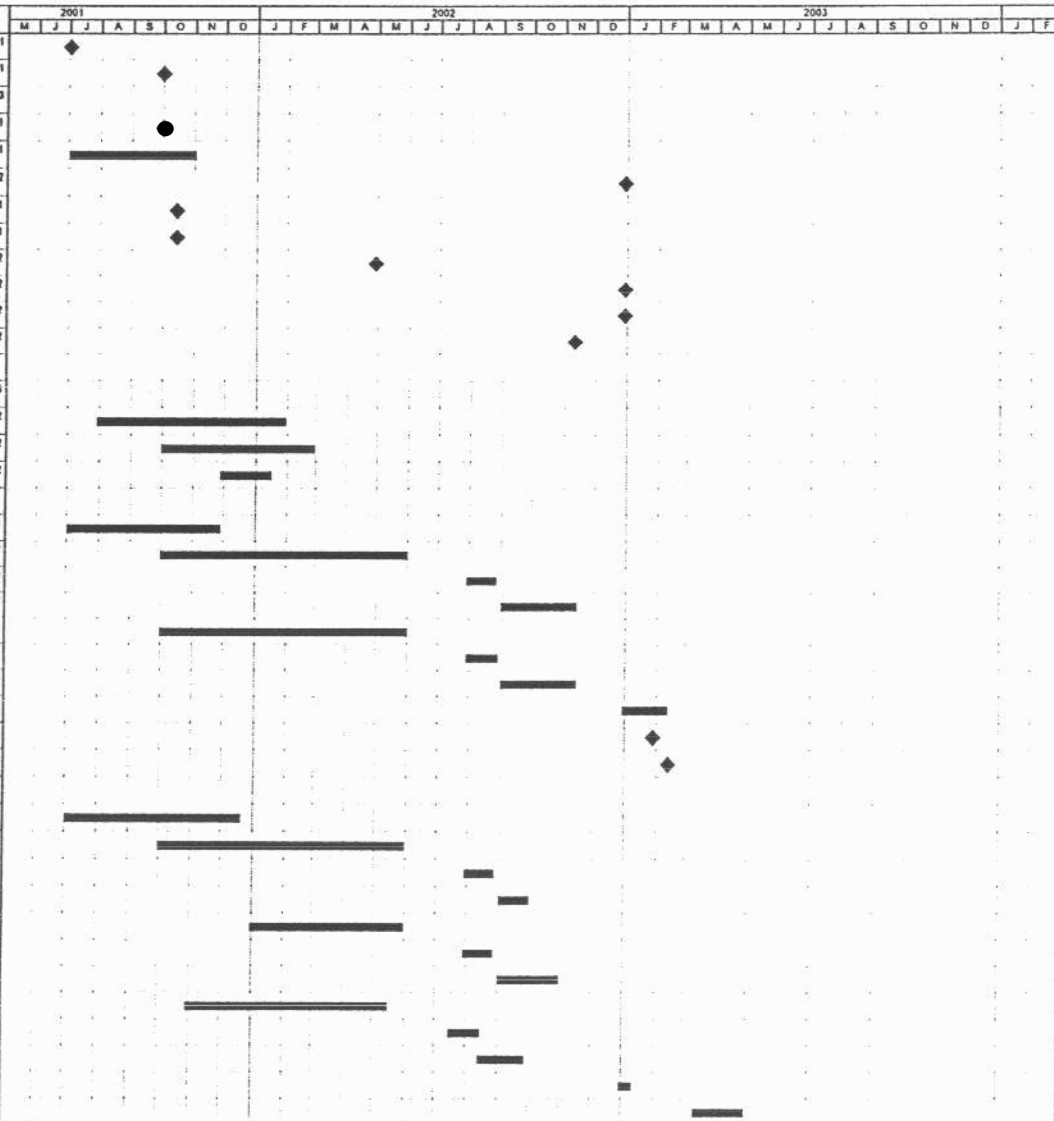
This need determination application was filed on September 24, 1999, and the need determination hearing is expected to be held in December 1999. The Commission's order is expected by the middle of March 2000. OGC expects to file the Site Certification Application

FIGURE 13
OKEECHOBEE GENERATING PROJECT
PROJECT SCHEDULE

PG&E Generating™

Okeechobee Generating Project

ID	Task Name	Start	Finish
1	**Notice to Commence Engineering**	Mon 7/2/01	Mon 7/2/01
2	**Notice to Proceed**	Mon 10/1/01	Mon 10/1/01
3	**Project Key Dates**	Mon 7/2/01	Wed 6/18/03
4	-Access to Site	Mon 10/1/01	Mon 10/1/01
5	-Site Preparation	Mon 7/2/01	Thu 11/1/01
6	-Water Supply for Commissioning and Operation	Mon 12/30/02	Mon 12/30/02
7	-Water Available for Construction	Mon 10/15/01	Mon 10/15/01
8	-Power Available for Construction	Mon 10/15/01	Mon 10/15/01
9	-Waste Water Connection Available	Mon 4/29/02	Mon 4/29/02
10	-Fuel Gas Available	Mon 12/30/02	Mon 12/30/02
11	-Fuel Oil Available	Mon 12/30/02	Mon 12/30/02
12	-HV Electrical Interconnect Available	Mon 11/11/02	Mon 11/11/02
13			
14	Power island Unit 1	Mon 7/2/01	Wed 4/30/03
15	Arrangement Planning	Mon 7/30/01	Tue 1/29/02
16	Civil Engineering	Mon 10/1/01	Wed 2/27/02
17	Civil Construction	Wed 11/28/01	Tue 1/15/02
18			
19	Engineering GT System	Mon 7/2/01	Tue 11/27/01
20	Procurement GT & Auxiliaries	Mon 10/1/01	Fri 5/31/02
21	Transport GT & Auxiliaries	Tue 7/30/02	Mon 8/26/02
22	Installation GT & Auxiliaries	Mon 9/2/02	Wed 11/13/02
23	Procurement Generator & Auxiliaries	Mon 10/1/01	Fri 5/31/02
24	Transport Generator & Auxiliaries	Tue 7/30/02	Wed 8/28/02
25	Installation Generator & Accessories	Mon 9/2/02	Wed 11/13/02
26	Commissioning GT & Auxiliaries	Mon 12/30/02	Tue 2/11/03
27	First Ignition GT	Wed 1/29/03	Wed 1/29/03
28	First Synchronization GT	Thu 2/13/03	Thu 2/13/03
29			
30	Engineering W/S & ST	Mon 7/2/01	Wed 12/19/01
31	Procurement ST	Mon 10/1/01	Thu 5/30/02
32	Transport ST	Tue 7/30/02	Mon 8/26/02
33	Installation ST	Mon 9/2/02	Mon 9/30/02
34	Procurement Piping / Valves	Mon 12/31/01	Thu 5/30/02
35	Transport Piping / Valves	Tue 7/30/02	Mon 8/26/02
36	Installation Piping / Valves	Mon 9/2/02	Wed 10/30/02
37	Procurement Air cooled Condenser	Tue 10/30/01	Wed 5/15/02
38	Transport Air Cooled Condenser	Tue 7/16/02	Wed 8/14/02
39	Installation Air Cooled Condenser	Wed 8/14/02	Fri 9/27/02
40	Commissioning W/S & ST	Mon 12/30/02	Fri 1/10/03
41	Optimization Incl. Funct / Performance Test	Thu 3/13/03	Wed 4/30/03



Project: Rschedul
Date: Tue 9/21/99

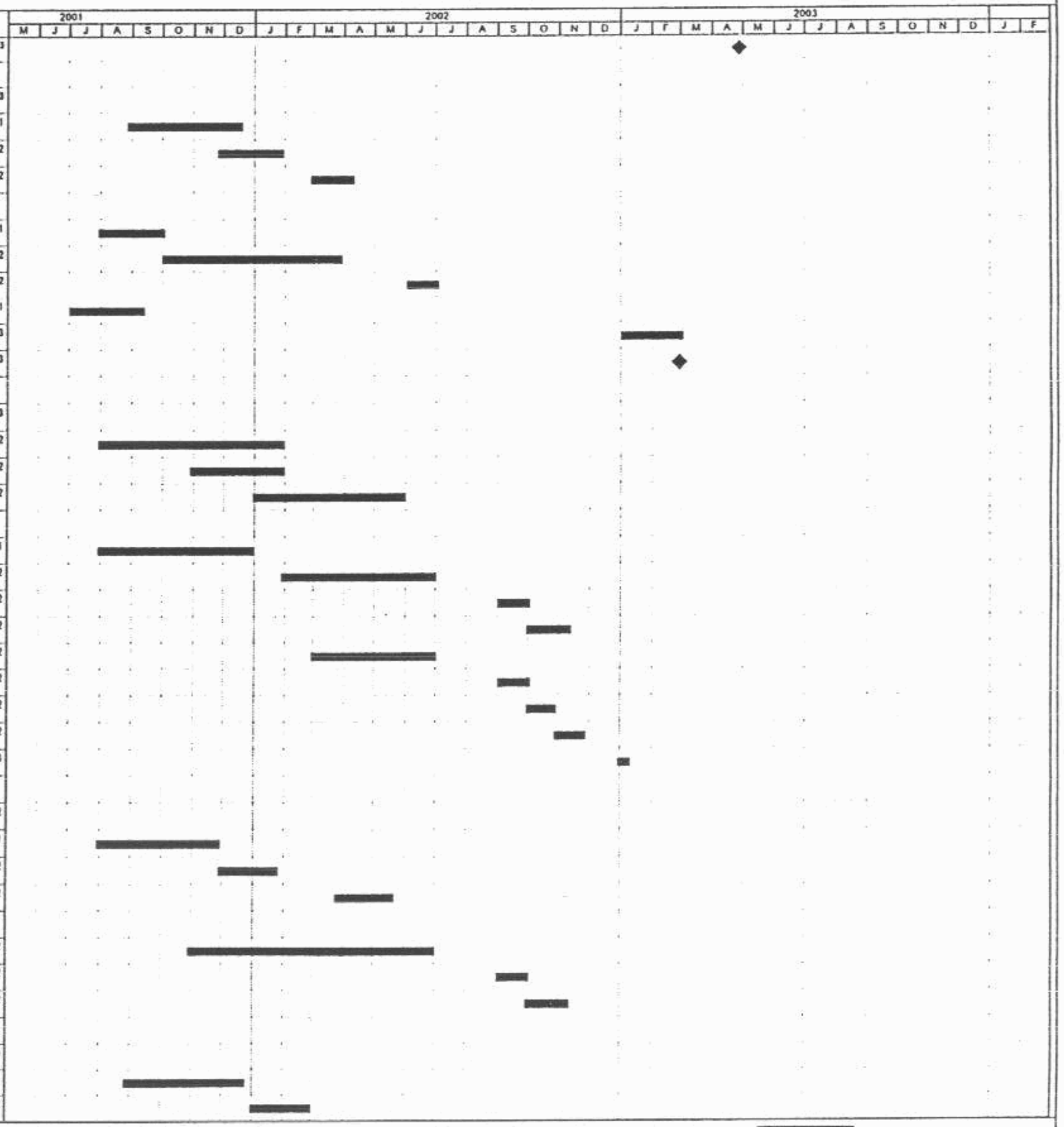
Task | Progress | Summary | Rolled Up Split | Rolled Up Progress | Project Summary
Split | Milestone | Rolled Up Task | Rolled Up Milestone | External Tasks

FIGURE 13
(continued)

PG&E Generating

Okeechobee Generating Project

ID	Task Name	Start	Finish
42	Substantial Completion Unit 1	Mon 4/28/03	Mon 4/28/03
43			
44	**Heat Recovery Steam Generator Unit 1**	Mon 7/2/01	Mon 3/3/03
45	Arrangement Planning	Tue 8/28/01	Wed 12/19/01
46	Civil Engineering	Mon 11/26/01	Tue 1/29/02
47	Civil Construction	Wed 2/27/02	Wed 4/10/02
48			
49	Engineering HRSG	Mon 7/30/01	Tue 10/2/01
50	Procurement HRSG	Mon 10/1/01	Fri 3/29/02
51	Transport HRSG	Mon 6/3/02	Wed 7/3/02
52	Installation HRSG	Mon 7/2/01	Wed 9/12/01
53	Commissioning HRSG	Thu 1/2/03	Mon 3/3/03
54	First Steam to Turbine	Fri 2/28/03	Fri 2/28/03
55			
56	**Electrical & Control Building Unit 1**	Mon 7/30/01	Fri 1/10/03
57	Arrangement Planning	Mon 7/30/01	Wed 1/30/02
58	Civil Engineering	Mon 10/29/01	Wed 1/30/02
59	Civil Construction	Mon 12/31/01	Fri 5/31/02
60			
61	Engineering Electrical System	Mon 7/30/01	Mon 12/31/01
62	Procurement Electrical Equipment	Tue 1/29/02	Mon 7/1/02
63	Transport Electrical Equipment	Mon 9/2/02	Wed 10/2/02
64	Installation Electrical Euipment	Mon 9/30/02	Tue 11/12/02
65	Procurement Control Equipment	Thu 2/28/02	Mon 7/1/02
66	Transport Control Equipment	Mon 9/2/02	Wed 10/2/02
67	Installation Control Equipment	Mon 9/30/02	Mon 10/28/02
68	Cabling	Mon 10/28/02	Wed 11/27/02
69	Commissioning Electrical System	Mon 12/30/02	Fri 1/10/03
70			
71	**Transformer Area Unit 1**	Mon 7/30/01	Mon 11/11/02
72	Arrangement Planning	Mon 7/30/01	Wed 11/28/01
73	Civil Engineering	Wed 11/28/01	Fri 1/25/02
74	Civil Construction	Mon 3/25/02	Tue 5/21/02
75			
76	Procurement Transformer	Mon 10/29/01	Mon 7/1/02
77	Transport Transformer	Mon 9/2/02	Wed 10/2/02
78	Installation Transformer	Mon 9/30/02	Mon 11/11/02
79			
80	**Fuel System**	Mon 7/30/01	Tue 3/11/03
81	Arrangement Planning	Mon 8/27/01	Mon 12/24/01
82	Civil Engineering	Mon 12/31/01	Thu 2/28/02



Project: 8-schedul
Date: Tue 9/21/99

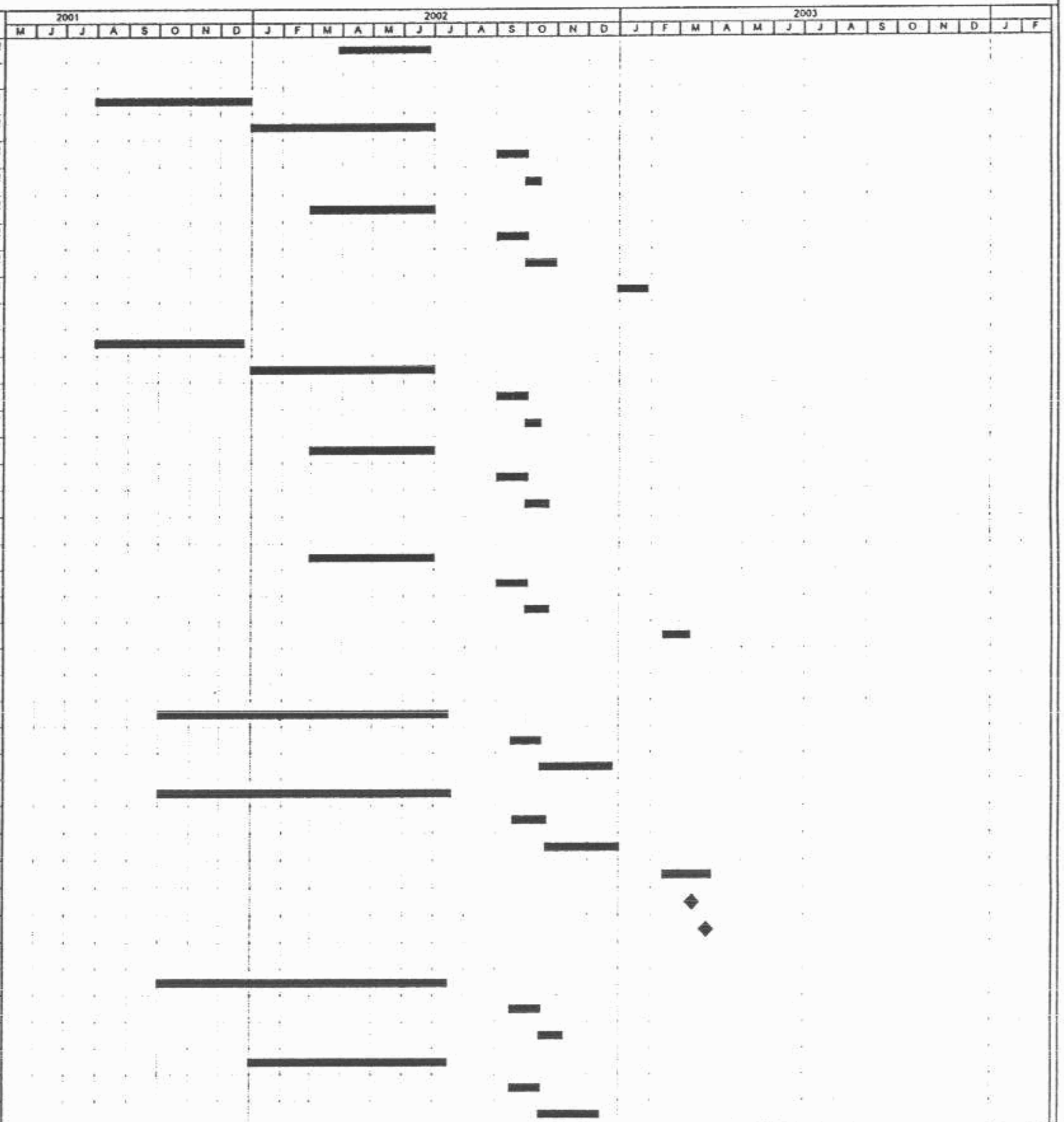
Task · Progress · Summary · Rolled Up Split · Rolled Up Progress · Project Summary
Split · Milestone · Rolled Up Task · Rolled Up Milestone · External Tasks

FIGURE 13
(continued)

PG&E Generating™

Okeechobee Generating Project

ID	Task Name	Start	Finish
83	Civil Construction	Thu 3/28/02	Wed 6/26/02
84			
85	Engineering Fuel Gas System	Mon 7/30/01	Mon 12/31/01
86	Procurement Fuel Gas Equipment	Mon 12/31/01	Mon 7/1/02
87	Transport Fuel Gas Equipment	Mon 9/2/02	Wed 10/2/02
88	Installation Fuel Gas Equipment	Mon 9/30/02	Tue 10/15/02
89	Procurement Fuel Gas Piping	Thu 2/28/02	Mon 7/1/02
90	Transport Guel Gas Piping	Mon 9/2/02	Wed 10/2/02
91	Installation Fuel Gas Piping	Mon 9/30/02	Wed 10/30/02
92	Commissioning Fuel Gas System	Mon 12/30/02	Tue 1/28/03
93			
94	Engineering Fuel Oil System	Mon 7/30/01	Mon 12/24/01
95	Procurement Fuel Oil Equipment	Mon 12/31/01	Mon 7/1/02
96	Transport Fuel Oil Equipment	Mon 9/2/02	Wed 10/2/02
97	Installation Fuel Oil Equipment	Mon 9/30/02	Tue 10/15/02
98	Procurement Fuel Oil Tank	Thu 2/28/02	Mon 7/1/02
99	Transport Fuel Oil Tank	Mon 9/2/02	Wed 10/2/02
100	Installation Fuel Oil Tank	Mon 9/30/02	Wed 10/23/02
101			
102	Procurement Fuel Oil Piping	Thu 2/28/02	Mon 7/1/02
103	Transport Fuel Oil Piping Installation Fuel Oil Piping	Mon 9/2/02	Wed 10/2/02
104	Installation Fuel Oil Piping	Mon 9/30/02	Wed 10/23/02
105	Commissioning Fuel Oil System	Thu 2/13/03	Tue 3/11/03
106			
107	**Power Island Unit 2**	Mon 10/1/01	Wed 6/18/03
108	Procurement GT & Auxiliaries	Mon 10/1/01	Mon 7/15/02
109	Transport GT & Auxiliaries	Mon 9/16/02	Wed 10/16/02
110	Installation GT & Auxiliaries	Tue 10/15/02	Wed 12/25/02
111	Procurement Generator & Auxiliaries	Mon 10/1/01	Thu 7/18/02
112	Transport Generator & Auxiliaries	Wed 9/18/02	Mon 10/21/02
113	Installation Generator & Accessories	Mon 10/21/02	Wed 1/1/03
114	Commissioning GT & Auxiliaries	Thu 2/13/03	Tue 4/1/03
115	First Ignition GT	Fri 3/14/03	Fri 3/14/03
116	First Synchronization GT	Fri 3/28/03	Fri 3/28/03
117			
118	Procurement ST	Mon 10/1/01	Mon 7/15/02
119	Transport ST	Mon 9/16/02	Wed 10/16/02
120	Installation ST	Tue 10/15/02	Thu 11/7/02
121	Procurement Piping / Valves	Mon 12/31/01	Mon 7/15/02
122	Transport Piping / Valves	Mon 9/16/02	Wed 10/16/02
123	Installation Piping / Valves	Tue 10/15/02	Fri 12/13/02



Project: Schedul
Date: Tue 9/21/99

Task · Progress · Summary · Rolled Up Split · Rolled Up Progress · Project Summary
Split · Milestone · Rolled Up Task · Rolled Up Milestone · External Tasks

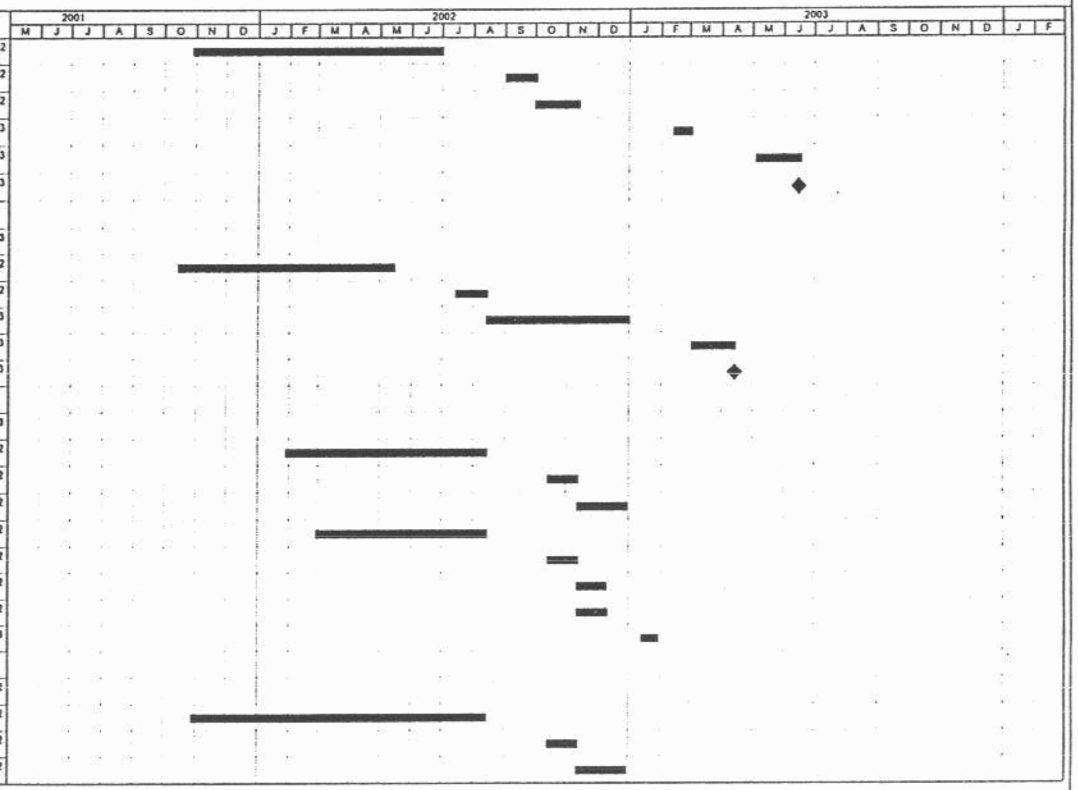
Page 3

FIGURE 13
(continued)

PG&E Generating

Okeechobee Generating Project

ID	Task Name	Start	Finish
124	Procurement Air cooled Condenser	Mon 10/29/01	Mon 7/1/02
125	Transport Air Cooled Condenser	Mon 9/2/02	Wed 10/2/02
126	Installation Air Cooled Condenser	Tue 10/1/02	Wed 11/13/02
127	Commissioning W/S & ST	Thu 2/13/03	Mon 3/3/03
128	Optimization Incl. Funct / Performance Test	Mon 5/5/03	Wed 6/18/03
129	Substantial Completion Unit 2	Mon 6/16/03	Mon 6/16/03
130			
131	**Heat Recovery Steam Generator Unit 2**	Mon 10/15/01	Mon 4/14/03
132	Procurement HRSG	Mon 10/15/01	Wed 5/15/02
133	Transport HRSG	Mon 7/15/02	Wed 8/14/02
134	Installation HRSG	Wed 8/14/02	Wed 1/1/03
135	Commissioning HRSG	Mon 3/3/03	Mon 4/14/03
136	First Steam to Turbine	Mon 4/14/03	Mon 4/14/03
137			
138	**Electrical & Control Building Unit 2**	Tue 1/29/02	Wed 1/29/03
139	Procurement Electrical Equipment	Tue 1/29/02	Wed 8/14/02
140	Transport Electrical Equipment	Mon 10/14/02	Tue 11/12/02
141	Installation Electrical Equipment	Tue 11/12/02	Mon 12/30/02
142	Procurement Control Equipment	Thu 2/28/02	Wed 8/14/02
143	Transport Control Equipment	Mon 10/14/02	Tue 11/12/02
144	Installation Control Equipment	Tue 11/12/02	Tue 12/10/02
145	Cabling	Tue 11/12/02	Wed 12/11/02
146	Commissioning Electrical System	Tue 1/14/03	Wed 1/29/03
147			
148	**Transformer Area Unit 2**	Mon 10/29/01	Mon 12/30/02
149	Procurement Transformer	Mon 10/29/01	Wed 8/14/02
150	Transport Transformer	Mon 10/14/02	Tue 11/12/02
151	Installation Transformer	Tue 11/12/02	Mon 12/30/02



Project: 8-schedul
Date: Tue 9/21/99

Task — Progress — Summary — Rolled Up Split — Rolled Up Progress — Project Summary

Split — Milestone — Rolled Up Task — Rolled Up Milestone — External Tasks for the Project by June 2000. The land use hearing is expected to be held by fall 2000, and the site certification hearing is expected to be held by early 2001. Final certification by the Siting Board is expected by October 2001. Details of the permitting schedule are shown in Figure 14 of these Exhibits.

M. Operations and Maintenance Plan.

PG&E Operating Services Company will have the responsibility for operating and maintaining the Project pursuant to a management contract with OGC. The Project's forced outage rate is expected to average approximately 2% per year. The maintenance outage rate is expected to average approximately 5% per year. The ABB turbines have a 6,000 hour maintenance cycle. A minor inspection, referred to as a Type A inspection, will be conducted at the end of 6,000 hours of operation. A slightly more detailed inspection, referred to as a Type B inspection, will be conducted at the end of 12,000 hours of operation. Another Type A inspection will be conducted at the end of 18,000 hours of operation, and a major inspection, referred to as a Type C inspection, will be conducted at 24,000 hours of operation. This cycle will be repeated for the life of the equipment. Type A and B inspections take approximately 4 to 7 days, and Type C inspection can take up to 30 days. Thus, the specific annual capacity factors for the Okeechobee Project are expected to average 93%, but they will be greater in years when

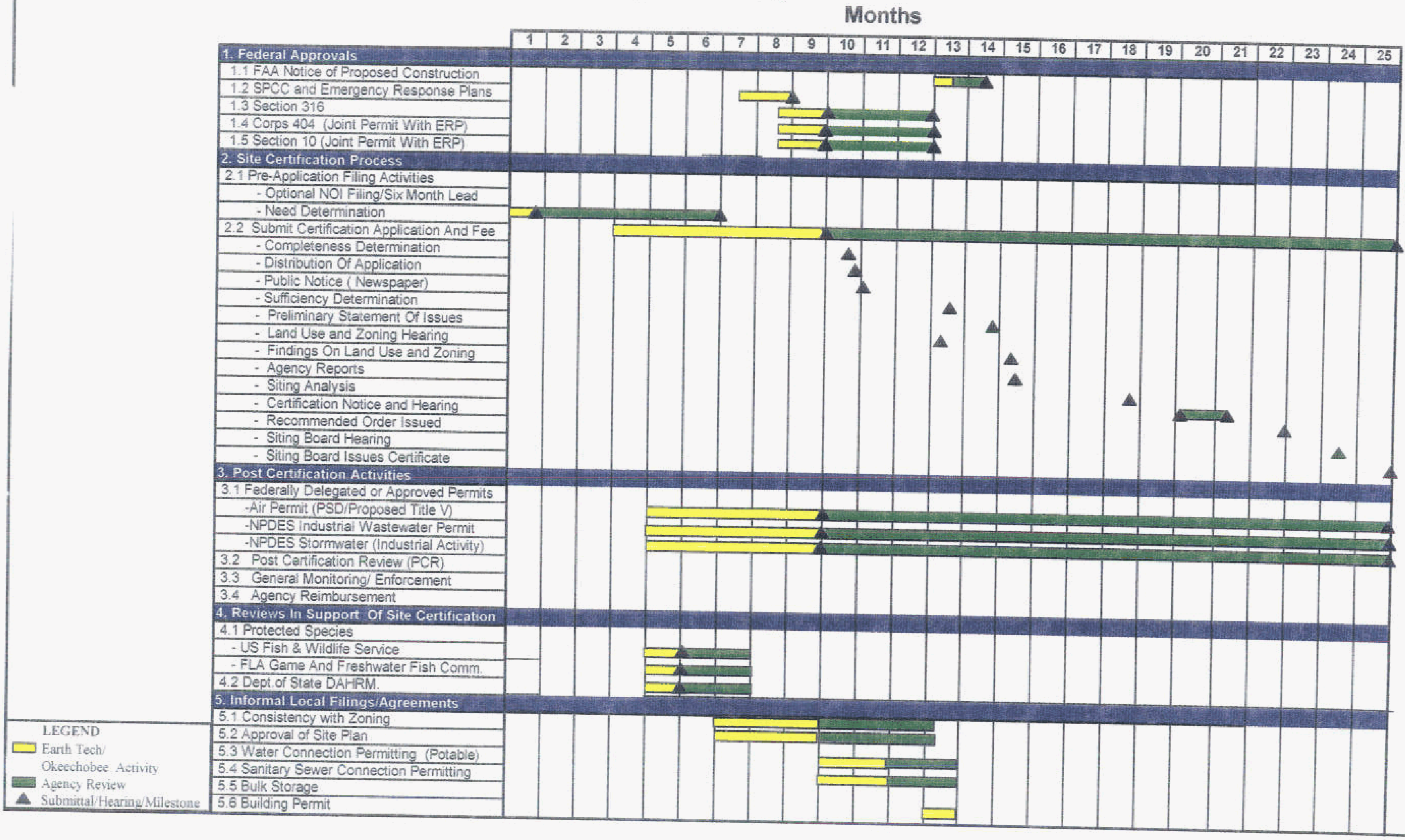
EARTH TECH

Figure 14

Environmental Licensing Schedule

Merchant Generating Facility, Okeechobee, Florida

Assumptions: 1. No adjustments to project concept after Month 3; 2. No major amendments to Site Certification Application; 3. Immediate Completeness Determination; 4. Site in Compliance With Local Zoning



only a Type A and B inspection is conducted, and less than 93% in years when a Type C inspection is performed.

IV. NEED FOR THE OKEECHOBEE GENERATING PROJECT

The Okeechobee Generating Project will provide total net generation capability of 514.3 MW in the summer and 561.3 MW in the winter. This additional capacity will meet the power supply needs of Okeechobee Generating Company, L.L.C. and will significantly increase the reliability of power supply in Peninsular Florida.

A. Power Supply Needs of Peninsular Florida.

Peninsular Florida's firm winter peak demand is projected to increase from approximately 36,000 MW in 1999 to more than 44,000 MW in 2008. Peninsular Florida's firm summer peak demand is projected to increase from approximately 34,000 MW to more than 41,000 MW over the same period. See Table 3 and Figures 15 and 16. Net Energy for Load in Peninsular Florida is projected to increase from approximately 186,000 GWH in 1999 to approximately 228,000 GWH in 2008. See Table 4 and Figure 17. As of January 1, 1999, total Peninsular Florida existing generating capacity was 39,128 MW for the winter and 37,338 for the summer. See Table 5. Tables 6 and 7 present projected capacity and reserve margin information for Peninsular Florida, with and without the capacity of the Okeechobee Generating Project.

The Okeechobee Generating Project will provide reliable and cost-effective power to power marketers and to utilities that provide retail service in Peninsular Florida. Peninsular Florida

TABLE 3

PENINSULAR FLORIDA, HISTORICAL AND PROJECTED SUMMER AND WINTER FIRM PEAK DEMANDS 1991-2008

PEAK DEMAND (MW)

	1991	1992	1993	1994	1995	1996	1997	1998
SUMMER	27662	28930	29748	29321	31801	32315	32924	37153
WINTER	28179	27215	28149	32618	34552	34762	30932	35907

	1999	2000	2001	2002	2003	2004	2005	2006
SUMMER	34023	34703	35380	36157	36988	37804	38638	39597
WINTER	35977	36819	37793	38749	39663	40566	41450	42476

	2007	2008
SUMMER	40443	41266
WINTER	43374	44286

FIGURE 15
PENINSULAR FLORIDA, HISTORICAL AND PROJECTED SUMMER PEAK DEMANDS

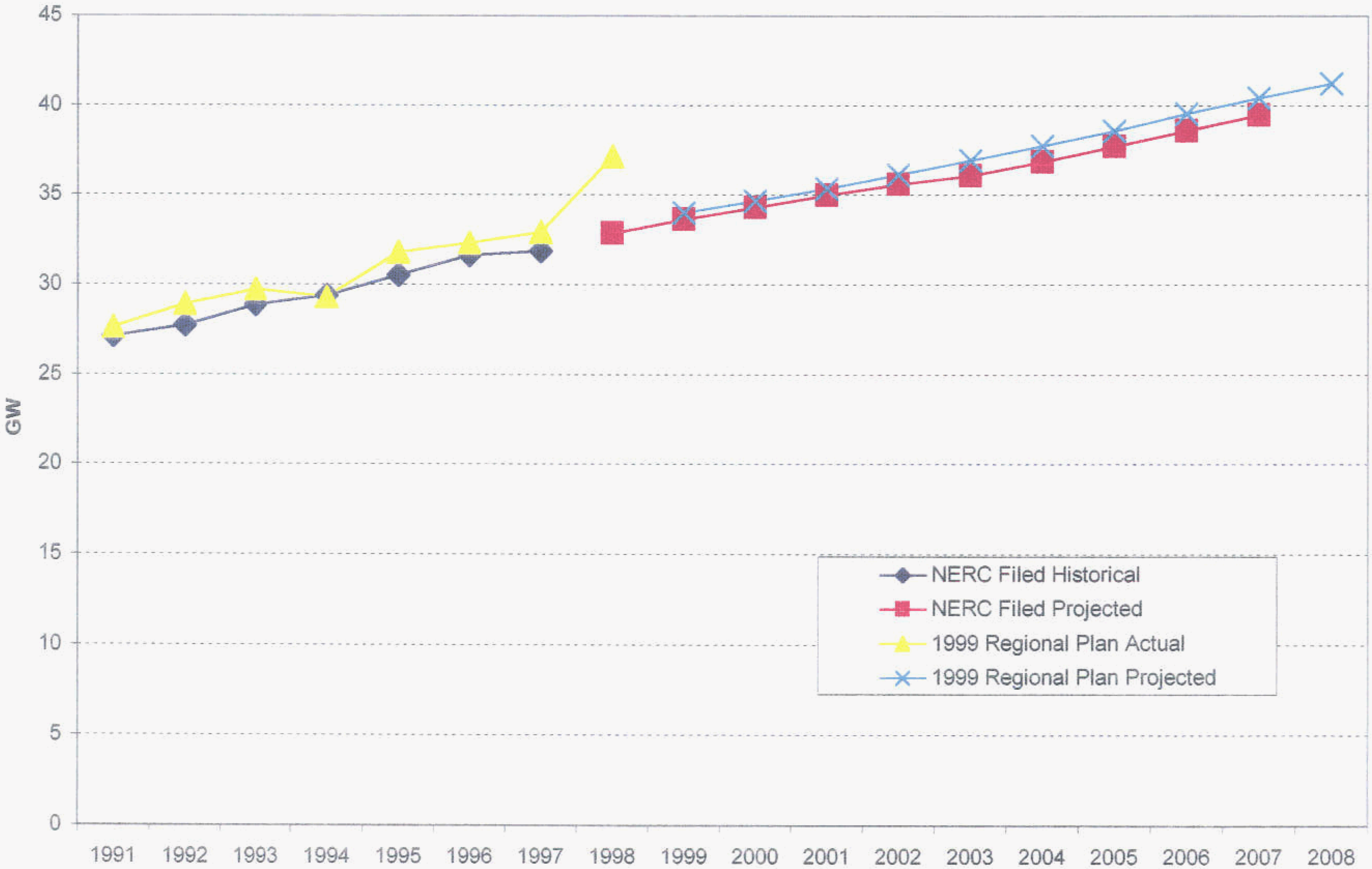


FIGURE 16
PENINSULAR FLORIDA, HISTORICAL AND PROJECTED WINTER PEAK DEMANDS

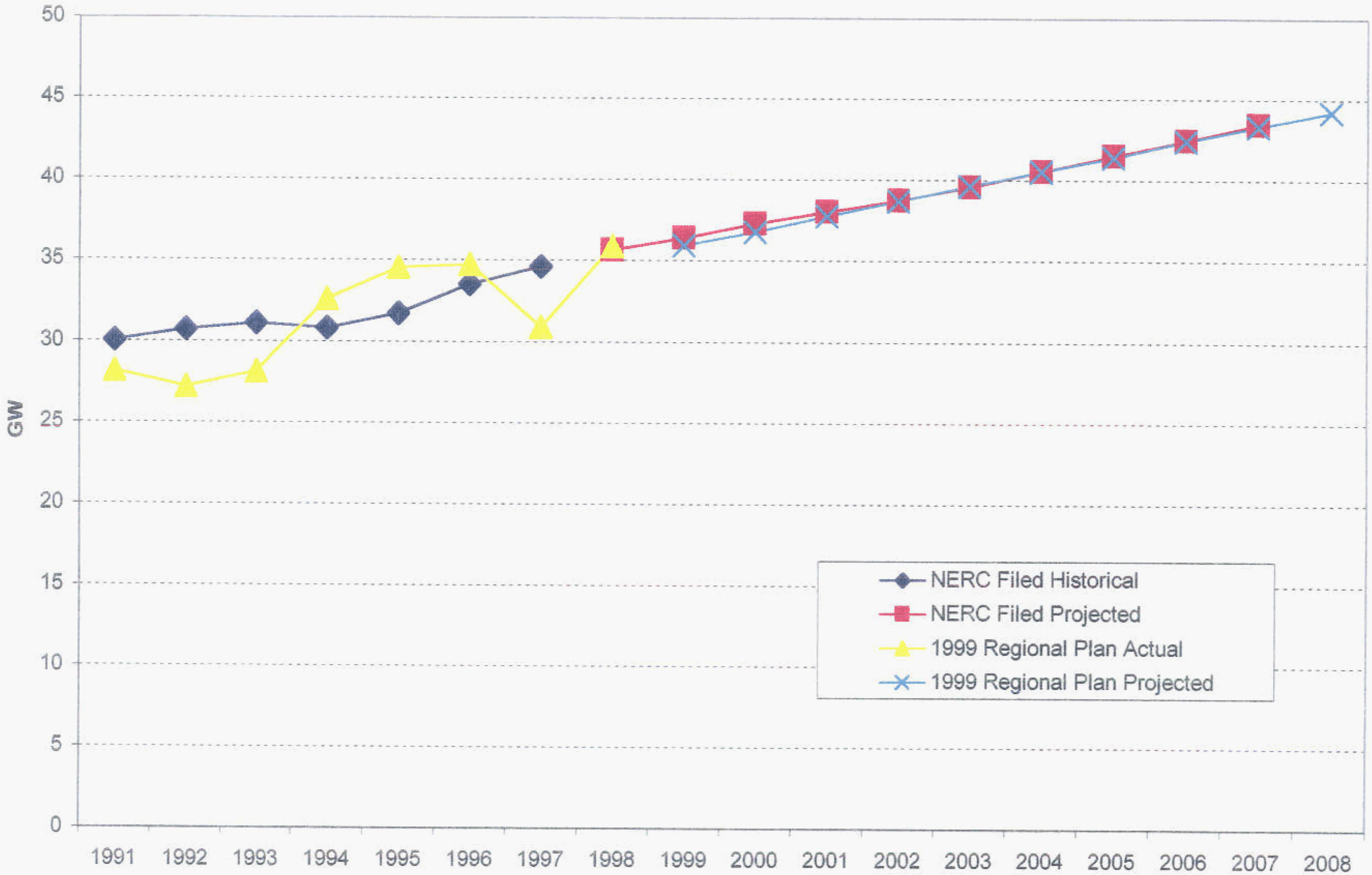


TABLE 4

PENINSULAR FLORIDA, HISTORICAL AND PROJECTED ENERGY REQUIREMENTS 1991-2008

Historical Energy Requirements (GWH)						
	1991	**1992**	**1993**	**1994**	**1995**	**1996**
ENERGY REQUIREMENTS	146786	147728	153269	159353	168982	173327
LOAD FACTOR %	59.46	58.13	58.82	55.77	55.83	56.76

Historical & Projected Energy Requirements (GWH)						
	1997	**1998**	**1999**	**2000**	**2001**	**2002**
ENERGY REQUIREMENTS	175534	187868	186374	190955	195687	200060
LOAD FACTOR %	60.86	57.72	59.14	59.04	59.11	58.94

Projected Energy Requirements (GWH)						
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
ENERGY REQUIREMENTS	204884	209492	214094	218611	223179	227645
LOAD FACTOR %	58.97	58.79	58.96	58.75	58.74	58.52

FIGURE 17
PENINSULAR FLORIDA, HISTORICAL AND PROJECTED NET ENERGY FOR LOAD

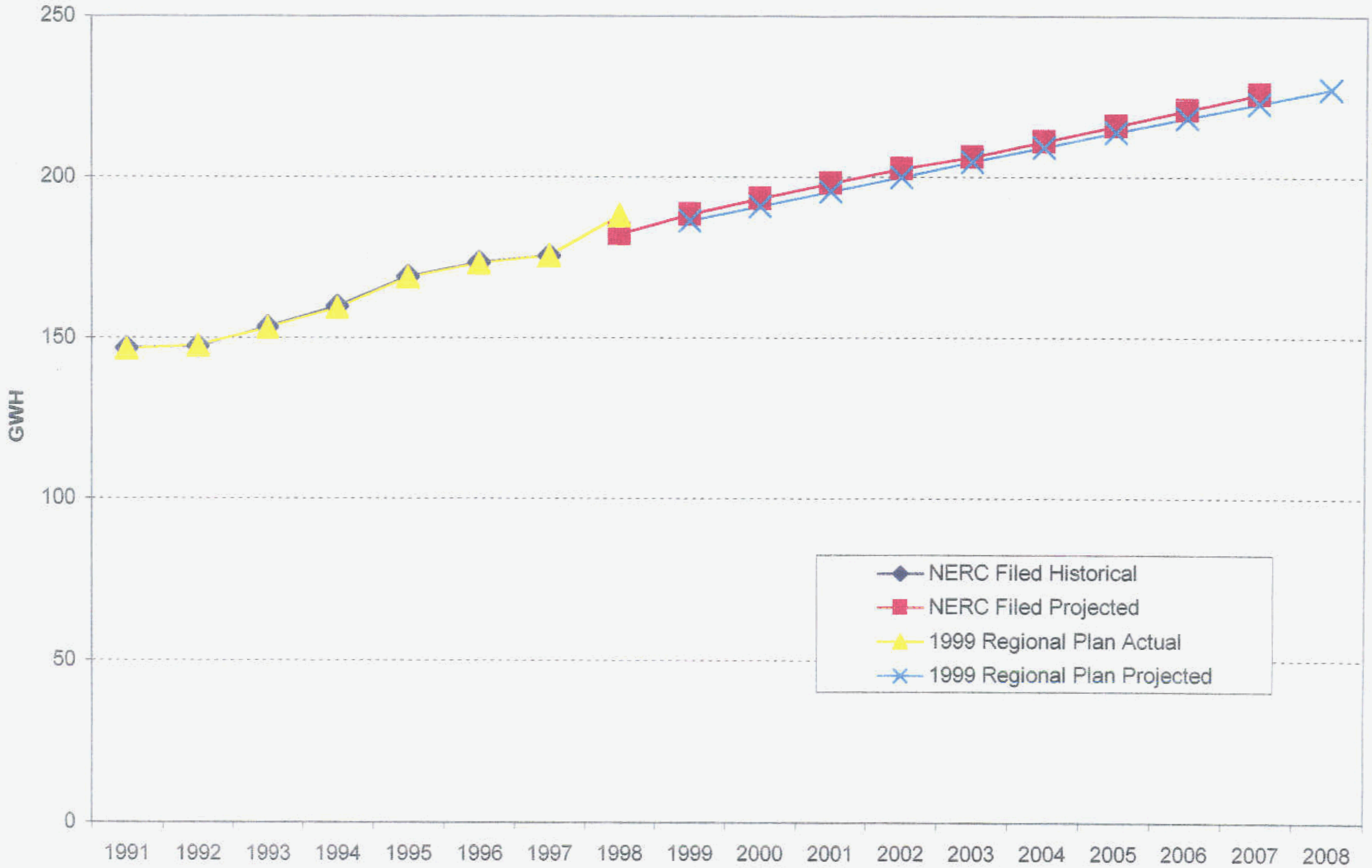


TABLE 5

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

	NET CAPABILITY	
UTILITY	**SUMMER**	**WINTER**
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOC., 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
JACKSONVILLE ELECTRIC AUTHORITY	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 UTILITIES EXISTING CAPACITY	35,165	36,880
NON-UTILITY GENERATING FACILITIES (FIRM)	2,076	2,129
NON-UTILITY GENERATING FACILITIES (NON-FIRM)	97	119
TOTAL PENINSULAR FLORIDA EXISTING CAPACITY	**37,338**	**39,128**

Data Source:
<u>1999 Regional Load & Resource Plan</u>
Florida Reliability Coordinating Council

TABLE 6

SUMMARY OF PENNINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK WITHOUT OKEECHOBEE GENERATING PROJECT

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1999	36,125	1,640	2,076	39,841	36,788	3,053	8.30	2,765	34,023	5,818	17.10
2000	36,518	1,755	2,076	40,349	37,541	2,808	7.48	2,838	34,703	5,646	16.27
2001	38,065	1,682	2,076	41,823	38,223	3,600	9.42	2,843	35,380	6,443	18.21
2002	40,151	1,658	2,055	43,864	38,959	4,905	12.59	2,802	36,157	7,707	21.32
2003	41,340	1,566	2,055	44,961	39,781	5,180	13.02	2,793	36,988	7,973	21.56
2004	41,777	1,566	2,055	45,398	40,593	4,805	11.84	2,789	37,804	7,594	20.09
2005	42,638	1,566	2,045	46,249	41,433	4,816	11.62	2,795	38,638	7,611	19.70
2006	43,207	1,566	1,912	46,685	42,398	4,287	10.11	2,801	39,597	7,088	17.90
2007	44,655	1,566	1,906	48,127	43,252	4,875	11.27	2,809	40,443	7,684	19.00
2008	45,369	1,566	1,891	48,826	44,066	4,760	10.80	2,800	41,266	7,560	18.32

*476 MW OF DUKE-NEW SMYRNA CAPACITY ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002

SUMMARY OF PENNINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK WITH OKEECHOBEE GENERATING PROJECT, 514 MW IN 2003

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
1999	36,125	1,640	2,076	39,841	36,788	3,053	8.30	2,765	34,023	5,818	17.10
2000	36,518	1,755	2,076	40,349	37,541	2,808	7.48	2,838	34,703	5,646	16.27
2001	38,065	1,682	2,076	41,823	38,223	3,600	9.42	2,843	35,380	6,443	18.21
2002	40,151	1,658	2,055	43,864	38,959	4,905	12.59	2,802	36,157	7,707	21.32
2003	41,854	1,566	2,055	45,475	39,781	5,694	14.31	2,793	36,988	8,487	22.95
2004	42,291	1,566	2,055	45,912	40,593	5,319	13.10	2,789	37,804	8,108	21.45
2005	43,152	1,566	2,045	46,763	41,433	5,330	12.86	2,795	38,638	8,125	21.03
2006	43,721	1,566	1,912	47,199	42,398	4,801	11.32	2,801	39,597	7,602	19.20
2007	45,169	1,566	1,906	48,641	43,252	5,389	12.46	2,809	40,443	8,198	20.27
2008	45,883	1,566	1,891	49,340	44,066	5,274	11.97	2,800	41,266	8,074	19.57

*476 MW OF DUKE-NEW SMYRNA CAPACITY ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002
**514 MW OF OKEECHOBEE GENERATING PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2003
SOURCES: Florida Reliability Coordinating Council,
1999 Regional Load & Resource Plan, Peninsular Florida,
July, 1999; Okeechobee Generating Company, L.L.C.

TABLE 7

SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK WITHOUT OKEECHOBEE GENERATING PROJECT

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. % OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. % OF PEAK
1999/00	37,803	1,772	2,129	41,704	39,989	1,715	4.29	4,012	35,977	5,727	15.92
2000/01	39,497	1,694	2,129	43,320	40,929	2,391	5.84	4,110	36,819	6,501	17.66
2001/02	41,549	1,671	2,129	45,349	41,865	3,484	8.32	4,072	37,793	7,556	19.99
2002/03	43,773	1,566	2,108	47,447	42,808	4,639	10.84	4,059	38,749	8,698	22.45
2003/04	44,087	1,566	2,108	47,761	43,726	4,035	9.23	4,063	39,663	8,098	20.42
2004/05	45,009	1,566	2,098	48,673	44,651	4,022	9.01	4,085	40,566	8,107	19.98
2005/06	45,793	1,566	1,965	49,324	45,553	3,771	8.28	4,103	41,450	7,874	19.00
2006/07	47,218	1,566	1,959	50,743	46,600	4,143	8.89	4,124	42,476	8,267	19.46
2007/08	48,182	1,566	1,944	51,692	47,502	4,190	8.82	4,128	43,374	8,318	19.18
2008/09	48,172	1,566	1,944	51,682	48,441	3,241	6.69	4,155	44,286	7,396	16.70

*548 MW OF DUKE-NEW SMYRNA CAPACITY ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002/03

SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK WITH OKEECHOBEE GENERATING PROJECT, 561 MW IN 2003/04

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. % OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. % OF PEAK
1999/00	37,803	1,772	2,129	41,704	39,989	1,715	4.29	3,784	35,977	5,727	15.92
2000/01	39,497	1,694	2,129	43,320	40,928	2,392	5.84	3,955	36,819	6,501	17.66
2001/02	41,549	1,671	2,129	45,349	41,865	3,484	8.32	4,078	37,793	7,556	19.99
2002/03	43,773	1,566	2,108	47,447	42,808	4,639	10.84	4,153	38,749	8,698	22.45
2003/04	44,648	1,566	2,108	48,322	43,726	4,596	10.51	4,232	39,663	8,659	21.83
2004/05	45,570	1,566	2,098	49,234	44,651	4,583	10.26	4,307	40,566	8,668	21.37
2005/06	46,354	1,566	1,965	49,885	45,553	4,332	9.51	4,335	41,450	8,435	20.35
2006/07	47,779	1,566	1,959	51,304	46,600	4,704	10.09	4,365	42,476	8,828	20.78
2007/08	48,743	1,566	1,944	52,253	47,502	4,751	10.00	4,392	43,374	8,879	20.47
2008/09	48,733	1,566	1,944	52,243	48,441	3,802	7.85	4,415	44,286	7,957	17.97

*548 MW OF DUKE-NEW SMYRNA CAPACITY ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002/03
**561 MW OF OKEECHOBEE GENERATING PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2003/04
SOURCES: Florida Reliability Coordinating Council,
<u>1999 Regional Load & Resource Plan, Peninsular Florida</u>
July, 1999; Okeechobee Generating Company, L.L.C.

needs more than 10,000 MW of new installed capacity in order to maintain installed generation reserve margins between 6% and 9% for the winters of 2003/2004 through 2008/2009. (See Table 7.) The Project will contribute meaningfully to Peninsular Florida's summer and winter reserve margins and to cost-effective power supply.

According to the 1999 Regional Load & Resource Plan, dated July, 1999, prepared by the Florida Reliability Coordinating Council (the "FRCC 1999 Resource Plan"), without the Okeechobee Generating Project, Peninsular Florida's summer reserve margins in 2003 through 2008 will range from 10.1 percent to 13.0 percent, without exercising load management and interruptible capabilities. With the Project, the reserve margins will be improved by approximately 1.2 to 1.3 percent in each year, i.e., from 11.3 percent to 14.3 percent. The annual summer reserve margins for Peninsular Florida, with and without the Project's capacity, are shown in Table 6.

Similarly, based on data presented in the FRCC 1999 Resource Plan, without the Okeechobee Generating Project, Peninsular Florida's winter reserve margins in 2003/2004 through 2008/2009 will range from 6.7 percent to 9.2 percent, without exercising load management and interruptible capabilities. With the Okeechobee Generating Project, the reserve margins will be improved by approximately 1.2 to 1.3 percent in each year, i.e., from 7.9

percent to 10.5 percent over this period. Winter reserve margins for Peninsular Florida, with and without the Project's capacity, and with and without exercising load management and interruptible resources, are shown in Table 7.

The Project is expected to operate at an average annual capacity factor of approximately 93 percent from 2004 through 2013, reflecting approximately 8,150 operating hours per year and approximately 4.3 million MWH per year of net generation. See Table 8.

Power produced by the Project will be sold in the wholesale market to other utilities and power marketers for use in Peninsular Florida. OGC projects that all, or virtually all of the sales from the Project over the 2004-2013 period are expected to be to other utilities and power marketers for use in Peninsular Florida (i.e., within the FRCC region), on the basis of the relative economics of the Project and other Peninsular Florida generation facilities. It is unlikely that power produced from the Project will be consumed outside Florida. In Georgia, Alabama and Mississippi, the wholesale market clearing price for electricity is typically lower than in Florida and the cost of fuel transportation to these states is less than in Florida. In addition, electricity generated in Florida would have to incur the expense of being wheeled through the State to the other markets, an expense electricity generated in

TABLE 8

OKEECHOBEE GENERATING PROJECT PROJECTED OPERATIONS AND FUEL SAVINGS

COLUMN [1] YEAR	[2] GENERATION (MWH)	[3] CAPACITY FACTOR %	[4] PRIMARY ENERGY SAVED (MMBtu)	[5] SAVINGS @ 100% NO. 6 OIL DISPLACED (BARRELS)	[6] SAVINGS @ 100% NATURAL GAS DISPLACED (MCF)
2004	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2005	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2006	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2007	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2008	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2009	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2010	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2011	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2012	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
2013	4,301,510.40	93.00	15,162,824	6,930,163	15,162,824
TOTALS			**151,628,242**	**69,301,634**	**151,628,242**

NOTES:(1) Primary energy saved estimated as the difference between Btu required to generate MWH in Column [2] in gas/oil steam generators with an average heat rate of 10,300 Btu/kWh and the Btu required to generate the same MWH at the OGC Project's heat rate of 6,775 Btu/kWh.
(2) Oil savings reflects total oil displaced assuming that all of the Project's output displaces oil-fired steam generation.
(3) Gas savings reflects net gas reduction to generate MWH in Column [2].

those other markets would avoid. Moreover, transmission export capability at the Georgia/Florida interface is limited. The site of the Project was chosen to best accommodate sales to the Florida wholesale market, i.e. Peninsular Florida's other utilities and power marketers.

The advanced technology, natural gas-fired combined cycle design of the Project is consistent with the type of capacity being added by many other Peninsular Florida utilities. Table 9, which presents data from utility ten-year site plans and other published sources, shows that from 1999 through 2008, other Peninsular Florida utilities are projecting the addition of nearly 7,000 MW of gas-fired combined cycle capacity.

The studies of the Project's operations prepared for OGC were prepared using the Altos North American Regional Electricity Model ("Altos Electricity Model") and the Altos North American Regional Gas ("NARG") Model developed by Altos Management Partners, Inc., an economic and management consulting firm with offices in San Jose, California, and Dallas, Texas. Descriptions of these models are included in the Appendices to these Exhibits. The Altos Electricity Model is a 32-region integrated model of the North American electricity system that includes generation, transmission, consumption, fuels, and fuel competition. The model includes all of the generation regions, all of the existing and prospective transmission interconnections, and all of the demand regions of North America. (Generally speaking, the model includes all of the reliability coordinating regions in the United States, Canada, and Mexico, plus numerous sub-regions. For example, the model treats the Southern Electric Reliability Council region ("SERC") as four separate sub-regions: the Southern Company system, TVA, VCR (Virginia and the Carolinas), and Energy, which was formerly designated as the southeastern component of the Southwestern Power Pool.

The Altos Electricity Model includes transmission system integration and interconnection, consideration of multiple fuels and energy products, existing capacity and its cost structure, future changes in the cost structure of existing plants, retirements and decommissioning, new generation plant entry, inbound and outbound transmission capabilities, transmission entry, and demands and load shapes that vary over time.

The NARG Model includes all gas supply basins, all existing and prospective interconnecting pipelines, and all of the gas demand regions of North America. In the NARG Model, each category of resource in each supply region is characterized by a detailed supply sub-model. Each pipeline is characterized by a detailed transportation sub-model, and each demand region is characterized by a detailed demand sub-model. The NARG Model estimates, over time, the set of regional prices that simultaneously clear the markets in every wellhead, wholesale, and other market in North America.

B. **Power Supply Needs of Okeechobee Generating Company, L.L.C.**

The only business purpose of OGC is to own the Project in a manner that will provide reliable, competitively priced, environmentally clean power in the Florida wholesale market without risk to Florida's retail electric customers. PG&E Generating, through OGC, is developing the Project consistent with the policies of the Federal Energy Regulatory Commission and the Florida Public Service Commission to increase wholesale competition so that electric consumers may enjoy the benefits of competitively priced generation. Accordingly, OGC needs the Project to participate as a competitive supplier in the Florida wholesale power market. The addition of the Project will help create a robust, competitive wholesale power market in Florida.

C. **Strategic Considerations**.

The Project is also consistent with strategic factors that may be considered when determining to build a power plant, both from OGC's perspective and from the perspective of the State. The Project will be fueled by domestically produced natural gas, rather than by an imported fuel that is subject to interruption due to political or other events. The Project will also provide a primary impetus and will be a significant customer contributing to the construction of a second major trans-Florida natural gas pipeline. The Project has a low installed cost and a highly efficient heat rate, assuring its long-term economic viability. As a merchant plant, the Project will provide power with no risk to Florida electric customers and will impose no obligation on either Florida utilities or their customers. The Project's gas-fired combined cycle technology is exceptionally clean environmentally, protecting against risks associated with future changes in environmental regulations while improving the overall environmental profile of electricity generation in Florida.

V. COST-EFFECTIVENESS OF THE OKEECHOBEE GENERATING PROJECT

The Okeechobee Generating Project is the most cost-effective alternative available to Peninsular Florida for meeting the future power supply needs of the utilities and their retail electric customers. The Project is also the most cost-effective alternative available to OGC for meeting its anticipated wholesale sales obligations. Moreover, based on its highly efficient heat rate and low direct construction cost, the Project is demonstrably cost-effective relative to virtually all other gas-fired combined cycle power plants proposed for Florida over the next ten years. Accordingly, the Project is expected to provide cost-effective power to Peninsular Florida.

A. Cost-Effectiveness to Peninsular Florida Electric Customers.

The Project will be cost-effective to Peninsular Florida because it will provide a necessarily cost-effective option for retail-serving utilities to obtain needed capacity and energy for resale to their customers, and because it will thus help to hold down wholesale power costs.

Additionally, the Project's costs and efficiency compare favorably to other gas-fired combined cycle generating units planned or proposed by other utilities in Peninsular Florida. Table 9, which presents data from the utilities' ten-year site plans and other published sources, shows that of all the new gas-

TABLE 9

COMPARISON OF PENINSULAR FLORIDA PLANNED AND PROPOSED GENERATING UNITS

PLANNED & PROPOSED UTILITY/UNIT	IN-SERVICE YEAR	CAPACITY SUMMER MW	CAPACITY WINTER MW	FUELS PRIMARY	FUELS ALTERNATE	HEAT RATE (Btu/kWH)	EQUIVALENT AVAILABILITY FACTOR %	TOTAL INSTALLED COST ($/KW)	DIRECT CONSTRUCTION COST ($/KW)	TECHNOLOGY TYPE
OKEECHOBEE*	2003	514	561	GAS	NO. 2	6,775	93	N/A	$345	COMBINED CYCLE
DUKE/NSBPP**	2002	476	548	GAS	NONE	6,832	96	N/A	$325	COMBINED CYCLE
FPL/FT.MYERS***	2002	926	1,102	GAS	NONE	6,795	96	$541	$420	COMB. CYCLE/REPOWER
FPL/SANFORD***	2003	927	1,101	GAS	NONE	6,795	96	$587	$449	COMB. CYCLE/REPOWER
FPL/MARTIN 5	2006	419	448	GAS	NO. 2	6,081	96	$590	$464	COMBINED CYCLE
FPL/MARTIN 6	2007	419	448	GAS	NO. 2	6,081	96	$604	$464	COMBINED CYCLE
FPL/UNSITED	2008	419	448	GAS	NO. 2	6,081	96	$698	$519	COMBINED CYCLE
TALLAH/PURDOM 8	2000	233	262	GAS	NO. 2	6,940	NR	$483	$434	COMBINED CYCLE
FPC/HINES 1****	1999	470	505	GAS	NO. 2	6,962	91	$600	NOT REPORTED	COMBINED CYCLE
FPC/INTRCSS 12-14	2000	249	297	GAS	NO. 2	11,814	91	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
FPC/HINES 2	2004	495	567	GAS	NO. 2	6,800	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
FPC/HINES 3	2006	495	567	GAS	NO. 2	6,800	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
GVLLE/J.R. KELLY	2001	110	110	GAS	NO. 2	7,880	84	$375	$364	COMBINED CYCLE
SEC/HARDEE 3	2002	488	572	GAS	NO. 2	6,170	93	$412	$378	COMBINED CYCLE
FMPA-KUA										
CANE ISLAND 3	2001	244	267	GAS	NO. 2	6,815	92	$430	$320	COMBINED CYCLE
CANE ISLAND 4	2007	72	82	GAS	NO. 2	11,959	96	$447	$291	COMBUSTION TURBINE
LKLAND McINTSH 5	2002	337	384	GAS	NO. 2	6,523	91	$671	$671	COMBINED CYCLE
LKLAND McINTSH 4	2004	238	238	COAL	PET. COKE	8,776	74	$664	$664	CIRCULATING FLUID BED
JEA NORTHSID 1-2	2002	265	265	PET. COKE	COAL	9,946	90	NOT REPORTED	$658	CIRCULATING FLUID BED
JEA KENNEDY CT 7	2000	149	186	GAS	NO. 2	11,120	97	NOT REPORTED	$261	COMBUSTION TURBINE
JEA BANDY CT 1-3	2001	149	186	GAS	NO. 2	11,120	97	NOT REPORTED	$264	COMBUSTION TURBINE

* OKEECHOBEE GENERATING COMPANY DATA IS BASED ON INFORMATION FROM NEED DETERMINATION FILING, AND INCLUDES THE COST OF DIRECTLY ASSOCIATED TRANSMISSION LINES.

** DUKE/NSBPP DATA IS BASED ON INFORMATION FROM NEED DETERMINATION FILING, AND INCLUDES THE COST OF DIRECTLY ASSOCIATED TRANSMISSION LINES.

*** FOR COMPARABILITY TO THE OTHER VALUES SHOWN HERE, THE COST FOR FPL'S REPOWERING PROJECTS IS SHOWN ON THE BASIS OF DOLLARS PER KW OF INCREMENTAL CAPACITY. UNLIKE FPL's 1998 TEN YEAR SITE PLAN, FPL's 1999 TEN YEAR SITE PLAN PRESENTED COST DATA ON THE BASIS OF DOLLARS PER KW OF TOTAL CAPACITY AT THE REPOWERED FT. MYERS AND SANFORD STATIONS.
THE TOTAL INSTALLED COST PER KW OF TOTAL CAPACITY, AS SHOWN IN FPL's TEN YEAR SITE PLAN, WAS $367/KW FOR FT. MYERS AND $392/KW FOR SANFORD.

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

SOURCES: 1999 Ten Year Site Plan Filings, Schedule 9
Okeechobee Generating Company, L.L.C.

fired combined cycle power plants proposed by Peninsular Florida utilities, only the Cane Island 3 unit, a joint project of the Florida Municipal Power Agency and the Kissimmee Utilities Authority, and the Duke Energy New Smyrna Beach Power Project, are expected to have direct construction costs comparable to those of the Project. The other plants with generally comparable heat rates reflect direct construction costs, on a dollars-per-kW basis, significantly greater than those of the Project.

Assuming economically rational, cost-minimizing behavior by Florida's retail-serving utilities it is reasonable to conclude that they will only buy power from the Project when it is cost-effective for them to do so, i.e., when it is less expensive for them to buy power from the Project than to generate it themselves or to buy from another supplier. Reasonably assuming that the cost of power purchased from the Project is passed directly through to the purchasing utilities' ratepayers, i.e., that it is passed through the utilities' fuel and purchased power cost recovery charges and not subjected to any markup or diverted to other wholesale purchasers for a profit, such purchases will necessarily be cost-effective to those ratepayers. This is because the retail-serving Peninsular Florida utilities are not obligated to buy -- nor subject to being forced to buy -- the Project's output. Similarly, as distinguished from traditional regulatory treatment, Florida electric customers are not vulnerable to being required to pay for either the capital or operating costs of the Project. As distinguished from traditional utility-built generation, Florida customers will only pay for power that they use from the Project-- i.e., power that their retail-serving utilities rationally choose to buy and resell to them as a cost-saving measure compared to other power supply options.

Moreover, because the Project will be constructed entirely with private funds and because no utility or retail ratepayers are being asked to commit to purchase the Project's output, no ratepayers will be at risk for either the construction or operating costs of the Project. Because the Project's output will be sold only at wholesale to other utilities and power marketers for use, predominantly, if not entirely, within Florida, such sales will necessarily be at cost-effective prices to the purchasing utilities. (If the prices for purchases from the Project exceed the cost of other power supply alternatives, utilities will simply obtain needed power elsewhere and not purchase power from the Project.) Thus, the Project will necessarily provide economic power supply to the purchasing utilities and their retail ratepayers.

Finally, as noted above, the presence and operation of the Okeechobee Generating Project will suppress wholesale power prices in Peninsular Florida. Analyses performed by Altos Management Partners for OGC indicate that the Project is expected to suppress wholesale prices by about $0.27 to $0.30 per MWH, yielding total estimated power supply cost reductions of approximately $280 million (NPV) over the first ten years of the Project's operation. See Table 10.

B. Cost-Effectiveness to Okeechobee Generating Company, L.L.C.

The Project also represents the most cost-effective alternative available to Okeechobee Generating Company for meeting its anticipated wholesale power commitments. Table 11 shows the generating alternatives evaluated by OGC. Economic evaluations conducted for OGC by Altos Management Partners considered gas-fired combustion turbines, gas-fired combined cycle units, gas-fueled steam generation units, conventional pulverized coal steam units, and integrated coal gasification combined cycle units. Table 12 presents the comparative cost and performance data developed by Altos for use in their analyses. These evaluations clearly indicate that the best choice for OGC and Peninsular Florida, considering economics, cost-effectiveness, reliability, long-term flexibility, and strategic factors is gas-fired combined cycle capacity. This is borne out by the fact that other Florida utilities are planning to add several thousand MW of similar capacity, and by the fact that this type of unit is the technology

TABLE 10

PENINSULAR FLORIDA, SUMMARY OF PROJECTED SAVINGS FROM OKEECHOBEE GENERATING PROJECT

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED ANNUAL SAVINGS FROM OGC ($MILLION)	NET PRESENT VALUE @ 10% 1999 DOLLARS ($MILLION)	CUMULATIVE NPV @ 10% 1999 DOLLARS ($MILLION)
2004	211,223.0	$0.31	$65.479	$40.657	$40.657
2005	216,068.0	$0.31	$66.981	$37.809	$78.466
2006	221,084.0	$0.30	$66.325	$34.035	$112.502
2007	226,090.0	$0.30	$67.827	$31.642	$144.144
2008	228,350.9	$0.30	$68.505	$29.053	$173.196
2009	230,634.4	$0.29	$66.884	$25.787	$198.983
2010	232,940.8	$0.29	$67.553	$23.677	$222.660
2011	235,270.2	$0.28	$65.876	$20.990	$243.650
2012	237,622.9	$0.28	$66.534	$19.273	$262.923
2013	239,999.1	$0.27	$64.800	$17.064	$279.986

BASE YEAR=1999

TABLE 11

OKEECHOBEE GENERATING PROJECT GENERATING ALTERNATIVES EVALUATED

I. GENERATING TECHNOLOGIES CONSIDERED

COMBUSTION TURBINE-GAS

COMBINED CYCLE-GAS

PULVERIZED COAL STEAM

COAL GASIFICATION COMBINED CYCLE (IGCC)

GAS STEAM

II. COMBINED CYCLE MANUFACTURES CONSIDERED

ABB (ASEA BROWN-BOVERI)

GE (GENERAL ELECTRIC)

SIEMENS/WESTINGHOUSE

TABLE 12

COST-EFFECTIVENESS OF ALTERNATIVE GENERATION TECHNOLOGIES

	COMBINED CYCLE GAS	COMBUSTION TURBINE GAS	INTEGRATED COMBINED CYCLE-GAS	STEAM TURBINE COAL	STEAM TURBINE GAS
PROJECTED UNIT PERFORMANCE DATA					
HEAT RATE [Btu/kWh]	6,775	11,800	8,600	9,800	10,100
CAPACITY FACTOR *	93.00%	42.84%	66.71%	86.00%	28.60%
INSTALLED CAPACITY COSTS	$450	$325	$1,450	$1,400	$500
PRODUCTION COSTS					
FUEL COSTS [$/MMBTU]	2.15	2.15	1.49	1.49	2.15
VARIABLE O&M [$/MWH]	0.30	0.10	1.30	2.26	3.34
CYCLING COST [$/MWH]	2.00	1.50	3.00	2.25	3.66

SOURCE: Altos Management Partners.

*PROJECTED AVERAGE ANNUAL CAPACITY FACTOR FOR EACH TECHNOLOGY, INCLUDING FORCED OUTAGE RATE, PLANNED MAINTENANCE OUTAGE RATE, AND PROJECTED ECONOMIC OPERATIONS.

of choice for the majority of new power plant capacity planned in the United States.

VI. CONSEQUENCES OF DELAY

Delaying the construction and operation of the Okeechobee Generating Project will adversely affect the reliability of the Peninsular Florida bulk power supply system, will adversely affect the availability of adequate electricity at a reasonable cost, and will adversely affect the environment of Florida.

A. Reliability Consequences of Delay.

The Okeechobee Generating Project will be a highly reliable and highly efficient gas-fired combined cycle power plant. It will use proven, state-of-the-art technology. The Project's high reliability -- an equivalent availability factor of 93 percent -- assures its contributions to improving the reserve margins and reliability of the Peninsular Florida power supply system.

Tables 6 and 7 demonstrate that the Project will improve Peninsular Florida's summer and winter reserve margins by approximately 1.2 to 1.3 percent beginning with the Project's in-service date in the Spring of 2003 and continuing throughout the period covered in the FRCC 1999 Resource Plan.

The presence of this additional 550 MW (514.3 MW summer, 561.3 MW winter) of reliable capacity will improve reliability and reduce Peninsular Florida's exposure to outages due to extreme weather or unanticipated events such as major generation outages. The presence of this capacity will mean that, in an extreme event, approximately 550 MW of load will be served that would not otherwise be served. This means that the Project would enable Florida's retail-serving utilities to maintain service to approximately 90,000 to 110,000 residential customers (at a coincident peak demand of 5 kW to 6 kW per household) during such conditions.

If the Project is not constructed and brought into commercial operation in 2003 as planned and sought, these reliability benefits will be lost, and Florida electric customers will be exposed to a greater probability of service interruption than they would experience if the Project were built as planned and sought by OGC.

B. Power Supply Cost Consequences of Delay.

The Okeechobee Generating Project is a proven, highly reliable, and highly efficient gas-fired combined cycle power plant. The Project's high efficiency assures its contributions to reducing wholesale power supply costs in Peninsular Florida.

The presence of the Project will reduce generation costs and will also suppress wholesale power prices, to at least some degree, in Peninsular Florida. This is the simple economic result of an increase in supply (i.e., an outward shift in the supply curve for bulk power). Even at nominal differences in the wholesale cost of power with and without the Project, the savings can be expected to be substantial. Moreover, the Project will provide real, tangible economic benefits - real reductions in the amount of primary fuels used to generate the same amounts of electricity - to Florida and to society in general by virtue of the Project's more efficient use of fuel.

If the Project is not constructed and brought into commercial operation in 2003 as planned and sought, these economic benefits will be lost, and Florida electric customers will pay more for their power service than they would otherwise, and more for that service than they have to.

C. **Environmental Consequences of Delay**.

The Okeechobee Generating Project is a high-efficiency, state-of-the-art, natural gas-fired combined cycle electric generating plant. Because of its high efficiency and the use of clean-burning natural gas as its primary fuel, the Project will bring net air emissions benefits to Florida. The Project will displace production from older, less efficient and less environmentally desirable power plants, e.g., less efficient oil-fired steam generating plants, less efficient gas-fired steam generating units, and combustion turbine plants fired by oil or gas. This displacement will result in substantial savings in primary fuel consumption for electricity generation, thus resulting in reduced air emissions from power production in Florida.

The projections prepared for OGC indicate that the Project's generation will generally displace production from older steam generating units fired by heavy fuel oil and natural gas, which generally have heat rates in the range of 10,000 to 11,000 Btu per kWh. Regardless of the type of primary fuel displaced, the Project's operations will result in significant fuel savings; because of its better heat rate, the Project uses approximately 30 to 35 percent less primary fuel energy (Btu) than steam generation units to produce the same amount of electricity.

In addition, under reasonable assumptions regarding the types of marginal fuels displaced by the Project's operations, and reasonably assuming that the displaced oil-fired and gas-fired generation will not be sold outside Florida, the Project's operations are expected to improve the overall environmental profile of electricity generation in Florida. When the Project's output displaces generation using heavy fuel oil, there will be significant reductions in emissions of SO_2, NO_x, and measurable reductions in CO_2 emissions. Even when the Project displaces gas-fired steam generation, there will be reductions in emissions due to the Project's better heat rate, newer turbine design, and emissions controls, resulting in lower emissions of NO_x, SO_2, and CO_2. If the Project is not constructed and brought into commercial operation in 2003 as planned and sought, these environmental benefits will be lost, and pollution from electric generation in Florida will be significantly greater than it would otherwise be.

APPENDICES

APPENDIX A

FERC ORDER APPROVING MARKET-BASED RATE TARIFF

OF

OKEECHOBEE GENERATING COMPANY

8 8 FERC ¶ 61,21 9

767559

FILED
99 SEP 15 PM 4:11
FEDERAL ENERGY REGULATORY COMMISSION

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

September 15, 1999

Docket Nos. ER99-3637-000
ER99-3643-000
ER99-3668-000
ER99-3677-000
ER99-3693-000
ER99-3822-000
ER99-3911-000
ER99-4081-000

Van Ness Feldman, P.C.
ATTN: Margaret A. Moore, Esq.
Attorney for Oswego Harbor Power LLC
1050 Thomas Jefferson St., N.W.
Seventh Floor
Washington, D.C. 20007

Dewey Ballantine LLP
ATTN: Zori G. Ferkin, Esq.
Attorney for Okeechobee Generating Company
1775 Pennsylvania Avenue, N.W.
Washington, D.C. 20006-4605

Steptoe & Johnson LLP
ATTN: Jennifer L. Key, Esq.
Attorney for Duke Energy Merchants, LLC
1330 Connecticut Ave., N.W.
Washington, D.C. 20036-1795

CMS Enterprises Company
ATTN: Ali Ben Abdeslam, Esq.
Attorney for CMS Generation Michigan Power, L.L.C.
Fairlane Plaza South
330 Town Center Drive, Suite 1100
Dearborn, MI 48126-2712

Van Ness Feldman, P.C.
ATTN: Margaret A. Moore, Esq.
Attorney for Midwest Generation, LLC
1050 Thomas Jefferson St., N.W.
Seventh Floor
Washington, D.C. 20007

Paul, Hastings, Janofsky & Walker LLP
ATTN: William D. DeGrandis, Esq.
Attorney for Casco Bay Energy Company, LLC
1299 Pennsylvania Avenue, N.W.
Tenth Floor
Washington, D.C. 20004-2400

Rath, Young and Pignatellis
ATTN: M. Curtis Whittaker, Esq.
Attorney for Northbrook New York, LLC
One Capital Plaza, P.O. Box 1500
Concord, NH 03302-2600

LeBoeuf, Lamb, Greene & MacRae, L.L.P.
ATTN: Elias G. Farrah, Esq.
Attorney for Bay State GPE, Inc.
1875 Connecticut Avenue, N.W.
Suite 1200
Washington, D.C. 20009

Dear Sirs and Madams:

You submitted for filing with the Commission rate schedules under which applicants will engage in wholesale electric power and energy transactions at market-based rates. Your submittals, as modified below, comply with the Commission's requirements for market-based rates and are accepted for filing. They are designated and made effective as indicated in Appendix A to this order.

Okeechobee Generating Company (Okeechobee) requests authority to engage in sales of ancillary services (regulation, energy imbalance, spinning reserves and supplemental reserves) at market-based rates. Duke Energy Merchants, LLC (Duke) also requests authority to engage in sales of ancillary services at market-based rates. In these filings, Okeechobee and Duke request permission to make sales of ancillary services subject to the conditions set forth in Avista Corporation, 87 FERC ¶ 61,223 (1999)

(Avista), with respect to similarly situated entities which are unable to develop a reliable market power analysis for ancillary services. Because Okeechobee's and Duke's rate schedules do not reflect all of the requirements of Avista, e.g., they do not contain all of the limitations identified as necessary and appropriate in Avista, we will deny their requests for authorization to make sales of ancillary services at market-based rates without prejudice to resubmittal.

We will grant the request of Oswego for authority to make sales of ancillary services at market-based rates into the PJM Power Exchange, the New York ISO market and the ISO New England market.[1]

We will grant the request of Casco Bay Energy Company, LLC (Casco Bay) for authority to make sales of ancillary services at market-based rates into the ISO New England market.[2]

We will grant the request of Northbrook New York, LLC (Northbrook) for authority to sell ancillary services at market-based rates under its proposed rate schedule, provided it amends its proposed rate schedule to specify that it will sell ancillary services into the PJM Power Exchange, the New York ISO market or the ISO New England market.[3]

Any waivers or authorizations requested by the applicants, other than Northbrook, are granted to the extent specified in Appendix B to this order. As to Northbrook, it is a licensee that is presently required, among other things, to comply with 18 C.F.R. §§ 141.14, .15 (1999)(providing for the filing both of the Form No. 80, Licensed Hydropower Development Recreation Report and of the Annual Conveyance Report). We will grant Northbrook the waivers and authorizations requested by Northbrook, with the exception of 18 C.F.R. §§ 141.14, .15 (1999), to the extent specified in Appendix B to this order. Northbrook thus will still be required to file the Form No. 80s and the Annual Conveyance Reports. Waiver of the prior or advance notice requirements, if requested, is

---

[1]See Atlantic City Electric Company, et al., 86 FERC ¶ 61,248 (1999); Central Hudson Gas & Electric Corporation, et al., 86 FERC ¶ 61,062 (1999); New England Power Pool, 85 FERC ¶ 61,379 (1998).

[2]See id.

[3]See id.

granted to the extent specified in Appendix A. The applicants must comply with the reporting requirements or other requirements specified in Appendix B to this order. [4]

The codes of conduct submitted by the applicants are accepted if consistent with Appendix C, which reflects requirements adopted in previous Commission orders. Because the code of conduct submitted by CMS Generation Michigan Power, L.L.C. is inconsistent with Appendix C, it is hereby rejected. As to this applicant, Appendix C has been designated as the applicable code of conduct.

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1999), an entity's filing of a timely notice of intervention or a timely, unopposed motion to intervene in a proceeding makes it a party to that proceeding.

Should an applicant or any of its affiliates deny, delay, or require unreasonable terms, conditions, or rates for natural gas fuel or services to a potential electric competitor in bulk power markets, then that electric competitor may file a complaint with the Commission that could result in the applicant's or its affiliate's authority to sell power at market-based rates being suspended. [5]

Sales of accounts receivable are not dispositions of jurisdictional facilities and are not within the scope of section 203 of the FPA. To the extent an applicant seeks a case-specific finding on this or any related point, it may file a petition for a declaratory order with the Commission.

Oswego, Duke, Midwest Generation, L.L.C (Midwest), Casco Bay and Northbrook seek Commission approval to reassign transmission capacity. We find their requests to be consistent with our requirements.

---

[4]On May 27, 1999, the Commission issued an order in which it modified the reporting requirements for long-term transactions applicable to public utilities without ownership or control over generation or transmission facilities that are authorized to sell power at market-based rates (power marketers). Southern Company Services, et al., 87 FERC ¶ 61,214 (1999), reh'g pending (Southern). Specifically, with respect to any long-term transaction agreed to by a power marketer after 30 days from the date of issuance of a final order in the Southern case, the power marketer must file a service agreement with the Commission within 30 days after service commences, rather than reporting transactions thereunder in its quarterly transaction summaries.

[5]See, e.g., Louisville Gas & Electric Co., 62 FERC ¶ 61,016 at 61,148 (1993).

Oswego, Okeechobee, Midwest, Casco Bay and Northbrook must inform the Commission of the date service commences or the date of acquisition of the facility, as appropriate.

By direction of the Commission.

Linwood A. Watson, Jr.,
Acting Secretary.

APPENDIX A

Applicants are hereby informed of the following rate schedule designations:

Oswego Harbor Power, L.L.C.
Docket No. ER99-3637-000
Rate Schedule Designation
Effective Date: Date of Commencement of Service

Designation	Description
FERC Electric Tariff, Original Volume No. 1 (Original Sheet Nos. 1 - 4)	Market-Based Rate Tariff with Code of Conduct

Okeechobee Generating Company
Docket No. ER99-3643-000
Rate Schedule Designation
Effective Date: Date of Commencement of Service

Designation	Description
FERC Electric Tariff, Original Volume No. 1 (Original Sheet Nos. 1-3)	Market-Based Rate Tariff and Code of Conduct

Duke Energy Merchants, LLC
Docket No. ER99-3668-000
Rate Schedule Designations
Effective Date: August 11, 1999

	Designation	Description
(1)	Rate Schedule FERC No. 1	Market-Based Rate Schedule
(2)	Supplement No. 1 to Rate Schedule FERC No. 1	Code of Conduct

CMS Generation Michigan Power, L.L.C.
Docket No. ER99-3677-000
Rate Schedule Designation
Effective Date: September 20, 1999

Designation	Description
FERC Electric Tariff Original Volume No. 2 (Original Sheet Nos. 1- 4)	Market-Based Rate Tariff and Code of Conduct (Appendix C)

Midwest Generation, L.L.C.
Docket No. ER99-3693-000
Rate Schedule Designation
Effective Date: Date of Commencement of Service

Designation	Description
FERC Electric Tariff, Original Volume No. 1 (Original Sheet Nos. 1 - 2)	Market-Based Rate Tariff and Code of Conduct

Casco Bay Energy Company, LLC
Docket No. ER99-3822-000
Rate Schedule Designation
Effective Date: Date of Commencement of Service

Designation	Description
FERC Electric Tariff Original Volume No. 1 (Original Sheet Nos. 1 - 4)	Market-Based Rate Tariff and Code of Conduct

Northbrook New York, L.L.C.
Docket No. ER99-3911-000
Rate Schedule Designation
Effective Date: Date of Acquisition of Facility

Designation	Description
FERC Electric Tariff, Original Volume No. 1 (Original Sheet Nos. 1-3)	Market-Based Rate Tariff and Code of Conduct

Bay State GPE, Inc.
Docket No. ER99-4081-000
Rate Schedule Designation
Effective Date: September 13, 1999

Designations	Description
FERC Electric Tariff, Original Volume No. 1 (Original Sheet Nos. 1-3)	Market-Based Rate Tariff and Code of Conduct

APPENDIX B

(1) If requested, waiver of Parts 41, 101, and 141 of the Commission's regulations, with the exception of 18 C.F.R. §§ 141.14, .15 (1999), is granted. Licensees remain obligated to file the Form No. 80 and the Annual Conveyance Report.

(2) Within 30 days of the date of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liabilities by those applicants who have sought such approval should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211 and 385.214.

(3) Absent a request to be heard within the period set forth in Paragraph (2) above, if the applicants have requested such authorization, the applicants are hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of the applicants, compatible with the public interest, and reasonably necessary or appropriate for such purposes.

(4) If requested, until further order of this Commission, the full requirements of Part 45 of the Commission's regulations, except as noted below, are hereby waived with respect to any person now holding or who may hold an otherwise proscribed interlocking directorate involving the applicants. Any such person instead shall file a sworn application providing the following information:

(a) full name and business address; and

(b) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(5) The Commission reserves the right to modify this order to require a further showing that neither the public nor private interests will be adversely affected by continued Commission approval of the applicants' issuances of securities or assumptions of liabilities, or by the continued holding of any affected interlocks.

(6) If requested, waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15 and 36.16, is granted for transactions under the rate schedules at issue here.

(7) (a) Applicants who own generating facilities may file umbrella service agreements for short-term power sales (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales (including risk management transactions if they result in actual delivery of electricity). For long-term transactions (longer than one year), applicants must submit the actual individual service agreement for each transaction within 30 days of the date of commencement of service. To ensure the clear identification of filings, and in order to facilitate the orderly maintenance of the Commission's files and public access to documents, long-term transaction service agreements should not be filed together with short-term transaction summaries. For applicants who own, control or operate facilities used for the transmission of electric energy in interstate commerce, prices for generation, transmission and ancillary services must be stated separately in the quarterly reports and long-term service agreements.

(b) Applicants who do not own generating facilities must file quarterly reports detailing the purchase and sale transactions undertaken in the prior quarter (including risk management transactions if they result in actual delivery of electricity). Applicants who are power marketers should include in their quarterly reports only those risk management transactions that result in the actual delivery of electricity.

(8) The first quarterly report filed by an applicant in response to Paragraph (7) above will be due within 30 days of the end of the quarter in which the rate schedule is made effective.

(9) Each applicant must file an updated market analysis within three years of the date of this order, and every three years thereafter. The Commission reserves the right to require such an analysis at any time. The applicants must also inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. These include, but are not limited to: (a) ownership of generation or transmission supplies; or (b) affiliation with any entity not disclosed in the applicants' filing that owns generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area. Alternatively, the applicants may elect to report such changes in conjunction with the updated market analysis required above. Each applicant must notify the Commission of which option it elects in the first quarterly report filed pursuant to Paragraph (7) above.

APPENDIX C

[APPLICANT]
SUPPLEMENT NO. _ TO RATE SCHEDULE NO. _

STATEMENT OF POLICY AND CODE OF CONDUCT WITH RESPECT TO THE RELATIONSHIP BETWEEN [POWER MARKETER] AND [PUBLIC UTILITY]

Marketing of Power

1. To the maximum extent practical, the employees of [Power Marketer] will operate separately from the employees of [Public Utility].

2. All market information shared between [Public Utility] and [Power Marketer] will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are not bound by this provision, but they may not serve as an improper conduit of information to non-support personnel.

3. Sales of any non-power goods or services by [Public Utility], including sales made through its affiliated EWG's or QF's, to [Power Marketer] will be at the higher of cost or market price.

4. Sales of any non-power goods or services by the [Power Marketer] to [Public Utility] will not be at a price above market.

Brokering of Power

To the extent [Power Marketer] seeks to broker power for [Public Utility]:

5. [Power Marketer] will offer [Public Utility's] power first.

6. The arrangement between [Power Marketer] and [Public Utility] is non-exclusive.

7. [Power Marketer] will not accept any fees in conjunction with any Brokering services it performs for [Public Utility].

APPENDIX B

FERC LETTER ORDER GRANTING EXEMPT WHOLESALE GENERATOR CERTIFICATION

TO

OKEECHOBEE GENERATING COMPANY

88 FERC ¶ 62,177

FILED FEDERAL ENERGY REGULATORY COMMISSION
OF THE SECRETARY WASHINGTON, D.C. 20426

764541

99 AUG 24 PM 4:08

OFFICE OF THE GENERAL COUNSEL FEDERAL ENERGY REGULATORY COMMISSION

AUG 24 1999

Ms. Laurel W. Glassman
Dewey Ballantine LLP
1775 Pennsylvania Avenue, N.W.
Washington, D.C. 20006-4605

Re: Docket No. EG99-188-000

Dear Ms. Glassman:

On July 13, 1999, you filed an application for determination of exempt wholesale generator status on behalf of Okeechobee Generating Company pursuant to section 32 of the Public Utility Holding Company Act of 1935 (PUHCA). Notice of the application was published in the Federal Register, 64 Fed. Reg. 39,973 (1999), with interventions or comments due on or before August 6, 1999. None was filed.

Authority to act on this matter is delegated to the General Counsel. 18 C.F.R. 375.309(g). Based on the information set forth in the application, I find that Okeechobee Generating Company is an exempt wholesale generator as defined in section 32 of PUHCA.

A copy of this letter will be sent to the Securities and Exchange Commission.

Sincerely,

Douglas W. Smith
General Counsel

APPENDIX C

METHODOLOGY AND USE OF THE ALTOS NORTH AMERICAN REGIONAL ELECTRIC MODEL

METHODOLOGY AND USE

OF THE

ALTOS NORTH AMERICAN REGIONAL ELECTRIC MODEL

Dr. Dale M. Nesbitt
Michael C. Blaha

ALTOS
MANAGEMENT PARTNERS INC

Altos Management Partners
27121 Adonna Ct.
Los Altos Hills, CA 94022
(650) 949-3541 Voice
(650) 948-3396 FAX

METHODOLOGY AND USE

OF THE

ALTOS NORTH AMERICAN REGIONAL ELECTRIC MODEL

Dr. Dale M. Nesbitt
Michael C. Blaha

ALTOS
MANAGEMENT PARTNERS INC

Altos Management Partners
27121 Adonna Ct.
Los Altos Hills, CA 94022
(650) 949-3541 Voice
(650) 948-3396 FAX

September 24, 1999

Contents

LIST OF FIGURES

1 INTRODUCTION AND OVERVIEW

Electricity is not the first commodity to be deregulated or unbundled or "decoupled" from a related transmission function. Decoupling of commodity supply from transmission is likely to subject electricity markets to precisely the same type of competitive, market, and financial forces to which virtually all other commodities have been subjected for a long time, and it renders the textbook model of economic supply-demand balancing empirically correct and predictive. In building an electricity market model, Altos has combined solid fundamental economic principles together with lessons learned from recently completed deregulations to help us guide our model design decisions so that we can support asset and marketing and trading businesses in electric power.

Before describing the Altos North American Regional Electric Model, there are a few realities of the electric power market as it will unfold in the future that need to be articulated:

- First and foremost, electric power plants are destined to become entrepreneurial, merchant elements, not regulated items. Regulators will no longer guarantee forced passthrough of fixed costs. It will be necessary to trade and arbitrage all their inputs and all their outputs in order to truly maximize value from those plants. This single change in the regulatory environment subjects electric generation assets to the vagaries of the market and therefore to unprecedented price uncertainty.

- Second, it will be necessary to carefully and scrupulously manage both the forward cost to market of generating plants as well as the capacity expansion and retirement decisions related to those plants. Plant costs can no longer go unmanaged; they must be scrupulously and carefully understood, measured, and managed. After all, it will be the difference between sales and cost that will dictate profits, not just "cost plus" as in the old days.

- Third, generation owners need accurate and credible forward electricity and fuel price curves in order to manage their asset and trading businesses, more credible and more accurate than their competitors. Portfolio generation companies are in an "arms race" against their large competitors, the company with the best forecast winning out over the worse companies. There is no escape from the need for accurate and credible price anticipation.

- Fourth, price risks may or may not need to be managed. Large, diversified portfolio generators might well be able to shoulder regionally diversified market price risk. They may not want to "give away the upside in order to avoid the downside" as required by most risk management instruments. On the other hand, small to medium sized companies will most definitely want to hedge their generation assets using liquid, traded instruments to do so. In either case, risk management is no better than one's perception of the future MEAN or average price. Forecasting the future MEAN is critical to success.

In building the model described herein, we are helping our clients attack the foregoing needs head on. We help our clients manage price expectations better and more accurately than their competitors and act correctly and decisively based on those better price expectations. No matter what one might hear from efficient market or trading gurus, **it is the company with the best price forecast that will win.** Electricity markets will never be sufficiently efficient or complete to allow complete, perfect, frictionless hedging or idealized price discovery. With the paucity of storage and inventorying, electricity will always be volatile and somewhat unpredictable. More so than most other commodities, electricity begs for model-based forward price estimation to complement the imperfect information that will be revealed by markets.

In the discussion to follow, we will put forth the basic structure of our market model and supporting analytical techniques, which we have constructed to assist our clients and their selected partners to develop effective and maximally profitable asset acquisition, marketing, and trading activities. We should emphasize that our modeling system guides decisions related to both physical assets and trading instruments. After all, trading instruments (options, swaps, structured deals, etc.) are fundamentally no different from physical assets. Like physical assets, trading instruments make money based on price differences in the market. In the discussion to follow, we will use the word "asset" to describe physical plants, projects, existing capacity, or financial instruments that are the subject of arbitrage and trading. This document outlines the design of our North American multiregional electricity model and its supporting data base.

We should mention that the method of valuation presented here focuses primarily on what we term the intrinsic, deterministic value of the asset. The discussion here is based on the notion of valuing the asset based on a cogent and correct but deterministic set of forward prices. In a companion paper, we have developed a method to extend the intrinsic valuation procedure described here to calculate the full probabilistic value of an asset or a portfolio of assets, i.e., the full option value of the asset plus the deterministic, intrinsic value. The companion paper is based on the idea of using the deterministic value presented here as the MEAN of the forward probability distribution over forward price and augmenting it with a sophisticated Markov model of forward price volatility, mean regression, and serial correlation.

The Altos North American Regional Electric Model is an application developed in MarketPoint, which is a generalized economic modeling software package.

2 MEASURING ASSET PROFITABILITY

2.1 One Individual Asset

Evaluation of asset profitability typically begins with a discounted cash flow (DCF) or similar method configured as shown in Figure A-1. Into the asset profitability calculator shown in the figure we put the fixed and variable costs of the asset (bottom); the corporate book and tax parameters (top); the corporate time and risk parameters (usually a hurdle rate) designated at the top; the "government takes" or other government royalty, lease bidding, production sharing, or other levies at the top; and projections of the price of the products[1] and the price of the inputs (left). The asset profitability calculator then creates one or more measures of corporate profitability, indicated by the "meter" at the right. Sometimes asset profitability calculators contain detail on asset operations, and other times they are simple, passive DCF calculations implemented on a spreadsheet.

Invariably, when evaluating an asset, the profitability calculator is run through a series of sensitivity ("What if?") cases. Costs are varied, prices are varied, book and tax parameters are varied, corporate measures of time and risk are varied, and the calculator is put through its paces. Not surprisingly, what people find as a result of such sensitivity analysis is this:

- the **DIFFERENCE** between the price of the product and the price of the input is the most important variable affecting asset profitability. Every asset is in effect playing a "basis differential game," being "long" on product and "short" on input. This is fundamental; assets are always long with regard to their product and short with regard to their inputs. Assets are the quintessential "swaps."

- this **PRICE DIFFERENCE** is the least understood of all the inputs, and companies have precious little reliable information upon which to base their estimate of this price difference.

We emphasize the pivotal importance of the price differential across the asset, which we draw conceptually as in Figure A-2. Suppose we knew the product price forward into the future beginning at the time at which we initiate possession of the asset (indicated as the product price curve in the figure) and we knew the prices forward into the future of the input factors (indicated as the forward cost curve in the figure). Using that information, we could easily subtract the forward cost from the product price to calculate the contribution to margin from the asset at each point in its future life. This contribution to margin is the contribution to corporate profitability attributable to the asset

[1] In electric power applications, the problem is more complicated than this simple characterization. The price of the product varies continuously, and the plant must be turned on and off or ramped upward or downward to capture revenues or avoid losses. The revenues captured when the plant is on are related to the market price. The discussions in this paper assume that the plant is turned on and off so as to best capture margins.

in each forward year of its life. If we know the contribution to margin in each forward year of the asset's life, we in effect know the shaded area in the figure, and we can calculate the discounted present value of that shaded area as of the time we take possession of the asset. By so doing, we are in effect calculating the discounted present value of the shaded area in the figure, and we interpret this as the present value of the future yield to the company that is specifically attributable to the asset. It is the contribution today to corporate wealth that is attributable to the future yield on the asset.

The discounted present value of the future margin generated by the asset is the contribution to corporate wealth today represented by the asset. If we already own the asset, it represents the intrinsic value of the asset to the corporation. If we are considering acquiring the asset, it is the benchmark against which we must compare the cost to acquire the asset. If the cost to acquire the asset exceeds the net present future value of the asset, one does not want to acquire the asset. If the cost to acquire the asset is lower than the net present future value of the asset, one will want to consider acquiring it. (Whether we actually acquire it depends on our capital budgeting process, which compares all potential business ventures whose acquisition costs are lower than the present value of future returns and picks the best.) Once we know the discounted present value of the shaded area in Figure A-2, the decision to acquire the asset is simple—just compare the acquisition cost against the future yield.

Two critically important insights emerge from Figure A-2. First, **one cannot escape the need to project forward prices for the products of and the inputs to each and every asset it owns, each and every asset it considers owning, and each and every asset it considers selling**. There is no escape from the need to predict forward prices more accurately and more correctly than one's competitors. The company that makes the better forward price projections wins (statistically speaking) because it has more accurate knowledge of the values of its assets. The company that makes the poorer forward price projections loses (statistically speaking) because other people identify and take the best opportunities first.

Second, **not only is the problem of projecting forward prices critically important to the asset business, so is the problem of projecting forward asset operating costs**. To wit, the bottom curve in Figure A-2 is just as important as the top curve in understanding asset profitability. It is the DIFFERENCE between the curves that matters. It is incumbent upon us to understand and anticipate forward cost to market of each and every asset it owns. It is critically important to understand, measure, and project the cost structure of our evolving asset business. We will return to this theme shortly, articulating how we have approached the cost side of the problem. Before doing so, we will continue discussing the revenue side, i.e., the market side.

2.2 Individual Asset Risk

In light of the central importance of the price difference across the asset, companies sometimes reason: "We don't really know what the price difference will be, so let's just put in probability distributions for the critical forward variables. Let's put in probability distributions over plant costs. Let's put in probability distributions over book and tax parameters. Let's put in probability distributions over prices or price differences. This will allow us to calculate a probability distribution over asset profitability. We can use this probability distribution to assess the risk-return nature of the asset. This will give us the right answer."

Such a probability approach, often implemented as a "Monte Carlo" simulation, decision tree, influence diagram, or At Risk! Excel add-in, is illustrated in Figure A-3. Notice in the figure that probability distributions are placed onto all the input arrows to the profitability calculator. The probability calculator then calculates the probability distribution over profitability from the independent probability distributions over each of the inputs. This procedure is literally fraught with conceptual and practical difficulties, but many managers feel mighty comfortable because they are taking account of uncertainty. Yet the process is usually badly flawed.

How do people typically implement such a calculation, and why do they get into trouble? They begin by estimating independent probability distributions over each of the individual inputs to the profitability calculator. They then enumerate all possible combinations of settings for all the input variables using probability trees as shown in Figure A-4, calculate the probability of each combination of variables, and thereafter run the profitability calculator once for each combination. In this way, they obtain what they interpret as a probability distribution over asset profitability (which we call a profit lottery) as shown in Figure A-5. The probability distribution over profitability in Figure A-5 depicts the expected profitability of the asset (shown to be slightly positive in the figure), the standard deviation (shown to be rather wide in the figure), the "skewness" of the probability distribution (in the figure, the distribution is stacked toward the left hand or low profitability side, and in fact higher order properties. Parenthetically, in our experience, Figure A-5 is typical of individual assets: a high probability of low or negative profits but a "long positive tail," representing the remote possibility of a "home run."

While the approach of estimating probability distributions over asset profitability parameters seems intuitively appealing and correct, it misses the boat in the most important dimension. It does not take into account whether the asset under consideration is correlated or uncorrelated with the rest of one's business or with the rest of the market. It does not consider whether the asset is in point of fact simply one more small addition to the selfsame large lottery the business is already playing, i.e., whether the asset is tightly correlated with the rest of one's business and therefore offers limited diversification benefits. Conversely, it does not consider whether the asset brings new and independent elements of uncertainty to one's asset portfolio and therefore offers systematic diversification advantages. It does not consider whether the asset is anticorrelated with the rest of one's portfolio and therefore offers valuable hedging and risk mitigation possibilities. It simply ignores altogether how the asset fits into one's overall asset portfolio and whether it renders the portfolio better or worse. To illustrate with a simple example, the profitability of a new oil well anywhere in the world is directly and positively correlated with the profitability of every other oil well everywhere else in the world. A new oil well does not diversify risk; it is simply adds to an already large oil price lottery. World oil price strongly ties oil wells' profitabilities together. Is this true of electric generation assets, which can occur in highly Balkanized markets separated by high transmission costs, or is electric generation an intrinsically coupled and correlated business that has the same risks as the oil business? Prospective and current generation owners surely need to understand this.

The difficult part of managing one's business portfolio is to ensure that the assets in the portfolio are mutually complementary and that their returns are not completely correlated, i.e., that asset profitabilities are not completely contingent on the exact same set of events. We need to be sure that each of the assets in one's portfolio is at least partially independent of the other assets. One needs to be sure that with each new asset we are not simply buying a bigger and bigger piece of the same old lottery unless we are absolutely convinced that each incremental piece offers increasingly attractive returns to compensate for the increasing portfolio risk. (Unfortunately, in the real world, each additional asset tends to offer decreasingly attractive expected returns rather than increasingly attractive prospects. Diminishing marginal returns is an immutable rule of business and economic life.) If one does not manage the correlation characteristics of his asset portfolio, the volatility of his share price will be increased, the price of his stock will not appreciate as rapidly, dividends will not accrue as rapidly, his credit rating will not be as high and his cost of capital will suffer, and his stock's "beta" will be higher than it should be.

Our approach systematically and structurally takes account of the important correlating as well as uncorrelating forces across a portfolio. While our technique, like many others, is able to evaluate the average profitability of each individual asset, it is able to quantify the correlating and uncorrelating forces and thereby give a true representation of the risk-return nature of an asset portfolio. It does not deceive onr into thinking that the value of the portfolio is merely the sum of the average returns of each business activity that comprises it. It recognizes the reality that with assets "2 + 2 is not necessarily equal to 4." Indeed, with our correct correlation mathematics, "2 + 2 equals 5 for sufficiently large values of 2 and 2 + 2 equals 3.5 for sufficiently small values of 2!" Portfolio mathematics is critical to the success of any company who owns any assets at all, paper or physical assets.

2.3 A Market-Based Approach To Asset Valuation

How do we approach the problem of valuing individual assets and portfolios of business assets? The answer is illustrated in Figure A-6, a critically important extension of the simple asset calculation in Figure A-1. In Figure A-6, we make the identical asset profitability calculation as in Figure A-1. However, we generate consistent projections of prices of products and inputs using a **full multi-regional market model** as shown at the left. Inputs to the full multi-regional market model are indicated at the bottom of the diagram. They include the full forward cost to market estimates including all variable and fixed costs for all existing and prospective plants and assets in the market, including not only the particular asset being analyzed (indicated at the right) but also all assets that compete with or complement the particular asset being analyzed. By assembling a market-wide asset data base and delivering it to a full multi-regional market model, we ensure that the price calculations indicated in Figure A-2 take proper and consistent account of one single collection of technology cost and performance estimates. That is, the price calculations are fundamentally determined by a common and correct set of estimates of all plants in the market, including their forward costs to market (i.e., variable costs and nonsunk fixed costs), all plants that might prospectively enter the market including their full capital and operating costs over their lifetimes, and all plants that might be driven from the market by stronger competitors. By including all capacity currently in place and all capacity that might prospectively enter or exit the market, the price calculation in the full multi-regional market model is able to account for all correlations between plants, technologies, processes, and fuels. The multi-regional market model does not go awry by failing to account for common technologies and processes employed in similar ways everywhere in the market. It does not miss the "zero sum" nature of competitive markets in which similar assets positioned in geographically disparate locations must compete for common markets, winner take all. It does not therefore miss the fact that the electricity market is structurally interconnected and intertwined. It protects Altos customers from making egregious valuation mistakes and overpaying for assets.

By introducing a structural representation of the market, we are able not only to forecast forward prices on a structural basis but also to systematically correlate the various prices in our markets: electricity versus gas prices, electricity versus coal prices, coal versus gas prices, regional price differences at the wellhead and the busbar, etc. We are also able to calculate the structural relationships between prices at different locations and prices at different points in time. By so doing, the vagaries and naiveté's otherwise involved in direct subjective estimation of prices and price correlations are eliminated. The interrelationships among the assets in our portfolio are properly calculated, and the risk-return nature of our portfolio is properly quantified. Most importantly, we are able to systematically understand and predict the price differentials between products and inputs that dictate the profitability of our assets.

Why are such structural correlations important? The reason, quite succinctly, is that the profitability of an electric power plant is a function of the "spark spread" across that plant, defined in the vernacular as the price differential between electricity and the fuel (e.g., natural gas). Would-be asset owners need to know not only what the spark spread will be but also what variables will affect it. Will higher gas prices widen or narrow the spark spread, or will electricity price rise right along with gas price? If the latter is true, the profitability of the asset is insensitive to gas price. If the profitability is sensitive to gas price, a gas price hedge strategy might ameliorate asset ownership risk. However, if the profitability is insensitive to gas price (i.e., electricity price moves right along with gas price), a gas price hedge strategy would be futile. Rather than being the hedge you thought it was, it is pure speculation. Needlessly adding speculation when you thought you were adding hedging devalues one's company and debilitates financial performance.

2.4 Market-Based Approach To Asset Portfolio Risk

To add the dimension of uncertainty to our market-based approach is straightforward. In order to evaluate the true riskiness of each asset in our portfolio, all we need to do is postulate probability distributions over the critical inputs to Figure A-7 rather than to Figure A-1: (1.) Technology cost and performance estimates, (2.) Inputs to the market model, and (3.) Corporate book and tax parameters. The procedure surrounding Figures A-4 and A-5 can be directly extended to the larger and more comprehensive market modeling context, as Figure A-7 summarizes. After inputting such information into Figure A-7, our system can calculate a probability distribution over the true profitability of the asset, taking full and explicit account of the correlations between the asset, the rest of one's portfolio, and the market as a whole. Such an approach does not miss the critical correlations between plant and technology cost and performance estimates, market prices, and asset profitability. It gets the inter-asset correlations right and ensures that one is properly measuring the variance as well as the expected return in his overall portfolio. It shelters the asset owner from mistakenly and imprudently buying a hedging instrument he or she does not need and thereby worsening rather than improving risk.

3 STRUCTURE OF THE FULL REGIONAL MARKET MODEL TO PROJECT PRICES AND PRICE DIFFERENCES

Having identified the need to understand prices and price differentials in order to guide our asset strategy, we are faced with the prospect of building a model to assist us in doing so. As we approach the problem of building such a model, we must recognize a few fundamental facts. First, the price differential across an asset is determined by the market. It is not determined by the cost of the individual asset being analyzed. In the coming deregulated electricity world, the price differential will no longer be determined by rate base formulas through which fixed as well as variable costs can be imposed by companies downstream on electric customers with regulatory complicity. It will not be determined by system lambdas, which reflect the fact that fixed costs were imposed on customers completely apart from energy sales. To be valid, our market model must represent the market at large, not just the individual asset being valued. It must include all assets presently in place combined with all assets that might be built combined with all assets to be retired, and it must consider how those assets jointly and mutually dictate future prices and profits. In the real world, prices are formed from the AGGREGATE of all assets in place, not any individual asset. The premium is on proper representation of the aggregate collection of assets, not on any individual asset.

Second, the price differential across any asset depends on fuel price, heat rate curve (from which we calculate fuel cost), variable cost, operating and maintenance cost, wheeling cost and radius, new equipment installations, future cost evolution, demand variation, and a plethora of economic and cost considerations. Clearly the box in Figures A-6 and A-7 entitled "Cost and Performance Estimates" must be addressed comprehensively. Later sections in this document outline the difficult problem of assembling the necessary cost and performance estimates for every existing plant in the system and every prospective future plant in the system as we have approached it.

Third, and extremely important, future prices and price differentials cannot be discerned from market observations. For commodities such as electricity, there are simply no spot or futures markets to observe and therefore no market observations to be made. Markets are so distorted by fixed cost passthroughs outside energy markets that those energy prices do not represent the intrinsic cost structure of the industry nor the intrinsic value of the commodity. Even after some semblance of spot and forward markets emerge, they are likely to be so lightly traded (so "thin") that they will provide only the most rudimentary price information but will not support sale or purchase of commodity. What good is observation of a price that will not sustain sale or purchase? It is at best a gross indicator of general market trends, an academic nicety.

Clearly what we need to support our marketing, trading, and asset acquisition and divestiture decisions is a forward projection of electricity, gas, coal, and oil prices that truly represents what those commodities will sell for over the life of the asset. We do not want an academic or hypothetical projection or incomplete market observation, we want a projection of what the actual, real, concrete, palpable market will sustain. Because we cannot look to securities and commodities that trade in broad exchange markets for guidance, what technique should we use? The answer is that we should use "high technology," i.e., state-of-the-art, quantitative economic science, to help us represent what is likely to happen as the future electricity market opens for competition. Economic science, which is becoming and will continue to become increasingly pertinent, is from our perspective represented in Figure A-8.

If we want to understand and predict present and forward electricity prices, we must quantify the supply curve for electricity, the demand curve for electricity, and (not shown) the transmission grid that interconnects supply with demand. We must extend and extrapolate the simple supply-demand curve pair in the diagram to consider every region of North America and every future time point in sufficient detail so that the consequent projections of prices are sensible and complete. This is the challenge that faces us and that we have met in building our model. The remainder of this appendix will briefly describe the process by which we quantified and integrated the electricity supply situation, the transmission situation, and the demand situation and thereby built our Multiregion North American Electric model. We reiterate that our overriding purpose is to provide accurate and credible projections of future electricity and fuel prices with which to conduct the evaluations summarized above.

3.1 Representation of Electricity Supply

3.1.1 Regionalization

The first step in constructing our model was to regionalize the generation, transmission, and demand regions of the North American electric and fuel markets. Figure A-9 provides a schematic representation of the regionalization used. In building our model, we wanted to retain sufficient regional detail so that we could properly represent the capital stocks of generation capacity and fuel supply in each region as distinct from every other region. However, we did not want the model to become so large and unwieldy that it became unrunnable. The regionalization in Figure A-9, based in significant measure on the NERC regions and subregions, provided an effective compromise between the objectives of extensive regional detail at one end of the spectrum and workability and usability at the other.

Within each of the subregional model segments depicted in Figure A-9 resides a comprehensive model of indigenous generation, inbound transmission, native load, and outbound transmission. The regional network submodel, common for all 30 regions, is depicted in Figure A-10. Notice how it enumerates the full range of regional generation options at the lower left, the full range of incoming transmission options at the lower right, the native load (including load shape) at the upper left, and the outbound transmission at the upper right. Our approach is fundamentally tied to network diagrams of the form in Figure A-10, just as our North American Regional Gas (NARG) model is tied to analogous regional network diagrams for gas supply, transportation, and demand markets.

3.1.2 MarketPoint Allows Subregionalization

In the real world, individual assets are located in specific, highly localized regions of the United States, and the fuel, generation, inbound transmission, outbound transmission, and demand infrastructure in the immediate regions surrounding the plant fundamentally affect the value of the asset. It is necessary, therefore, to disaggregate the regions near the asset in more detail than the regions further from the asset. To illustrate how MarketPoint allows that, consider a hypothetical asset that might be built in southern Texas, i.e., Southern ERCOT. For such a plant, we would need to further disaggregate the ERCOT portion of the Altos North American model as indicated schematically in Figure A-11. To wit, we cannot simply use the original highly aggregated representation of ERCOT; we must represent ERCOT in a high degree of nodal detail so that we can understand the interplay between generation and transmission within ERCOT as well as the interplay between ERCOT and the rest of the United States and the continent. MarketPoint allows us to disaggregate ERCOT into the detailed "nodal" substructure shown in Figure A-12. As indicated in the figure, the expanded MarketPoint model is a nodal pricing model of ERCOT, and it is embedded in and interconnected to the entire North American electric grid. It calculates market clearing prices and energy flows at every node within the ERCOT system and every node within the North American system, all on an interconnected basis.

The red elements in the figure represent regions or "nodes" in ERCOT. As indicated in the figure, the specific nodes used to represent ERCOT for purposes of this discussion of a prospective South Texas plant include

- VALL (Rio Grande Valley)
- CBEN (Central Power and Light South)
- CPS (San Antonio)
- AEN (Austin)
- LCRA (Lower Colorado River Authority)
- HLP (Houston)
- STEC (South Texas Electric Coop)
- JWT (Jewett)
- TU (Texas Utilities-Dallas)
- TU/E (Cooperatives east of Dallas)

- TU/W (Texas Utilities-West)
- WTX (West Texas)
- BRYN (Bryan/College Station)
- TNMP (Texas New Mexico Power Pool)

These nodes are conceived of as locations at which there are aggregates of generation, aggregates of load, aggregates of inbound transmission, and/or aggregates of outbound transmission. These nodes themselves can therefore be thought of as regional market entities that compete against each other as well as complement each other within the ERCOT system. We think of generators in each of the red nodes as competing for load not only in the node in which their generation is physically located but also in contiguous nodes in which their generation might have a competitive advantage over incumbents in that node. In MarketPoint, just as in the real world, there is "rivalry" among the nodes in ERCOT to meet the demands resident within each node. It is this internodal rivalry that dictates which generators will run, which will not, which segments of the transmission system will be used, which will not, and where after all such rivalry plays out prices in ERCOT will ultimately be driven. It is this rivalry that dictates what ERCOT prices will be into the future.

The yellow ovals in the nodal diagram in Figure A-12 are also very important. They represent transmission capabilities in expressed in terms of MW of capacity that interconnect the ERCOT nodes. Specifically, they represent first contingency transmission capabilities along the transmission corridors between the nodes or regions. First contingency transmission capability is used to represent transmission capacity between the nodes because nodal prices are determined by total, aggregate flowing quantities, not contracted quantities, uncontracted quantities, portions of total quantities, or some other subset of total energy. After all, it is total energy into and out of each node that sets the market clearing price at that node. The numbers inside the yellow ovals in Figure A-12 depict the transmission capability assumptions upon which this study is based, i.e., the first contingency transfer capabilities.

MarketPoint systematically and internally balances inbound and outbound transmission against indigenous generation at every individual market node that comprises ERCOT (and in fact North America as a whole). Every individual nodal market within ERCOT is assumed by MarketPoint to be served by the most competitive mix of plants plus inbound transmission lines possible, given that every other nodal market is being served by its own most competitive possible mix of plants plus inbound transmission lines.

3.1.3 Temporal Assumptions

MarketPoint contains a very general internal representation of time and temporality. This allows MarketPoint models to be build and modified very easily compared to the alternative. Indeed, dealing with model temporality is generally the hardest part of modeling. To be specfic, MarketPoint allows

- **Whatever number of time points you want.** There is no limit on the number of time points. You can have hourly, daily, weekly, monthly, annual, or multiannual time points.

- **Whatever interval between the time points you want.** As an example of what you can do, you can begin the model horizon with 12 monthly time points followed by six annual time points followed by six biennial time points.

- **Whatever number of sub-time points within each time point you want.** There is no limit on the number of increments you can use to represent a load duration curve or discretize a period-wise chronological load at each time point within the model.

Figure A-13 illustrates the temporality that is supported by the MarketPoint modeling system.

3.1.4 Incorporating Forward Cost to Market for Existing Generation Units in a Region

Having regionalized the North American market as in Figures A-9 through A-12, the next task is to specify the nature of the existing generation mix region-by-region. In the lexicon of the network diagram in Figure A-10, we need to "populate the generation nodes" with generation plant data. This has been accomplished according to the logic illustrated in Figure A-14. To generate the necessary data, we have estimated the capacity and the forward cost to market for every one of the generation units in a given region—utility-owned units and independently owned units alike. Thereafter, we line up the units in that region in ascending order of forward cost as shown in Figure A-14. For each unit in the stack, the width of the supply curve for that unit represents the capacity to produce electricity, and the height of the supply curve represents the forward cost of doing so with that unit. The lower right envelope of this stack (i.e., the lower right boundary of the curve) represents the electricity supply curve available from the aggregate of all the existing generation units in the region. It is the sought-after supply curve based on the capital stocks that exist today.

What types of judgments and adjustments have been necessary to craft the supply stack in Figure A-14? The answer lies in a brief description of how one must think about forward cost to market for each of the existing generation plants. Figure A-15 summarizes what we have included and not included in each element of the generation supply stack in Figure A-14. Beginning at the bottom, notice that we have included as part of the forward cost all fuel-related costs (bottom) and all variable costs (e.g., consumables). Variable cost is assumed to include costs that will be incurred if the plant operates but will NOT be incurred if the plant does not operate. Variable costs are those that need not be borne if the plant does not operate. They are avoidable. The second from the bottom element of the diagram is understood to include all nonfuel costs that can and will be foregone and avoided if the plant is not run.

Turning to the most difficult element of the forward cost stack, designated fixed operating and maintenance cost in Figure A-15, it is clear that a portion of the fixed O&M cost must be included in forward cost because it can be avoided if the plant does not run. For example, the basic, minimum, prudent maintenance cost necessary to keep the plant in service can be avoided by shutting down the plant. In a competitive market, such cost will have to be repatriated through energy sales; otherwise, plant owners will be obliged to permanently shut down the plant because it loses money with every KWh of operation. In the figure, therefore, a portion of the nonvariable O&M cost must be included in the forward cost of the plant and therefore included in the height of the supply curve.

It is also true that because fixed O&M costs are presently being repatriated largely through fixed cost passthrough as part of the regulatory compact, completely apart from energy sales, they have arguably been substantially higher than would be sustained in a competitive market. (Such argument is similar to but not identical with the Averch-Johnson effect, which argues that if utility companies are paid to make risk free investments, they will over invest relative to an economically efficient level.) The portion by which fixed O&M costs are too high and will not be repatriated through energy sales in the forthcoming competitive electricity market must be excluded from forward cost to market. They must appear above the horizontal line in Figure A-15 and they must be viewed as sunk costs (if they are incurred at all). The question of fixed O&M costs is a difficult problem, one that has consumed a great deal of debate and analysis related to this model. We are convinced ours is the correct approach, but analysis and revision must continue.

There is another interpretation of forward cost to market, which is equivalent to the foregoing, that merits extended discussion. Using the analogy of a jet aircraft that is owned by an airline company, we see in Figure A-16 that its cost structure is comprised of four fundamental elements: variable operating cost, cycling cost, preservation cost, and all sunk costs. Variable costs include fuel, consumables, crew, etc. Cycling costs include incremental costs necessary to provide the specific time schedule of services demanded by their market. Preservation cost represents the lowest prudent cost required to maintain the aircraft in serviceable form so that it can carry passengers and generate revenue. It can be regarded as mileage- or flight hour-dependent maintenance costs and other such fixed maintenance items. Finally, there are a number of sunk and/or allocated costs that can be attributed to ownership of the airplane (e.g., depreciation, gate leases, airport fees). These sunk costs are truly sunk and are independent of the operation or the airplane.

In assembling a forward cost curve for an airplane, we would argue that it should be composed of the variable cost plus the cycling cost plus the preservation cost. These three categories of cost, and only these three categories, can be considered avoidable if the airline company were to sell their plane to Air Ghana, Air Nigeria, etc. or simply decommission it. To wit, variable cost, cycling cost, and preservation cost are avoidable by simply divesting the asset. If the market fails to repatriate such cost through ticket sales, the airline company can and will choose not to incur those costs. The decision not to incur any of these three categories of cost—variable cost, cycling cost, or preservation cost—is tantamount to a decision to divest the airplane. Whether or not to operate the airplane is a function of the SUM of all three of these forward costs to market. It is critically important to realize that the market must repatriate ALL forward costs—variable cost, cycling cost, and preservation cost—or the asset will be retired and removed from the North American asset mix. Precisely the same is true for power plants, semiconductor plants, steel mills, and all other capital assets. If the market (or some government agency that provides an equivalent subsidy) fails to repatriate variable cost, cycling cost, and preservation cost, electric plants will be decommissioned and abandoned.

The curve in Figure A-16 must be recast in terms of variable cost, cycling cost, and preservation cost. Figure A-17 illustrates. Clearly, the forward cost to market for any electric plant must, in the absence of full cost passthrough via regulatory formula, include each of these three categories. The forward cost estimates we apply in our model have taken great effort to embed the view implicit in Figure A-17. Given this view, it is absolutely clear that forward prices will NOT be equivalent to "system lambdas." System lambdas reflect only fuel costs and nonfuel pure variable operating cost. They systematically exclude those elements of cost so important to the forthcoming merchant world—cycling and other service costs and preservation costs. Any model that purports to equate forward price with forward system lambda is both incorrect and misleading. We should also note in passing that the cycling and preservation costs of much of the older capacity resident within the North American generation plant inventory is quite high. There is large difference between pure variable cost and total forward cost to market for these older plants. This large difference imperils the competitiveness of these older plants and attracts entry, a phenomenon our model is uniquely able to model. This is a critically important point. Old plants must compete against all other plants in the generation inventory, and those old plants must carry the heavy disadvantage of high nonvariable O&M cost. When those plants are transformed from their present highly protected state of fully regulated plants with full cost passthrough to merchant plants that face market prices for both fuel and power, their high O&M costs will become increasingly daunting.

Turning to the last cost category, all embedded capital costs and capital recovery factors must be viewed as sunk costs and will not be repatriated or repatriatable through energy sales. Gone with the demise of fixed cost passthrough is the notion of "return on and return of rate base." Gone is the notion of guaranteed repatriation of embedded capital outside energy sales. Gone in the forthcoming merchant era is the notion of fixed cost passthrough downstream to unwitting customers who are forced to accept it. In the coming merchant world, there are no customers who can be forced to do anything! Just like other industries ranging from gold, oil, semiconductors, or agriculture, yesterday's capital costs and cash flows deriving therefrom are sunk and unaffected by future plant operation. Those costs must not be included in forward cost to market estimates necessary to run a market model. While we want to consider the possibility of embedded costs (i.e, stranded costs) being repatriated in transmission or distribution tariffs within the electric power system, we also will want to consider the possibility that they will either be recovered totally outside the energy system or not recovered at all by electric utility shareholders.

The most difficult aspect of measuring forward cost to market has proven to be estimating what magnitude of formerly fixed operating and maintenance costs should be included as a forward cost and how much it contributes to the height of the supply curves? What portion of historical preservation costs will actually be borne by and repatriated to generation owners in the competitive market? We have made such estimates for each of the units in each of the 30 regions of North America and incorporated them into our estimates of the heights of the supply curves.

We have implemented our plant data management system within a proprietary software system known as MarketPoint. One of the outputs of that system is the region-by-region supply stacks discussed in detail in this section. Figure A-18 puts forth the supply stack calculated for the WSCC:California-Southern Nevada generation region.

3.1.5 Scope and Origin of the Generation and Transmission Data Base

As indicated in Figure A-19, we have downloaded some 24,000 generating plants that comprise North America including capacities and forward costs from publicly and privately available sources. Before arraying them as shown in the figure, it has been necessary to undertake a rather extensive reconciliation and comparison process. We should caution that such downloading has not been conducted as a simplistic, thoughtless, mechanical process. It is much more difficult than that; analysis and "thinking" are required. There is much anomalous cost and capacity information embedded in commercially and publicly available sources (e.g., RDI, ES&D) that has to be ferreted out and adjusted. It has been necessary for us to render judgments and adjustments to many of the plant capacity and forward cost estimates in order to create supply curves that are credible and reasonable. It has also been necessary to adjust them to consider the coal, gas, oil, and nuclear fuel cost projections into the future we want to use. We should emphasize that we have downloaded not only utility-owned, muni-owned, and coop-owned units but also privately and independently owned generation units. In the merchant market of the future, there is fundamentally no difference or distinction between utility-owned and non-utility-owned units. We have access to proprietary data bases that enumerate all independently owned as well as utility-owned generation units in North America.

We should point out that we have gone to great effort to include each and every MW of capacity that exists in each of our regions including investor owned utilities, munis, cooperatives, and independently owned generation whether it has been reported or not. Because it is the aggregate of supply--reported plus unreported supply—that in aggregate combines to satisfy demand, we have taken great effort to include all the independent as well as reported generators in every region. We have frequently seen other consultants and modelers report lower capacities than we do and consequently report and advocate lower reserve margins than we do. Why would they lack such access, and why should Altos have it? It is because most consultants and others simply take the generation unit and load data as reported by the NERC Electric Supply and Demand report and pass it on in the form of reserve margin and other calculations. They put it in models, they put it into supply stacks, calculate reserves, etc. Keep in mind, the NERC reports simply bundle and pass along information that is reported by individual reporting utilities. The problem with data based on NERC is that it systematically excludes many of the so-called "phantom units" because such independently owned units often have no capacity contracts with utilities and therefore utilities do not have to report them to NERC or to anyone else. Because utilities report only capacity they have under contract, there is a systematic low bias in utility reports and the consequent NERC reports; their reported capacity is systematically low. To reiterate, utilities rightly consider only that capacity that is under contract and therefore is routinely a part of their business.

Are the "phantom plants" to which we have alluded at all visible? Is there a systematic way to observe where they are and how big they might be? The answer is yes Utilities are required to report to FERC on a substation by substation basis inbound and outbound sources of energy by source, loads and generation, loss rates, reactance, voltages on transmission systems, and the like. (This is required as part of their FERC 715 transmission reporting.) Embedded in the voluminous FERC 715 information (which is a compilation of the detailed substation by substation transmission and energy reporting) is production by source from each and every generation station in the United States by name whether or not that particular generation station might be under contract to a utility and therefore whether or not it might be included in NERC reporting. To wit, the requisite plant by plant information is resident within the FERC 715s; they collectively contain more complete and accurate information as to precisely what capacity exists in each region whether or not that capacity is under contract to any resident utility, muni, or coop. In other words, the FERC 715s are the place where the fundamental substation by substation buy and sell information is recorded, nowhere else.

Altos has downloaded every FERC 715 for every substation in the United States and accumulated the energy inflows and outflows at every location by source to infer how much capacity truly exists at each substation within the United States. This is a very ambitious software engineering process, one that requires knowledge of how to download the FERC 715 data in automated form, how to read it with a computer program, how thereafter to process and sort it to infer what capacity truly exists at what substation, and finally how to aggregate it into the type of supply stack information in Figure A-15.

Because utilities do not themselves report uncontracted capacity, consulting companies that lack Altos' software capability sometimes access other plant data sources such as the Energy Information Administration Inventory of Power Plants and assume that they are accurate because all power plants in the country are required to report to the EIA and therefore are contained therein. However, Altos has found this to be an inaccurate source as well. It too is problematic because it includes not only phantom generation but also industrial self generation. There is no offset for internal industrial consumption that must be matched with industrial self generation; EIA merely reports gross generation capacity. Furthermore, there is a significant reporting time lag in the EIA information. It is an annual report, and it is typically 1-2 years behind (as many EIA documents are). Also, it is purely historical; EIA does not project capacity additions. There is an obvious bias toward overreporting large plants-utility, phantom, plus self generation-but overreporting small plants. The EIA documentation is not therefore as satisfactory as the 715 method.

Does any of this matter? Of course. Having reviewed the FERC 715 data on a substation by substation basis, we observe time and again that at time of peak, utilities are not always running their own indigenous peaking units. They are buying as available energy from another local source at time of peak! This is not at all unusual; it occurs frequently. Resident utilities are choosing to use these phantom generators at time of peak and not therefore to fire up their own peaking capacity. Without the FERC 715 information, one could not verify this or measure this at all. This practice of using as available energy as a peaking source means that the local utility is using phantom capacity rather than its own capacity to meet peak reserve requirements. Obviously, the reserve requirement under such practice is higher than what is being reported by utilities to NERC. Furthermore, the very fact that as available energy is available at time of peak means that it is above and beyond the consumption levels at the plant sites where the as-available generation occurs. It is clearly "excess" with regard to self use. Recognizing that these as available energy sales some from excess capacity with regard to industrial self use, the FERC 715s are giving us exactly what we want—capacity and energy that are available to the electric grid.

The MarketPoint input data system has been configured as shown in Figure A-19. The system contains plant data for every utility-owned and independently owned generation unit in North America as shown on the left. It compares and reconciles all the publicly and privately available data source and develops a single, consistent, reasonable set of generation data. The electric data base is an important part of the MarketPoint product and is provided to our customers along with the model.

3.1.6 Cost Reduction and Performance Improvements for Existing Units in a Given Region

As we have observed in every industry that has deregulated, "the good get better and the bad become moribund." There is tremendous incentive immediately following deregulation for existing plants to reduce their forward cost to market over time. Darwinian natural selection (survival of the fittest) virtually guarantees that it will occur. Such cost reductions obviously include reducing fixed O&M, both the market repatriatable portion and the nonrepatriatable portion. As a directly relevant example, consider that airlines (and maintenance contractors) have reduced prudent and mandatory maintenance costs for their 747s as far as they prudently can, and those reduced costs have been repatriated through airline ticket revenues. Airlines have also reduced or eliminated altogether excess or imprudent fixed O&M they may have been charging before deregulation. In short, they have learned to repatriate that portion of maintenance cost that is required by them and their competitors to remain airworthy, and they have eliminated redundant or unnecessary costs. Competitive forces compel them to be constantly vigilant in seeking out and eliminating fixed O&M costs that can be prudently eliminated.

Figure A-20 represents the downward pressure against forward cost to market experienced by the presently existing generation capital stocks, i.e., it represents how cost reduction affects the entire supply stack from Figure A-14. The stack of supply curves represented in blue represents presently existing capacity and forward cost embedded in presently existing vintages of plant and equipment. The downward-shifted stack represents the downward migration in forward cost to market for each individual vintage of plant currently in place and collectively for the entire set of vintages. Keep in mind, this downward shift occurs as plant owners simultaneously and/or individually reduce the three important elements of costs—variable cost, cycling cost, and preservation cost. We have carefully considered and represented this downward evolution in our model.

Based on empirical observation of every industry that has been deregulated, it is absolutely unacceptable to hold the cost structure for the existing capital stock of plants constant and static at today's level. We have rendered difficult judgments regarding the most likely future evolution of forward cost structure of the existing mix of plants in place, and we have embedded that judgment in our model. We believe that plants that do not reduce costs are likely to exit the market and only plants that reduce costs will remain in the mix. We characterize this inexorable cost reduction as shown in Figure A-21. In effect, we have placed existing vintages of plant on a "learning curve" through the future to reflect our judgment as to what is possible and/or likely.

3.1.7 Retirements of Existing Units in a Given Region

Alas, notwithstanding the inexorable pressure for cost reduction, many existing plants simply cannot hope to survive. Competition is quintessentially Darwinian, the weak, the old, and the sick do not survive. Some economists have dubbed capitalism a system of "graceful obsolescence." Plants retire because they age, and their operating and maintenance costs escalate to noncompetitively high levels. It is well to consider that the average age of electric generation capital stocks is over 20 years in North America, older than at any time in the past. Cost escalation in the older plants resident within that mix is inevitable. Cost escalation in plants currently in cold shutdown is inevitable, and it is likely that few or none of those plants will ever reenter the market.

What does aging mean? How is it manifest in terms of forward cost to market for a given plant? The answer is obvious when one considers his or her personal automobile. When the car is new, its forward cost to market (fuel cost plus maintenance cost) is low and flat, remaining so until the car hits a certain age. After a certain age, the sum of fuel cost plus maintenance cost begins inexorably to appreciate. Maintenance becomes more frequent and more costly. Whereas maintenance used to mean an oil change, it now means a transmission overhaul or a valve job. Whereas outages used to mean running out of gas, outages now mean two weeks in the shop while the user commits to a rental car. We can plot the phenomenon of plant aging conceptually as in Figure A-22. The top right portion of the supply curve (the old, high cost plants in place today), can be expected to shift over time to the left as companies abandon those old plants in favor of new plants or imports via transmission from contiguous areas. We have given a great deal of attention in our electricity model to the problem of quantifying which plants are likely to escalate in forward cost to market the most quickly and thereby be the most quickly "out of the money." On a region-by-region basis, we have made an assessment of the rate of escalation of forward cost to market escalation due to aging and an estimate therefore of how far the leftward shift in Figure A-22 might indeed be.

It should be noted that these are long run effects that may be tempered by numerous factors. In many instances, e.g., Texas and California, the introduction of significant amounts of new merchant capacity is not causing unit retirements. Rather, it is increasing generation supply, increasing reserve margins, and increasing regional reliability.

3.1.8 Ingress and Egress of Transmission to and from Each Generation Region

As if cost evolution in existing plants were not a difficult enough problem, deregulation opens the Pandora's box of "competition from afar" via long distance electric transmission. While in the halcyon days of rate of return regulation, utility companies could generate exclusively for their own accounts, staving off transmission and generation entrants into their service territories through franchise control, they now face the prospect of transmission entering their service regions and competing with their generation assets. That is the "bad news." There is, however, offsetting "good news." Generation companies can compete with plants in contiguous service territories by exploiting outward bound transmission, thereby augmenting the markets they can serve. The logistics of inbound and outbound transmission add a degree of competition and a degree of analytical complexity to the electric power industry that has not been present historically. The historical types of models used in the industry, particularly production simulation dispatch models, were and are unequipped to represent the inbound and outbound transmission issues that will begin to affect the industry in the future. Production simulation models should go the way of the dinosaur, a relic of an industry environment that is long since gone.

How do we represent the emerging open access transmission system and its implications for electric power? The answer is apparent from the structure of the map in Figure A-9 and the subregional network diagram in Figure A-10 or Figure A-12. We have represented existing and prospective transmission linkages among all the contiguous regions and subregions in the diagram, we have represented all the indigenous generation alternatives within each region and subregion, and we have represented electricity demand within each region and subregion. To wit, we have used "brute-force enumeration" to characterize all the existing and prospective generation, inbound transmission, outbound transmission, and native consumption options within each region and between each pair of contiguous regions. Focusing on transmission, within each of the regions and subregions in Figure A-9 and Figure A-10, we have represented generation, transmission, and consumption as shown in Figure A-23.

The title of Figure A-23 is significant, the "conventional wisdom" of the electric transmission business. The "conventional wisdom" suggests that generators in a particular region will generate power and wheel it to their own customers (which we term intra-regional wheeling), ship it to customers in contiguous regions, and receive it from generators in contiguous regions. It is usually further conjectured that such transactions will all occur at a single tariff, a "postage stamp tariff." A postage stamp tariff or rate is a single, common rate for point to point transmission service, but the rate is independent of the entry point and the exit point. Postage stamp rates charge a shipper to "get on and get off the train" but do not levy a distance-dependent charge. Postage stamp rates have the property that wheeling costs are the same, absolutely identical, for all entry and exit points on the transmission system. Wheeling power a distance of 300 yards costs the same as wheeling it 350 miles. While we want to admit into our model the possibility of postage stamp transmission rates for both intra-region and inter-region wheeling, we also want to admit the possibility of market-sensitive rates, distance dependent rates, and zone rates in electric transmission, just as we have seen evolve in the gas and telecommunications businesses. There is no earthly region why rates should equilibrate to a single postage stamp rate. On the contrary, postage stamp rates hurt certain transmission linkages, and the owners of those linkages can be expected to reset their tariffs as a competitive measure. We have retained the ability to consider the widest possible range of transmission rates and infer what particular set or sets of rates are likely to be market-sustainable.

Motivated by our ambitious goals for modeling electric transmission, we have proceeded as follows. We have implemented the structure in Figure A-23 for each of the 30 regions and subregions in Figure A-9, but we have connected them together as shown in Figure A-24.

The reason for the interconnection indicated in Figure A-24 is that we want to allow the possibility that the transmission tariff from the left region to the right region is DIFFERENT from the transmission tariff from the right region to the left region. We also want to allow the possibility that the intra-regional wheeling tariff in the left region is DIFFERENT from either of the two inter-regional tariffs, and that all are DIFFERENT from the intra-regional tariff on the right. This is not to say that we dismiss the possibility that they might all be the same. On the contrary, the structure we have built allows us to set them all equal to represent prospective postage stamp wheeling. However, it is to say that we want to preserve the possibility of setting them all to be different and thereby to represent scenarios whereby owners of transmission strive to price at market rates and strive to extract whatever rents they can whenever they can extract them. We also strive to represent the possibility that transmission might enter on an unregulated, unguaranteed, greenfield way at some time in the future. (The example of privatized highways argues that merchant entrepreneurs might build transmission if there is sufficient rent earning possibility they can glean from such entry.)

There is one other critically important aspect of our transmission submodel that merits discussion here. Referring to the inter-region and intra-region wheeling links, they have a fixed maximum capacity today. We have made a great deal of effort to estimate and input today's transmission system maximum capacities in the model. We have attempted to represent maximum inter- and intra-regional capacities so that we can identify near term bottlenecks caused by transmission capacity limitations. In addition, however, just as with generation, it is possible to reinforce existing transmission infrastructure to increase inter-regional and intra-regional transmission capacity. It is also possible to implement greenfield transmission capacity, adding lines that are either parallel to existing lines or lines along fundamentally new routes. Our model considers existing transmission capacity, the cost and capacity of augmenting existing capacity, and the cost and capacity of building new, greenfield transmission capacity. Just as with other commodities, prospective new electric transmission competes against old, and the combination of prospective new and old transmission compete against indigenous generation.

Figure A-25 represents economically what the combination of cost improvements in existing plants combined with incoming transmission can do to the original supply curve that characterizes only the existing capital stocks (black in the figure). Intuitively, there is a large increment of energy supply from incoming transmission that can materialize at or near a given price. This increment of incoming transmission energy competes "one-up" against the existing generation mix within the region. Furthermore, the existence of this transmission increment, because it drives the lower right boundary of the supply curve downward and to the right, has the prospect to dramatically depress market clearing prices of electricity in the region. In effect, it creates additional supply to chase a fixed level of demand. When additional supply chases a fixed level of demand, prices cannot help but fall (relative to what they would otherwise be). Indeed, incoming transmission depresses prices in the region into which it enters. Always.

By implementing the transmission increment as shown in Figure A-25, we are able in the power model to represent the true effects of inter- and intra-regional wheeling. We will not naively miss the prospective effects of incoming transmission buoyed by generators in contiguous regions who are striving to increase profits. We will not inadvertently miss "competition from afar," directed as it will assuredly be to high margin business. We will not inadvertently overvalue indigenous assets in any given region because we fail to consider the possibility of aggressive incoming transmission into the region.

By the same token, however, we will not fail to properly represent the fact that outbound transmission can create heretofore-unavailable energy markets for existing plants in certain regions. Our model considers the fact that outbound transmission can be an attractive business alternative for existing and prospective new generators in certain regions. Outbound transmission means that plants need not necessarily be sited contiguous to markets. Plants can be sited many miles away more contiguous to attractive fuel supplies and the electricity transported on an increasingly competitive transmission system to new markets. The more transmission that leads away from an existing plant, the larger the prospective market that plant sees. Larger prospective market available to a given plant means a higher selling price for the output from that plant. The model strives to balance (in the economic sense) the price-stimulating influence of outbound electric transmission against the price-suppressing influence of inbound electric transmission. We believe we have the tools and the emerging data to do so, and we have carefully employed them in valuing a rather broad range of assets and business prospects thus far.

Before leaving the issue of transmission, we need to represent what transmission implies for contiguous regions. Figure A-26 illustrates two regions, one a region (at the left) with excess generation capacity relative to demand and one (at the right) with tight capacity relative to demand. Notice that the region with excess capacity at the left evidences a lower market-clearing price than the tight region in the absence of interconnecting transmission. As illustrated in the figure, if the incremental cost of transmission is smaller than the price differential that would be sustained in the market between the two regions if they were isolated, transmission will enter. As it enters, the critical insights are those shown in the figure:

- Price in the region where the transmission originates will INCREASE. Outbound transmission stimulates market-clearing price because it provides more demand against a constant generation mix.

- Price in the region where the transmission terminates will DECREASE. Inbound transmission decreases market clearing price because it provides more supply against a constant customer mix.

- If the cost of transmission happened to be higher than the price differential between regions in the absence of transmission, there would be absolutely no transmission between the regions. Transmission will have absolutely no effect on the price in either region or the flow between them.

- In the absence of transmission limitations, the price differential between the two regions will shrink to the point at which it equals the transmission cost between the regions. In other words, transmission capacity will enter up to the point at which the price differential between the regions is exactly equal to the marginal transmission cost between regions.

- If there exists an immutable upper bound on transmission, the price differential between the two regions will remain larger than the transmission cost between the regions. Transmission will depress the price differential, but it will not be sufficient in size to depress the price differential all the way to marginal transmission cost.

Transmission is difficult to model because one does not know a priori which regions will have low prices during which periods and which regions will have high prices during which periods. The only way to accurately model transmission is through "brute force," systematically enumerating every existing and prospective transmission link complete with cost and capacity between every pair of regions in the model. This is precisely why dispatch-oriented production costing models have completely "fanned" on transmission. They have absolutely no hope of modeling transmission, for they require that one input an a priori estimate of what transmission assets are present in each region. It is not physically possible to have an asset from region A available in region A as a generation asset and simultaneously in region B as a vertically integrated generation-transmission asset, as dispatch models would force you to assume. Our approach is the only dynamic approach we know of that can represent the simultaneity of transmission implicit in Figure A-9.

3.1.9 Prospective Entry of New Generation Units into a Given Region

As if the foregoing issues were not sufficiently daunting and difficult, it is true that if the price of electricity rises to the point at which that price is capable of repatriating the full capital cost plus the full operating cost of a new, greenfield facility plus a minimum market-level rate of return necessary to draw capital from financial markets into that new, greenfield facility, we must expect such new, greenfield facilities to be built and enter the market. In effect, the full capital and operating cost of a greenfield facility must "cap" the price of energy in each of the 30 generating and consumption regions. There is no way that long term prices should exceed the full cost of a greenfield facility for very long. Increasingly easy entry will guarantee that it will not.

Figure A-27 represents the fact that new greenfield units can be expected to enter if the prices rises sufficiently to draw them into the market. Notice at the right hand side of the diagram that if the full fixed and variable cost of a greenfield unit plus a return to its owners will be repatriated by electricity prices, that greenfield unit will enter. Furthermore, there is no limit in each region on the entry of greenfield units. Gas combined cycle plants are literally commodities in their own right and can be added wholesale on a consistent and common basis. Recognizing the fact that entry is very easy and relatively quick, we must represent the fact that the supply curve becomes horizontal at an electricity price necessary to fully repatriate all fixed plus variable costs of a new greenfield unit. It is this flattening of ultimate electricity prices that inevitably obsoletes and shuts down old electric generation capacity. Old capacity is replace by the entry of new, whose full fixed plus variable cost undercuts the variable cost of the old, decrepit units.

We should note in Figure A-27 the use of the terms marginal variable cost and marginal capital cost. What we are attempting to indicate in the figure is that the price of electricity is capped by the "marginal new unit," the unit that offers the best sum of fixed plus variable cost. What the precise configuration of this unit is given local fuel costs, altitude, temperature, and other characteristics varies from region to region. We have gone to great effort to estimate the capital cost, operating cost, and heat rate of each and every prospective new unit that could conceivably enter the market in each region. This information is part of the model database. New units enter if the price rises to the point where it crosses the flat portion of the supply curve at the extreme right of the figure. In MarketPoint, new equipment costs have been estimated from developers, equipment vendors, and cognizant electric power professionals by our staff and represents an important judgmental assumption to the model.

Greenfield entry is important in the sense that the rate and magnitude of capital stock rollover and new equipment entry in other industries that have deregulated has been colossally underestimated. The telecommunications industry was rife with stories of overcapacity during Judge Greene's Modified Final Judgment to break up AT&T, yet

North America experienced a literal explosion of capacity. The gas industry was rife with stories of excess reserves and a gas bubble during FERC Order 436, yet in spite of prices falling by almost ½ in real terms since then, North America still experiences massive drilling, reserve additions, abundance of supply, and low prices. We have given special attention to the question of greenfield entry because we do not want to repeat the mistakes of other deregulating industries. Furthermore, we want to identify specific greenfield entry opportunities for our clients.

3.1.10 Summary of Supply Representation (Generation Plus Transmission)

It is important to summarize the issues we have accounted for related to electric energy supply. Figure A-28 does so. Notice in the figure, we have taken great effort to represent on a region by region basis the following five supply- and transmission-related phenomena:

- Cost and capacity of existing generation capacity
- Cost reduction that will evolve in existing generation capacity
- Imminent retirements in noncompetitive generation capacity
- Ingress and egress of transmission capacity to and from every North American region
- Entry of new, greenfield capacity based on the full fixed and variable forward cost to market.

The figure summarizes how MarketPoint represents each of these phenomena individually and collectively. We are unaware of any analytical framework save ours that systematically and formally represents each of these five supply phenomena, collectively or individually.

3.2 Representation of Demand

Having completed our generation and transmission overview in the previous section, we now turn to the question of incorporating electric energy demand into our model(s). Electricity demand varies by hour of day, day of week, week of year, and year. Furthermore, because electricity is not storable, it is the ultimate in "just in time" (JIT) manufacturing product. Literally 100 percent of all inventory must be embedded in standing capacity to produce, not in inventory that can be stored and resold upon demand. With today's technology, one cannot store electrons for later use. They flow and are used when they are generated. Generation units are like flashlights. When one turns on the switch, the flashlight produces light. When one turns off the switch, the flashlight immediately ceases to produce light. Like a flashlight beam, one cannot turn on the light during times when he does not need it and inventory it for when he does need it.

Projecting electric energy demand is akin to predicting demand for light from the flashlight. We need to project the hour by hour, day by day, week by week, and year by year demand for the beam of light, i.e., the aggregate stream of electric energy required by the customers in a given region. Figure A-29 recognizes that the hourly demand for electric energy must be projected region by region throughout the 30 regions we use to comprise the North American electricity market.

How can we determine what the hourly load variation is, and how can we project it 10 or more years into the future? To do so, we have accessed the hourly demand reports by every utility and other reporting entity in the country. We have accessed this voluminous information in automated form by hour by reporting entity over a complete three year historical period. It is our intention in so doing to be comprehensive, generating histories of demand by hour for every reporting entity in North America over the past three reporting years. By so doing, we are able in effect to develop a historical load duration curve for every hour of the year. This highly detailed information will allow us to build comprehensive models of demand at different levels of detail over different time horizons for our model.

What is the demand side methodology we have used? The raw, reported data alluded to above represents a historical demand schedule, which varies by time of day, week, season, and year. Figure A-29 provides a conceptual illustration of the time-varying historical data we have assembled to populate our demand model within every subregion in North America and every node of every regionalized model such as the ERCOT model in Figure A-12. The figure emphasizes that electricity demand is different for every historical hour reported in every region at every reporting point in North America. Indeed, there is a time-varying schedule of demand of the form in Figure A-29 stretching over the past three years at every point in North America.

The next step is to aggregate the raw information hour-by-hour, region-by-region to create 30 regional aggregates of hour-by-hour electric energy consumption. To wit, we have taken the curves of the form in Figure A-29 and aggregated them hour by hour according to the geographic subdivisions in Figure A-9. After such aggregation, we can develop an overall curve of the form in Figure A-29 for each of the 30 regions that comprise our model.

Once we have assembled this hour-by-hour load pattern over the three year historical period for the 30 regions of our model, we need to aggregate this data to the level required by the market model we wish to use. We can either maintain the hour-by-hour chronological form of the data, or we can use it to calculate daily, weekly, seasonal, and/or annual representations of load and load duration. Before discussing exactly how we have processed and aggregated the hourly demand data, it is worthwhile to define unequivocally what we mean by a load duration curve. To develop load duration curves, we begin with the hour by hour demand schedules for each of the 30 regions as depicted in Figure A-29 and reorder them in sequence from highest demand to lowest demand in the given year. This demand reordering process can be used to create regional load duration curves as depicted in Figure A-30. Such load duration curves represent total demand that occurs during a year, and they represent the total demand that occurs in every individual hour of the year. However, by reordering demands from highest hour to lowest hour, we lose the chronology of hourly demand by day, by week, and by season. All we would have is a highest-to-lowest snapshot of annual demand as distributed throughout the hours of the year. Whether this reordered series of demands is sufficient for a given need depends on whether we are studying hourly and daily load following. If not, the unordered representation of loads is sufficient. If so, we need to retain the chronology.

Using the WSCC, California and Southern Nevada as an example, Figure A-31 illustrates three different analyses of the demand data we have undertaken. To begin, the figure depicts the average daily demand pattern for each of the twelve months of the year, which is termed "Monthly Average Hourly Demand" in the figure. The average daily load shapes are the solid curves that embody the characteristic double peak in the winter and the characteristic single peak in the summer. They are derived from three year average hour by hour demand by month as derived from the Altos demand data base. Such daily load shape information is used to simulate daily operation in our models. Referring again to Figure A-31, we have crafted 12 monthly load duration curves and a single annual load duration curve. The 12 monthly load duration curves are used to populate our monthly models, and the annual load duration curve is to populate our longer run annual models. The comprehensiveness and hour-by-hour chronology of our demand side information is critical to developing demand side data of the type shown in Figure A-31.

It is useful to review how we take the fundamental demand information in the form of Figure A-31. We will use the monthly load duration curve as an example. The monthly load duration curves that come from the FERC 714 information we have assembled have the form in Figure A-32, which are just the monthly load duration curves from Figure A-31 for each month of the year. The first step is to select a number of discrete increments into which we want to disaggregate the continuous curve in Figure A-32. That is, if we wanted to use a "stairstep" approximation to Figure A-32, how many stairs would we want to use in order to get a good enough approximation to the curve. If we had elected to use ten stairs to approximate the curve, we would be able to draw the 10-stair discrete approximation to the continuous curve in Figure A-32 as shown in Figure A-33. The process of moving from the continuous curve in Figure A-32 to the discrete approximation in Figure A-33 can be done using extremely sophisticated, statistical fitting methods, or it can be done approximately.

Notice that the curve in Figure A-33 distinguishes ten different, discrete demand levels because it has ten different, discrete horizontal "tranches" (or blocks). Beginning at the left, we see the highest tranche, and we see a series of declining tranches until we get to the lowest horizontal tranche at the lower right. Each of these ten horizontal tranches corresponds to ten different levels of demand, each of which we express in MW. But the discrete curve also tells us how many hours each of the ten discrete levels of demand occurs. For example, the highest and leftmost level of demand persists in the diagram for 1 percent of the hours in the month. Assuming that there are 730 hours in the month, this means that the highest and leftmost level of demand persists in the diagram for 7.3 hours in the month. The second to highest and second to leftmost level of demand persists for 3-1=2 percent of the hours in the month, i.e., 14.6 hours in the months. Continuing this logic across the diagram, we see that it is in effect a histogram for the occurrence for ten different levels of demand. If we calculate the supply-demand equilibrium for each of these ten different levels of demand, our model will calculate a histogram or market clearing price. There will be ten different, distinct market clearing prices each with a corresponding frequency of occurrence. That is precisely what the MarketPoint model does in its simplest form. Figure A-34 illustrates how this occurs. Ten demand points (each with a frequency of occurrence) go into the model. Ten supply-demand crossing points are calculated, giving ten market clearing prices on the vertical axis. These ten market clearing prices occur with exactly the same frequency of occurrence as the ten demand tranches that generated them. Therefore, the ten prices are in effect a histogram over prices during the month, a so called price duration curve.

Figure A-35 shows direct output from the model. In order to understand the market clearing prices depicted in that figure, consider that load has been disaggregated into ten monthly periods:

- Average load during top 1 percent of hours (designated 1%).
- The average load excluding the top 1 percent of the hours but including the top 3 percent of the hours (designated 3%).
- The average load excluding the top 3 percent of the hours but including the top 5 percent of the hours (designated 5%).
- The average load excluding the top 5 percent of the hours but including the top 15 percent of the hours (designated 15%).
- The average load excluding the top 15 percent of the hours but including the top 35 percent of the hours (designated 35%).
- The average load excluding the top 35 percent of the hours but including the top 60 percent of the hours (designated 60%).
- The average load excluding the top 60 percent of the hours but including the top 80 percent of the hours (designated 80%).
- The average load excluding the top 80 percent of the hours but including the top 90 percent of the hours (designated 90%).

- The average load excluding the top 90 percent of the hours but including the top 98 percent of the hours (designated 98%).
- The average load excluding the top 98 percent of the hours but including the top 100 percent of the hours (designated 100%).

In effect, the percentage terms indicated in the legend represent the percent of time that the given or larger load persists. For example, the 3% curve represents the 97th fractile of load; the load exceeds this level only 3% of the time. This component of load is relatively peaky; load is higher than this level for only 3% of the hours of the month. Therefore, the percentages shown in the price diagram represent the percentage of time that the price is equal to or larger than the indicated curve.

Figure A-35 represents just such a price duration curve that was calculated by the Altos model in support of the Duke New Smyrna Beach application in Florida. It is immediately apparent from the diagram that we used five demand tranches rather than ten because there are five price lines in the diagram. Nonetheless, we have calculated a price duration curve for every month of the year in Florida and plotted the estimated production cost of the Duke New Smyrna Beach unit. This is precisely what the model is designed for and is so good for.

Our electric energy demand projection combined with a normalized load duration curve calibrated to historical load shapes constitutes a forward demand schedule in the electric model. In the lexicon of economic theory, this demand projection represents an "inelastic" projection of electric energy demand. We have the capability on a load category by load category basis to specify a price elasticity of demand so that the actual projected demand for electricity by the model is price sensitive. This capability is represented schematically in Figure A-36. Notice in the figure that we specify price-sensitive demand curves for each of the discrete increments of load. There is a peak load demand curve complete with price sensitivity, an intermediate load demand curve complete with price sensitivity, and a base load demand curve complete with price sensitivity. We believe this price sensitivity to be potentially important as the true marginal cost of on peak power becomes increasingly exposed to electricity customers for the first time. In the past, customers have been insulated from the true marginal cost (i.e., the true price) of peak load power because of regulatory cross subsidies of peak load prices by base load prices and of residential customers (who cause the peak to a significant degree) by industrial customers. Our price sensitivity feature has not yet been fully studied or exploited, but it promises to be important to asset valuation and trading in some regions during some periods of time.

4 SUMMARY OF MODEL STRUCTURE

To summarize, the Altos North American Electric Power Model can be represented schematically as shown in Figure A-28. The model contains a complete representation of supply including

- generation as it presently exists,
- cost reduction in present capital stocks,
- retirement of present and future capital stocks,
- existing and new increments of inbound transmission,
- existing and new increments of outbound transmission, and
- prospective entry of new plants and new technologies.

The model contains a complete representation of inbound and outbound inter-regional transmission that can accommodate not only postage stamp transmission tariffs but also a rich and complete range of distance-based, zone-based, value-based, monopolistic, or other tariff structures. On the demand side, the model is capable of representing demand on a chronological basis, but the present implementation used to support long and short run decision is based on a discretized load duration curve approximation. Viewed as an integrated whole, the model represents changing supply and changing demand and finds the market clearing price and quantity. In our lexicon, the model finds the "magic crossing point" between supply and demand. The market clearing price represented by this magic crossing point varies throughout the year as shown in the figure.

5 CONCLUSION

Altos and our customers have developed increasing confidence in the results of the MarketPoint model, and more companies are becoming increasingly committed to using it to guide their asset valuation decisions and our marketing and trading decisions. We believe that the model can generate competitive advantage, allowing us to increase profits and reduce risks of our asset and trading businesses and to coordinate and marry them at the most fundamental level.

Figure A-1: Evaluation of Asset Profitability

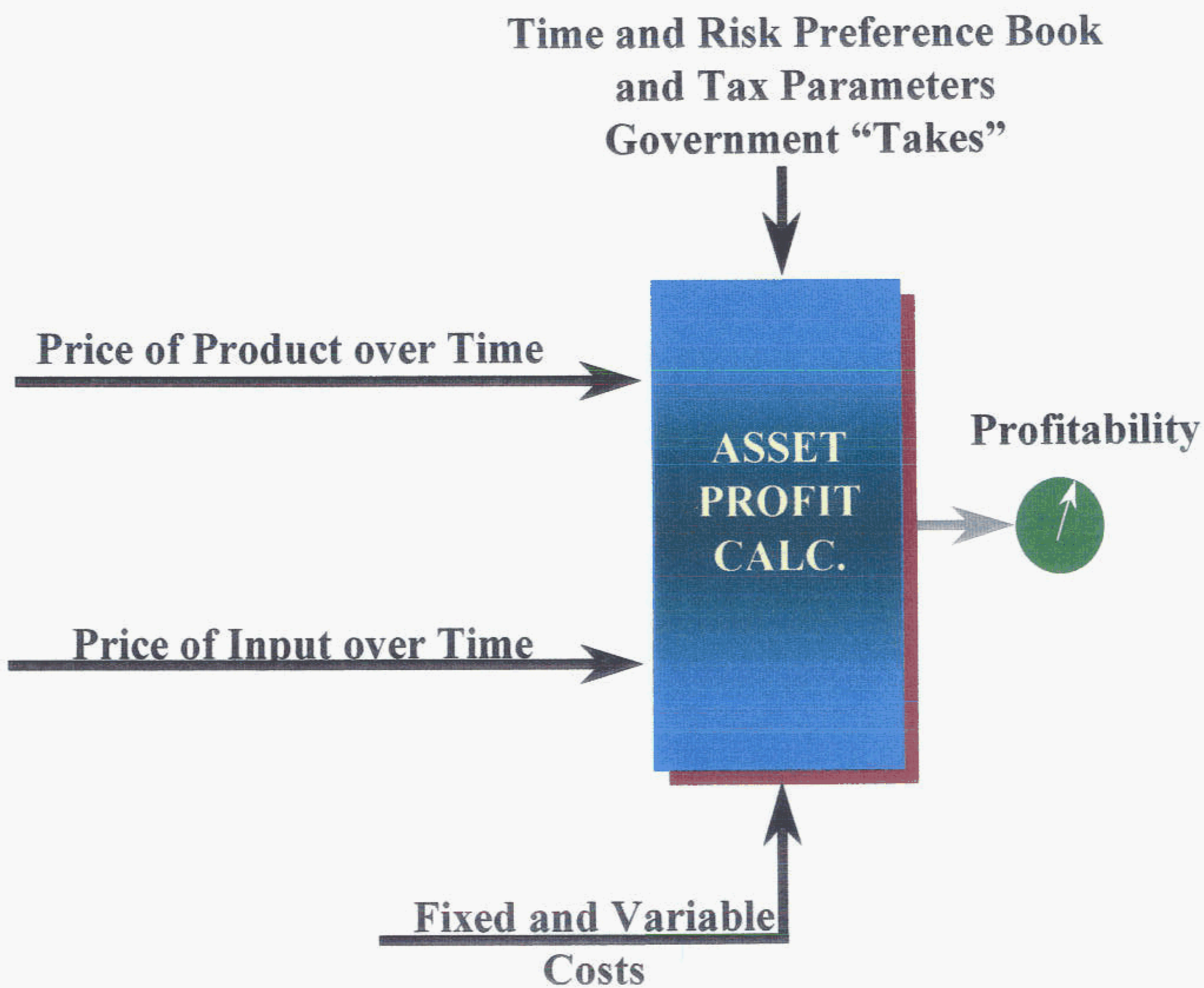


Figure A-2: Price Differential Across the Asset Is the Most Important Determinant of Value

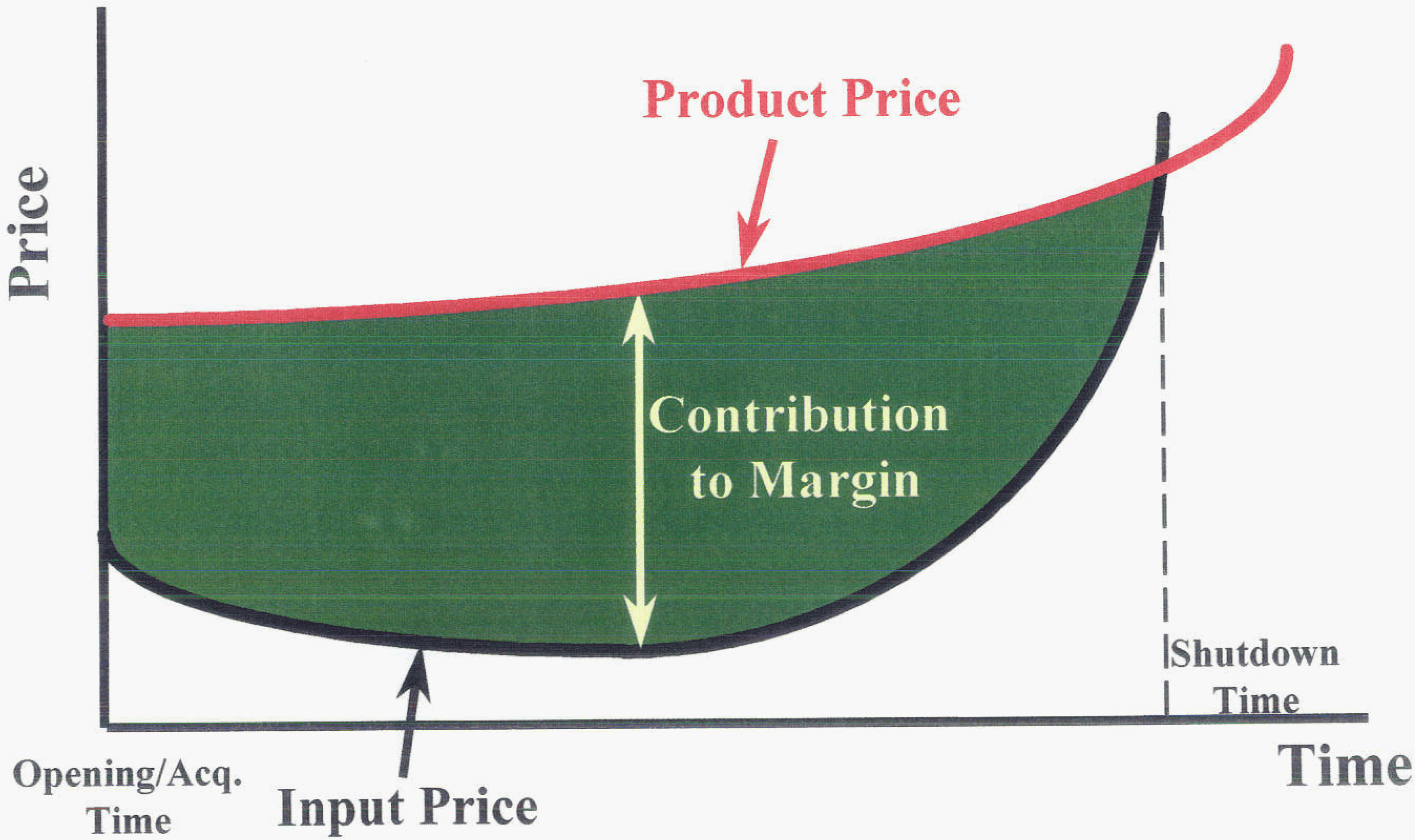


Figure A-3: You Could Put Probabilities Into Your Profit Calculator...

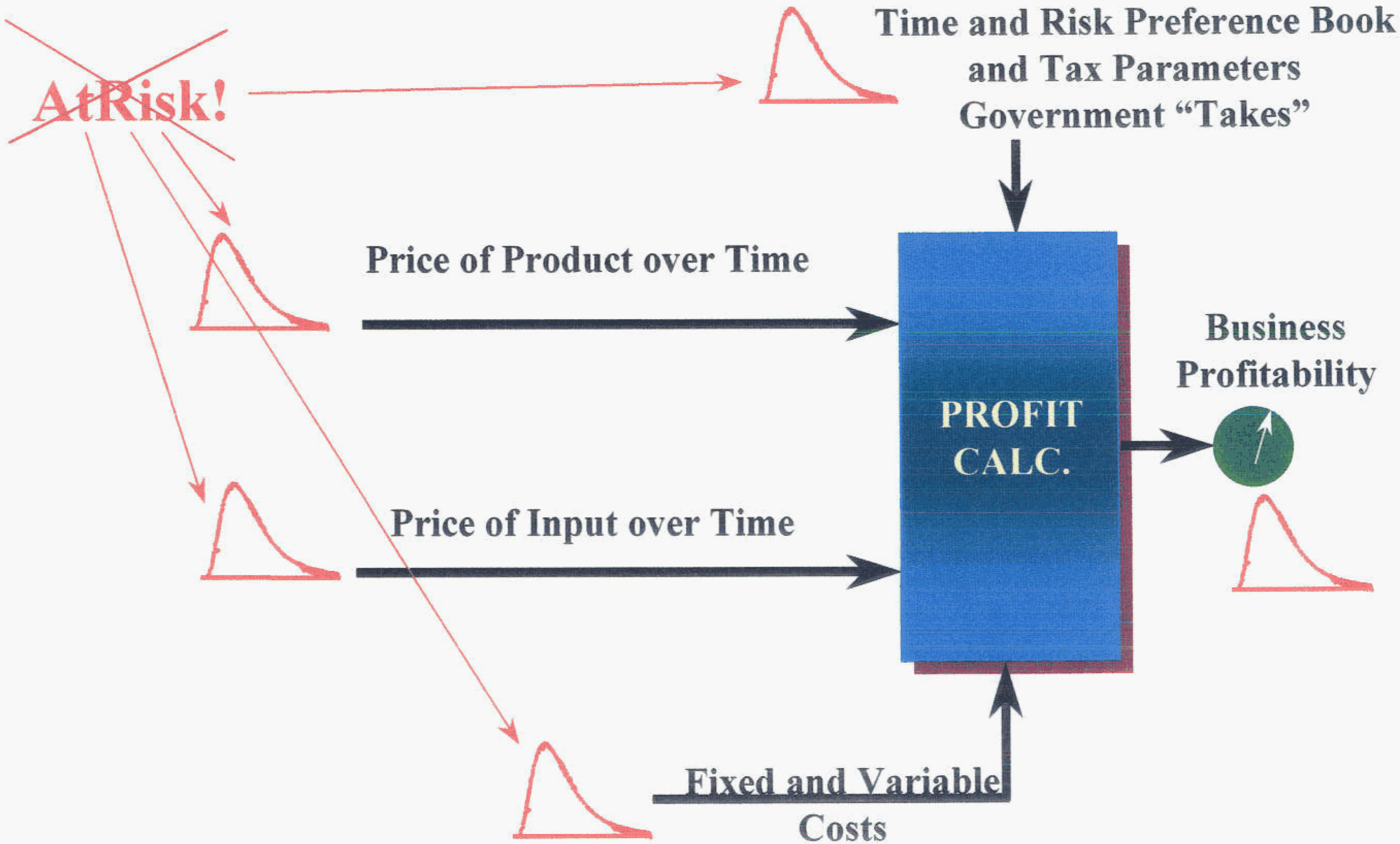
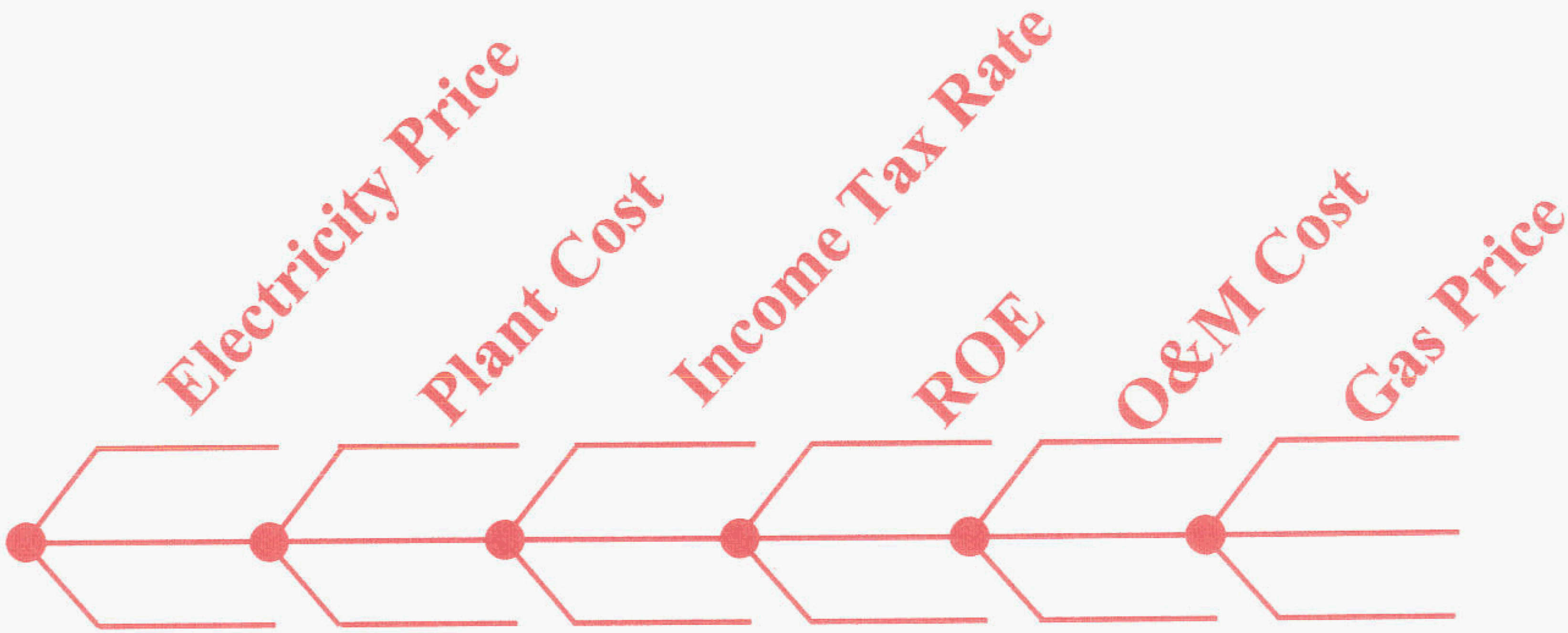


Figure A-4: And Then Run Out a Series of Probability-Weighted Scenarios...



3^6 combinations (=3^6 calculations)

3^6 probabilities

Figure A-5: ...Ending With a Probability Distribution Over Project Profitability

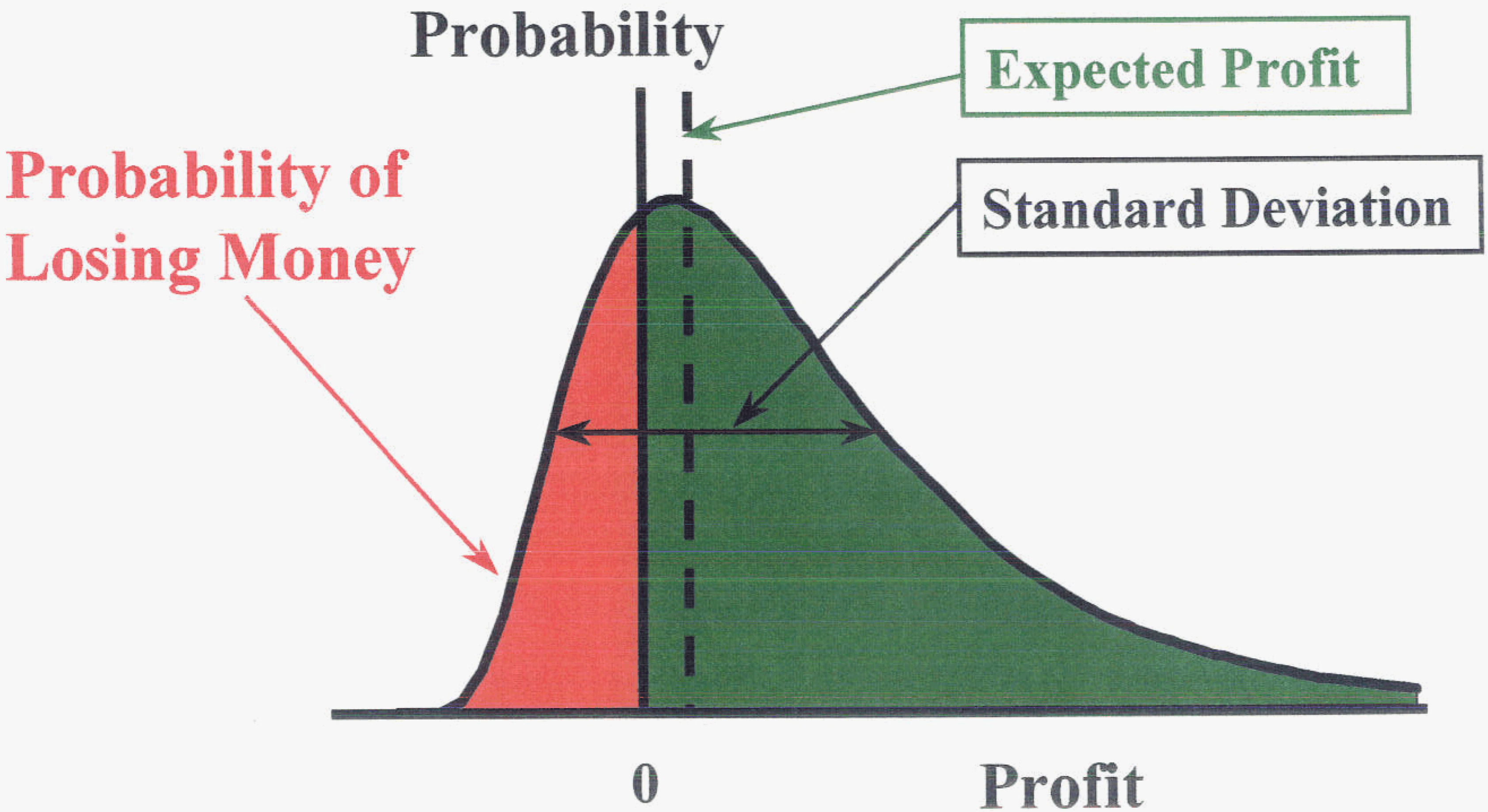


Figure A-6: Melding Full Regional Market Model with Profitability Calculator

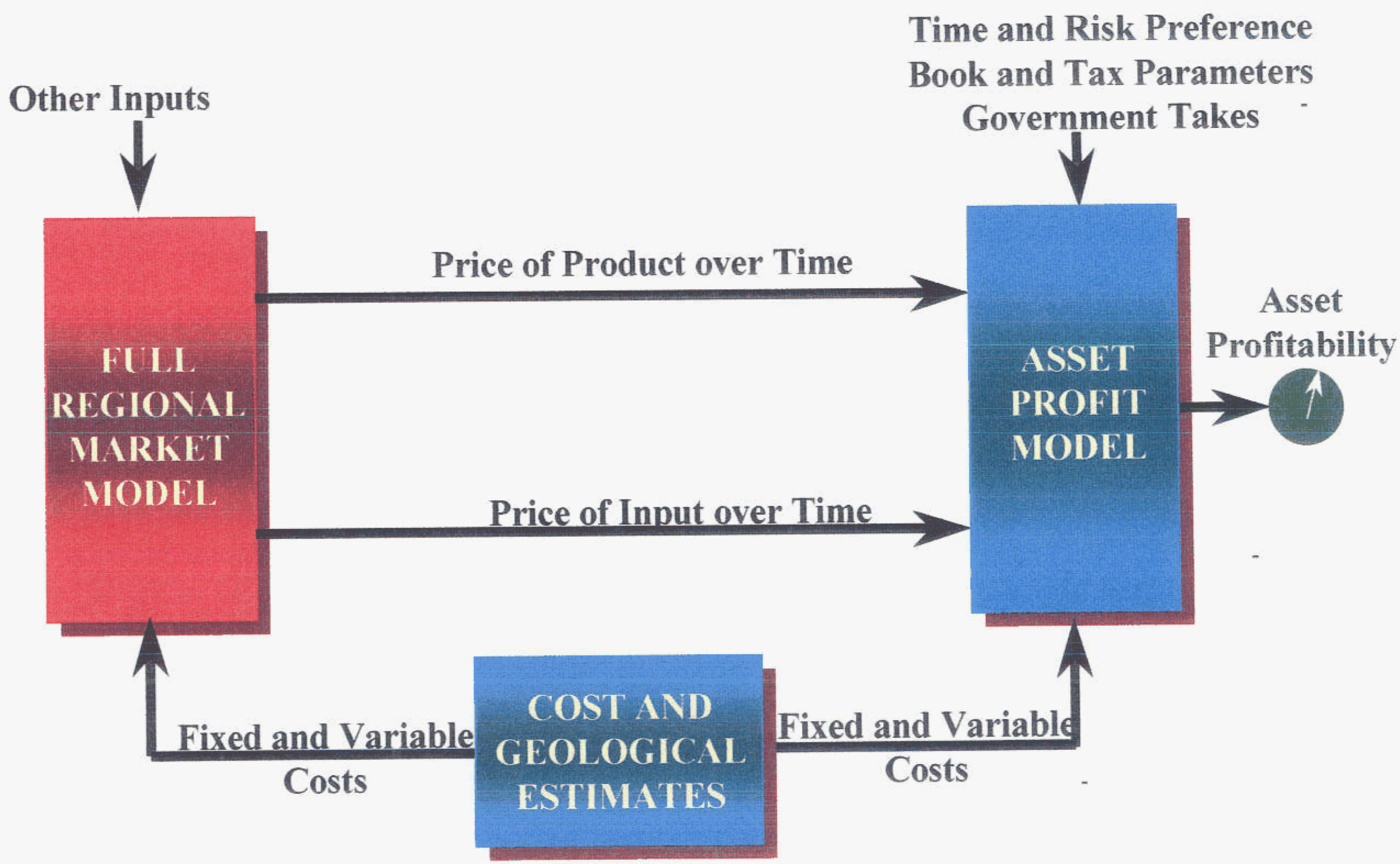


Figure A-7: We Do Risk-Return Valuation in a Full Market Context

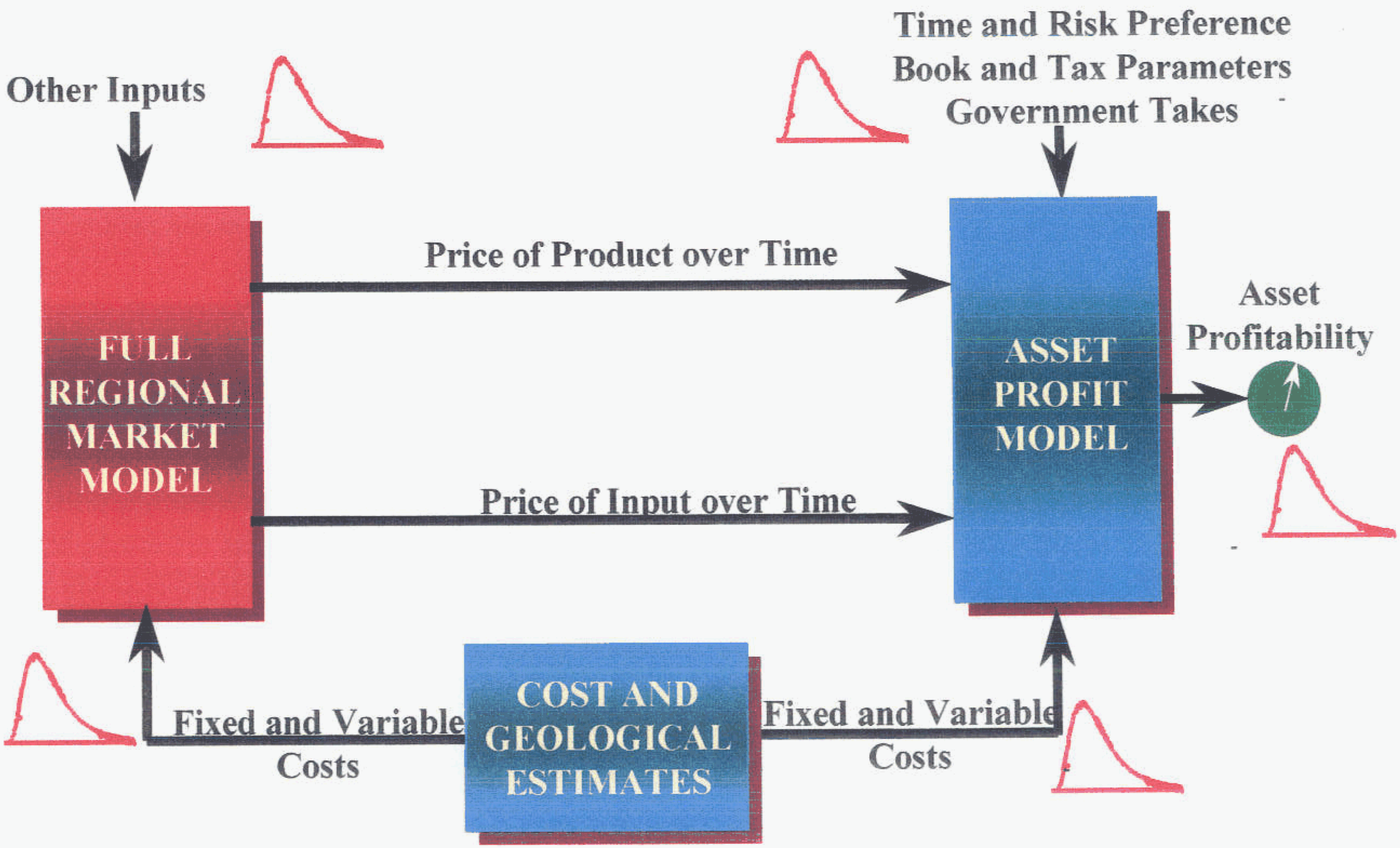


Figure A-8: After Deregulation Here Is How the World Will Work

The fundamental economics of supply and demand

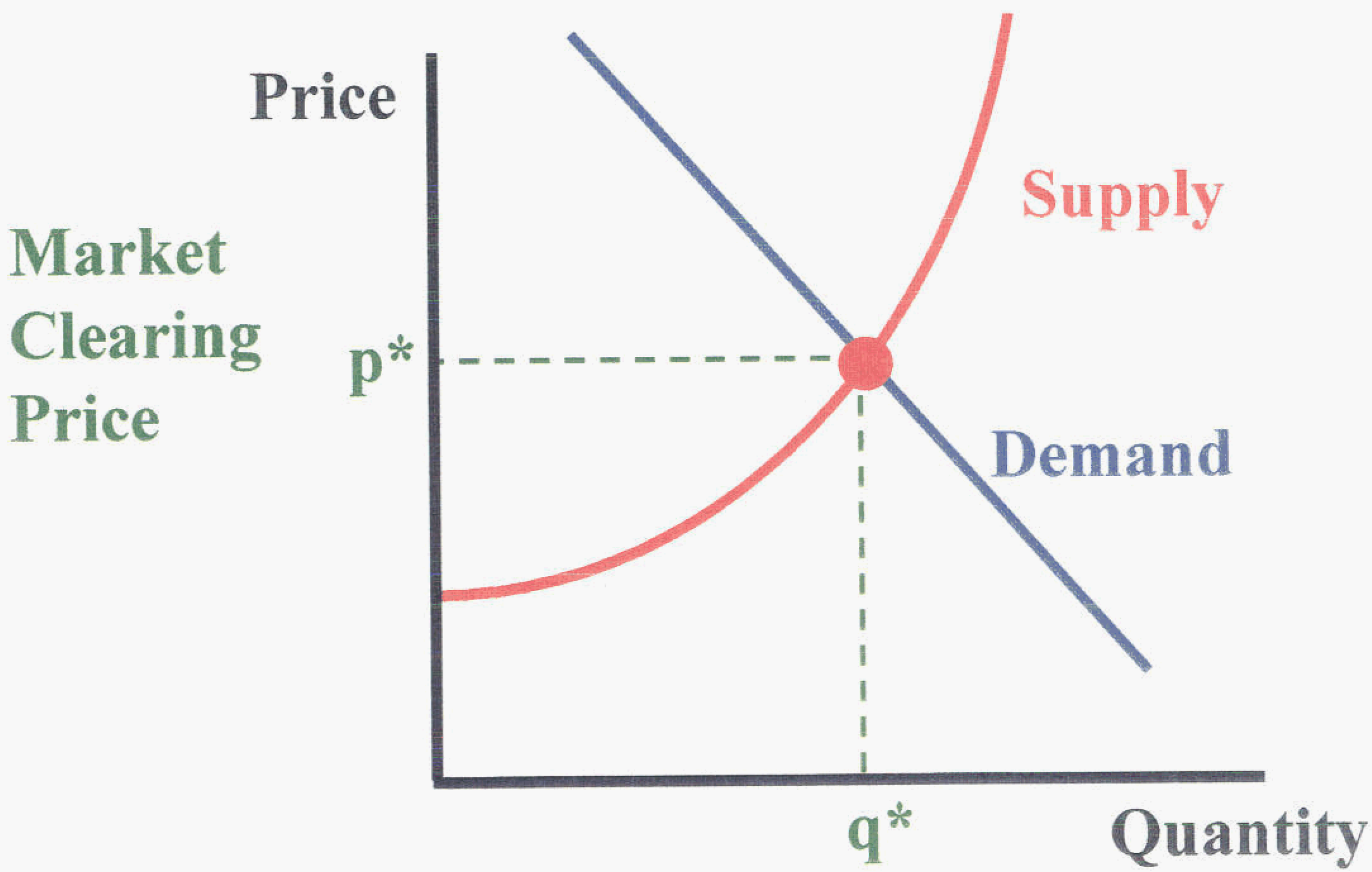


Figure A-9: Altos North American Electric Model

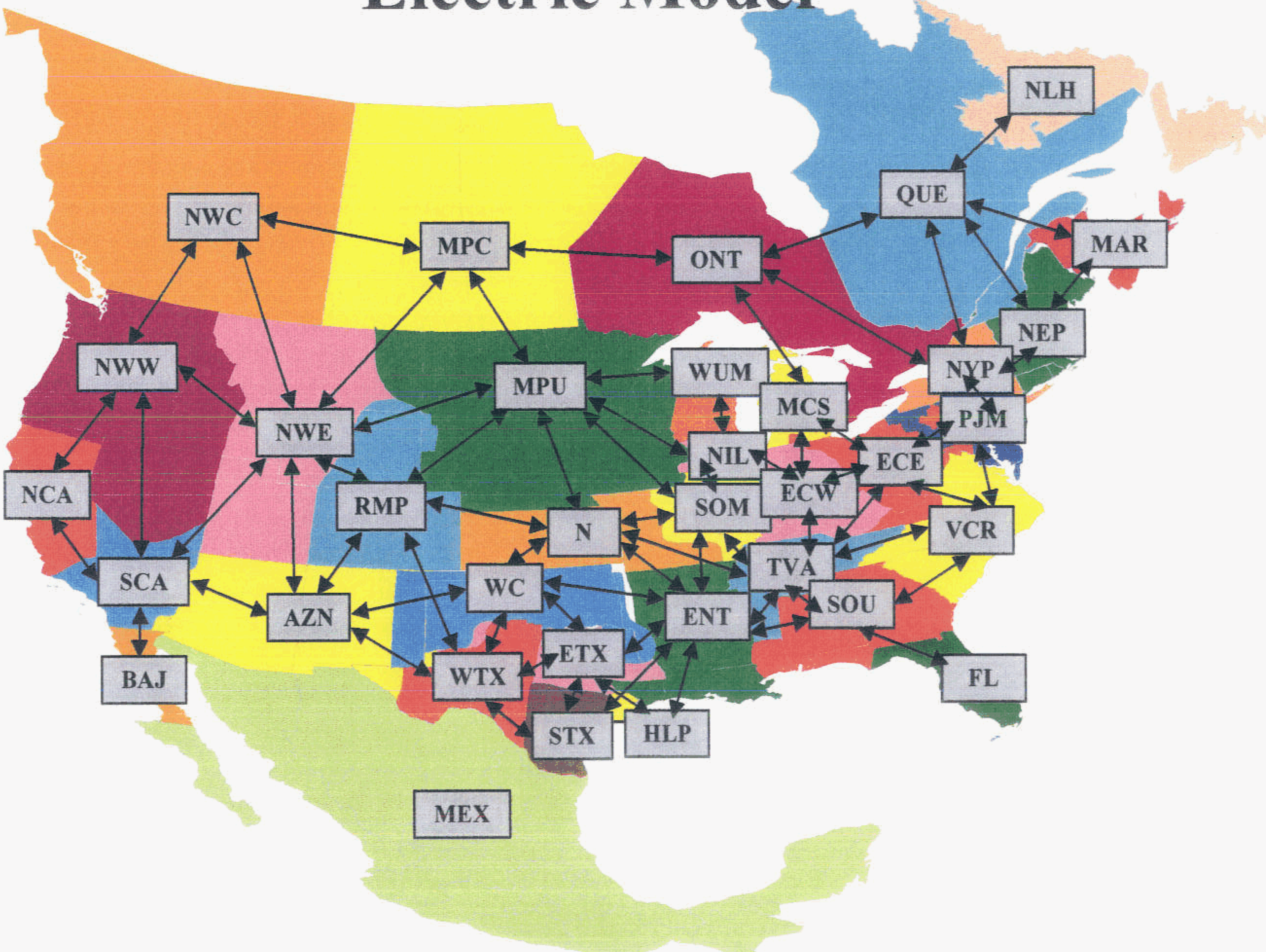


Figure A-10: Sophisticated Network Representation of Regional Options

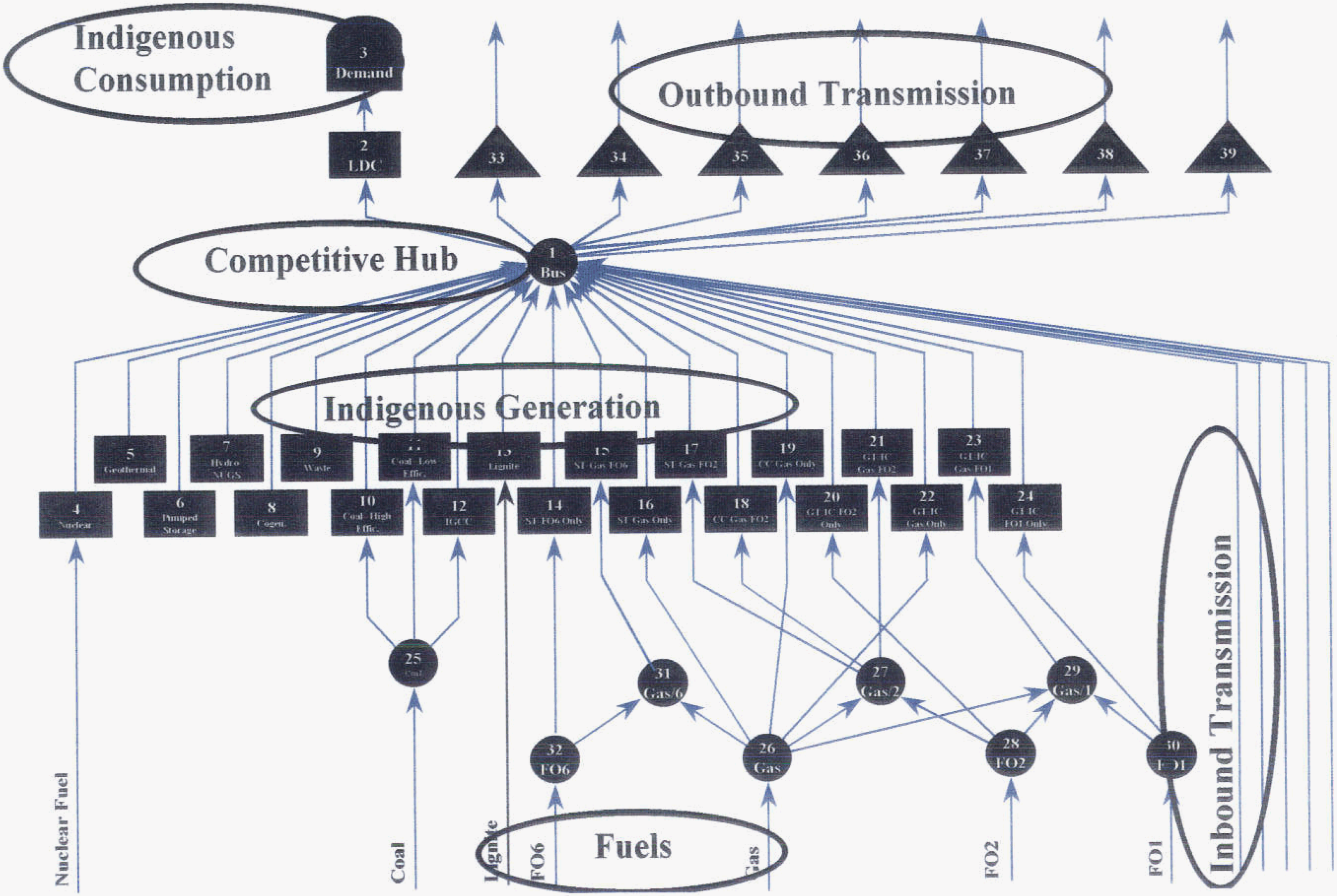


Figure A-11: Embed Detailed ERCOT Model within North American Model

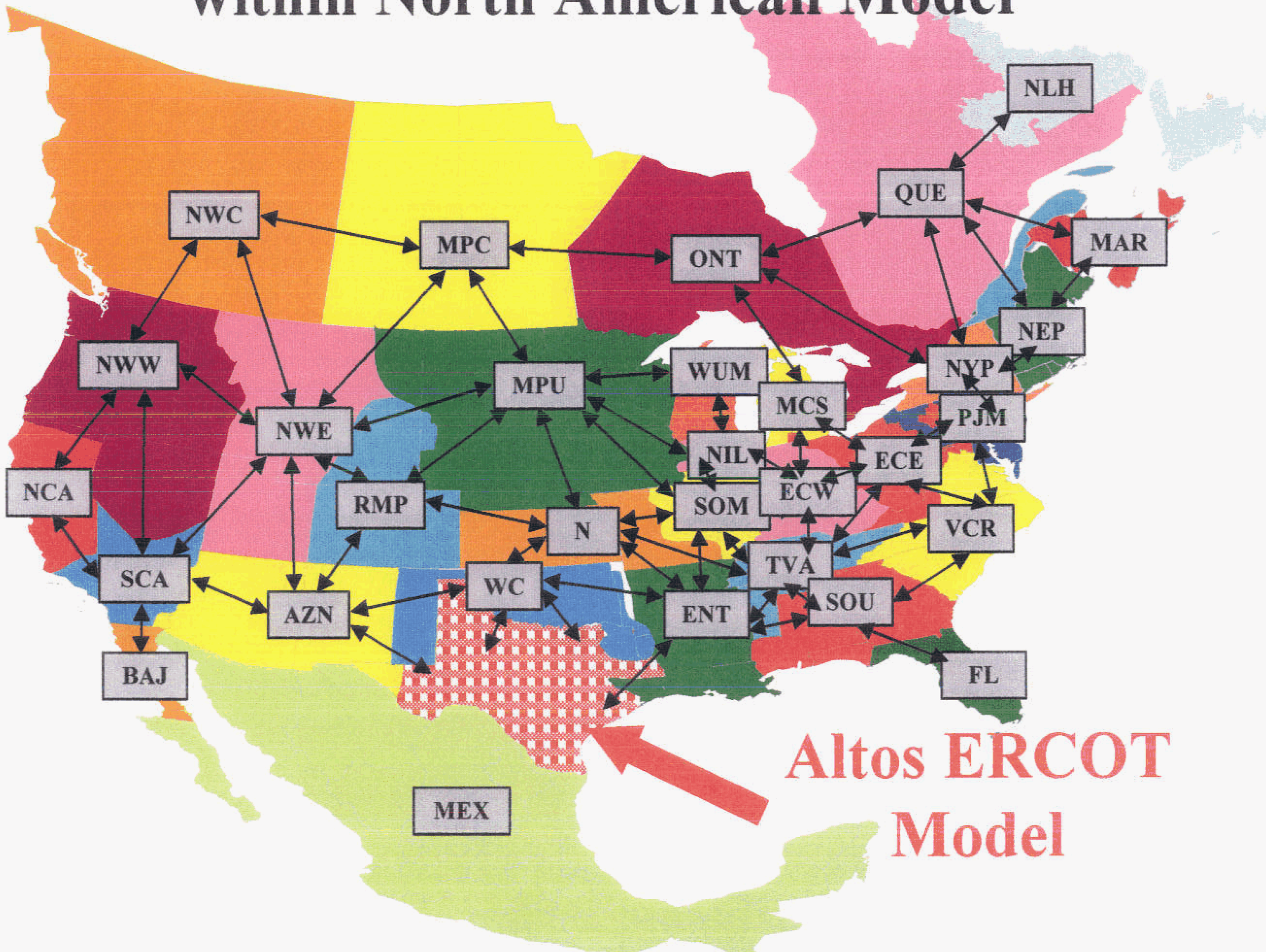


Figure A-12: Detailed Nodal Representation of ERCOT

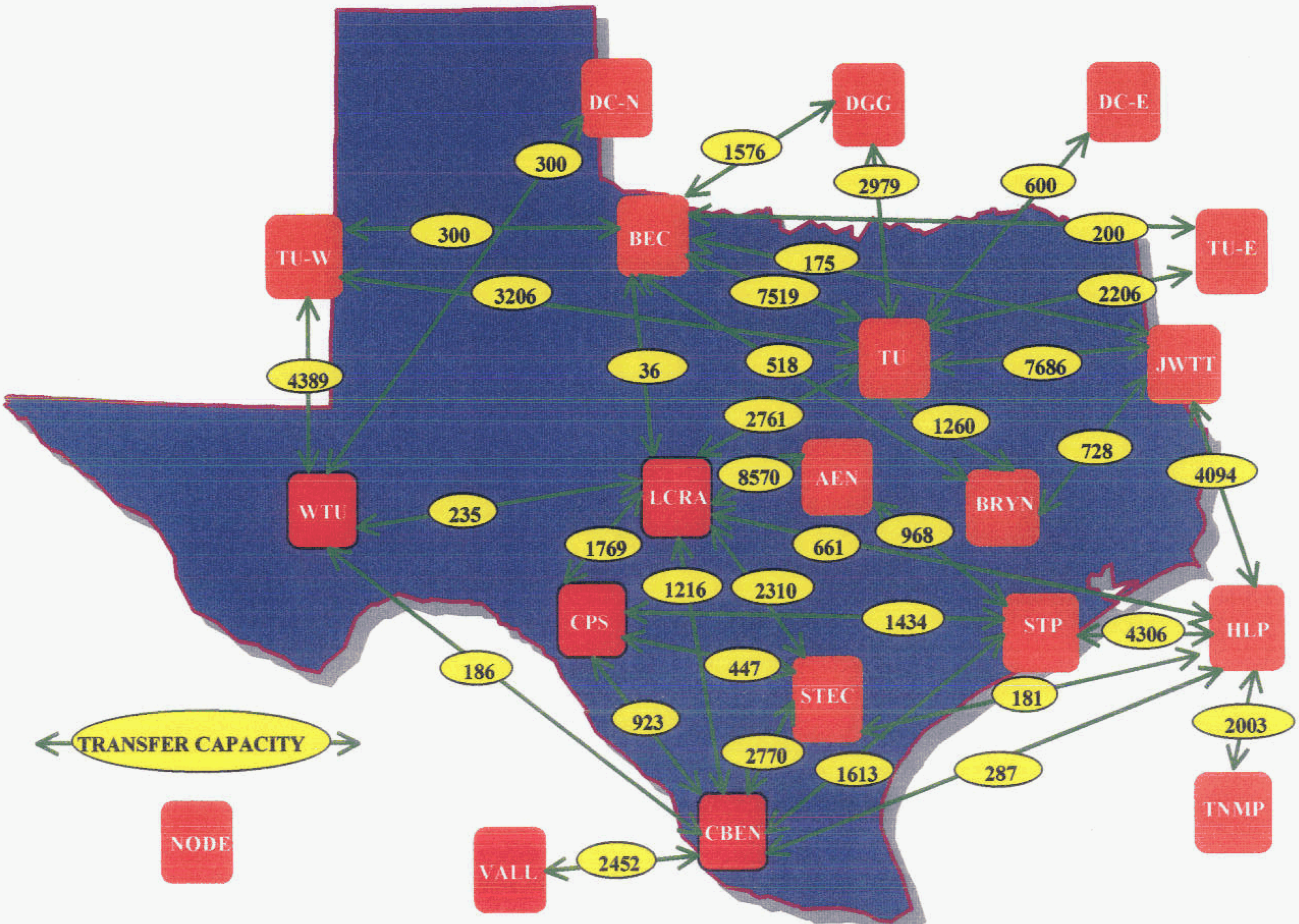


Figure A-13: MarketPoint Allows Completely General Time Period Structure

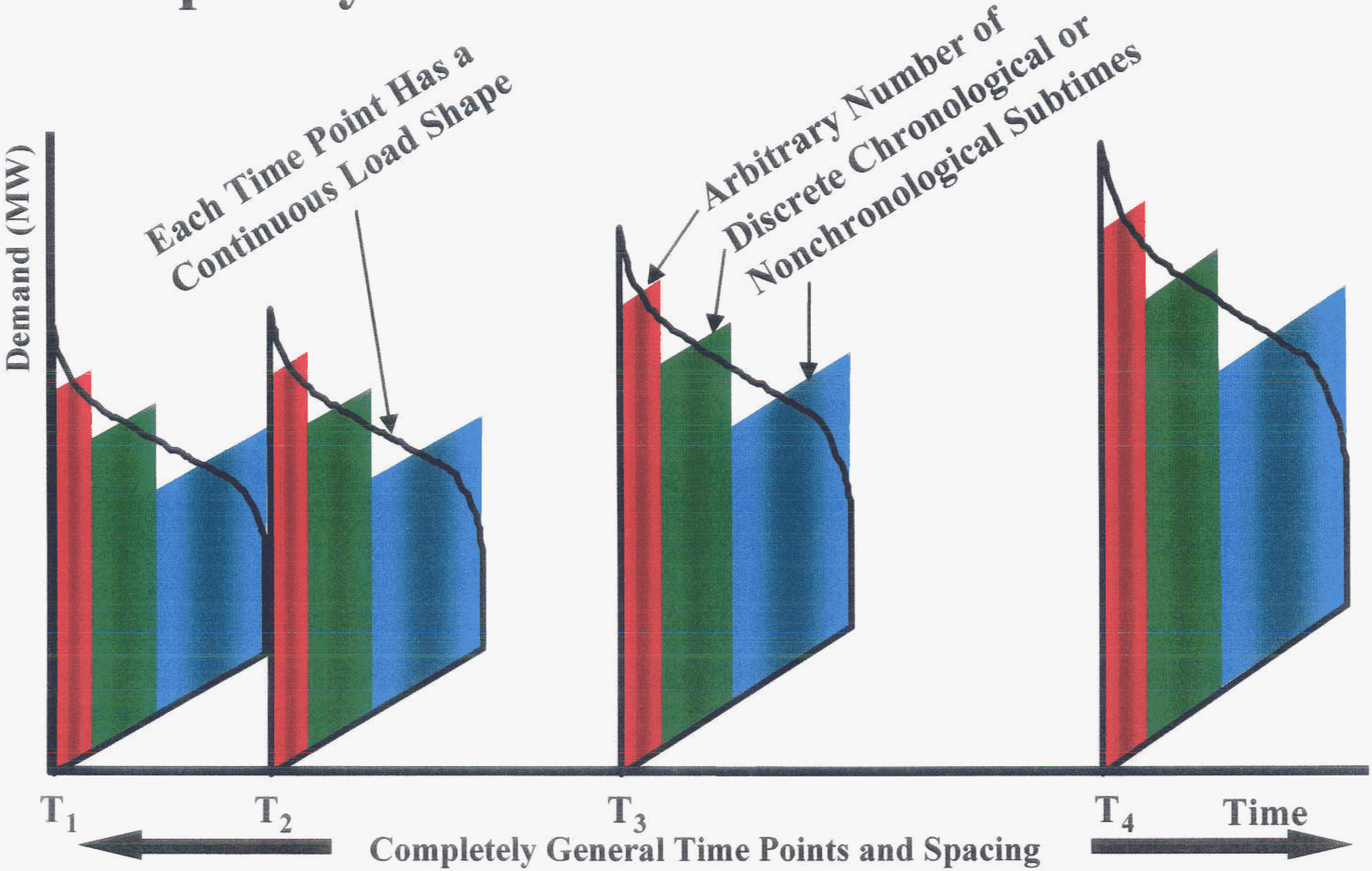


Figure A-14: We Have Assembled the Generation Supply Stack for Pre-existing Units

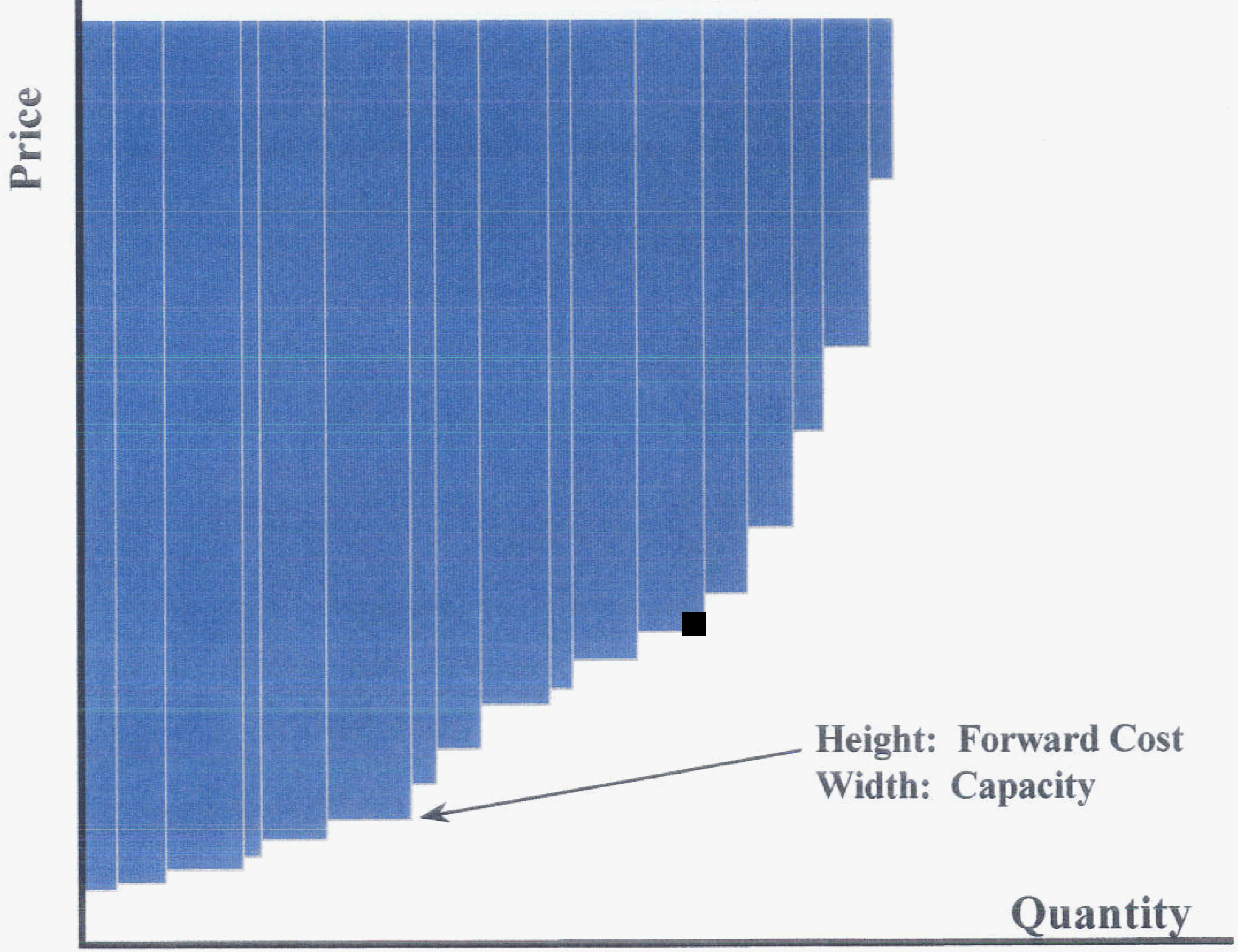
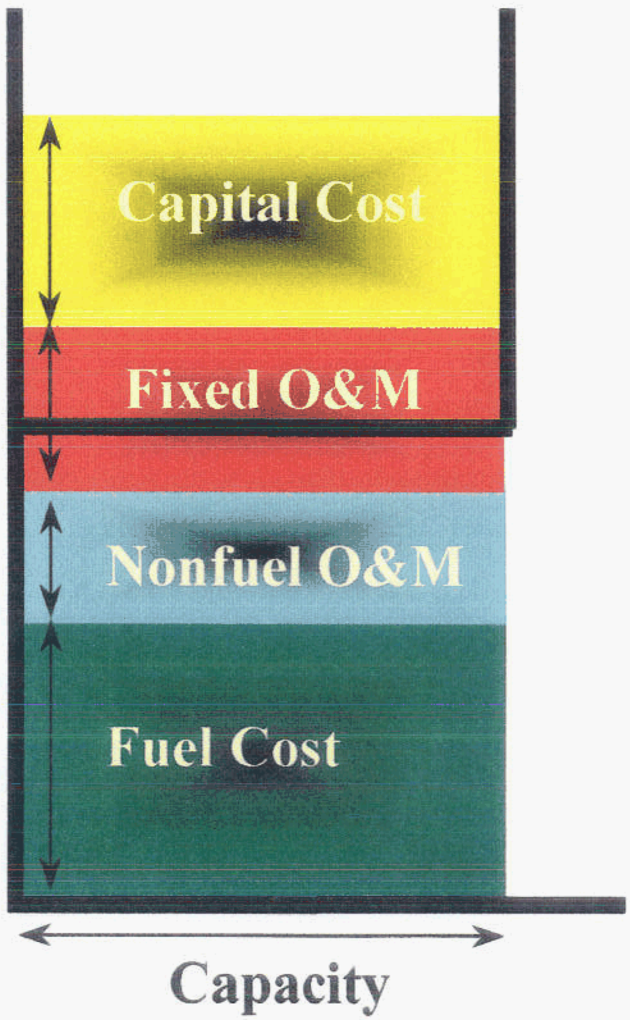


Figure A-15: For Each Producing Unit, We Estimate Forward Cost To Market



- FORWARD COST EXCLUDES
  - Capital cost
  - Some Fixed O&M (Preservation)
- FORWARD COST INCLUDES
  - Some Fixed O&M (Cycle)
  - Nonfuel variable O&M
  - Fuel cost
- WIDTH OF SUPPLY CURVE IS CAPACITY

Figure A-16: Cost Structure for an Airplane

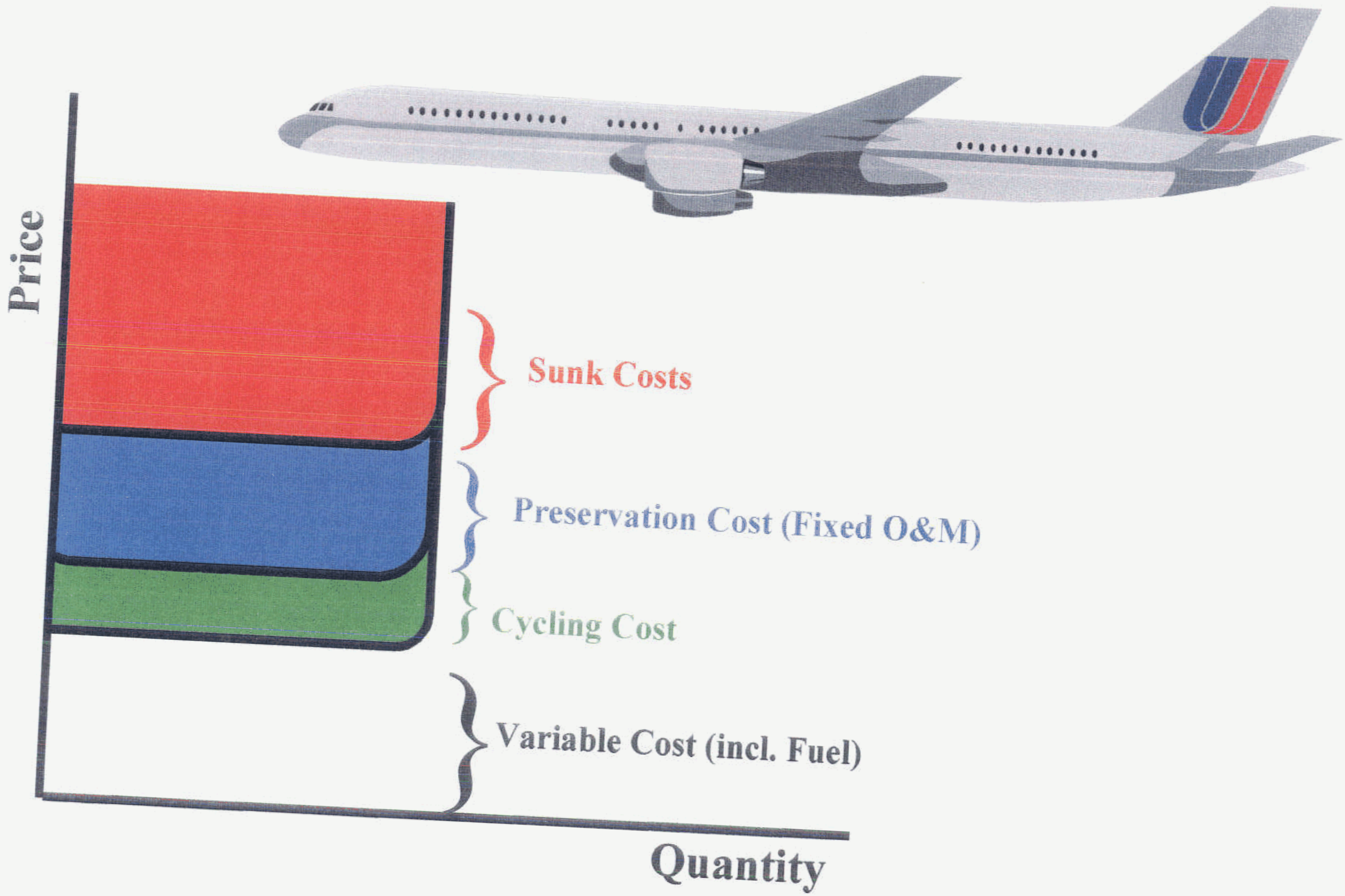


Figure A-17: Recategorization of Plane Forward Costs

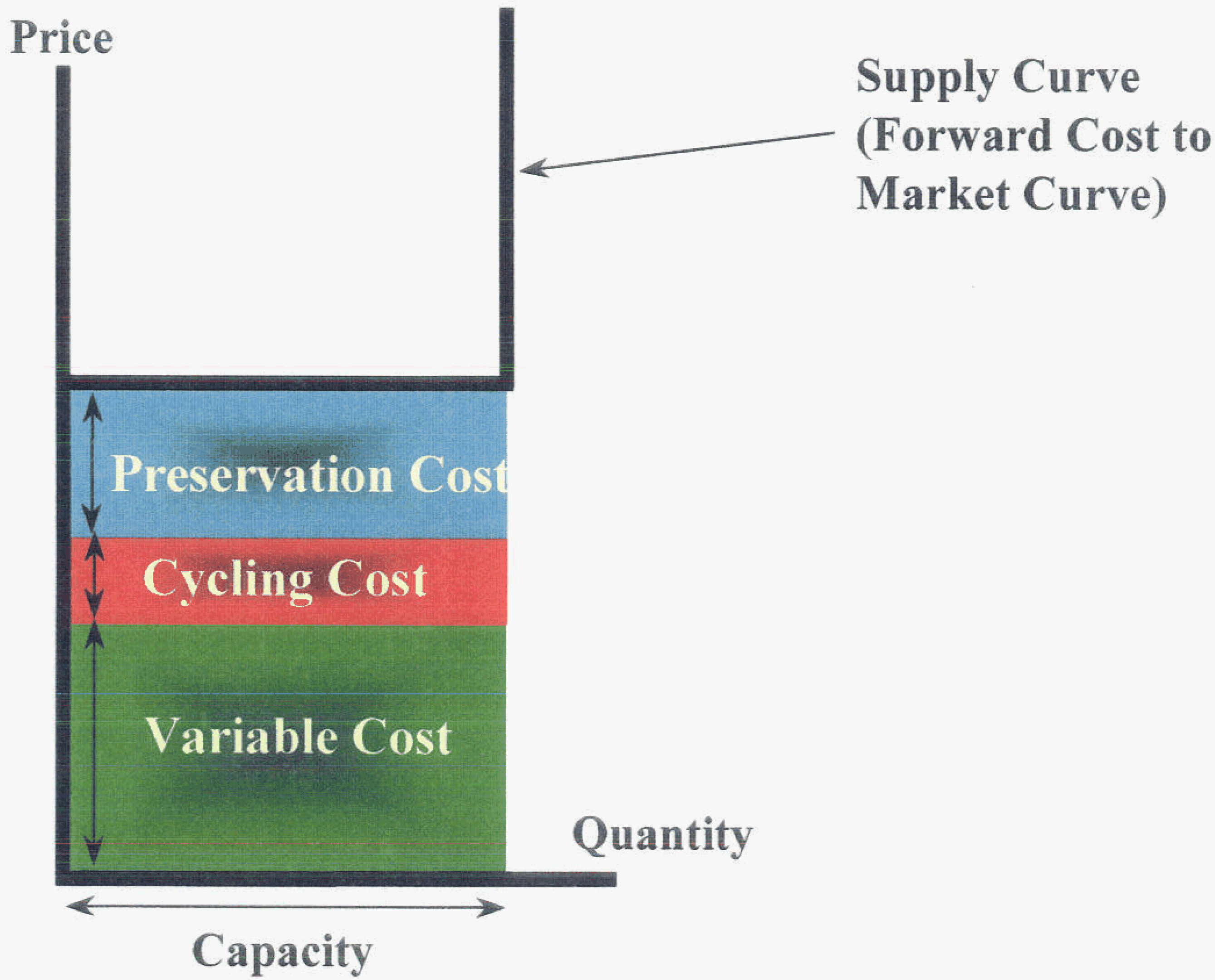


Figure A-18: California Supply Stack

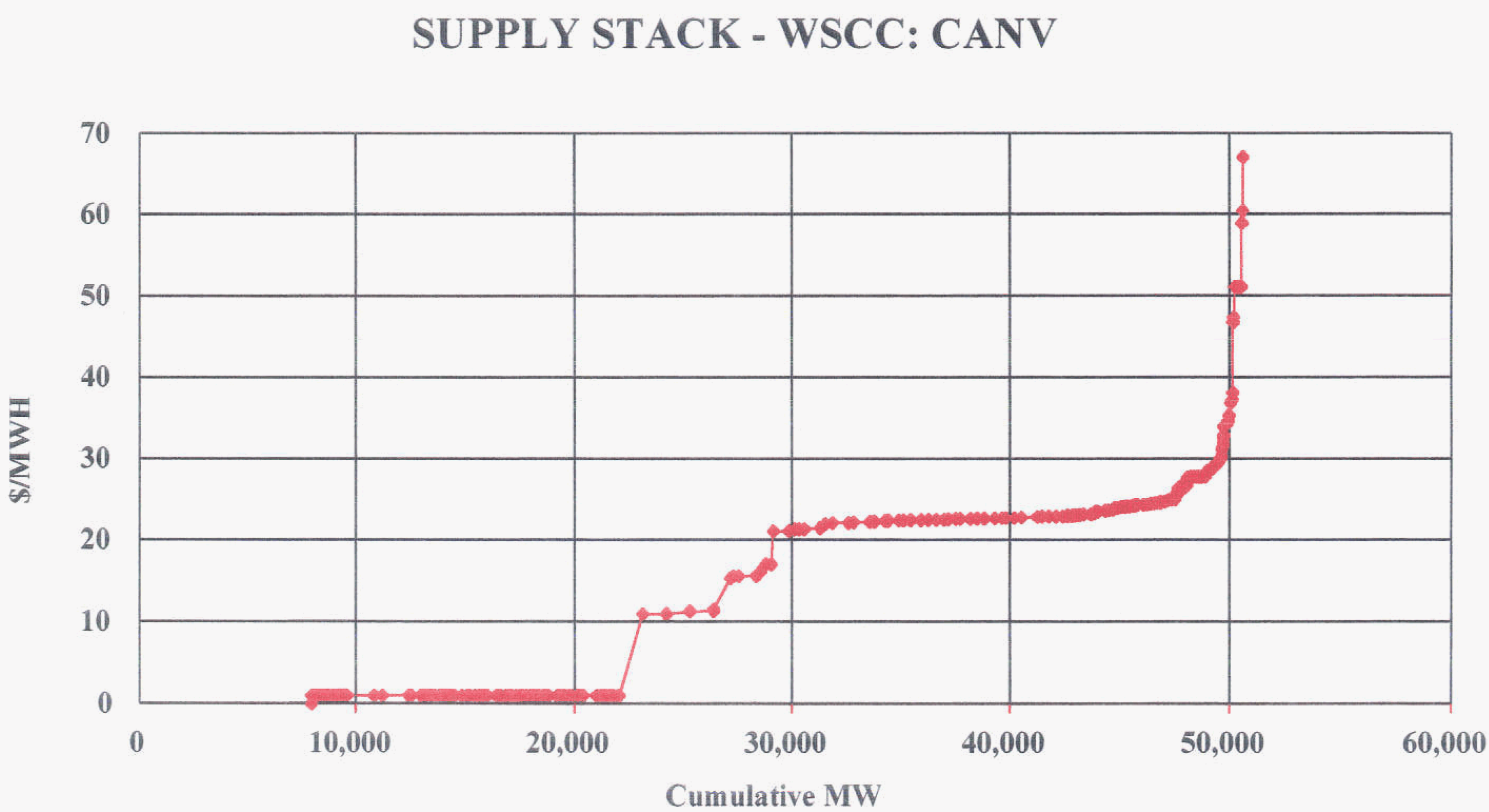


Figure A-19: We Have Automated All the Data Input

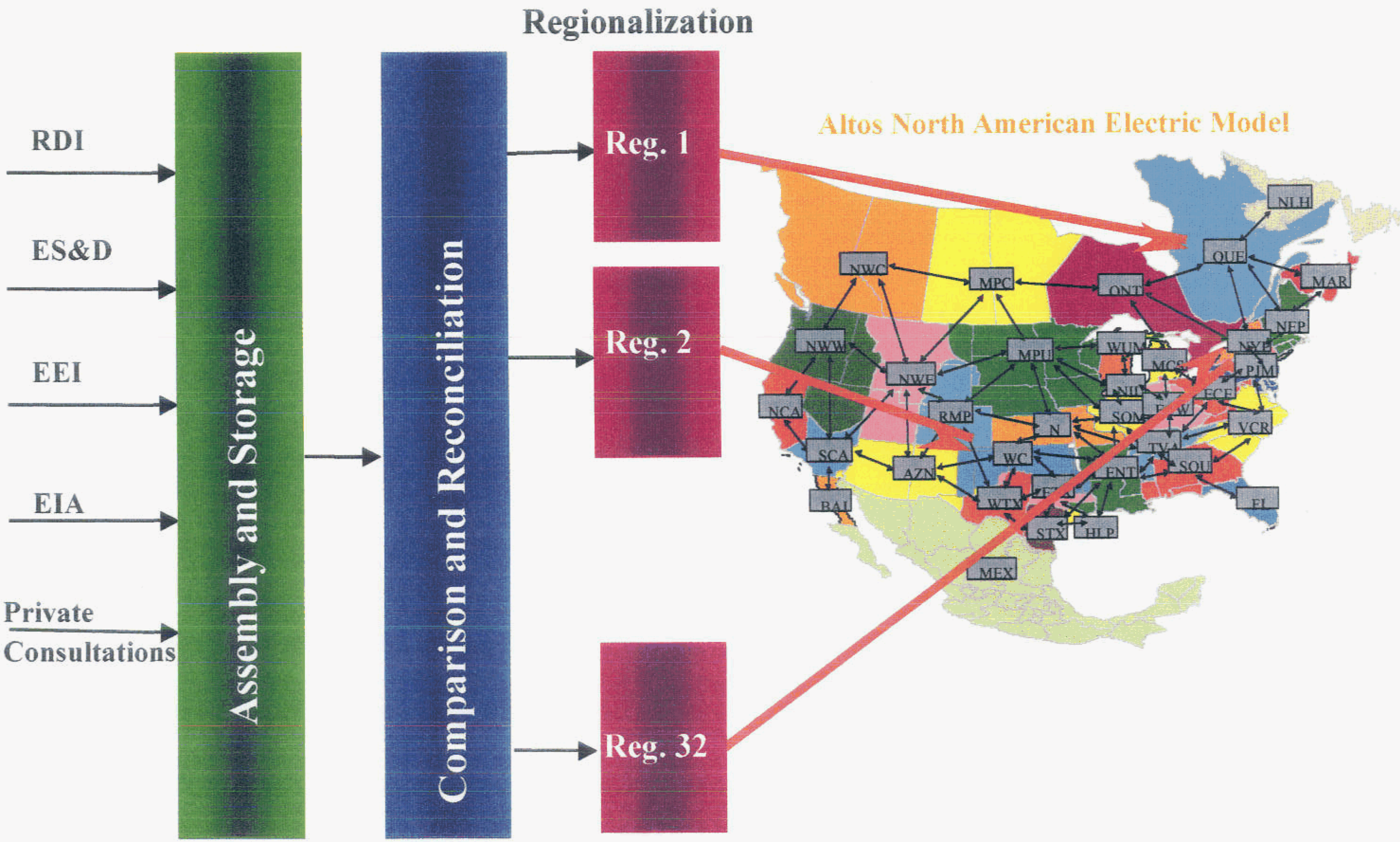


Figure A-20: Competitive Pressure Reduces Forward Cost of All Units

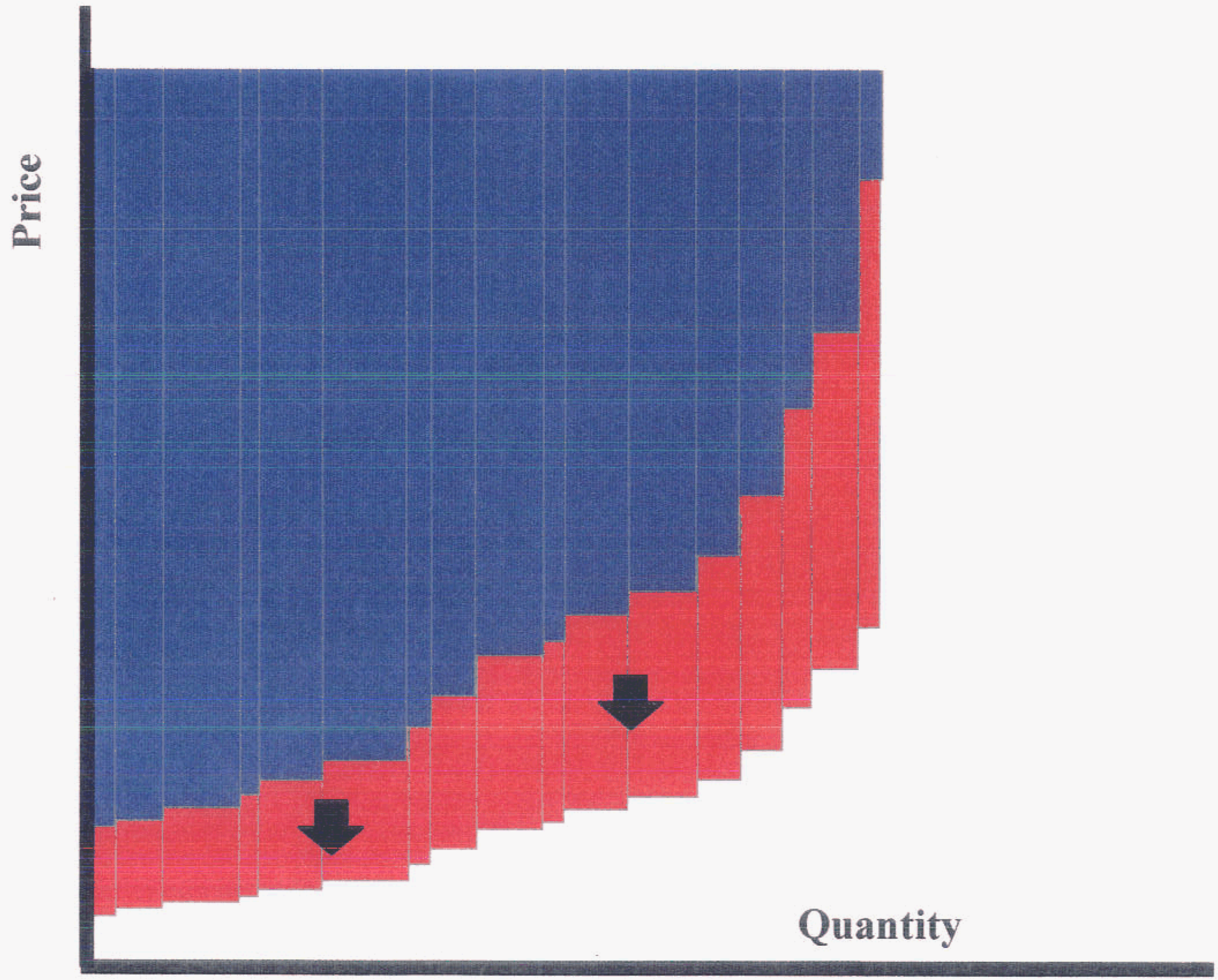


Figure A-21: Competition Pushes Costs Down

Cost reduction never fails in a competitive economy

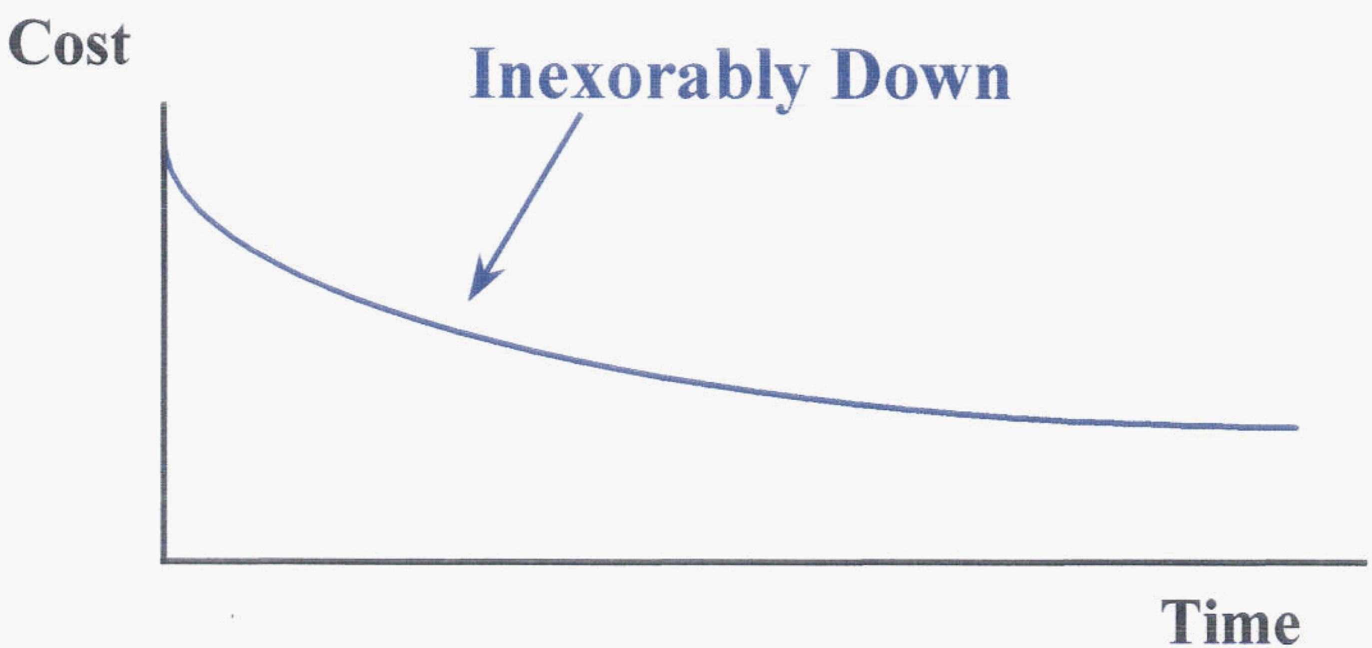


Figure A-22: Competitive Pressure Retires Old Plants

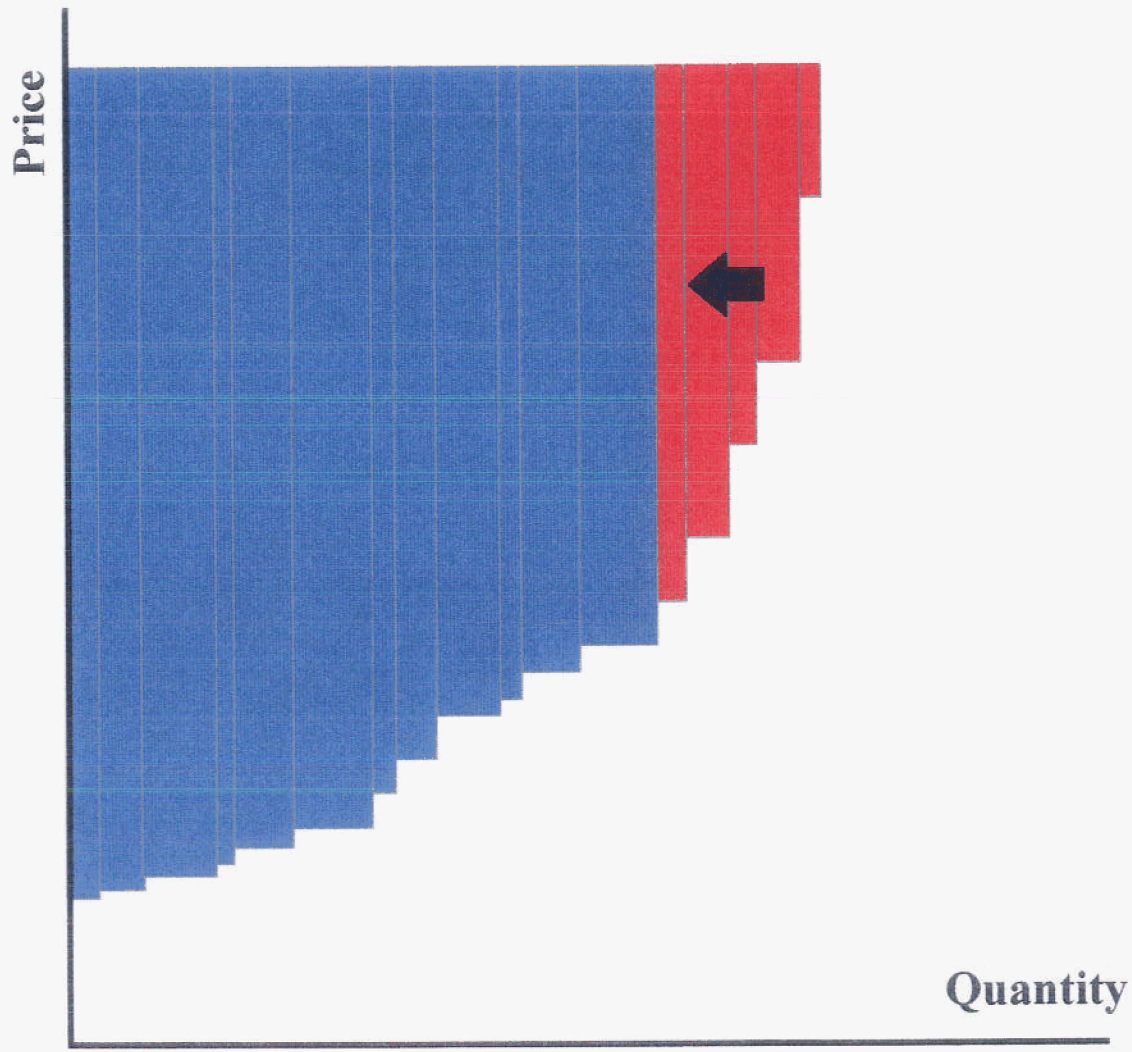


Figure A-23: Transmission Conventional Wisdom

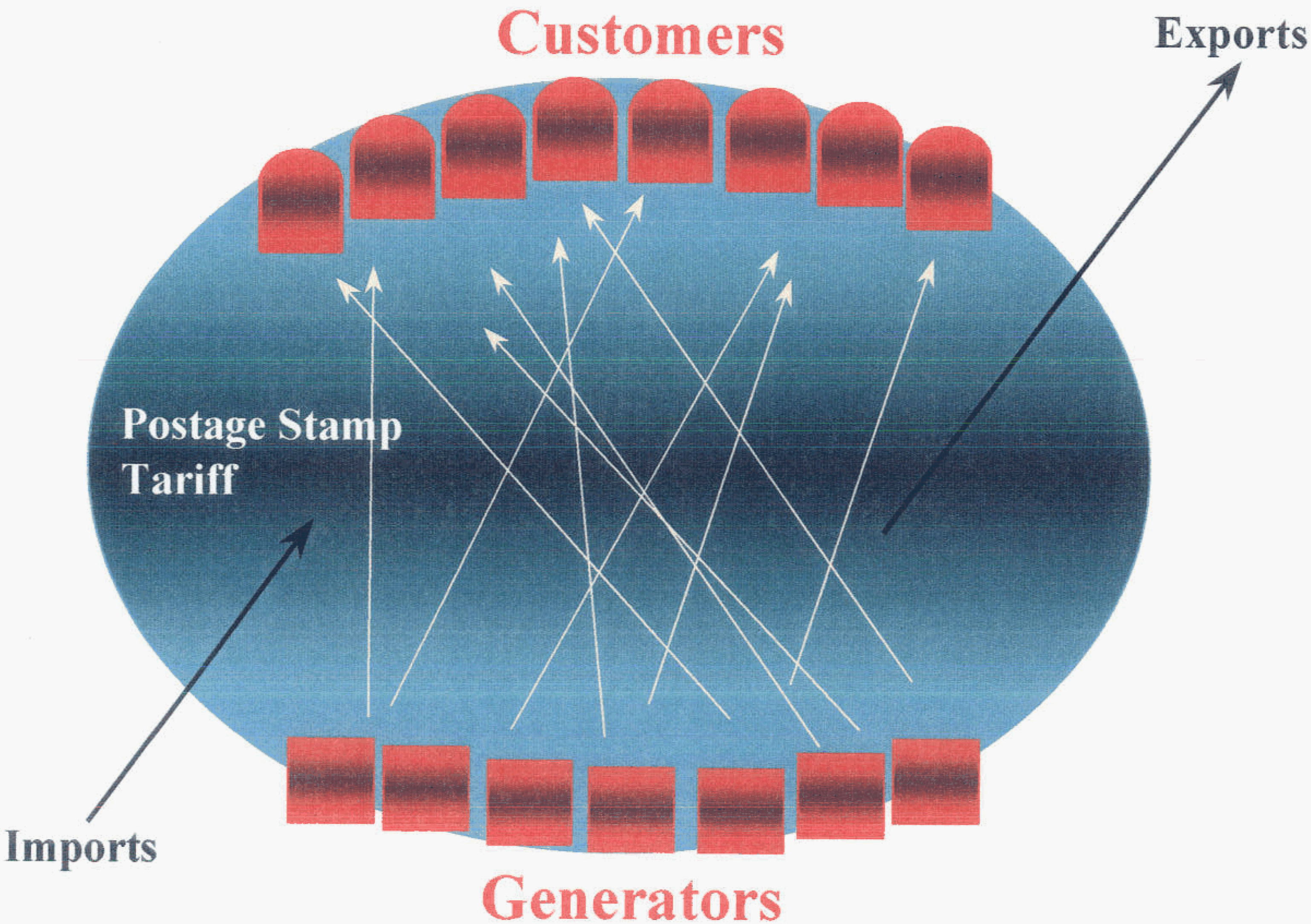


Figure A-24: Interconnected Existing And Prospective Wheeling Links

All interregional tariffs and capacities estimated

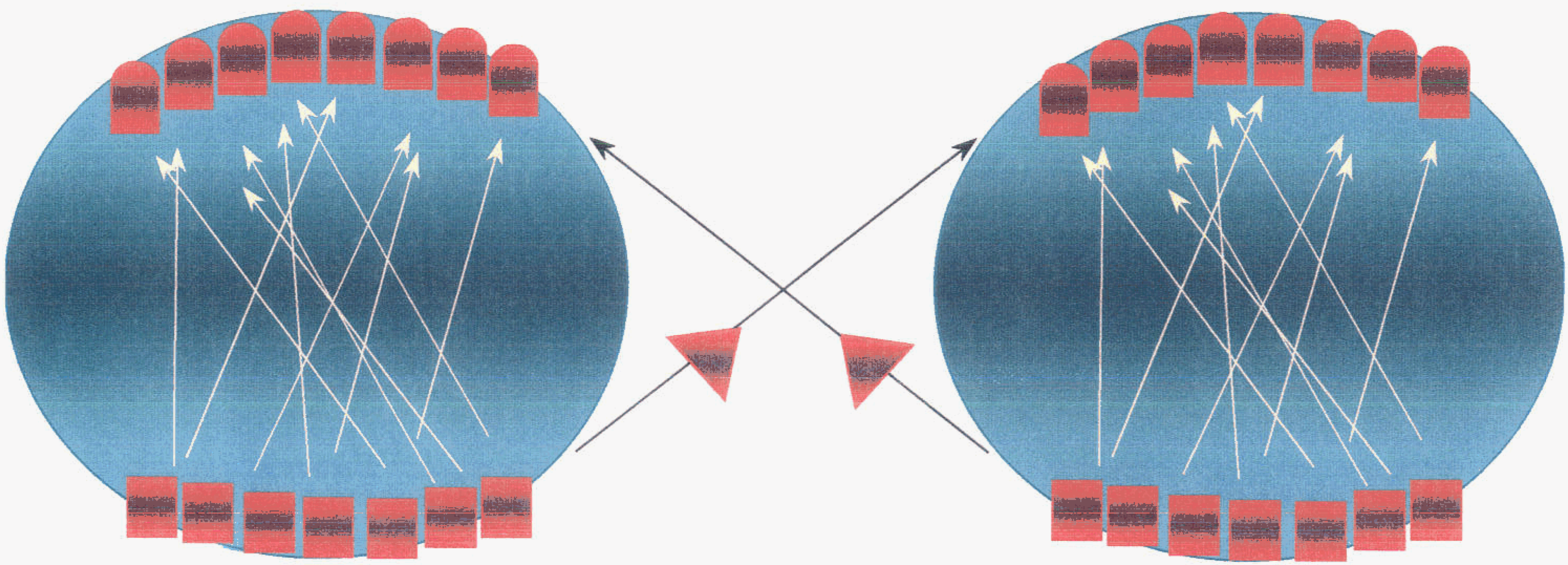


Figure A-25: Incoming Transmission Adds Supply And Reduces Cost

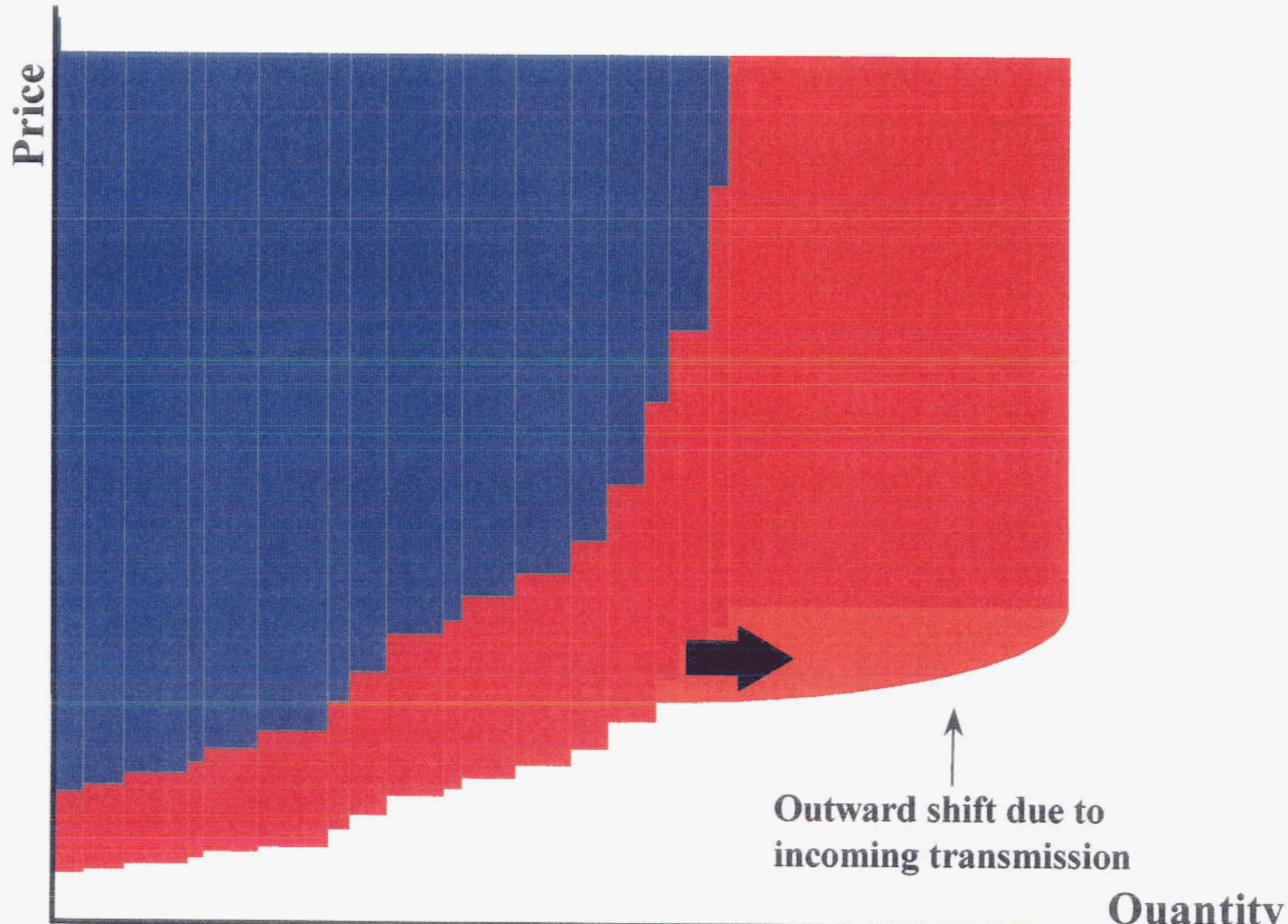


Figure A-26: Transmission Dictates Prices and Differentials

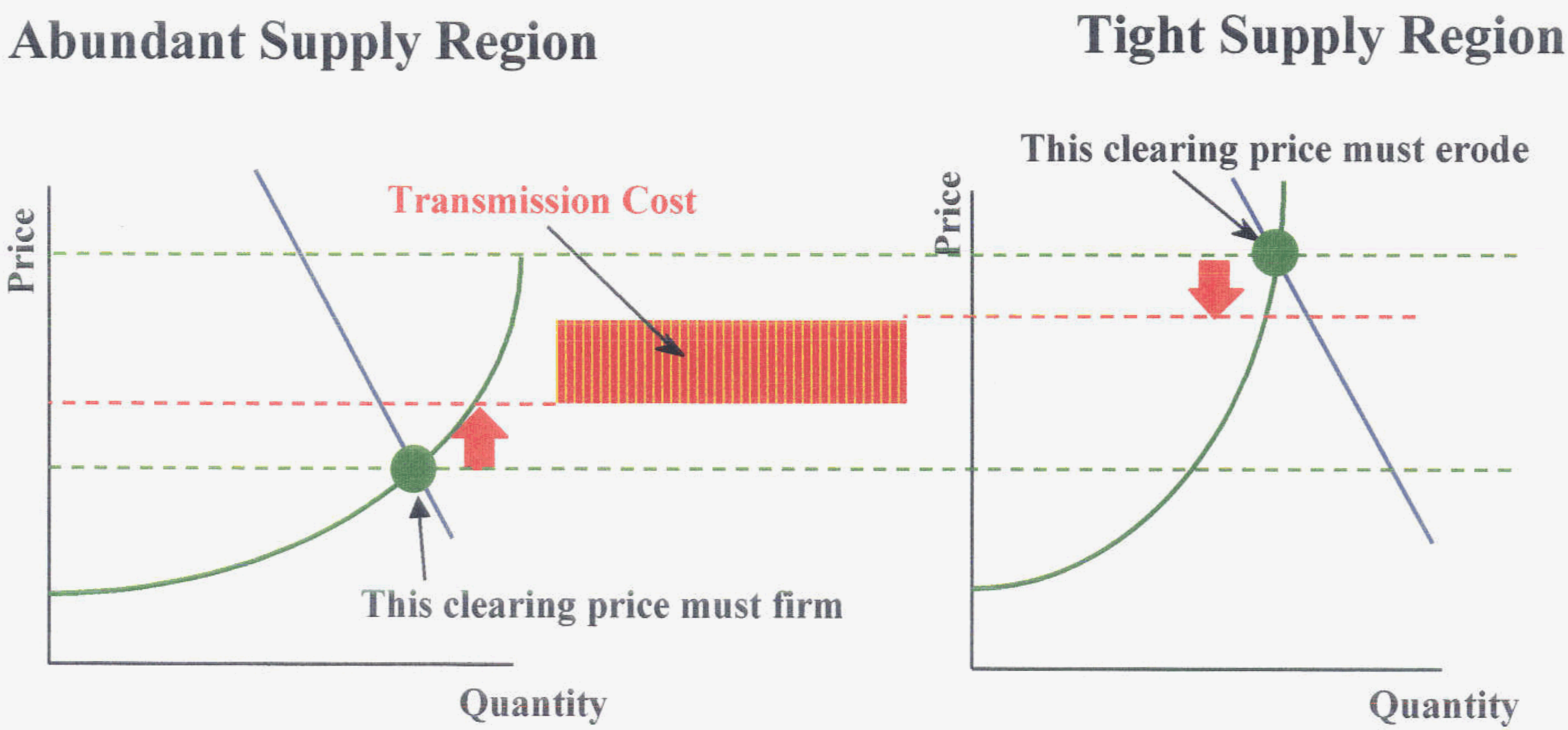


Figure A-27: Never Underestimate New Entry

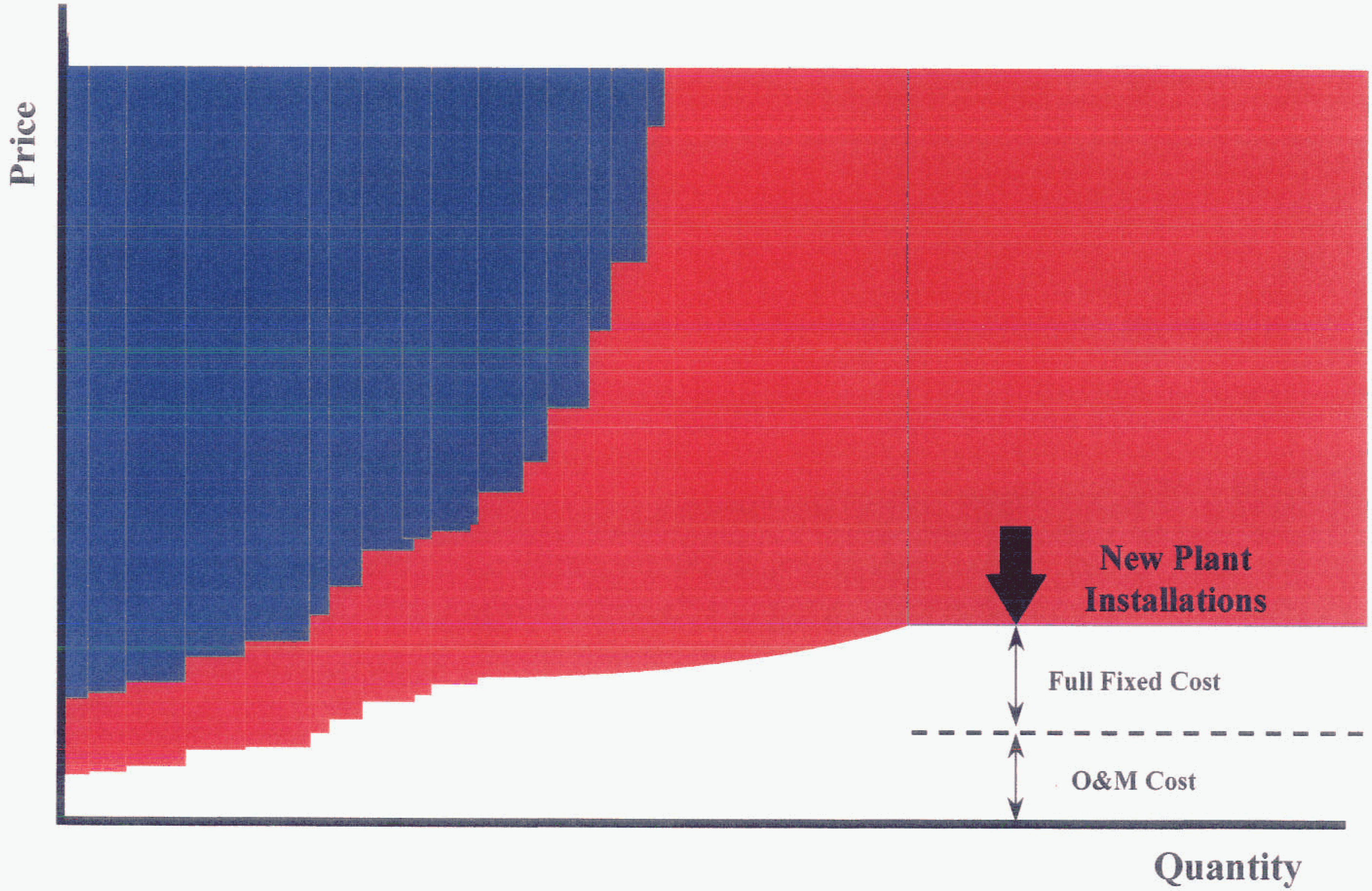


Figure A-28: The Key Phenomena MarketPoint Represents

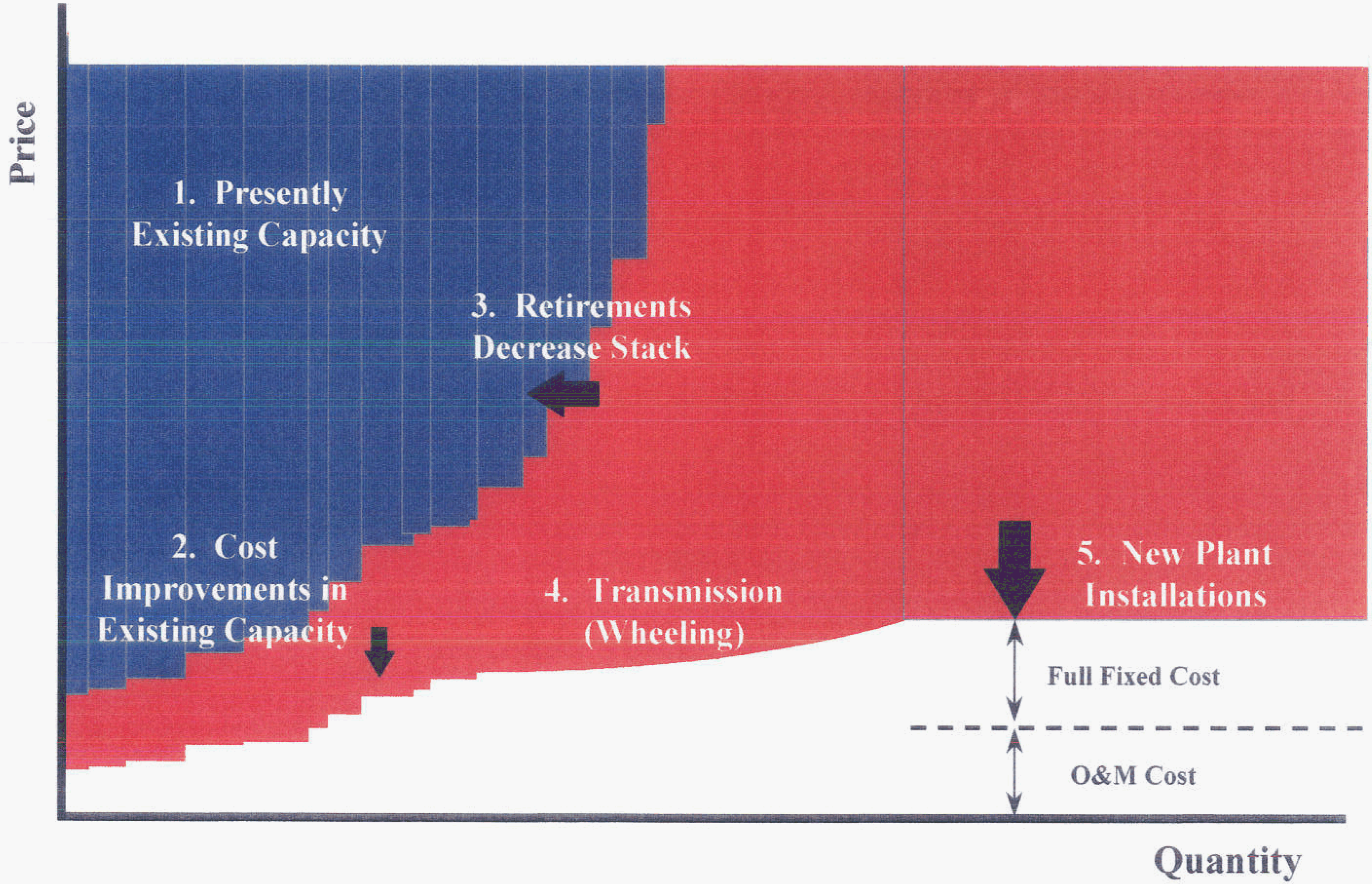


Figure A-29: We've Measured Demand Variation by Time of Day, Week, Season and Year

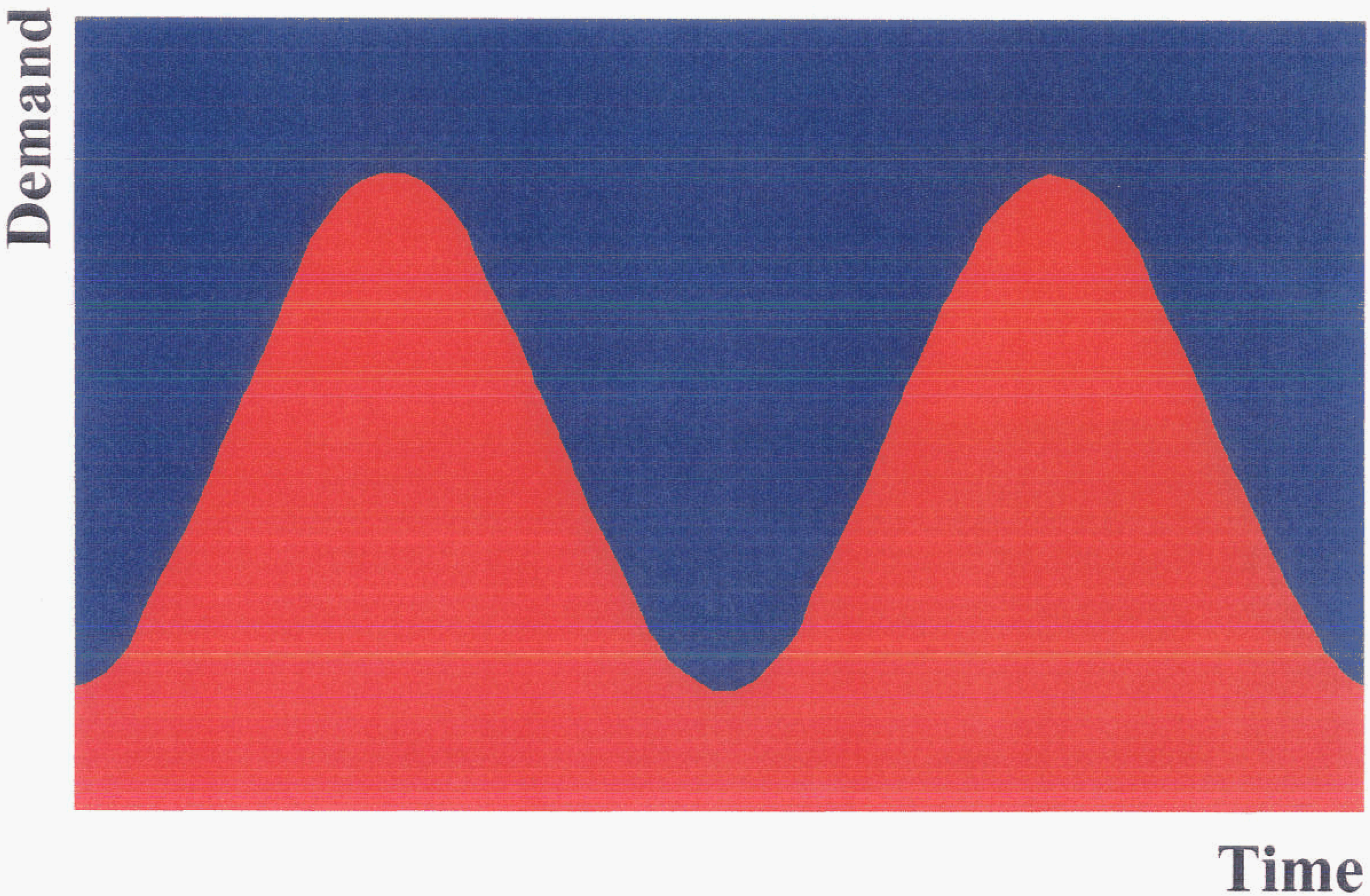


Figure A-30: Create Monthly Load Duration Curve by Sorting

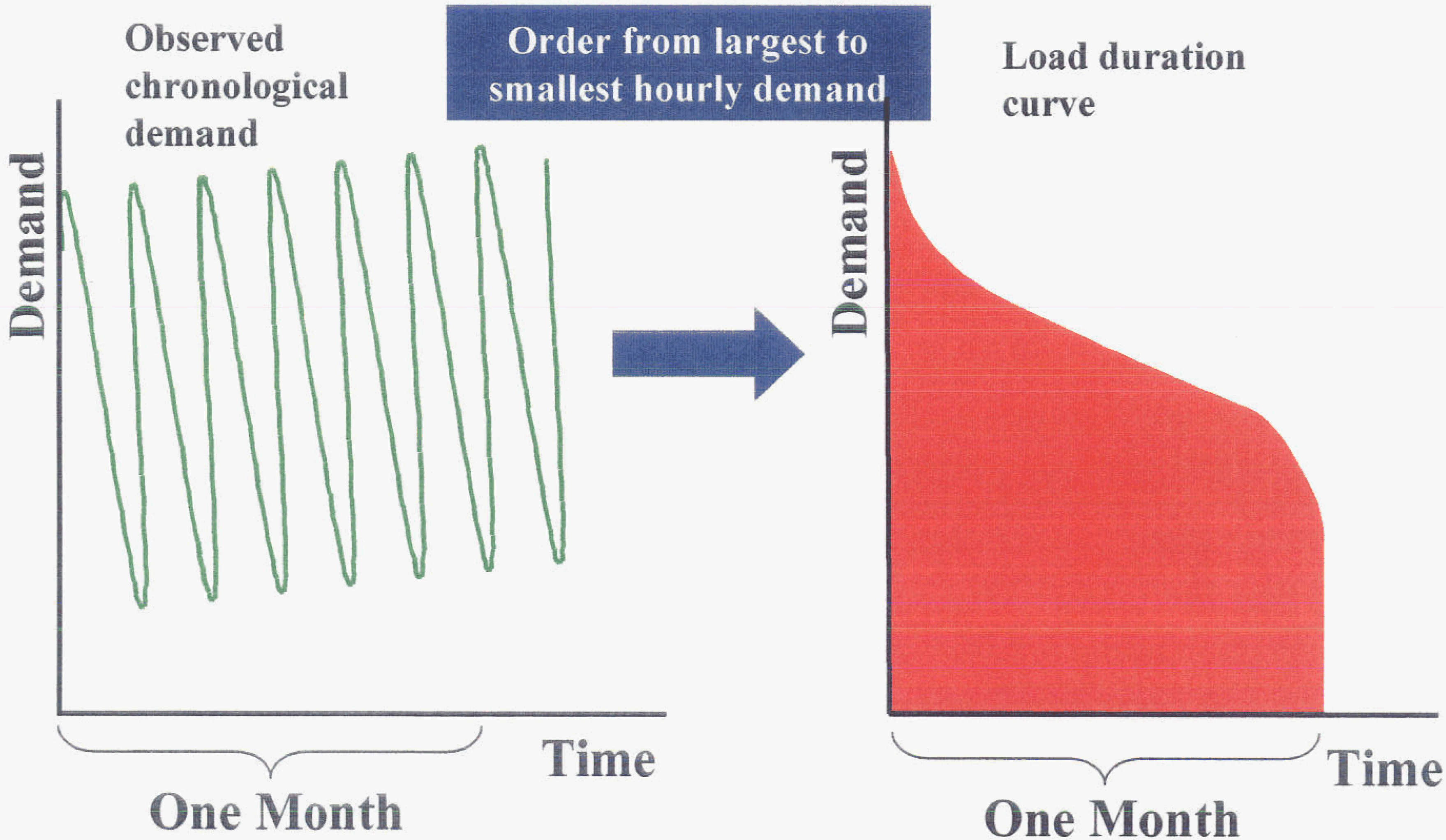


Figure A-31: California-Nevada Historical Pattern of Load

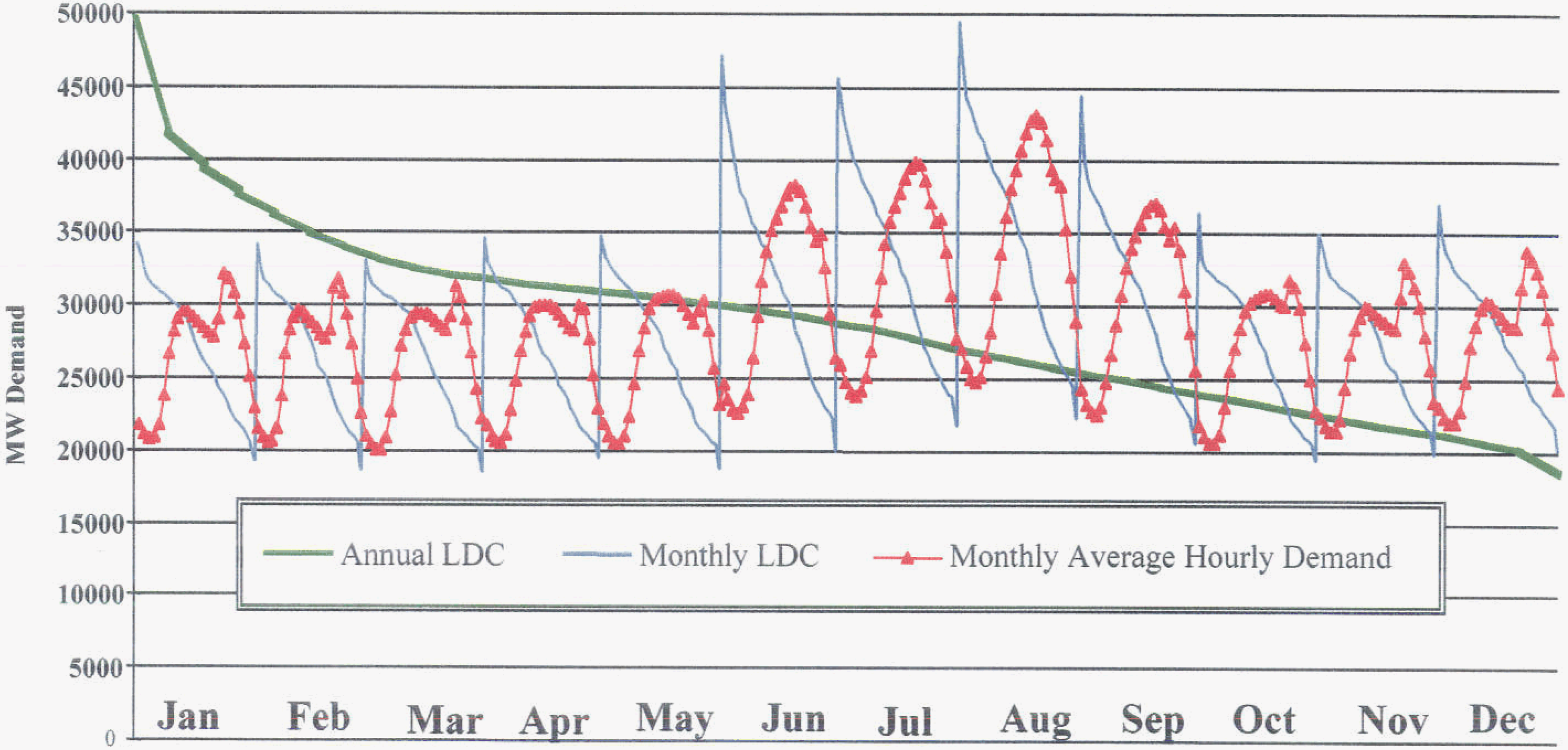


Figure A-32: We Begin with a Continuous Load Duration Curve for Each Region in the Model

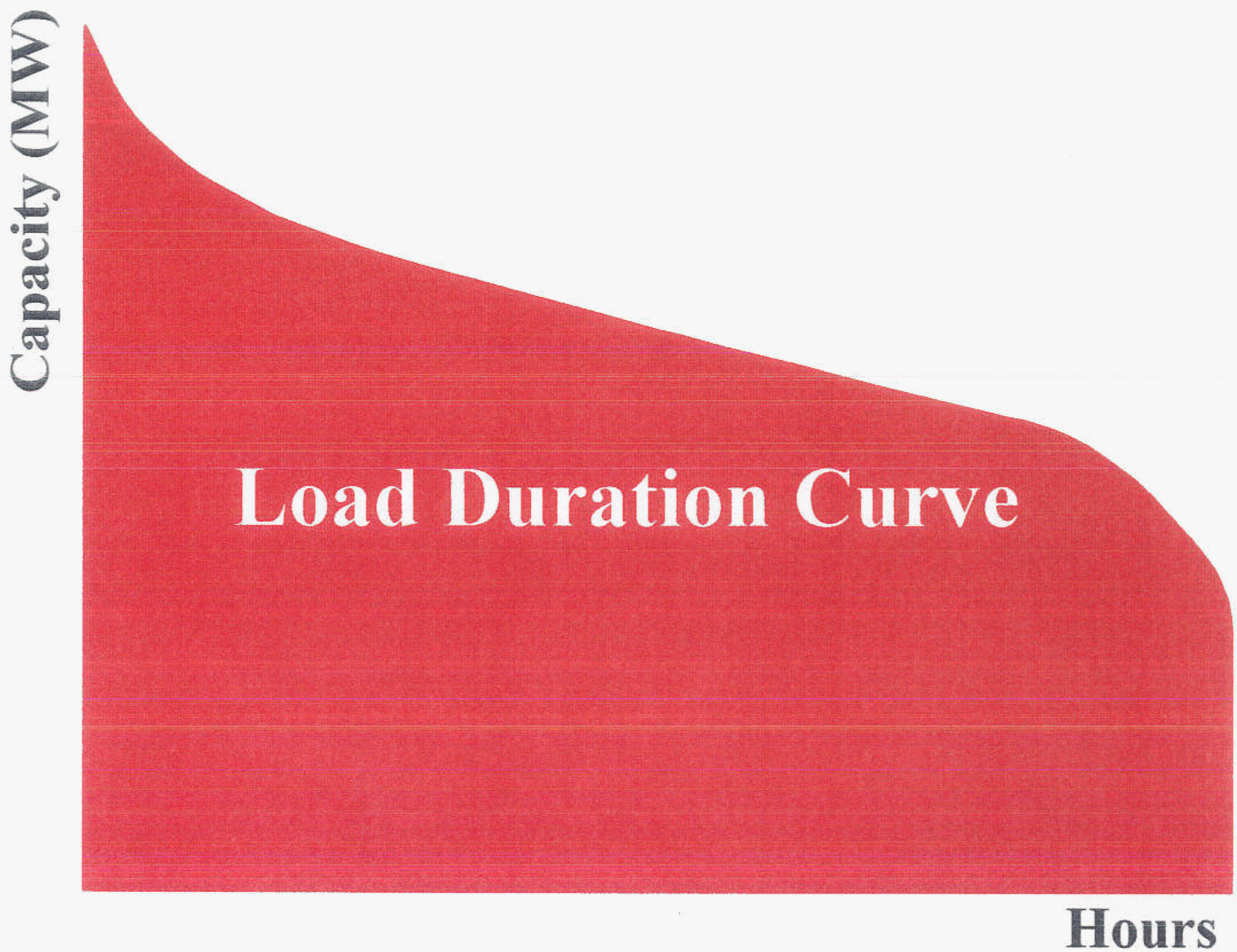


Figure A-33: Disaggregate Each Month into Ten Load Tranches

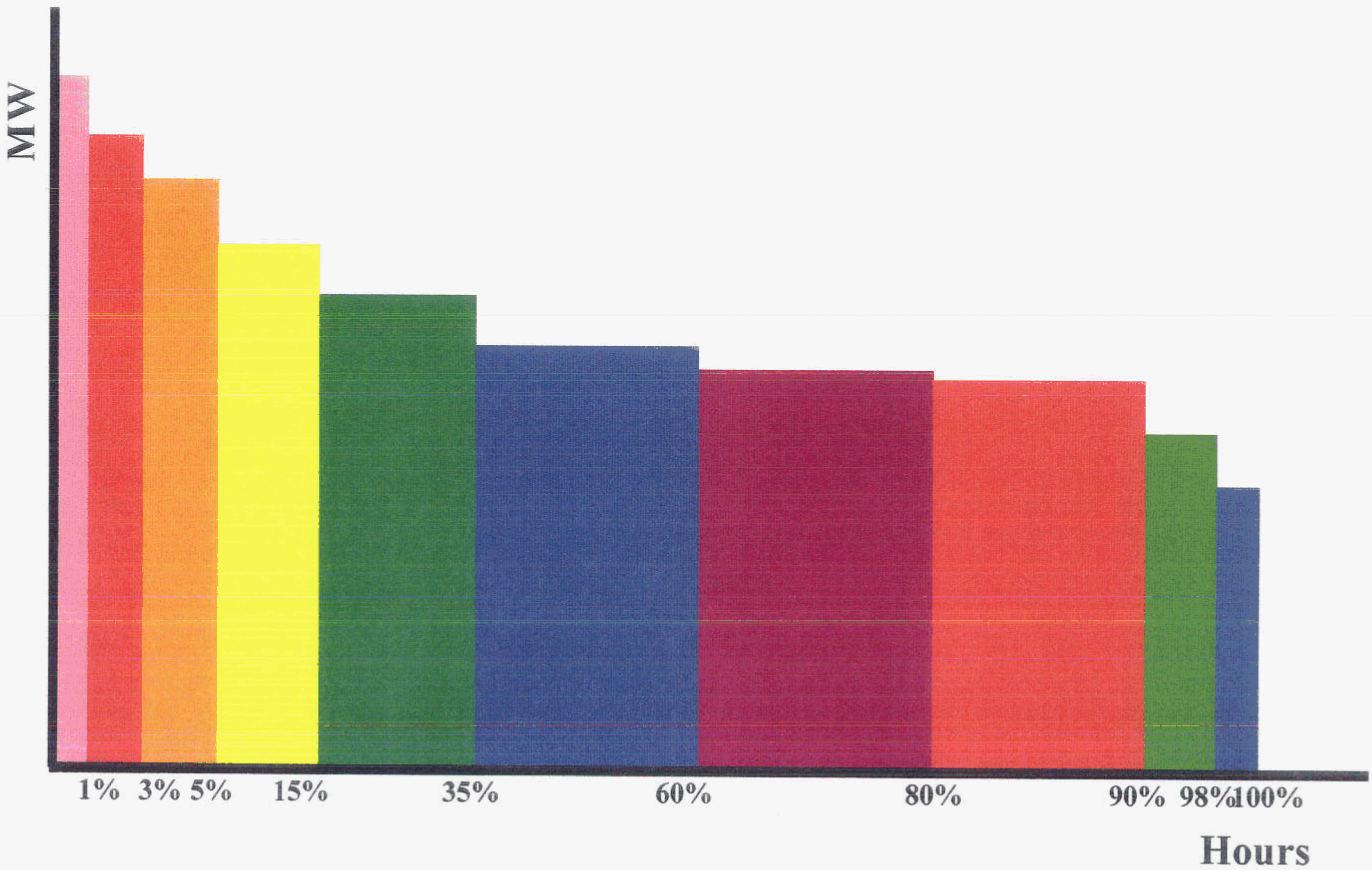


Figure A-34: Discretized Load Duration Curve Gives Ten Market Clearing Prices

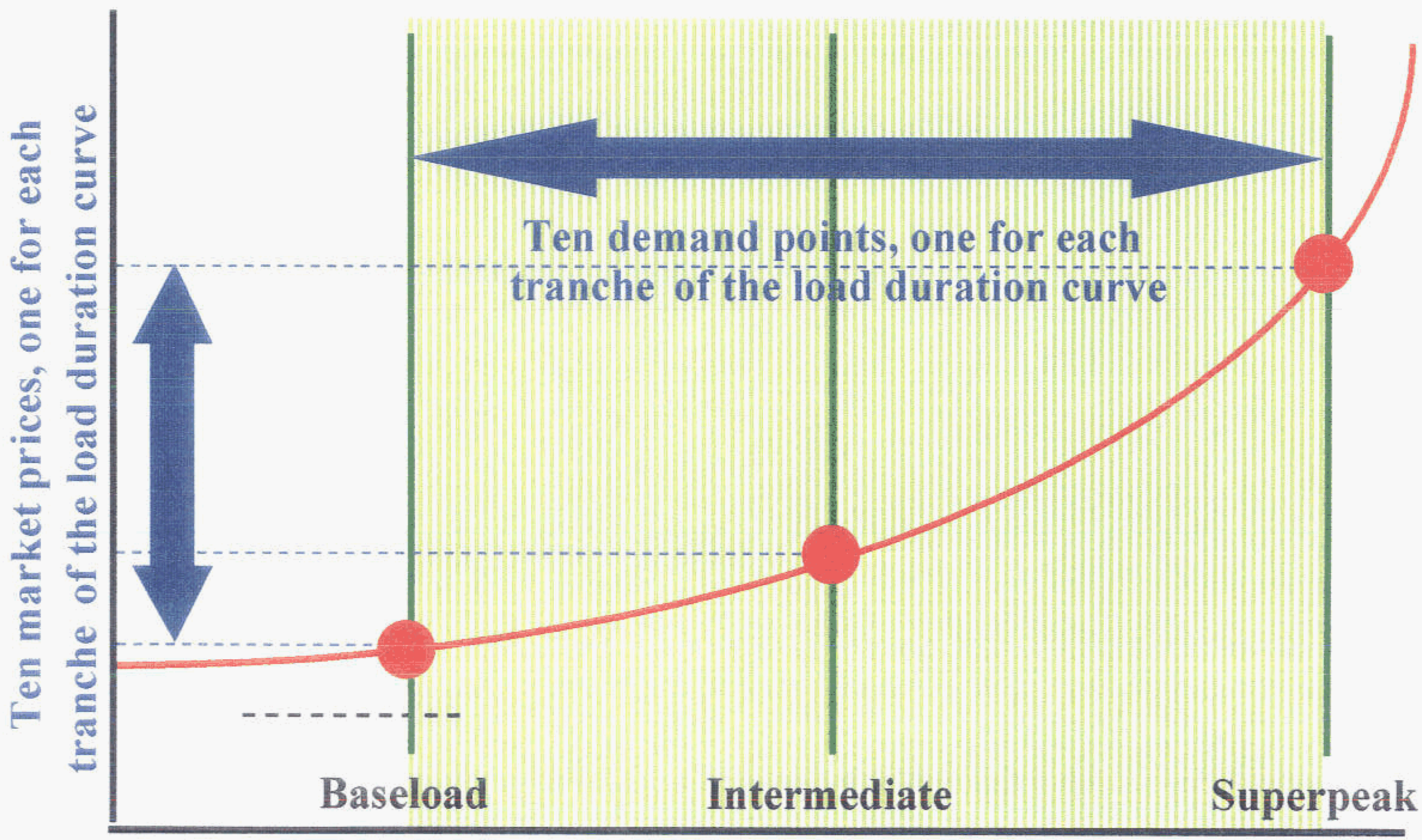


Figure A-35: The Duke/Altos Model Predicts Forward Market Clearing Price in Florida

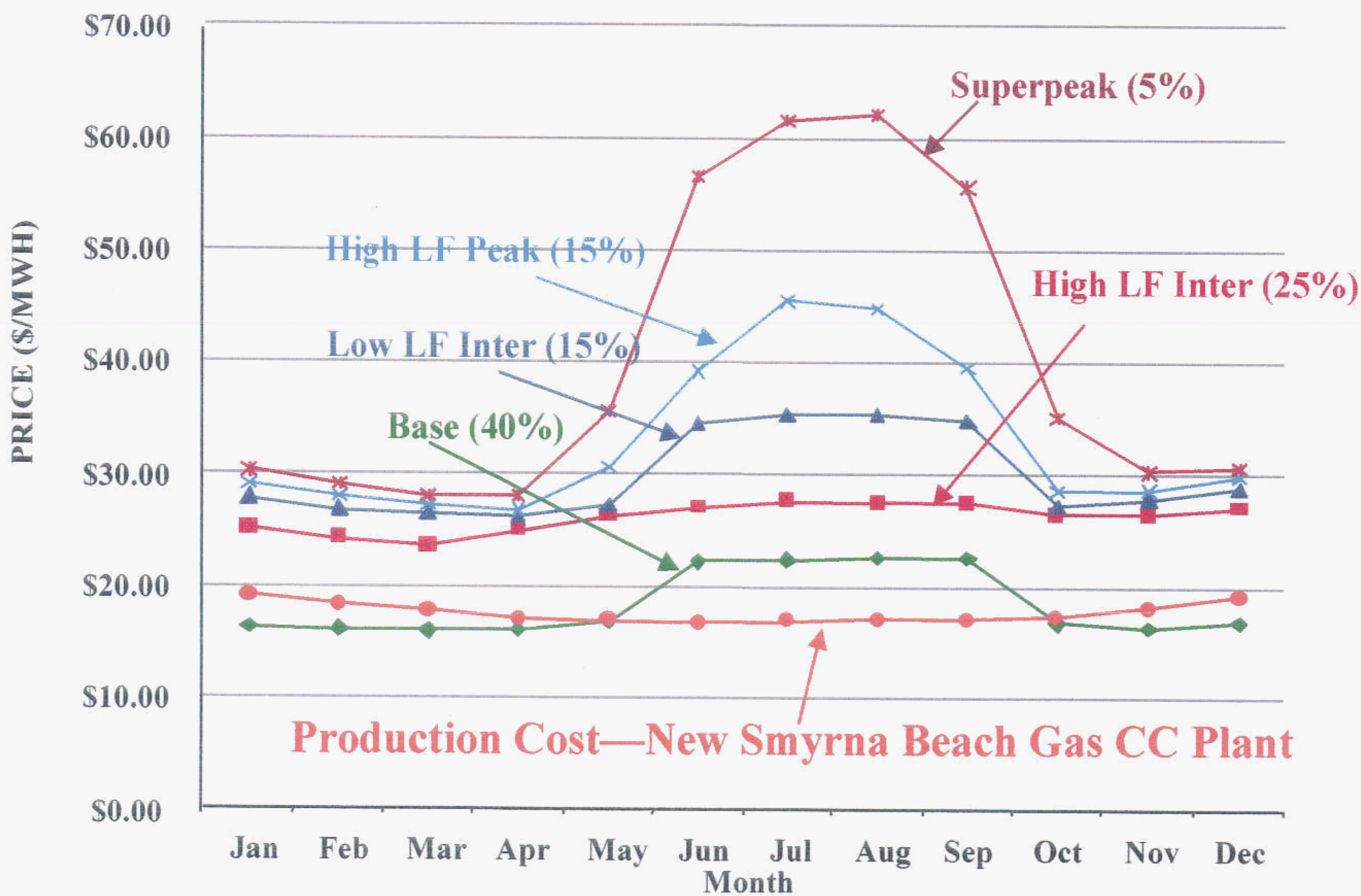
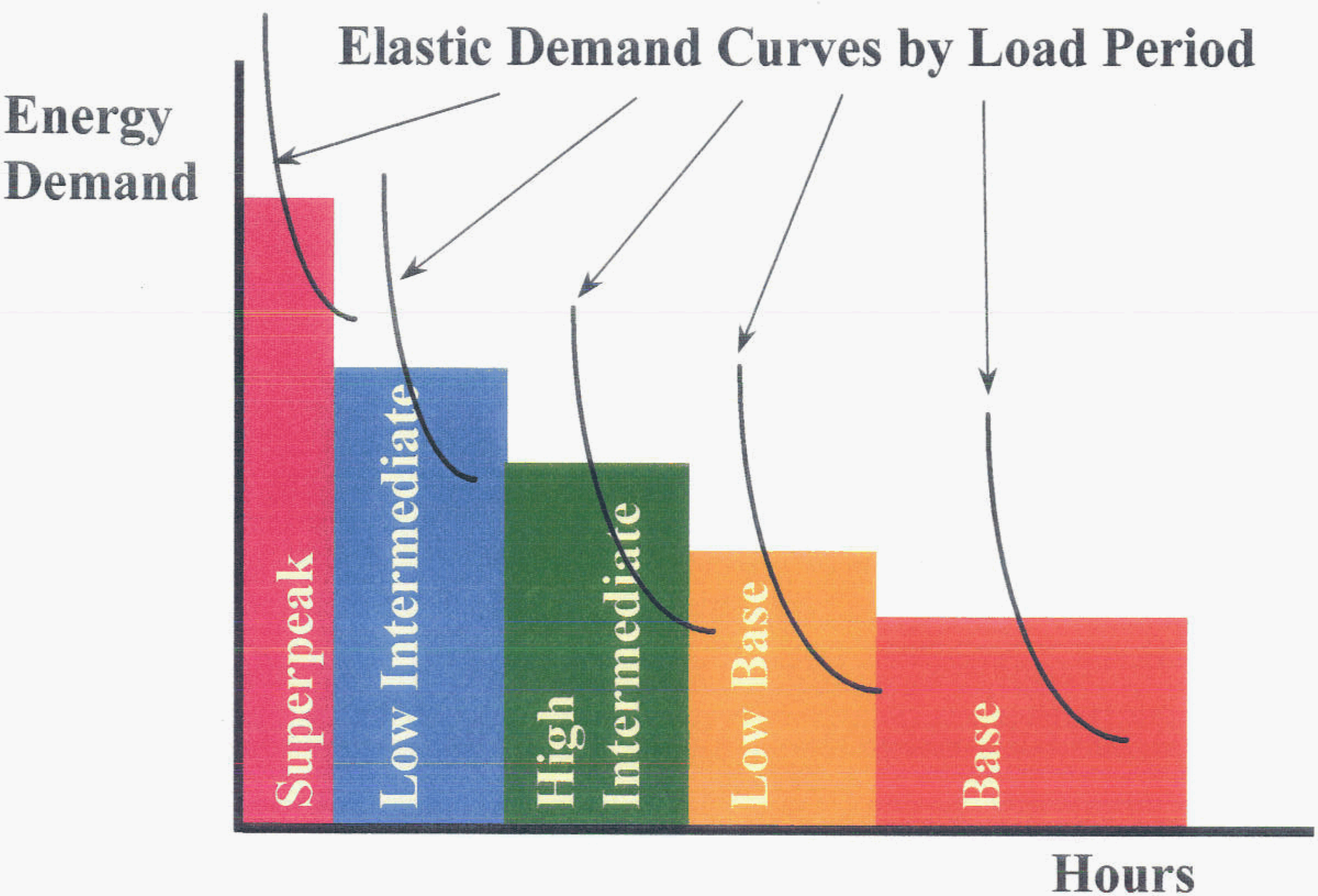


Figure A-36: We Can Consider Price Elasticity in Each Load Period



APPENDIX D

OVERVIEW OF THE ALTOS NORTH AMERICAN REGIONAL GAS MODEL

OVERVIEW OF THE

ALTOS NORTH AMERICAN REGIONAL GAS MODEL

Dr. Dale M. Nesbitt

ALTOS
MANAGEMENT PARTNERS INC

Altos Management Partners
27121 Adonna Ct.
Los Altos Hills, CA 94022
(650) 949-3541 Voice
(650) 948-3396 FAX

TABLE OF CONTENTS

1. OVERVIEW AND SUMMARY OF NARG

1.1. General

The North American Regional Gas (NARG) model[1] is an economic model of the natural gas industry of North America that represents how regional interactions between supply, transportation, and demand determine price, quantity, and reserve additions. The objective herein is to describe the NARG model works. We have provided enough detail to illustrate rather comprehensively how the model works, yet we have omitted the detailed mathematics. Readers desiring a more mathematical description are referred to Nesbitt, Haas, and Singh, The GRI North American Regional Gas Supply-Demand Model, Decision Focus Incorporated report to the Gas Research Institute, 1988. The balance of this initial section discusses the time horizon and time period conventions resident within the model. Section 2 characterizes the resource model in depth. Section 3 describes the demand side of the model, and Section 4 outlines the pipeline transportation component of the model. Collectively, these sections provide enough methodological information to characterize rather completely how the NARG model works and why it represents North American gas markets in the best possible way.

1.2. Time Period Structure Of The NARG Model

The NARG model and the Generalized Equilibrium Modeling System (GEMS) approach upon which it is based are neither short- or long-term in nature. The GEMS approach is fully the most general approach in existence with regard to its dynamic assumptions. In particular, GEMS assumes that the future price schedule is a continuous, nonlinear function. (It makes a similar continuous assumption for flowing gas volume, reserve additions, and capacity additions.) The GEMS user specifies the time interval over which he or she wishes to sample from the continuous price (or other function) by specifying the following three parameters:

- Number of Time Points, i.e., the number of samples from the continuous future nonlinear price curve the user wishes to consider.

- Time Interval Between Time Points, i.e., the inter-time point interval the user wishes to consider.

- Number of Intra-Year Time Points, i.e., the number of subannual time points within each year the user wishes to consider. For example, in the short run gas model, we specify 36 monthly time increments. Time variation of core and noncore demand across these monthly time increments allows us to take account of seasonal demand variation and storage injection/withdrawal to fulfill it. GEMS allows us to specify as many intra-year periods as we like, including months (January, February, March,...) or others.

Armed with these inputs, which are "data" to the model and are not hard-wired into the computer code, GEMS creates the specified number of time points separated by the specified time interval. The long term version of the NARG model specifies ten (10) time points separated by a five (5) year interval with a single intra-year time increment. This creates a 45-year future model horizon,

[1] NARG and GEMS are tradenames owned by Decision Focus Incorporated.

sampling from the continuous nonlinear future price curve ten times, and considering only annual gas demand.

2. THE SUPPLY SIDE OF THE NARG MODEL

This section puts forth a rather complete description of the supply elements of the NARG model. We will discuss not only the rationale and details of the supply side calculation but also fully characterize the supply side data, where we get it, and why it is the best and most accurate descriptor of North American supply.

2.1. Regional Structure

The NARG model is a multiregional supply, transportation, and demand model. The reasoning underlying the supply regionalization is central to a full understanding of NARG. This section discusses how and why we have regionalized North America to take account of the resource deposition.

2.1.1. Regional Structure Of The United States

It would not be useful to subdivide the supply regions in the NARG model according to political or demographic boundaries (e.g., states, provinces, census regions). Rather, it is more useful and appropriate to subdivide the supply regions according to existing and prospective natural gas producing potential, i.e., to subdivide on a geological basis. In making such subdivision, consideration must be given to the structure of the existing and prospective future pipeline system. In particular, supply regions must be associated with the upstream ends of existing pipelines and with the upstream ends of anticipated new pipelines. The supply regions in the NARG model were selected with several considerations in mind.

First, when it is necessary to distinguish differences among gas producing basins in terms of transportation costs to demand regions that compete for that gas, those basins have been associated with distinct supply regions. That is, transportation cost differentials dictate supply regionalization.

Second, for those sources that will require new pipeline or gathering capacity, regional supply distinctions have been made. If a particular resource producing basin relies on the addition of new pipeline or gathering capacity to become economically viable, that supply region is distinguished from other supply regions. Indeed, in such cases, the supply region and the outward-bound pipeline are inextricably linked, and we must model them in effect as a pair. Proper consideration of the relationship between pipeline segments and resource production regions was one of the primary considerations that has in recent months motivated the disaggregation of the Texas intrastate portion of the natural gas system and disaggregation of the Gulf Coast and Gulf-to-Northeast pipeline links. To wit, we needed to disaggregate the Gulf Coast gas-producing region in order to represent in more detail its configuration relative to the supply basins it exploits and the interim or final demand centers it serves.

Third, when it is necessary to distinguish resource endowment and cost differences among producing basins, those basins are distinguished by region. In general, there are substantial differences among resource producing regions with regard to extent, cost, and distribution of the natural gas resource base. Some would argue that such heterogeneity of the resource base motivates an extremely detailed representation of natural gas supply. Countering such argument is the observation that much supply side aggregation is dictated by the specific structure of the pipeline system. We have sought to balance the desire for more supply side regional and technological detail with the desire to realistically represent the transportation corridors for delivering gas to market. However, it has become clear over time that it is increasingly necessary to disaggregate the Louisiana and Texas region of the Gulf of Mexico, both onshore and offshore. The region is that recently unfolding resource deposition information related to the onshore and offshore Gulf resource indicates substantially higher potential located in specific locations. Our disaggregation of the Gulf of Mexico resource base was designed to capture those newly emerging realities.

Fourth, many supply or pipeline projects have direct effects only in localized regions of the United States or Canada, yet the indirect effects proliferate broadly throughout all supply and demand regions of all countries represented. In effect, prices carry economic signals from the single directly affected region to all other regions of the country along all the paths of the pipeline network. The representation of the pipeline network must contain sufficient detail to represent all important existing and prospective future paths. Noting that pipeline connections cause adjacent markets to communicate, we are motivated to incorporate a larger rather than a smaller number of pipelines and pipeline corridors into NARG.

Fifth, government policy can be region-specific. Excessive aggregation across regions would obviate the ability of the model to properly represent government policy. For example, there are significant tax, financial, and other differences among regions, necessitating regional distinctions in the model. A specific illustration is the argument that the Alliance pipeline might use liquid sales to subsidize gas transportation. In such a scenario, the transportation cost along Alliance would be smaller than "normal" gas pipeline economics might otherwise dictate. The NARG model can represent such phenomena related to Alliance as well as a wide range of policy and other similar phenomena.

With regard to the conventional and deep natural gas resource base, the Potential Gas Committee (PGC) regions and designations were adopted and incorporated into the model. There are several reasons for this regionalization. First, much of the resource data is reported in geological and geographic zones consistent with the PGT regions. The PGC, the United States Geological Survey (USGS), and similar resource base reporting organizations have given a great deal of much thought to the appropriate degree of regional disaggregation of the conventional resource base. We have sought to incorporate that thought by adopting their regions.

Unconventional gas (tight sands, methane from coal deposits, and Devonian shale), which are commonly called "continuous deposits," are associated in the model with conventional gas supply regions and are distributed among the conventional gas supply regions as dictated by their actual physical location. The unconventional gas resource base is distinguished in the same degree of regional detail as the conventional gas resource base, but the realities of where it occurs are properly represented. Using the same regional distinctions for unconventional as well as conventional gas is particularly convenient and we think proper because the unconventional gas resource must enjoy the same access to the transportation system as conventional. Furthermore, the unconventional resource base is further down the economic ladder than the conventional resource base, meaning that the pipeline infrastructure built to exploit the lower cost conventional resource base is likely to dictate the exploitation pattern of the higher cost unconventional resource base.

Synthetic sources (e.g., coal gasification) are regionalized according to coal producing regions of the United States. The major coal producing regions of the United States have been associated with the various PGC supply regions and have been placed into the corresponding aggregate NARG model gas supply regions. For example, the North Dakota coal region (where minemouth coal gasification might occur) is considered to lie within the Northern Great Plains supply region. Small, exotic sources such as methane from waste or biomass are positioned within the various demand regions, representing the fact that they use only the distribution system, not the transportation system.

2.1.2. Regional Structure Of Canada

The regional structure of the Canadian gas system and the supporting resource data are distinguished as follows. The Western Canadian Sedimentary Basin has been disaggregated into the three provinces in which it resides, and the balance of the Canadian resource base has been distinguished regionally:

- British Columbia
- Alberta
- Saskatchewan
- Eastern Canada
- MacKenzie Delta
- Canadian Arctic (Beaufort Sea, Arctic Islands)

As with the United States, the particular regional disaggregation for Canada was chosen with several purposes in mind. First, we need to properly position the primary gas deposits in Canada. It is known that the vast majority of economic Canadian gas occurs within Alberta in the Western Canadian Sedimentary Basin. Yet, that there are significant gas deposits in British Columbia and Saskatchewan and that the latter deposits are positioned differently with regard to the Canadian transportation system.

Second, the Canadian resource base must be distinguished at a level of geographic detail necessary to support analysis of existing and prospective Canadian border import locations to the United States: Huntington/Sumas (Westcoast), Kingsgate (PGT), Monchy (Northern Border), Alliance, Emerson (Great Lakes), Niagara, and Iroquois. The level of border import and demand detail within the United States dictates the level of resource base disaggregation needed for Canada.

Third, it was necessary to distinguish key demand patterns in Canada, which in the past have influenced not only delivered gas prices in Canada but also export economics and government policy. In particular, much of Canadian gas demand occurs within Ontario, which is Canada's most populous and most politically influential province. However, Ontario demand must be served through long distance pipeline from Alberta either indirectly through the Great Lakes system or directly through TransCanada.. In recent years, Ontario has imported gas across the St. Claire lake from Detroit, thereby experiencing competition from the United States. Alberta and points intermediate (i.e., Saskatchewan) must therefore be distinguished.

Fourth, it is necessary to distinguish the more Northern, Arctic gas resource base in sufficient detail; otherwise, one cannot predict what is the most economical resource base exploitation pattern and what will be its impact on gas price throughout North America if any.

Finally, the eastern Canadian resource producing basin contiguous to the Sable Island has grown in importance. We have distinguished the Eastern Canadian, Sable Island resource base as well.

2.1.3. Geographic Representation Of Gas Import Alternatives

Border import locations are positioned at various points along the United States-Canadian border and the United States-Mexico border. There are two prospective border import locations from Mexico represented in the model. LNG import locations are positioned along the east, Gulf, and west coasts at various existing and prospective future locations. The NARG model is embedded within a World Gas Trade Model that explicitly calculated the LNG import point prices based on world supply-transportation-demand considerations. This is necessary to ensure that the prospective and existing interconnections to the rest of the world are credible.

2.1.4. Overall Regional Structure

The NARG model, which is the North American portion of the World Gas trade model, distinguishes three geographic regions, the United States, Canada, and Mexico. Alaska is represented as part of the United States, but the colossal transportation system that would be needed to move Alaskan gas to the Lower 48 United States and its interconnection with Canada is represented. The NARG model contains the following regional detail

- North Alaska (1)
- South Alaska (2)
- San Juan/Raton Basins (3)
- Rocky Mountain Basins (4)
- Northern Great Plains Basins(5)
- Anadarko/Arkoma Basins (6)
- Permian Basin (7)
- Gulf of Mexico Basins (8)
- Midwestern Basins (9)
- Appalachian Basin (10)
- Offshore Atlantic Coast (11)
- LNG Import Terminals (12)
- Canadian Border Import Locations (13)
- Mexico Border Import and Consumption Locations (14)
- Pacific Northwest Demand and Supply Region (15)
- West North Central-Mountain Demand Region (16)
- West South Central Demand Region (17)
- East North Central Demand Region (18)
- South Atlantic Demand Region (19)
- East South Central Demand Region (20)
- Middle Atlantic Demand Region (21)
- Oil Region (22)

- Southern California Supply Region (23)
- Northern California Supply Region (24)
- Pacific Gas and Electric Demand Region (25)
- Southern California Gas Company Demand Region (26)
- San Diego Gas and Electric Demand Region (27)
- EOR Demand Region (28)
- New England Demand Region (29)
- Gulf-to-Northeast Pipeline Corridor Transportation Region (30)
- Canada: British Columbia Supply Region (C1)
- Canada: Alberta Supply Region (C2)
- Canada: Saskatchewan Supply Region (C3)
- Canada: Northern Canada Supply Region (C4)
- Canada: Eastern Canada Supply Region (C5)
- Canada: Western Canada Demand Region (C6)
- Canada: Ontario Demand Region (C7)
- Canada: Canadian Oil Region (C8)
- Canada: Eastern Canada Demand Region (C9)
- Canada: British Columbia Demand Region (C10)

The indexes we have associated with each region correspond to the NARG model indexes used internally.

The regionalization of the NARG model is embedded in the network "tinkertoy" diagrams that will be provided under separate cover. In reviewing those diagrams, it will become immediately obvious just how the foregoing regions have been represented and what level of detail is contained within each region.

2.2. The Depletable Resource Supply Hexagons–How Do They Work?

This section outlines how the supply nodes in the NARG network operate. Implicit in this discussion are a number of critical dimensions of the NARG technique:

- What is the economic logic and rationale that underlies NARG?

- What is the data necessary to support the supply nodes? How should it be interpreted? How should it be assembled?

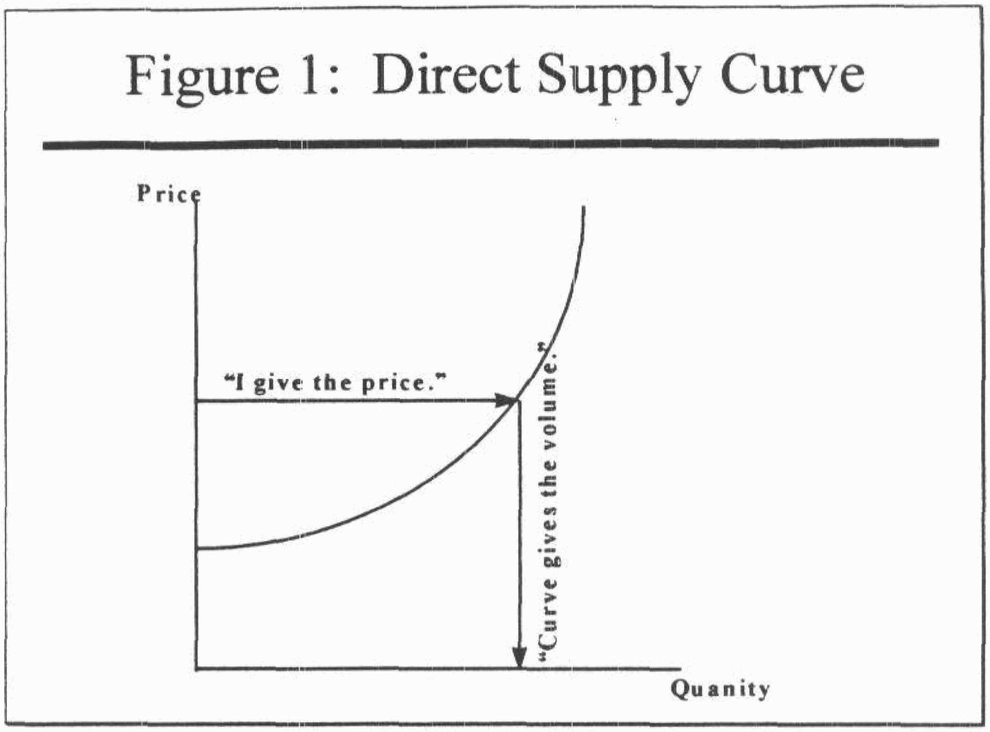
- What are the characteristics of supply-demand equilibrium in an economic system containing depletable resource processes? How can the supply-demand-balancing concept be applied to markets with depletable resource processes within?

- What is the right way to represent depletable resource production? There are so many incorrect or naïve ways to represent depletable resource production. There is only one right way. What is it?

- What is the right way to represent equilibration between resource markets (e.g., gas) and financial markets? Financial markets provide such variables as the cost of capital, which is related to returns on equity in broad financial markets and interest rates on debt in broad markets. How do we represent the fact that at supply-demand equilibrium, there can be no possibility of arbitrage between financial markets and gas markets? In a modeling sense, how can we be sure that the forward price and cost of gas are properly related to discount rates that represent costs of capital?

This section answers those questions in summary form. We have prepared much more detailed documentation elsewhere and can make copies available to our NARG customers upon request.

To begin this discussion, consider the simply notion of an economic supply curve. Figure 1 is a traditional static economic supply curve. It is static in the sense that it represents a single point in time, i.e., a "snapshot" in time. The simple static supply curve answers the following question: "If the market price were p, how much supply would the producer voluntarily and profitably deliver to the market?" Such a supply curve can be derived fundamentally by appealing to the notion of a price-taking, profit-maximizing producer doing the best he can given that everyone else in the economy is simultaneously doing the best they can. We have interpreted the supply curve as a price-taking, profit-maximizing producer elsewhere in our NARG documentation. (See Nesbitt, Haas, and Singh, The Gas Research Institute North American Regional Gas Supply-Demand Model, Decision Focus Incorporated report to the Gas Research Institute, 1988.) Keep squarely in mind, the notion of a supply curve is tantamount to the notion of a price-taking, profit-maximizing producer. In NARG, just as in the real world, producers are assumed to be striving to maximize profits. The notion of a price-taking producer is depicted in the simple static supply curve in Figure 1 by reading a price off the vertical axis and using the curve to find the corresponding quantity on the horizontal axis. The quantity on the horizontal axis has the property that it represents the very last Mcf in the market that can be produced profitably at the given price p. (The very last Mcf is termed the marginal Mcf.) All Mcf's less than the very last Mcf will be produced at a strictly positive profit; their cost will lie below that of the marginal Mcf. The very last Mcf can be produced at "breakeven," i.e., zero profit. Economists use the term "direct supply curve" for Figure 1 to indicate the fact that the market is specifying a price and the producers are deciding how much to produce at that price.



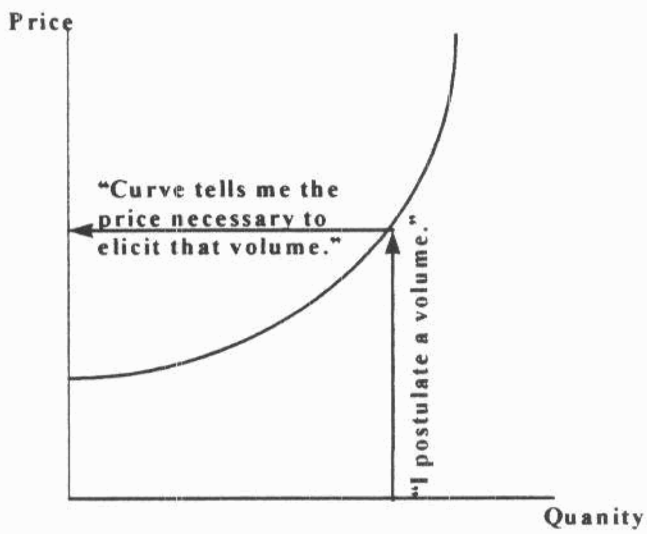
NARG uses the inverse of the direct supply curve, which is depicted in Figure 2. In particular, NARG specifies a quantity on the horizontal axis and uses the supply curve to read the corresponding price off the vertical axis. As indicated in Figure 2, the inverse supply curve as it is termed by economists begins by specifying a quantity or volume to be delivered to the market on the horizontal axis and then uses the inverse supply curve to read the price off the vertical axis necessary to motivate producers to voluntarily and profitably produce and deliver that specified quantity to the market. The notion of an inverse supply curve in Figure 2 is quintessential to the NARG calculation procedure in a way that will be made clear shortly. To reiterate, NARG will be asking the question: "If the market wanted me to deliver the quantity q, how high a price would the market have to sustain in order to induce me to voluntarily and profitably deliver that quantity?" The inverse supply curve is exactly the same as the direct supply curve; they are precisely the same curve. With the inverse supply curve, one reads the price from the vertical axis at a prespecified quantity from the horizontal axis by following the arrows in Figure 2 rather than the reverse direction in Figure 1.

Using the notion of an inverse supply curve, how does NARG work? The answer is simple. NARG successively executes the following set of steps:

1. Guess the supply volume, i.e., guess a quantity on the horizontal axis of Figure 2.
2. Read the price necessary to elicit that supply volume from the inverse supply curve by following the upward and leftward arrow in Figure 2.
3. Pass the price thus determined to the demand curve, i.e., to the portion of the market that lies downstream from the supply processes.
4. Determine the market demand that would occur at the price specified in step 3 by reading it from the demand curve. Figure 3, which represents the demand curve, illustrates how this is done.
5. Pass the demand quantity back to the supply curve.

6. If the demand passed back to the supply curve in step 5 is the same as the supply volume that was initially guessed in step 1, NARG is complete and can quit. If the demand from step 5 is different from the supply volume that was initially guessed in step 1, NARG replaces the guess in step 1 with the calculated volume from step 5 and repeats. NARG will have to execute this series of steps a number of times until the step 1 guess is the same as the step 5 guess. When the two successive guesses are equal, NARG has achieved supply-demand equilibrium. The NARG method is no more than a simple supply-demand cobweb method commonly seen in the economics literature and is illustrated in Figure 4.

Figure 2: Inverse Supply Curve



NARG works as a supply-demand cobweb procedure that finds the "magic crossing point" between supply and demand. The inputs to the NARG model are the two curves in Figure 4, the supply curve and the demand curve. The outputs from the NARG model are the price and the quantity where the two curves cross each other. To emphasize, **inputs are curves, and outputs are magic crossing points.** The magic crossing points represent market clearing prices and quantities traded at those prices. What is needed to create and run NARG is the supply curve and the demand curve. The remainder of this section describes how we conceive and assemble the supply curves basin by basin for natural gas supply and region by region for natural gas demand.

Figure 3: Demand Evaluation

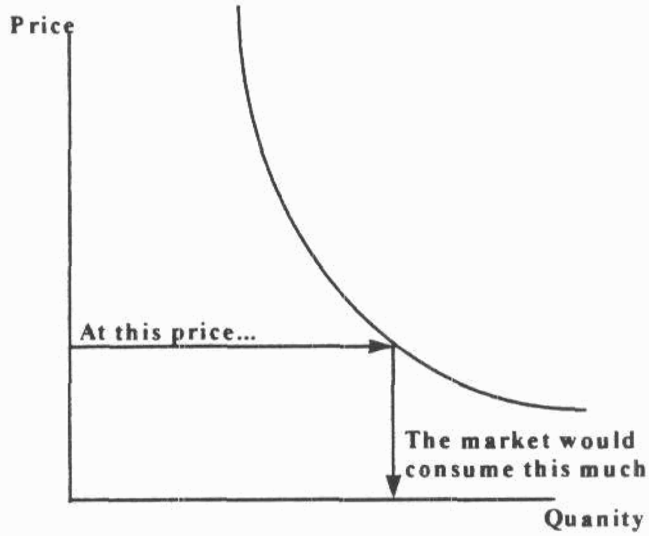
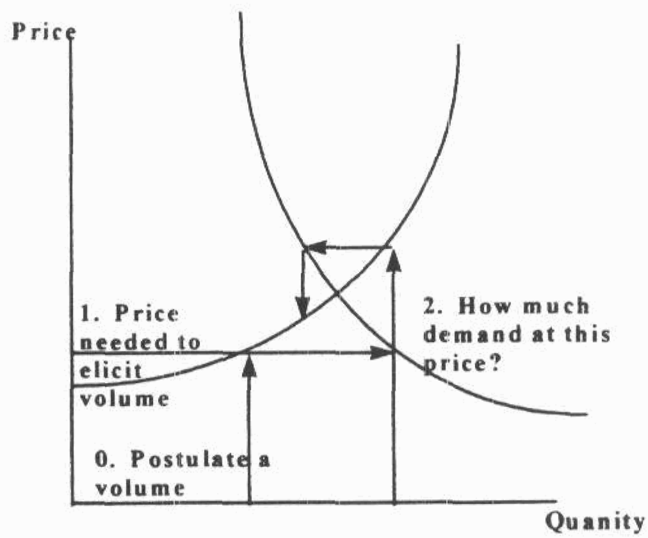


Figure 4: NARG's Iterative Supply-Demand Calculation



We should emphasize that representing primary resource production is not as simple as assembling a static, time-independent supply curve of the form in Figure 1 or Figure 2.

Depletable resource supply is most definitely NOT a static issue; it is an intrinsically dynamic issue. Depletable resource supply must specifically account for such phenomena as

- Production dynamics for each well, including the maximum possible level of production and the degree of cost escalation beginning from the time production from each vintage of well is initiated until the time that well is exhausted. The full life cycle production profile and cost of each well are intrinsically dynamic and must be considered.

- Successively ongoing exploration and production across a given basin. Successive, cumulative exploration and production is what causes a resource to be depleted in a given basin. Capital and operating costs and dry hole probabilities change as depletion exhausts resource deposits in descending order of attractiveness across each producing basin, and we must represent the dynamics of that process.

- Technological innovation, including 3D seismic, horizontal drilling, advanced drilling such as spiral drilling, etc. Such technological innovation has in the past decade stimulated aggregate volumes available in each basin and has depressed the cost of exploiting any given volume. Technological innovation has created an important dynamic force that we must carefully and explicitly represent.

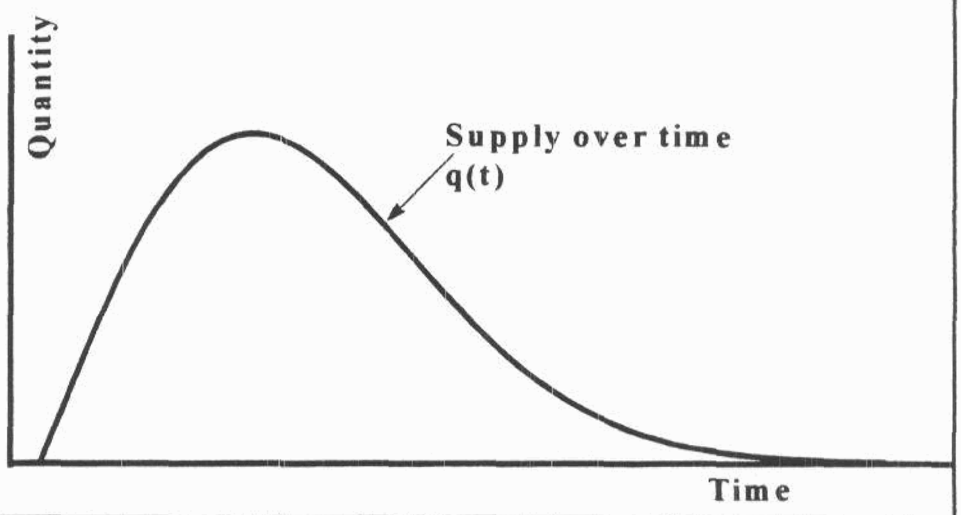
- Retirements of existing capacity. As old wells are retired, the fundamentals of short run supply change. This too is an important dynamic issue that NARG represents.

- Addition of new reserves and subsequent production from those reserves. NARG focuses on the process by which a market draws in new reserves and new production from those new reserves over time. In economists' jargon, NARG gives a great deal of attention to "entry" and "exit" in the primary resource producing sector.

NARG represents each of these elements in ways we are about to describe.

The analogy in Figure 2 of "start with a guess at quantity q; read the price p off the supply curve" will be preserved as we extend to a fully dynamic model. However, we have to carefully extend the notion so that it remains robust and correct. To do so, we have used the analogy "start with a guess at the production schedule q(t) forward through time; read the corresponding price schedule p(t) forward through time" off the supply curve. Rather than beginning with a scalar quantity q and reading off a scalar price p, we start with a time-vector q(t) and determine a time-vector p(t). To begin the NARG supply node calculation, therefore, we guess a gas production schedule q(t) forward through time. The forward gas production schedule q(t) extends forward throughout the entire time horizon of the model. Figure 5 illustrates what such a gas production schedule q(t) might look like.

Figure 5: Estimate of Forwarad Production Schedule



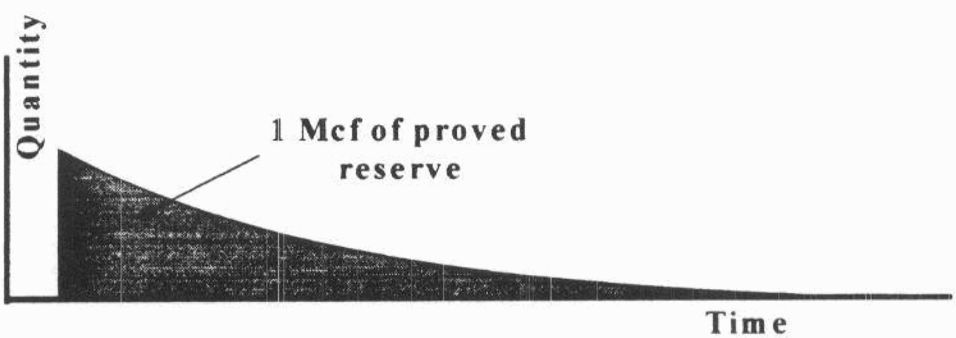
Beginning with the postulated schedule of gas production forward in time q(t) as indicated in Figure 5, we must first determine the schedule by which proved reserves must be added in order to sustain and meet the specified gas production schedule q(t). To wit, how much and when would reserves have to be added to meet the production schedule q(t) in Figure 4? The answer is found by first recognizing that each well, i.e., each vintage of well, experiences a geometrically declining level of production during its life. The production schedule from a well decays geometrically (exponentially) as shown in Figure 6. We use the convention that the area under what we call the "facility decline profile" (the exponential curve) is 1 Mcf. The facility decline profile therefore tells us what is the time pattern of future production that will derive from each Mcf of proved reserves today. For example, if there were 6.87 Tcf of proved reserves in place today, the production from that 6.87 Tcf of proved reserves will follow the shape of the facility decline curve in Figure 6 normalized to a total shaded gray area of 6.87 Tcf. Geometric facility decline curves are the fundamental building blocks of primary resource production, i.e., the fundamental relationship between proved reserves in the ground and flowing gas into the gathering and interstate pipeline system. The facility decline curve relates deliverability to proved reserves.

The facility decline curve is one of the fundamental data inputs to the NARG resource model. For each hexagonal tinkertoy in the model, i.e. for each increment of resource in each producing basin, we input a geometric decline rate for that tinkertoy. The reciprocal of the geometric decline rate is commonly known as the "reserves-to-production ratio." If we want a 10 year R/P ratio, we simply input a geometric decline rate of 0.1. This creates the following equation for the facility decline curve in Figure 6: $prod(t)=0.1*(1-0.1)^t$. Summation of this equation from 0 to infinity verifies that the area under the curve is indeed 1 Mcf. Annual production in the first year is 0.10 Mcf, production in the second year is 0.09 Mcf, production in the third year is 0.081 Mcf, and so forth.

As noted in Figure 6, the facilities decline curve is not restricted to be exponential in form. Indeed, one can specify any shape one wishes. For the current version of NARG, however, we have assumed that every resource node in the model has a geometric decline profile. R/P ratios in the current version range from 5 years on the low side (for deep water Gulf of Mexico gas) to 15 years on the high side for coalbed methane and tight sands. In practice, relatively little is lost by assuming geometric facility decline. Notwithstanding the fact that some resource "techies" made a big deal out of nuances in facility decline curves, sensitivity analysis in NARG will quickly confirm that it is changes in the R/P ratio, not detailed nuances, are what matter.

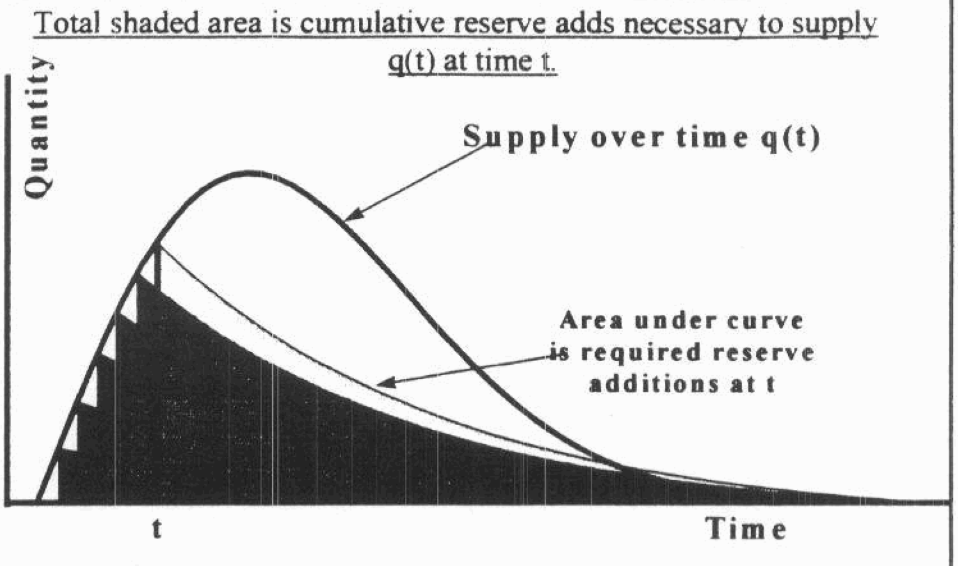
Figure 6: Production from a Well Declines Geometrically

NARG can use any shape; one need not assume only geometric decline.



Given the facility decline profile, how do we calculate the rate of proved reserve additions necessary to sustain the postulated quantity schedule q(t) in Figure 5? The answer is simple; we simply stack "exponential bricks" under the quantity schedule q(t). Figure 7 shows how. If we consider a given year t in the middle of the postulated forward production schedule q(t), we notice that reserves have to be proved before, during, and after time t. Before year t in the figure, there are five periods during which reserves have to be added to sustain the production schedule q(t) before year t. The quantity of reserves that have to be added in year t, indicated by the light gray exponential curve at the top, is that quantity necessary to make up the shortfall in production in year t and ensure that q(t) units are flowing to market.

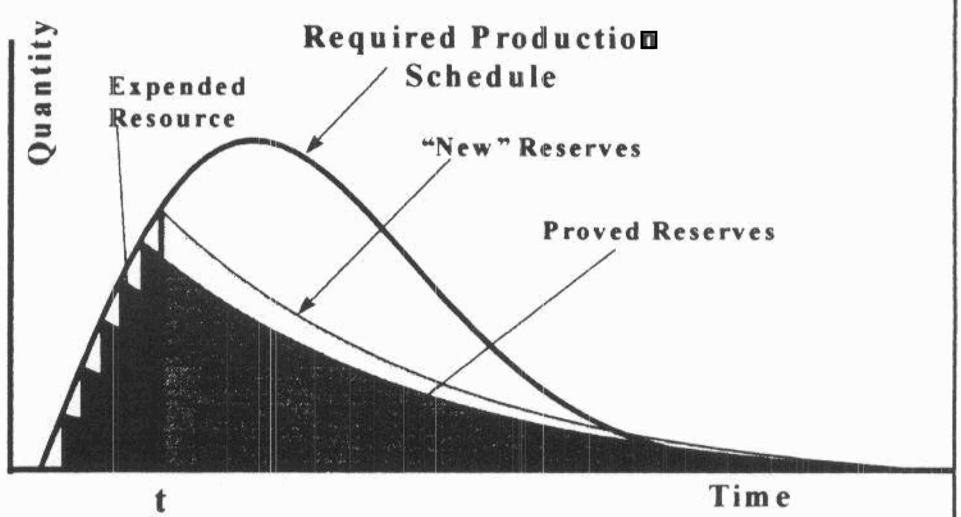
Figure 7: Meeting Demand Means Stacking in "Exponential Bricks"



The process of "stacking in" exponential bricks to satisfy the postulated production schedule is rather simple mathematically and rather revealing graphically and economically. If we keep track of the CUMULATIVE quantity of reserves proved since the beginning of time, we will have a plot of the total shaded area in Figure 7 as it grows over time. The total shaded area begins at zero when the postulated production schedule q(t) is zero. The shaded area grows to be equal to the area under the first exponential brick at time t=1. It grows to be equal to the sum of the areas under the first two exponential bricks at time t=2. It grows to be equal to the sum of the areas under the first three exponential bricks at time t=3. By the time we reach period t in the figure, the cumulative additions to reserves is equal to the entire shaded area in the figure. Cumulative additions to proved reserves is simply the growing gray area in Figure 7 over time. In a critically important sense, cumulative additions to proved reserves characterizes cumulative depletion and exhaustion of a given resource basin. Cumulative additions to proved reserves represents cumulative exploitation of the resource base in a given basin, i.e., cumulative extraction and exploitation of the resource base in that basin.

The concepts in Figure 7 contain some critically important elements and some critically important terminology. By reshading various portions of Figure 7, we can define and illustrate some critically important resource base concepts. At the left, we see in the most darkly shaded area that portion of previously proved reserves that have been delivered to market and burned as of time t. They are reserves that have been expended as of time t. They are gone forever and are not available for future consumption; they kept someone warm last winter. The medium gray area in the middle of the figure represents proved reserves in place as of time t. The total medium gray area represents reserves that are in existence as of time t and will be produced at time t or in some future time. They are "reserves" in the sense they are destined for market at some future time; they will not be withheld because their forward cost to market is low. They will not all come to market at once because they are constrained by their facility decline curve. The light gray area represents the quantity of new reserves that must be provided as of time t. In order to sustain the given production schedule q(t) through and including time t, producers must add reserves equal in magnitude to the light gray area at the top at time t. Clearly, as indicated in the figure, reserves must be added well ahead of production. Our clients tell us that Figure 8 has greatly clarified what in the heck people are talking about in the resource business. The figure makes clear what we mean by proved reserves; it is the middle gray shaded area. It is resource to be produced in the future but constrained by the remainder of the facility decline profiles for every vintage of well in place. It makes clear how much new reserves must be added in year t in order to sustain a given production schedule. To add fewer reserves is to fall short of the production schedule q(t).

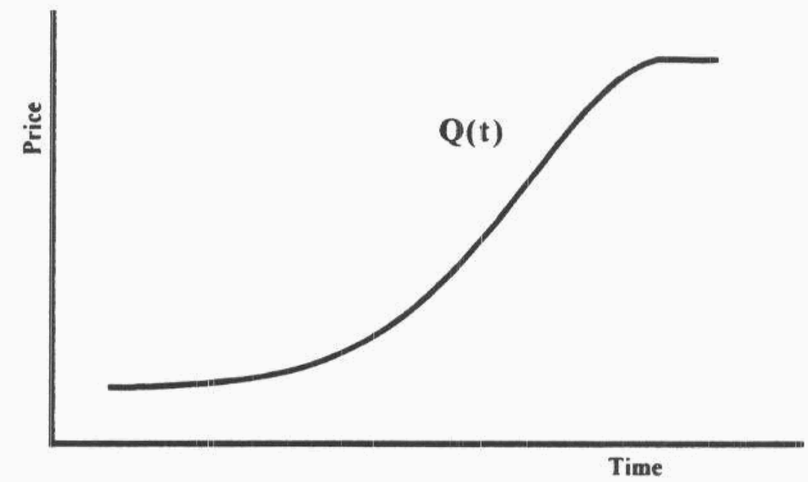
Figure 8: Critical Resource Terminology



The critical datum from Figure 8 that must be specified to the model is first year proved reserves, i.e., the middle gray area in the figure as of the first model year. NARG requires that the user specify how much proved reserve exists in every producing basin region by region throughout North America. This middle gray area is an important, user-specified input to the NARG model. NARG then adds new reserves during the forward horizon of the model according to the logic of the light gray area.

If we make a plot of cumulative reserve additions using the logic in Figure 8, i.e., the growing total shaded area, over time, it will have the monotonically increasing shape shown in Figure 9. Cumulative reserve additions will grow at a substantial rate initially or during some point in the production horizon of the basin and then will flatten out as little or no additional exploration and production occurs. Keep in mind, the curve for cumulative future reserve additions in Figure 9, denoted Q(t), is derived directly and unequivocally from the postulated schedule q(t) of future production.

Figure 9: Cumulative Future Reserve Additions over Time



Let us now turn to the question of how much the cost of each successive unit of reserves might change as the basin is exploited according to the cumulative reserve addition schedule in Figure 9. To do so, let us consider the resource producing basin as a "warehouse" that contains every Mcf of gas resident in the given somewhere on a shelf in that warehouse. Let us suppose further that the owner of the warehouse has lined up every Mcf of gas in his warehouse in ascending order of full fixed plus variable cost beginning at the door and extending inward further and further from the door as total costs go up. If we plot the cumulative volume of all gas in his warehouse against the cost of each successive Mcf of gas in his warehouse, we will obtain the curve in Figure 10. We term the curve in Figure 10 the resource marginal cost curve. In our experience, the resource marginal cost curve so defined is the most fundamental and most correct characterization of the resource deposition in a basin. It contains an unequivocal representation of BOTH the cost and the volume of reserves that can be proved and produced in a basin. It is not limited to volume, and it is not limited to cost. It explicitly couples volume with cost. We are very enamored of the representation in Figure 10 for several other reasons:

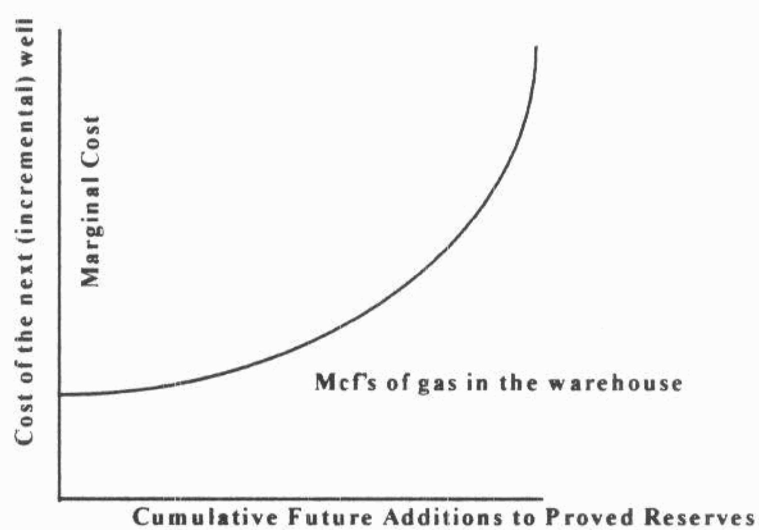
- It is unequivocal. There are no mistakes of interpretation. We know precisely what we mean. We must enumerate every Mcf of gas and attach a cost to every Mcf.

- The underlying definition of "technology" is unequivocal. If we want to impose technological learning, we must specifically extend the curve outward and to the right or downward in a way that simulates the application of the new technology. Alternatively, we must distort the curve outward and downward to simulate advancing technology.

- It is not confounded by dynamics. Dynamics, i.e., how fast reserves might be proved, are superimposed ex post facto from the outside, not embedded arbitrarily in the supply curves as they are in other models. By separating the dynamics from the resource deposition, we are able to make accurate characterizations of the resource in place and thereafter accurate characterizations of the dynamics and technology of exploration and production. We see this as a major strength of NARG. By contrast, the GRI/EEA Hydrocarbon model completely misses the boat because of its confounding of resource deposition with finding rate dynamics. By extrapolating historical finding rate trends, the model simply cannot escape from historical dynamic issues completely unrelated to the deposition of the resource itself. This is why the Hydrocarbon model has been so remiss at predicting forward production schedules and forward prices. Hydrocarbon model price projections have been a sad joke in the industry, an embarrassment, because they continue to confound the issue of total resource supply with the issue of the dynamics of extraction.

- It is not confounded by price. Price is explicitly entered as one variable, namely the variable on the vertical axis. The discussion of the shortcomings of the Hydrocarbon model pertain to this issue as well. That model confounds price and cost with they dynamics of production and intertwines it with the total volume available. As many of our customers have commented, the particular strength of this approach is that it allows one to put in the proper forward shape of the supply functions and thereby ensure that you do not miss the proper market price behavior.

Figure 10: Resource Marginal Cost Curve



The resource marginal cost curve in Figure 10 is the fundamental input to NARG that characterizes the volume and cost of resource deposits in each of the basins of NARG. Because we recognize that resource production requires both fixed (capital) and variable cost, we have actually input to NARG a pair of curves similar in concept to the single aggregate curve in Figure 10. The leftmost curve represents that capital cost necessary to prove each successive Mcf of reserves, and the rightmost curve represents the variable cost necessary to produce from each successive Mcf of reserves. Figure 11 illustrates. The fundamental resource inputs to NARG are

they are in other models. By separating the dynamics from the resource deposition, we are able to make accurate characterizations of the resource in place and thereafter accurate fully documented set of such pairs of curves for every increment of gas, onshore and offshore, deep and shallow, conventional and unconventional, foreign and domestic, throughout North America.

Even though the model contains the pair of supply curves in Figure 11, we will continue the discussion of how the resource model works by using the simplified curve in Figure 10. Given the schedule Q(t) of cumulative additions to proved reserves necessary to sustain the postulated schedule q(t) of production, which is depicted graphically in Figure 9, suppose we plot it on the horizontal axis of Figure 10 and read the corresponding marginal cost MC(t) from the marginal cost curve as indicated in Figure 12. That is, for each level of cumulative reserve additions Q(t), we proceed upward from that point on the horizontal axis, then proceed leftward from that point at which that vertical curve intersects the supply curve to the vertical axis. By so doing for every point Q(t) in the forward horizon of the model, we are in effect using the marginal cost curve to determine the schedule of marginal cost over time, i.e., MC(t). The forward schedule of marginal cost MC(t) is interpreted as follows. "If the production schedule q(t) were followed, the full cost of the last well to be drilled in year t, i.e., the marginal well in year t, would be MC(t). The schedule MC(t) is truly a schedule of the marginal well and its cost over time. It represents the full cost of the last Mcf to be added in each year. It is the worst well that is competitive in each future year.

Figure 11: Fixed Cost and Variable Cost of Resource Exploitation

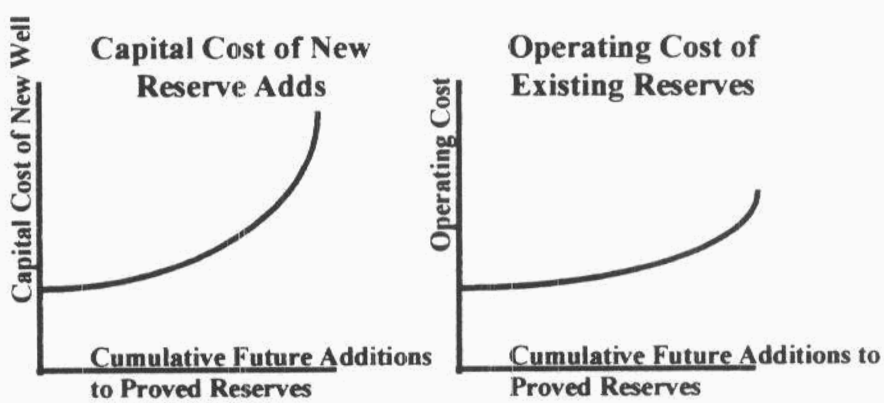
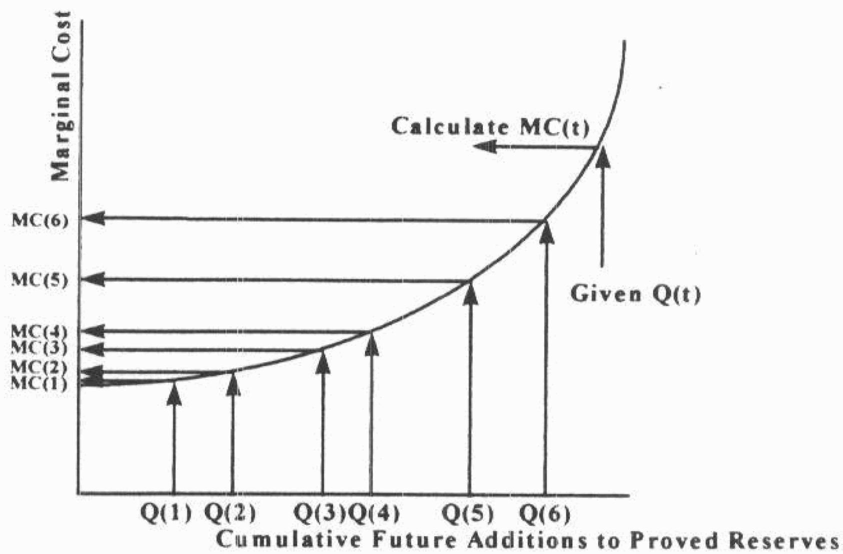


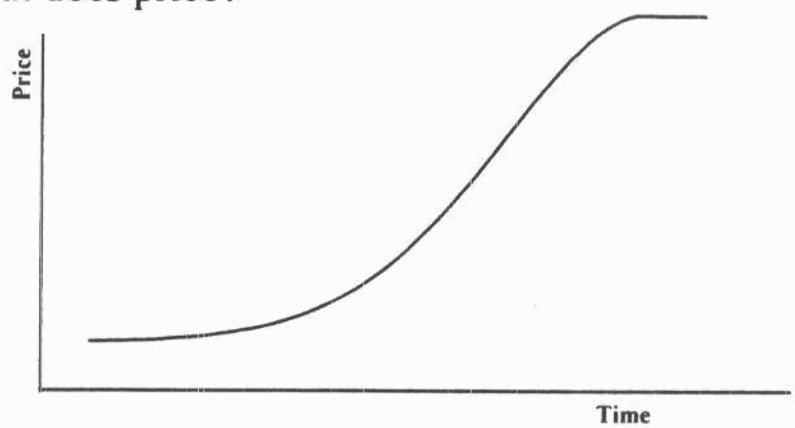
Figure 12: Calculating Marginal Cost over Time



The time schedule of marginal cost MC(t) derived from the foregoing procedure has the form in Figure 13. If the supply curve is upward sloping, the marginal cost curve will likewise be upward sloping because the cumulative reserve addition schedule Q(t) is monotonically increasing. The only way the marginal cost curve can be downward sloping over time is if technological innovation and cost reduction reduces cost faster than depletion as represented by the supply curve in Figure 10 escalates cost. This has probably occurred during certain periods of the 1980s and 1990s; however, it is unlikely to persist forever. Inexorable depletion will ultimately set in. The question, however, is when. The supply data embedded in the current version of the NARG model result in rather flat real supply curves for the next 30 years or more.

Figure 13: Cost of the Marginal Well (Marginal Cost) Over Time

- Marginal cost rises with cumulative depletion, but does price?



Once we have calculated the marginal cost schedule over time, are we done? Isn't price equal to marginal cost? The answer is an unequivocal NO! There is one critically important step left to go. Producers would not necessarily be willing to deliver wells to market at the postulated rate $q(t)$ if the price they got was the schedule $MC(t)$. To see why, consider the situation in Figure 14. A producer holding the marginal well at time t would receive the price $p(t+1)$ if he waited until time t+1 to deliver his marginal well. His cost would remain constant at $MC(t)$ if he delayed the marginal well to time t+1. Hence, the profit he would get by waiting would be $p(t+1)-MC(t)$. However, he would not receive the money until time t+1. Its discounted present value as of time t would be $\{p(t+1)-MC(t)\}/(1+r)$ where r is the producer's discount rate. As indicated in the figure, the profit margin received one year into the future but discounted one year back to the present would be a lower bound on the profit the producer would expect to get in the current year t. (The producer could get that much money by simply delaying the marginal well by one year, so the market would have to compensate him or he would not deliver the marginal well in year t and the production schedule $q(t)$ would not be met.) Indeed, the price $p(t)$ would have to be greater than or equal to $p^*(t) = MC(t) + \{p(t+1)-MC(t)\}/(1+r)$. The price necessary to elicit the production schedule $q(t)$ in year t would be $p^*(t)$, not $MC(t)$. It is this calculation of $p^*(t)$ that is made within NARG.

Why is this the correct model of resource pricing in a competitive market? The reason is simple. Under this simple equilibration between discounted present value of margins that can be captured over time, there is absolutely, unequivocally no incentive for arbitrage between the physical market for gas and the financial market as represented by the discount rate r. There is no incentive for people to convert their gas to money, secure in the knowledge that the money will escalate in value faster than the gas would have escalated had they left it in the ground. Likewise, there is no incentive to withhold gas from market, secure in the knowledge that gas prices will escalate fast enough so that you make more money on gas price appreciation than you would have made in the financial markets. There must be absolute, lockstep equilibration between gas markets and financial markets as represented by discount rates. Otherwise, the postulated forward price solution from the model will not be stable in the real world and cannot be advocated as a valid, reasonable, sustainable projection of forward gas price. The reasoning in Figure 14 assures that the "gas in the ground-money in the bank" tradeoff does not favor one over the other. All possible arbitrage between the two will have been completed so that there is stable, sustainable equilibration. This is absolutely critical to valid, reasonable forward price forecasting.

Figure 14: There Can Be No Arbitrage Possibility at Equilibrium

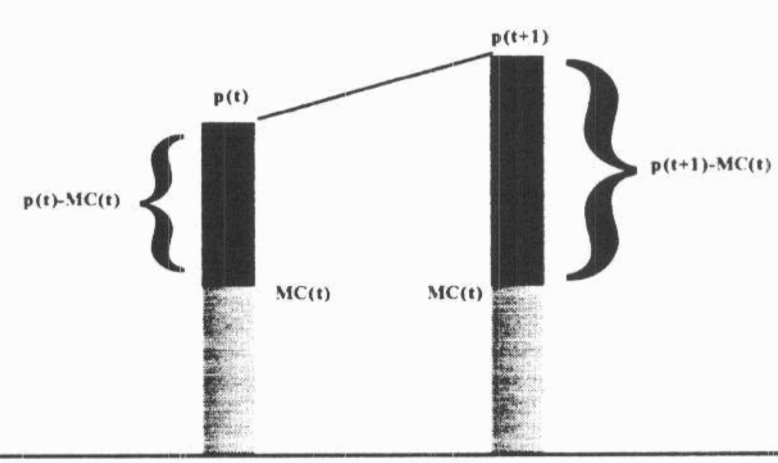
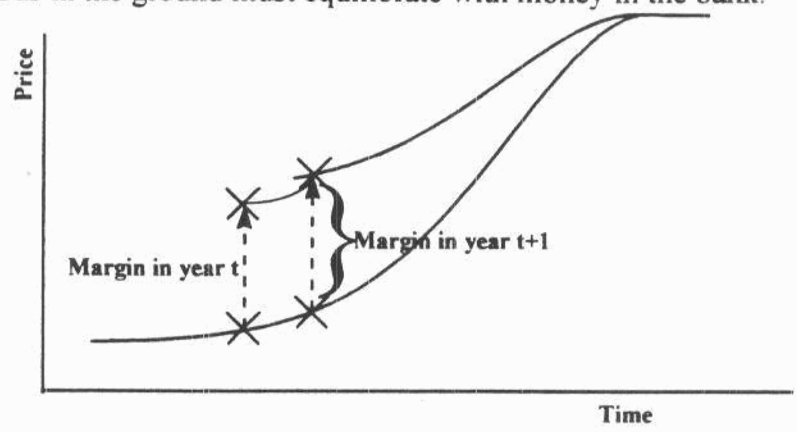


Figure 15 summarizes this notion that there must be complete equilibration between gas in the ground and money in the bank at equilibrium. The price schedule that is reported by the resource hexagon to the demand portions of the model must be the higher of the two curves, not the lower marginal cost schedule MC(t) in the diagram. The price reported to the demand portions of NARG must be such that no producer has any incentive to change his production schedule over time. If producers have incentive to change, assuredly, they WILL change. If they have incentive to changes, assuredly the price that contains such incentives will not be sustainable in the market. It cannot be a market-clearing price; it must not be reported to the demand side of the model for equilibration. This is a critically important feature of NARG not to be underemphasized. The price that is reported to the demand sectors from the supply models is such that no producer has any incentive to reschedule his production over time given that price schedule.

Figure 15: Price Must Not Allow Financial Arbitrage Over Time

Margin in year t at least as high as discounted margin from year t+1.

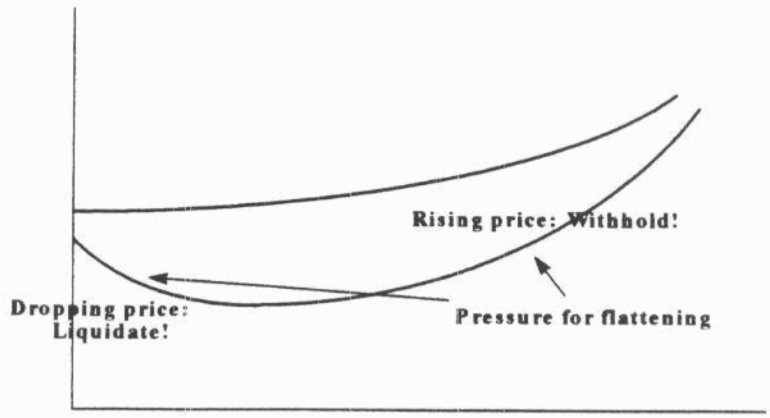
Gas in the ground must equilibrate with money in the bank.



Why go to all this trouble to equilibrate gas markets with financial markets? The answer is that we want to eliminate hockey stick and other "stupid" forward price projections. Hockey stick price forecasts are indeed stupid; they cannot be sustained in a market. To see why, consider Figure 16. During periods of rapid price de-escalation at the front end of the hockey stock price forecast, gas is crashing in value. Producers would face very strong incentives to drill their prospects and liquidate their resource holdings before their value deteriorates dramatically. Incentives to liquidate one's gas in the very short run would create strong market force to drop near term price and therefore flatten out the downward trend at the front end of the hockey stick forecast. To wit, there is systematic force that flattens an otherwise declining price trend. The front end of the hockey stick experiences forces that tend to flatten it. Similarly, during the period of rapid price escalation at the back end of the hockey stick price forecast, gas is soaring in value because of gas price appreciation. Producers would face very strong incentives to hoard their resource until after its price had escalated to new heights and liquidate it only thereafter. As producers hoard their gas at the front end, there would be shortage conditions and near term prices would escalate, tending to flatten out the escalating portion of the hockey stick. Therefore, there are strong, systematic forces that tend to flatten out the price-escalating portion of the hockey stick forecast. Obviously, hockey stick price forecasts of the type we see from the Hydrocarbon model as unequivocally wrong. They do not properly consider arbitrage between financial and physical markets. Such price forecasts cannot possible serve as the basis for cogent strategy and pipeline analysis.

Figure 16: Hockey Stick Price Forecasts Are Wrong

- The market arbitrages Hockey Sticks.



How might we summarize our resource module? We will do so from two perspectives. The first is the flow of logic beginning with a postulated production schedule forward in time q(t) and ending with a price schedule forward in time p(t). The second is to summarize the data that are needed to execute the resource process. The logical sequence of operations employed in the resource model is the following:

STEP	VARIABLE CALCULATED	OPERATION REQUIRED
1	Guess q(t)	Make a guess at production schedule
2	Calculate Q(t)	Calculate cumulative reserve additions necessary to sustain production schedule q(t)
3	Calculate MC(t)	Read marginal cost off resource marginal cost curve
4	Calculate p(t)	Calculate price p(t) from marginal cost MC(t) to eliminate intertemporal arbitrage
5	Report p(t) to demand model	Deliver the price schedule p(t) to the demand portion of the model
6	Get demand d(t)	Read demand d(t) from demand curve given price p(t) from resource process
7	Compare d(t) and q(t)	Determine whether supply and demand quantities are the same. If so, quit. If not, substitute d(t) for q(t) and repeat

The data required to implement the resource model are the following:

1. Reserves to production ratio, allowing us to calculate the facility decline curve in Figure 6.

2. Initial year proved reserves, i.e., the middle gray shaded area in Figure 8. This represents the inventory that exists in the first model year, an inventory that will be produced to market during the model horizon.

3. The pair of resource supply curves in Figure 11, which characterizes aggregate resource deposition in each resource producing basin.

4. The discount rate used to make the "no intertemporal arbitrage" equation in Figure 14. This discount rate must represent the market-determined cost of capital that directs resource exploitation decisions in the energy business. It is NOT a hurdle rate; it is a market-observed and market-determined cost of capital that faces energy producers.

These four elements fully comprise the NARG resource base. Keep in mind, we need each of these four elements for every increment of resource for every producing region in North America. That is, there is a separate reserves to production ratio, initial year proved reserves, pair of resource supply curves, and discount rate specified for every hexagon in the NARG model. To reiterate, we deliver the data resource data assumed for the current version of NARG to our customers and licensees so that they review, evaluate, and customize it.

A final note on the resource process is related to the age-old question: What is the output of the resource model? Based on the discussion herein, the outputs of the resource model are simple

- The equilibrium price schedule p(t) forward in time over the model horizon.
- The equilibrium production schedule q(t) forward in time over the model horizon.
- The equilibrium schedule of reserve additions Q(t) forward in time over the model horizon.

In short, model outputs are price, production, and reserve additions over the forward horizon.

3. THE DEMAND SIDE OF THE NARG MODEL

Having completed our discussion of supply, this section turns to the question of representing natural gas demand on a regional basis throughout North America. This discussion begins with how we have regionalized the demand side and thereafter puts forth our demand modeling technology.

3.1. Regional Structure

The degree of regional disaggregation on the demand side of the NARG model is governed by the census regions of the United States. There is much historical precedent to disaggregating gas demand by census region, and there is much accepted data. Furthermore, climatic distinctions among census regions are usually deemed adequate to reflect different weather and usage patterns throughout the United States. Two of the standard census regions have been aggregated. We have aggregated the West North Central census region with the Mountain census region to create the single, aggregate West North Central-Mountain region. The Pacific region has been substantially disaggregated. In particular, we have broken California away from the Pacific Northwest. Within California, we have represented PG&E, SoCal Gas, San Diego Gas and Electric, and the EOR demand region. Within Canada, the model aggregates the thirteen provinces and territories into four aggregate demand regions. Western Canada contains all provinces to the west of and including Manitoba except for British Columbia, which is represented as a separate and distinct region. Eastern Canada includes all provinces east of the Ontario/Manitoba border excluding Ontario, which is represented as a separate and distinct region.

3.2. How Do We Represent Gas Demand?

Inside each of the fifteen demand regions, the NARG model is structured to take account of key demand-side phenomena including demand stimulation at lower prices, demand suppression at higher prices, and interfuel substitution between oil and gas. In order to represent such phenomena, it is necessary to recognize the segmented nature of gas demand. To properly characterize gas demand, it is important to distinguish at least two types of consumers in gas markets. The first, sometimes termed the "core market," is largely captive and exhibits relatively inelastic gas demand. The remainder, termed the "noncore market," is possessed of an immediate alternative such as fuel oil. As long as gas price remains below that of the alternative, noncore gas demand is relatively firm. If gas price rises to or above the price of the alternative, noncore gas demand will switch away from gas toward the alternative.

A simple network characterization of gas demand can be represented in network form as in Figure 17. In the figure, energy is assumed to flow along the links through the processes from bottom to top. The figure depicts two demand "tombstones," one for core demand and one for noncore demand. Each tombstone contains a demand curve, i.e., a price-quantity relationship that specifies the quantity of gas (or gas-equivalent) that will be consumed at every possible price. Notice in the diagram that noncore demand can be satisfied either by gas or by the substitute (assumed to be oil in the diagram). Core demand can be satisfied only by gas. Gas moves from wholesale at the lower left through a core distribution process to core customers, and it moves through a noncore distribution process to the burnertip point of competition at which it must compete against oil.

Economists characterize the simple core/noncore network representation of demand using a demand curve such as that in Figure 18. The figure delineates the size of the core and noncore markets and shows the assumed oil price. In the figure, gas demand is shown to be equal to core demand for gas prices above the oil price and to be equal to core plus noncore demand for gas prices at or below the oil price.

In reality, core gas demand is somewhat elastic, and noncore gas demand is highly segmented, each segment facing a slightly different substitute price. Therefore, in reality, the demand graph in Figure 18 should be "rounded off" as shown in Figure 19. The demand curve in Figure 19, very characteristic of gas demand, has an inelastic portion at high gas prices, a very elastic "shoulder" for gas prices in the vicinity of oil price, and an inelastic portion at low gas prices. Results generated by the NARG model rely heavily on the distinctive pattern of gas demand in Figure 19.

Figure 17: Network Representation of Gas Demand

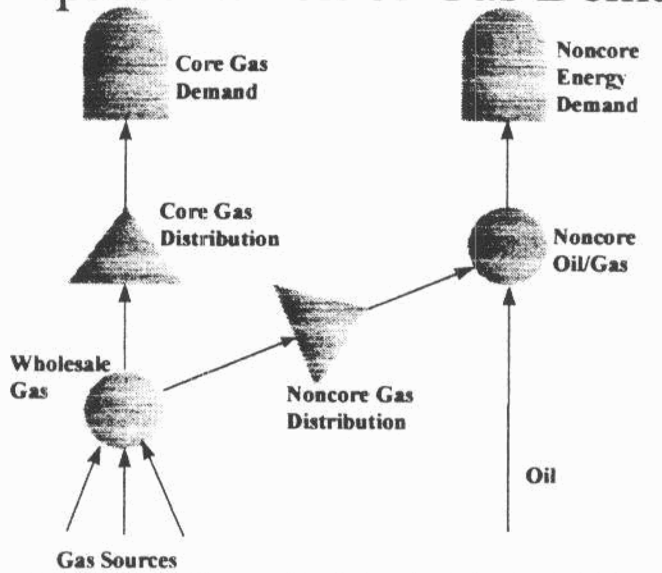


Figure 18: Segmented Representation of Gas Demand

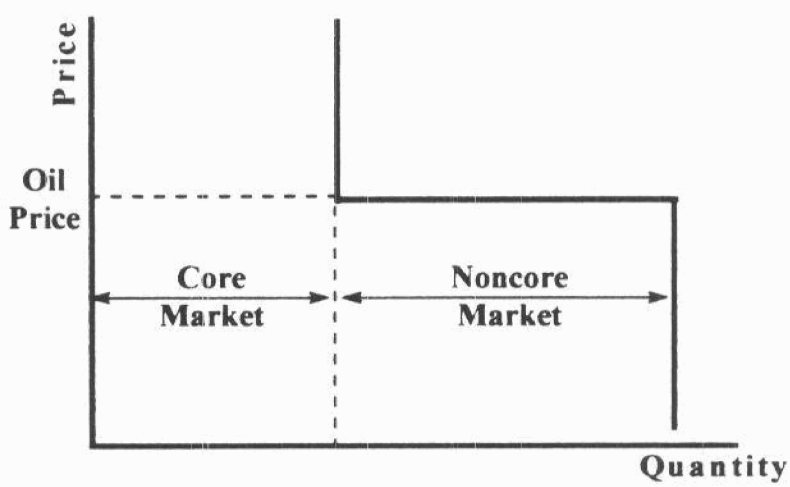
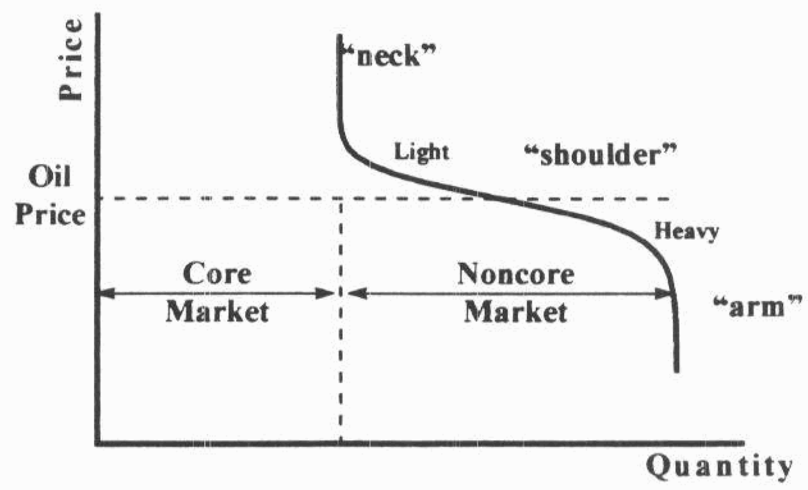


Figure 19. Wholesale Gas Demand Curve is Rounded Off



It is interesting to note that the width of the shoulder in Figure 19 has diminished during the past two decades as the industrial sector of the United States has emigrated or shrunk. What used to be a relatively broad shoulder in our formerly industrialized economy has now become a much narrower shoulder in our service economy. Such narrowing has vital consequences for the relationship between the market clearing price of gas relative to the price of oil, implying a much weaker degree of coupling between the two than was true historically.

Every demand region in the model contains the network structure in Figure 17 and therefore the demand curve structure in Figure 19. Thus, every demand region in the model represents demand stimulation/repression at different prices as well as substitution at the exogenously given price of the substitute. The data needed for the demand side of the NARG model is the demand curve in Figure 19 itself. In order to construct the demand curve in Figure 19, we need its constituent elements, which are best seen by referring to the "caricature" of demand illustrated in Figure 18:

- a demand curve (price versus quantity versus time) for noncore use. We need to place a demand curve into the core demand tombstone. Most often, we simply use a projection forward in time of noncore demand and assume that overall noncore demand is inelastic at that level.

- a demand curve (price versus quantity versus time) for core use. We need to place a demand curve into the noncore demand tombstone. Most often, we simply us a projection forward in time of core demand and assume that core demand is inelastic at that level.

- an estimate of noncore distribution cost, which is needed in order to properly represent burnertip gas pr ices relative to oil prices.

- a projected time schedule of the price of oil against which gas must compete.

- an estimate of core distribution cost.

- lag parameters that simulate adjustments in capital stock necessary for gas/oil substitution.

In particular, we need a projection of core and noncore market size, the price of oil, and the core and noncore distribution costs. We deliver to our NARG customers comprehensive analysis of how these data are conceived and assembled for NARG.

The two demand curves within the demand tombstones for each demand region have been inferred from GRI's 1996 Baseline forecast. In particular, we have divided GRI's sectoral gas demand projections into a core (nonsubstitutable) and a noncore (substitutable) component. We should emphasize that undue attention on demand is probably not warranted. In light of the bullish and escalating projections of natural gas supply in the Gulf Coast and elsewhere, gas supply has increased in importance relative to gas demand. This is not to say that demand issues are unimportant. It is to say, however, that gas demand is less important than gas supply.

3.3. The "Answer" Given By The Model – Market Clearing Prices And Quantities Flowing At Those Prices

Equilibrium models such as the NARG Model plot gas supply and demand curves on the same graph and seek to find the intersection. The intersection specifies a market-clearing price at which the market will tend to operate. Indeed, there are economic forces that drive the market toward that price. The intersection also specifies a quantity that will be traded in the market at the market-clearing price. Using the characteristic pattern of demand in Figure 19, we can make some rather profound and far-reaching conclusions about the nature of the regional supply-demand equilibrium. In particular, we see that there are three possible supply-demand cases that can occur, each of which has distinctive and important properties:

Case 1: The gas supply curve intersects the demand curve above the shoulder, as shown in Figure 20. The market clearing price (denoted p*) of gas is seen to exceed the price of oil. Furthermore, in this ease,

- gas supplies will be "tight."

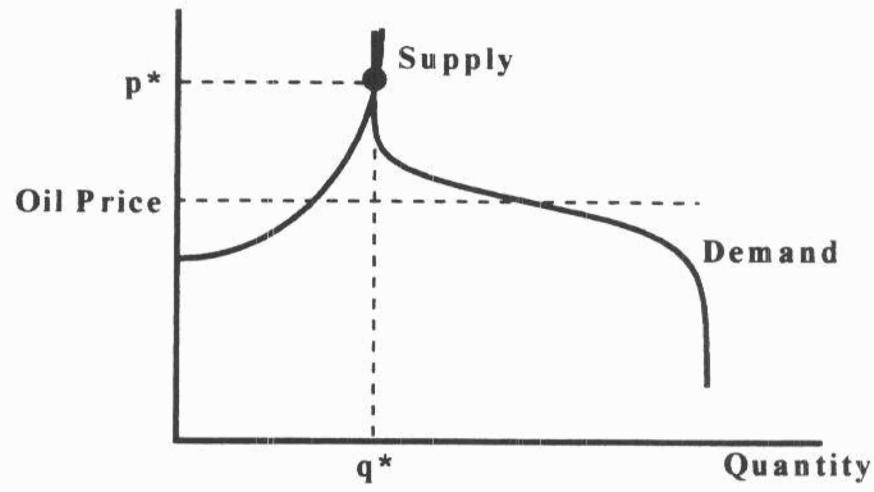
- noncore users will be driven to the substitute.

- a core user will be the marginal gas user.

- core users will be obliged to buy gas at a premium over oil.

Case 1 will occur if oil prices are low (that is, low shoulder in the demand curve), gas supplies are tight (that is, high gas supply curve), or gas demand is high.

Figure 20: Case 1--Gas Price Clears on "Neck;" Gas Price Above Oil Price

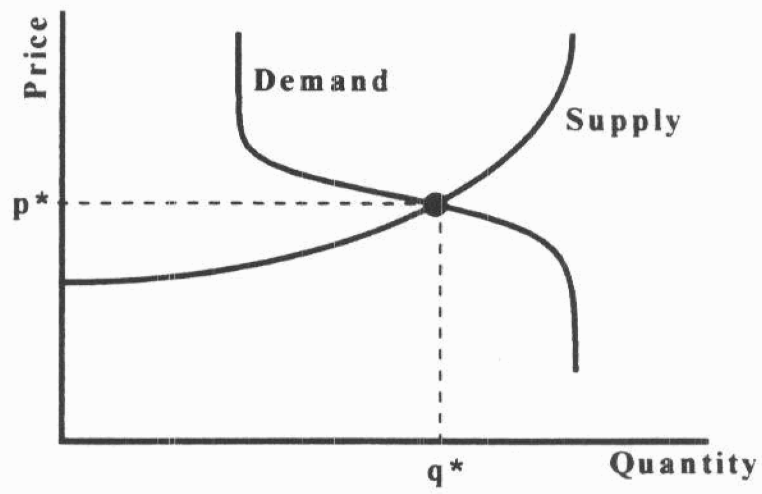


Case 2: The gas supply curve intersects the demand curve along the shoulder as shown in Figure 21. Notice that

- the market clearing price of gas will be equal to the price of oil.
- some noncore customers will use gas, while some will utilize the substitute.

This is the case that so many people implicitly assume ALWAYS applies to gas. Many people lazily and incorrectly assume that oil and gas prices must equilibrate. As we have seen in Case 1, this is not necessarily true. It is quite coincidental when Case 2 rather than Case 1 occurs.

Figure 21: Case 2--Market Clears on "Shoulder;"--
Gas and Oil Price Equal

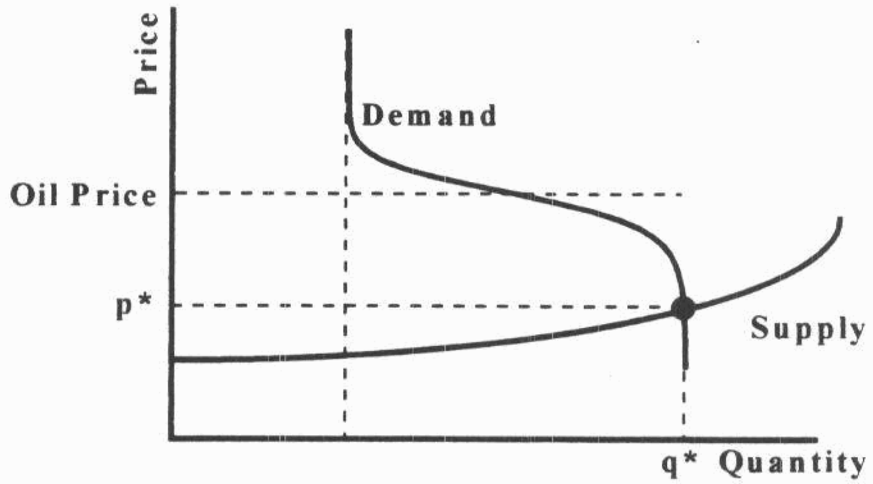


<u>Case 3: The gas supply curve intersects the demand curve below the shoulder as shown in Figure 22</u>. The market-clearing price of gas is seen to be below that of oil. In this case

- gas supplies will be "abundant."
- noncore users will be attracted to gas.
- a noncore customer will be the marginal source
- both core and noncore users will buy gas at a discount relative to oil.

Case 3 will occur if oil prices are high (that is, high shoulder in the demand curve), gas supplies are abundant (that is, low gas supply curve), or gas demand is low.

Figure 22: Case 3--Gas Market Clears on "Arm;" Gas Price below Oil Price



A conspicuous observation in Figures 20 through 22 is that in general **THE MARKET CLEARING PRICE OF GAS WILL NOT BE EQUAL TO THE PRICE OF OIL**. Gas and oil prices will not be at parity. Indeed, only if the supply curve intersects the demand curve precisely through the shoulder, that is, on the flat portion of the demand curve as in Figure 20, will the price of gas be equal to the price of oil. As we have already argued, the shoulder has narrowed substantially over the past two decades, rendering it decreasingly likely that Case 2 will occur.

Different supply-demand scenarios will in general correspond to one of the three cases discussed earlier. For example, a base case scenario might correspond to Case 3 (gas supply intersects demand below the shoulder so that gas price is below oil price). However, a low resource base scenario, all else equal, would shift the supply curve upward and to the left so that in fact Case 1 rather than Case 3 pertains; gas supply would intersect above the shoulder.

Comparison of high versus low gas resource base scenarios (and in fact almost any pair of scenarios involving different supply curves and/or different demand curves) leads to a critical conclusion:

THE MARKET CLEARING PRICE OF GAS WILL BE DIFFERENT BETWEEN DIFFERENT DEMAND, SUPPLY, AND OIL PRICE SCENARIOS.

This finding has profound ramifications:

- In general, the customary assumption of oil/gas price parity at the burnertip is wrong. To assume such parity is to get the wrong answer both for burnertip market clearing price and quantity consumed.

- In general, the customary practice of equating gas wellhead prices to oil price "netbacks"

From the burnertip through the pipeline system is wrong. To calculate oil price netbacks is to get the wrong answer both for wellhead market clearing price and quantity produced.

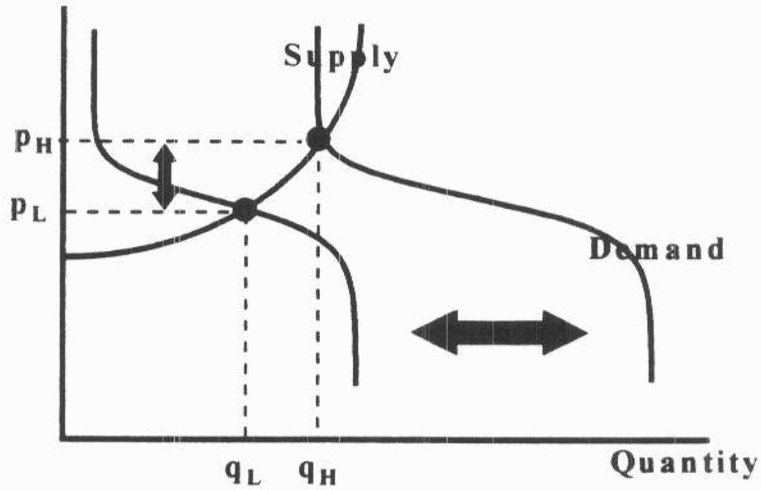
- Oil and gas prices are likely to move farther away from parity as the noncore market decreases relative to the core market. Conversely, the larger the noncore market, the nearer to parity oil and gas prices are likely to be.

We conjecture that the customary (and increasingly incorrect) procedure of netting back burnertip-equivalent oil prices to the wellhead originated in the days when the United States had a large industrial sector, that is, a large noncore market relative to the core market. Although not technically correct even in those days, oil price netbacks were serendipitous; there existed a broad noncore "shoulder" in the economy that virtually ensured that Case 2 would apply. However, now that the industrial sector has declined in size relative to the residential and commercial core sectors, Case 1 or Case 3 is much more likely to pertain today. Oil price netbacks are inevitably destined to be wrong today and in the future.

The alternative to assuming oil/gas price parity at the burnertip and calculating netbacks to the wellhead is to enumerate all present and potential future supply regions using supply curves, all present and potential future demand regions using demand curves with noncore shoulders, and all present and potential future transportation links connecting supply regions to demand regions and thereafter to explicitly compute the prices and quantities at which all supply and demand curves simultaneously intersect. This is precisely what the NARG model does.

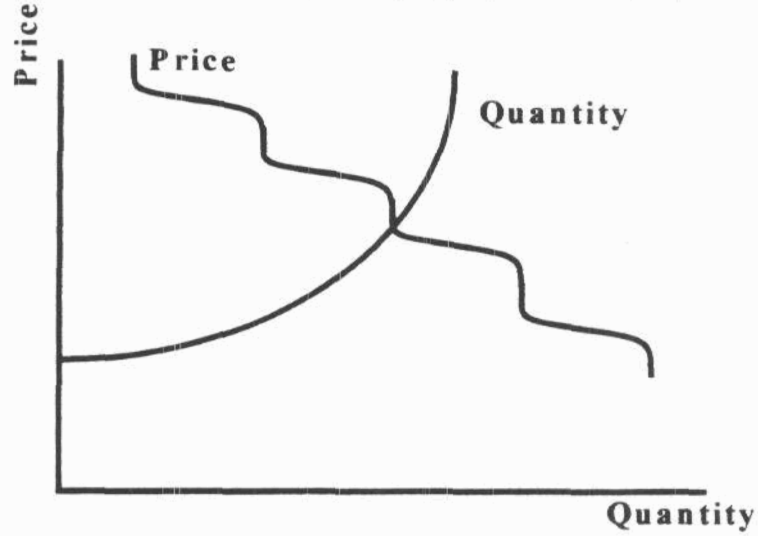
We should also point out that the Case 1-Case 2-Case 3 configurations change during the year as well. In the winter, we often see a Case 1 world in the Northeast and Midwest. Gas demand accelerates because of the cold weather, while gas supply stays constant because the pipeline supply system is fixed. In the summer, we see a Case 3 world persisting in the Gulf of Mexico. There are no heating demands, meaning aggregate demand is small and implying that the demand curve is pressed toward the left axis. During the course of the year, the demand curve oscillates from left to right, while the supply curve remains relatively fixed. As shown in Figure 23, this means that the market clearing price during the year moves upward and downward in a relatively predictable fashion. While the longer term version of the NARG model considers only average annual demand, the NARG model contains the logic to make the seasonal calculation illustrated in Figure 23.

Figure 23: Gas Demand "Wiggles" During the Year, Taking Price with It



Finally, many have argued that the simple oil-for-gas substitutability model that led to the "neck-shoulder-arm" demand curve pattern in Figure 19 is oversimplified. In particular, gas does not substitute for oil at a single oil price. Rather there are many different types and qualities of liquid fuels (No. 1 fuel oil, No. 2 fuel oil, Low sulfur No. 6 fuel oil, High sulfur No. 6 fuel oil, etc.), and there are a number of different segments that consume either those fuels or consume gas (e.g., electric generation using steam turbines, electric generation using combustion turbines, industrial process head, industrial boilers). Each segment and each fuel represent a different regime of oil-for-gas substitution, and the model needs to represent some or all of these segments. Such demand side disaggregation is quite easy to accomplish in NARG by simply expanding the network diagram in Figure 17 to consider additional segments and additional substitution commodities. In doing so, one would develop a demand curve that looks not like a "neck-shoulder-arm" pattern in Figure 19 but rather has a series of substitution zones as shown in Figure 24. This subsegmented representation of demand might or might not be important in certain applications. If it is, it can be easily accommodated by expanding the segmented network representation in Figure 17 to create the demand curve in Figure 24.

Figure 24: Demand Curve May Be Sub-Segmented



4. THE PIPELINE COMPONENT OF THE NARG MODEL

Turning from the supply and demand elements of the NARG model, we note that the degree of pipeline detail must be consistent with the degree of supply and demand detail elsewhere in the model as discussed earlier in this section. In particular, while we could enumerate and distinguish every individual pipeline in the United States, we have instead sought commonalities among supply regions, pipelines, and demand regions that allow aggregation. In fact, rather than representing individual pipelines, we have instead represented pipeline corridors from our supply regions to our demand regions. Indeed, these corridors are quite explicitly defined by the characterization of our supply and demand regions and by the configuration of the United States and Canadian pipelines systems that exist today.

Embracing the notion of pipeline corridors, we begin by considering the network of existing pipelines. Each of the existing pipeline corridors begins in a given supply region, extends perhaps through intermediate supply and demand regions, and terminates in a demand region. The network of existing pipeline corridors interconnects all currently producing regions with all currently consuming regions. We have given a great deal of attention and effort to representing the existing pipeline system, including capacity and cost. To our NARG customers, we deliver the pipeline data for existing pipeline routes throughout North America used in the NARG model.

Because the NARG model predicts the evolution of the North American gas system over the next 40 years, we cannot stop with existing pipeline corridors. Rather, it is necessary to enumerate all prospective future pipelines that might be built in the next 40 years. These prospective future pipelines connect new producing regions (or subregions) with various demand regions, and they connect Canada and Mexico to the United States. NARG enumerates the pipelines that can be prospectively built within the time horizon of the model. We will discuss shortly how we have characterized prospective new pipelines and pipeline expansions.

The prospective new pipelines in NARG are just that--prospective. They will be built only if they become economic. They will be built only if supplies at the upstream end, marked up to account for the cost of the new pipelines, constitute the most competitive source at the downstream end. We will discuss nuances of capacity expansion below (e.g., looping or compression augmentation for existing capacity). In the model, looping is considered as an option for all existing capacity as well as for the existing links of the new corridors.

Because the linkage between Canada and the United States is potentially so important, we have distinguished in some detail the pipelines in Canada that directly or indirectly lead to the lower 48 United States. These Canadian pipelines, should they be built, provide a route for hundreds of Tcf into United States markets should those Tcf become economically competitive.

In reviewing the Canadian export situation in the NARG model, the prospective routes from North Alaska through Alberta and ultimately to the United States and from Northern Canada (MacKenzie and Beaufort Sea) through Alberta and ultimately to the United States must be represented. The former pipeline represents the upstream leg of the ANGTS system while the latter pipeline represents the pipeline that will have to be built in order to exploit Canadian Arctic gas (the Polar project and prospective expansions). Competition between these two pipelines will in part determine the competitive viability of the various Arctic supply regions and of the pipeline projects proposed to serve them.

Once we have enumerated all the existing pipelines and pipeline corridors, we must represent the cost and the capacity of those corridors. How do we think about the supply curve for pipeline service? The answer is rather clear. If we knew the maximum annual throughput for a pipe and we knew the forward cost to market borne by the owner of that pipe from its origin to its destination, we could make a plot of the supply curve for that pipe as in Figure 25. The height of the supply curve is the forward cost to market, i.e., the variable cost the owner of the pipeline would have to bear in order to provide service. The width of the supply curve is the capacity, i.e., the annual throughput, of the pipe. The width represents the physical size of the facility, and the height represents the forward cost to continue to provide service. In the most fundamental sense, the supply curve for transportation service in Figure 25 is the economic representation of the cost and capacity of the pipe in question. It is completely devoid of the regulatory baggage of the past. There is no embedded or historical cost in the curve; there is only forward cost to market. There is no guarantee that the owner of the pipeline facility can or will recover any embedded historical cost; there is only the forward cost the owner has to bear in order to continue to provide the transportation service.

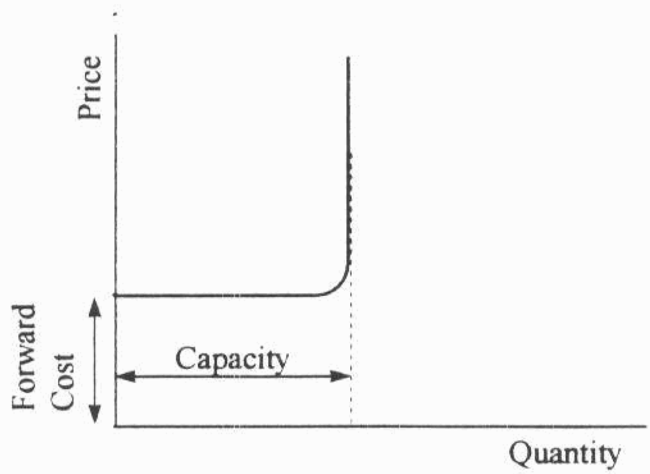
For every existing pipeline corridor in the NARG model, we have created a supply curve for pipeline service of the form in Figure 25. The data necessary to characterize such pipeline service includes

- The forward cost to market, i.e., the height of the pipeline supply curve. We have used pipeline costs specified by our customers and contractors over the years to characterize the cost along each existing pipeline link.

- The capacity of the pipe, i.e., the width of the pipeline supply curve. We have used estimates of capacity, i.e., maximum annual throughout, specified by our customers and contractors over the years to characterize the annual capacity of each existing pipeline link in the model.

The pipeline database delivered to our NARG customers contains such estimates for every pipeline link the North America as estimated for use in NARG.

Figure 25: Supply Curve for Existing Pipeline Service

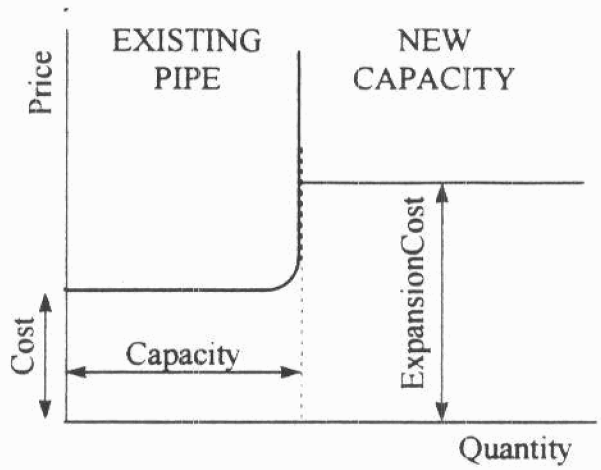


There are several generic types of pipeline capacity expansion that can be implemented:

- expansion of capacity of a given pipeline by such actions as looping or increasing pressure.
- expansion of capacity along a given corridor by adding a new pipeline.
- Addition of an entirely new, greenfield increment of pipe

We represent each of these types of capacity addition in the same fashion. We input an estimate of the full forward cost to market—capital cost plus operating cost—and graft it onto the right hand side of the existing capacity curve in Figure 25. Thus, the logic for adding new pipeline capacity within NARG is represented graphically as shown in Figure 26. Notice that once the market hits the full capital and operating cost of new capacity, such new capacity can enter without bound. The aggregate supply curve for existing plus new pipeline capacity in Figure 26 is estimated along every pipeline corridor, existing or prospective, in the NARG model. Therefore, in addition to the foregoing cost and capacity data for new pipes, we need an estimate of the full forward cost of expansion for new transportation capacity along that corridor.

Figure 26: Supply Curve for Pipeline Service



5. CONCLUDING REMARKS

NARG has become the industry-leading model of North American natural gas price and basis forecasting, asset valuation, pipeline addition, investment, abandonment, and long run marketing. It has outlasted most or all of its competition over the past 20 years. In the past year, we have been working assiduously to complement the long run annual structure of NARG with a short term (36 month) monthly model that can guide short term price and basis forecasting and can guide a broad range of trading and marketing decisions. The short run model, which has not yet been fully documented, will be ready for commercial use in the third quarter of 1997 and will be offered and licensed under the same terms as NARG.