

REVIEW OF ELECTRIC UTILITY 1999 TEN-YEAR SITE PLANS

VOLUME 1: REVIEW AND ANALYSIS

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LIST OF FIGURES	3
LIST OF TABLES	4
INTRODUCTION	5
PURPOSE	5
PUBLIC INVOLVEMENT	6
EXECUTIVE SUMMARY	7
FLORIDA RELIABILITY COORDINATING COUNCIL	8
SUITABILITY AND CRITICAL CONCERNS	8
RISKS AFFECTING PLANS	10
SUMMARY OF RESOURCE ADDITIONS	12
REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE ..	16
INTEGRATED RESOURCE PLANNING	16
LOAD FORECAST	18
EVALUATION OF LOAD FORECASTING METHODOLOGY	18
EVALUATION OF HISTORICAL FORECAST ACCURACY	19
DEMAND-SIDE MANAGEMENT	22
ENERGY CONSERVATION COST RECOVERY CLAUSE	24
CHANGES TO FEECA	25
DEMAND-SIDE MANAGEMENT GOALS	25
STATE COMPREHENSIVE PLAN	25
RELIABILITY REQUIREMENTS	27
RELIABILITY CRITERIA	27
POTENTIAL IMPACT OF MERCHANT PLANTS ON RELIABILITY	30
FUEL FORECAST	31
COAL	31
PETROLEUM	32
NATURAL GAS	34
NUCLEAR	34
RENEWABLES	35
GENERATION SELECTION	36
GENERATION SELECTION PROCESS	36
FLORIDA'S GENERATION MIX	37
CRITICAL CONCERNS	40
FRCC 1999 RESERVE MARGIN ANALYSIS	40
AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES	42
RESERVE MARGIN INVESTIGATION (DOCKET NO. 981890-EI)	43

RISKS AFFECTING PLANS	44
COMPETITION	44
NATURAL GAS AVAILABILITY	44
DECLINING COST-EFFECTIVENESS OF DEMAND-SIDE MANAGEMENT	
PROGRAMS	46
ENVIRONMENTAL COMPLIANCE	47
REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES	49
FLORIDA POWER CORPORATION (FPC)	49
FLORIDA POWER & LIGHT COMPANY (FPL)	52
GULF POWER COMPANY (Gulf)	56
TAMPA ELECTRIC COMPANY (TECO)	59
FLORIDA MUNICIPAL POWER AGENCY (FMPA)	62
GAINESVILLE REGIONAL UTILITIES (GRU)	65
JACKSONVILLE ELECTRIC AUTHORITY (JEA)	68
KISSIMMEE UTILITY AUTHORITY (KUA)	71
CITY OF LAKELAND (LAK)	73
ORLANDO UTILITIES COMMISSION (OUC)	75
CITY OF TALLAHASSEE (TAL)	77
SEMINOLE ELECTRIC COOPERATIVE (SEC)	79
DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY	
(Duke New Smyrna)	83
APPENDIX	84
STATUS OF NEED DETERMINATIONS / SITE CERTIFICATIONS ..	84
PLANNED, UNCERTIFIED GENERATING UNITS	85
PUBLIC WORKSHOP COMMENTS	85

LIST OF FIGURES

FIGURE 1	RESERVE MARGIN COMPONENTS - 1999	9
FIGURE 2	UTILITY RESOURCE ADDITIONS IN THE NEXT TEN YEARS	14
FIGURE 3	UTILITY RESOURCE MIX BY PLANT TYPE -- PRESENT AND FUTURE	14
FIGURE 4	PROPOSED MAJOR TRANSMISSION LINES	15
FIGURE 5	ANNUAL NET ENERGY FOR LOAD STATE OF FLORIDA -- HISTORY & FORECAST	20
FIGURE 6	SUMMER FIRM PEAK DEMAND STATE OF FLORIDA -- HISTORY & FORECAST	20
FIGURE 7	WINTER FIRM PEAK DEMAND STATE OF FLORIDA -- HISTORY & FORECAST	20
FIGURE 8	ESTIMATED IMPACT OF DSM ON NET ENERGY FOR LOAD STATE OF FLORIDA -- HISTORY & FORECAST	22
FIGURE 9	ESTIMATED IMPACT OF DSM ON SUMMER PEAK DEMAND STATE OF FLORIDA -- HISTORY & FORECAST	23
FIGURE 10	ESTIMATED IMPACT OF DSM ON WINTER PEAK DEMAND STATE OF FLORIDA -- HISTORY & FORECAST	23
FIGURE 11	CONSERVATION EXPENSES RECOVERED THROUGH THE ENERGY CONSERVATION COST RECOVERY CLAUSE	24
FIGURE 12	ENERGY CONSUMPTION PER RESIDENTIAL CUSTOMER STATE OF FLORIDA -- HISTORY & FORECAST	26

FIGURE 13	UTILITY FORECASTED RESERVE MARGIN -- STATE OF FLORIDA	29
FIGURE 14	UTILITY FORECASTED RESERVE MARGIN -- PENINSULAR FLORIDA	29
FIGURE 15	ENERGY GENERATION BY FUEL TYPE -- HISTORY & FORECAST	38
FIGURE 16	RESERVE MARGIN COMPONENTS - 1999	42
FIGURE 17	NATURAL GAS CONSUMPTION BY END-USER -- 1999	45

LIST OF TABLES

TABLE 1	RESOURCE ADDITIONS / (REDUCTIONS) IN THE NEXT TEN YEARS	13
TABLE 2	TOTAL RETAIL ENERGY SALES -- HISTORICAL FORECAST ACCURACY	19
TABLE 3	RELIABILITY CRITERIA FOR REPORTING UTILITIES	27
TABLE 4	PLANNED MERCHANT PLANT ADDITIONS	30
TABLE 5	FUEL PRICE FORECAST -- AVERAGE ANNUAL GROWTH RATE (1999 - 2008)	32
TABLE 6	NEXT UTILITY-PLANNED GENERATING UNIT ADDITION (CERTIFICATION NOT REQUIRED OR NOT YET RECEIVED)	37
TABLE 7	BASE CASE COMPOSITE EMISSION RATES FOR INVESTOR-OWNED ELECTRIC UTILITIES	47

INTRODUCTION

Section 186.801, Florida Statutes, requires generating electric utilities to submit a Ten-Year Site Plan (*Plan*) to the Florida Public Service Commission (Commission) at least once every two years. Each *Plan* contains projections of the utility's electric power needs for the next ten years and the general location of any proposed power plant sites and major transmission facilities. The *Plan's* purpose is to ensure early notification of these potential sites, and is not intended to be a binding plan of action on electric utilities. The Commission is responsible for making a preliminary study of each utility's *Plan* and must determine whether it is "*suitable*" or "*unsuitable*."

To fulfill the statutory requirement contained in Section 186.801, Florida Statutes, in 1997 the Commission adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code. Rule 25-22.071, Florida Administrative Code, requires the *Plan* to be filed annually, by April 1 of each year. However, this rule exempts utilities whose existing generating capacity is less than 250 megawatts (MW) unless they plan to build a new generating unit larger than 75 MW.

Section 377.703(e), Florida Statutes, requires the Commission to analyze and provide electricity and natural gas forecasts for analysis by the Florida Department of Community Affairs (DCA). This statutory requirement is fulfilled by the *Review of 1999 Ten-Year Site Plans*.

The Commission's *Review of 1999 Ten-Year Site Plans* consists of two volumes. Volume 1 contains the Commission's review and analysis of the *Plans*. Volume 2 contains comments from state, local, and regional government agencies as well as from other interested parties. Both volumes of the Commission's review are forwarded to the Florida Department of Environmental Protection (DEP).

The Commission's classification of a utility's *Plan* as "*suitable*" or "*unsuitable*" has no binding effect on the utility. Such a classification does not constitute a determination or finding in subsequent docketed matters before the Commission. If a utility's *Plan* raises a concern that requires Commission action, such action is formally undertaken after a public hearing.

By its very nature, planning is a dynamic process. Many factors that influence utility plans are subject to change. Variations in weather, economic conditions, and population growth can impact the results of a load forecast. Improvements in technology are constantly monitored, and changes in governing regulations and laws, as well as shifts in public policy, may impact utility plans. It is the responsibility of each utility to develop and maintain its plans based on the most up-to-date information available.

PURPOSE -- What is the purpose of this document?

- to review, and classify as "*suitable*" or "*unsuitable*", the *Plans* in accordance with Section 186.801, Florida Statutes;
- to analyze and provide electricity and natural gas forecasts to DCA in accordance with Section 377.703(3)e, Florida Statutes; and
- to review and highlight critical concerns with electric utility planning on both an individual utility and a Peninsular Florida basis.

INTRODUCTION

PUBLIC INVOLVEMENT

Pursuant to the State of Florida's policy of "government in the sunshine," all Commission workshops and hearings are open to the public. Members of the public may directly participate in any of the Commission's proceedings. The Commission held a public workshop on September 27, 1999 to solicit public comments on the *Plans*. The Commission received written comments from the Legal Environmental Assistance Foundation (LEAF). State agencies, regional planning councils, and water management districts also provided written comments on the *Plans*. These comments are summarized in the individual utility reviews contained in this document. Complete comments are contained in Volume 2.

To submit comments on this document or request additional information on utility planning issues, please write to:

*Director, Division of Electric and Gas
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850.*

EXECUTIVE SUMMARY

Pursuant to Section 186.801, Florida Statutes, a utility's Ten-Year Site Plan (*Plan*) is a preliminary study for planning purposes. The Commission's classification of a *Plan* as "suitable" or "unsuitable" has no binding effect on utilities, and such a classification does not constitute a determination or finding in subsequent docketed matters before the Commission. Because the *Plans* contain tentative data, there may not be sufficient information to allow regional planning councils, water management districts, and other review agencies to fully assess site-specific issues pertaining to their jurisdiction. When a utility files for certification under the Power Plant Siting Act or Transmission Line Siting Act, more detailed data are provided based on in-depth environmental assessments. This fact underscores the purpose of the *Plan* as an early notification process rather than a binding plan of action.

The following briefly summarizes how the Commission has complied with the requirements of Section 186.801, Florida Statutes.

REQUIREMENT

Review the need for electrical power in the area to be served

Review possible alternatives to the proposed *Plan*

Review anticipated environmental impact of proposed power plant sites

Consider views of local and state agencies regarding water and growth management issues

Determine consistency of *Plan* with the State Comprehensive Plan

Review *Plan* for information on energy availability and consumption

ACTION

Reviewed load forecasts, demand-side management (DSM) assumptions, and reliability criteria.

Reviewed DSM assumptions, fuel forecasts, and generation alternatives modeled to arrive at the projected expansion plan.

Since the Commission does not have expertise in this area, it requested comments from DEP and water management districts regarding environmental impacts and compliance. Comments are summarized in the individual utility sections of this report. Complete comments contained in Volume 2.

Requested comments from affected agencies. Comments are summarized in the individual utility sections of this report. Complete comments contained in Volume 2.

Evaluated energy-related aspects of the Comprehensive Plan. Reviewed comments provided by the Department of Community Affairs and from regional and local planning agencies on growth management and Comprehensive Plan issues. These comments are summarized in the individual utility sections of this report. Complete comments contained in Volume 2.

Reviewed load forecast data and methodologies used to arrive at load and energy forecasts.

EXECUTIVE SUMMARY

FLORIDA RELIABILITY COORDINATING COUNCIL

The Florida Reliability Coordinating Council (FRCC) was formed in October, 1996 to ensure electric reliability in Peninsular Florida. Prior to this time, Peninsular Florida was a subregion of the Southeastern Electric Reliability Council (SERC) region. Both the FRCC and SERC are separate regions of the North American Electric Reliability Council (NERC).

The FRCC has developed a formal reliability assessment process to annually review and assess issues that currently exist or have the potential for developing. FRCC member utilities are expected to exchange information in planning and operating areas related to the reliability of the bulk power supply, and review activities within the FRCC region relating to reliability. The FRCC has a reliability assessment group to determine which planning and operating studies will be performed during each year to address these issues.

In 1999, the FRCC published two documents which address the reliability of Peninsular Florida's electric grid. One such document, the *1999 Regional Load and Resource Plan*, contains aggregate data on demand and energy, capacity and reserves, and proposed new unit additions for the FRCC region (Peninsular Florida) as well as statewide. The second FRCC document, the *1999 Reserve Margin Analysis*, is an aggregate study of the existing and future reliability of Peninsular Florida's electric grid. The Commission used both FRCC documents in its review of the individual utility *Plan* filings.

SUITABILITY AND CRITICAL CONCERNS

The Commission has reviewed *Plans* filed by thirteen (13) reporting utilities in 1999. The Commission has determined that these *Plans* are *suitable* for planning purposes. However, the Commission has concerns with reliability issues resulting from the *Plans*. These concerns are discussed below.

FRCC'S 1999 RESERVE MARGIN ANALYSIS

Published in August, 1999, the *1999 Reserve Margin Analysis* is a reliability study of Peninsular Florida's electric grid covering the ten-year planning horizon. Under base case planning assumptions, the FRCC concluded that Peninsular Florida's utilities plan to meet or exceed a minimum 15% winter and summer reserve margin criterion and not exceed a maximum 0.1 days per year loss of load probability (LOLP) criterion.

As discussed starting on page 40, the Commission has numerous concerns with the *1999 Reserve Margin Analysis*. The primary concern is that the FRCC has not fully tested the viability of its 15% reserve margin criterion for Peninsular Florida and, thus, the criterion may be too low to ensure a reliable electric grid. Other related concerns are as follows:

- The analysis results in extremely low LOLP results driven by high forecasted unit availabilities.
- The 0.1 LOLP value appears to translate to an unrealistically low reserve margin level.

EXECUTIVE SUMMARY

- The FRCC's 15% planning reserve margin criterion can have a substantial adverse impact on operating reserves.
- A seasonal winter and summer peak reserve margin does not account for reliability concerns during off-peak periods of the year.

The Commission's concern with the viability of FRCC's 15% reserve margin criterion is mitigated in part by the expected addition of approximately 3,100 MW of new merchant plant capacity over the next five years. All proposed new merchant plant facilities are listed in Table 4 on page 30. Florida's utilities should purchase power from merchant plants if such a purchase is the least-cost alternative available. Thus, during periods of capacity shortages, merchant plants may enhance the reliability of Peninsular Florida's grid.

The Commission is also concerned that the level of winter reserves may be negatively affected by extreme low winter temperatures. This concern dates back to events occurring in December, 1989 where an estimated 4,700 MW of Peninsular Florida's load was not served due to unusually high demand coupled with low generating unit availability. Individual utilities attempt to minimize unit maintenance during peak periods. However, if the FRCC does not closely monitor and coordinate unit maintenance for Peninsular Florida's utilities, a repeat of the December, 1989 weather conditions could result in an even greater amount of unserved load. This concern is mitigated in part by the merchant plant capacity additions proposed over the next five years.

AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

For some Peninsular Florida utilities, reserve margins are comprised largely of non-firm resources such as load management and interruptible service. This appears to be primarily a near-term concern, because Peninsular Florida's utilities as a whole have forecasted a slight decrease in reliance on non-firm resources over the ten-year planning horizon. As shown in Figure 1, non-firm load makes up 70% of Peninsular Florida's 1999/2000 winter reserves and 47.5% of 1999 summer reserves. These values are slightly lower than last year's forecast, indicating that utilities are planning in future years to rely increasingly more on generation than on non-firm load.

FPC and TECO are the utilities most impacted by their reliance on non-firm load for reserves. FPC forecasts non-firm load to make up 89% winter (69% summer) of its 1999 reserve margin, while TECO forecasts 71% winter (75% summer) reliance on non-firm load for its 1999 reserve margin. In

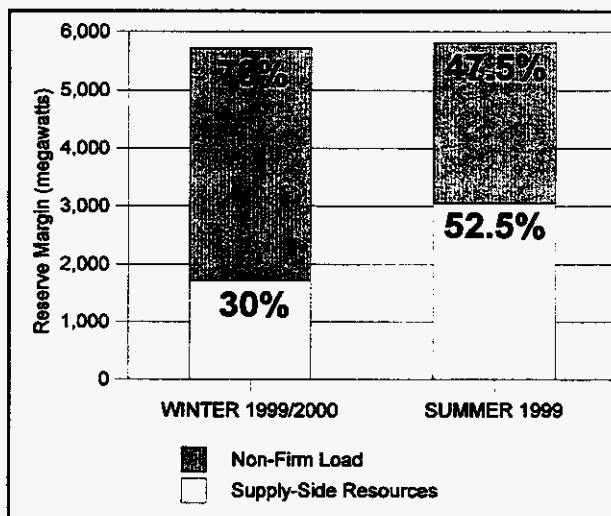


FIGURE 1
RESERVE MARGIN COMPONENTS - 1999

EXECUTIVE SUMMARY

1998, FPC lost nearly 70,000 load management program participants (8% of total) due to the utility's use of load control measures during extremely hot weather in the summer of 1998. Because residential customers can give the utility less than 30-days notice to leave the program, customer flight from load management can cause sudden near-term reliability problems. Both FPC and TECO have had complaints from large, non-firm customers regarding the increased frequency and duration of service interruptions.

RESERVE MARGIN INVESTIGATION (DOCKET NO. 981890-EI)

The Commission has had an ongoing concern with the level of Peninsular Florida's reserve margins and with the amount of non-firm resources which currently make up these reserve margins. In response to these concerns, on December 17, 1998 the Commission opened Docket No. 981890-EI to investigate the adequacy of reserve margins for Peninsular Florida's utilities. Gulf was not included in the Commission's investigation because Gulf's service territory is not contained in Peninsular Florida.

Many of Peninsular Florida's utilities filed direct testimony in Docket No. 981890-EI supporting the use of a 15% reserve margin planning criterion. As part of the Commission's investigation, the staff performed a vast amount of discovery on the FRCC and each of Peninsular Florida's generating utilities. As a result of the discovery, the Commission staff filed testimony on August 31, 1999 which criticized the continued use of a 15% planning reserve margin criterion for Peninsular Florida utilities. Many utilities filed rebuttal testimony which continued to support the use of a 15% reserve margin planning criterion.

On October 28, 1999, the three investor-owned utilities which were part of the investigation – FPC, FPL, and TECO – filed a proposed agreement in this docket. Pursuant to this agreement, FPC, FPL, and TECO agreed to adopt a 20% reserve margin planning criterion starting in the summer of 2004. The agreement also calls for the Commission to hold workshops to address the appropriate level of non-firm load for Peninsular Florida's utilities, and to address the use of distributed generation as a resource. Based on this year's *Plans*, TECO is the only investor-owned utility that does not meet the 20% criterion in 2004. Since FPC, FPL, and TECO combined make up approximately 75% of Peninsular Florida's generation, the Commission determined that the proposed agreement would mitigate many of the concerns underlying the level of reserves in Peninsular Florida. As a result, the Commission approved the agreement on November 30, 1999. The Commission will close Docket No. 981890-EI upon issuance of the final order.

RISKS AFFECTING PLANS

Because the future is uncertain, any utility's long-range plan will contain risks that affect the viability of the *Plan*. The major elements of risk are:

COMPETITION

As noted by some reporting utilities, the national debate on electric utility restructuring and retail competition is causing utilities to defer power plant construction and rely more on power purchases whose source is uncertain. Further, the cost of electric generating capacity, particularly

EXECUTIVE SUMMARY

natural gas-fired combined cycle and combustion turbine units, has dramatically decreased in recent years. As a result, self-service generation may become more attractive to large industrial retail customers. Utilities have become more cost-conscious in order to reduce rates to these large-use customers.

The possibility of retail competition may have already affected the long-term generation plans of Florida's utilities. According to some utilities, the threat of retail competition has driven utilities to wait until the last possible moment to commit to building new power plants. Waiting may allow utilities to minimize potential stranded costs due to new unit construction. The down side to this approach is that, to ensure system reliability, utilities may be forced to build combustion turbine units on short notice. This alternative may not necessarily result in a least-cost resource plan.

NATURAL GAS AVAILABILITY

Current national policies have helped to increase natural gas consumption in Florida. Florida's electric utilities continue to rely primarily on a single gas transportation pipeline company, Florida Gas Transmission (FGT), to supply direct customers and electric utility fuel requirements. Current estimates of the need for natural gas for all sectors exceed the current pipeline capacity of FGT's system. The FRCC has been notified of FGT's ability and willingness to expand the natural gas pipeline system to meet all projected electric demand. However, electric utilities should individually identify a contingency plan if gas transportation capacity is not subscribed to in advance and, subsequently, is not available when needed to fuel future generation expansions.

Three competing companies currently plan to construct new pipelines into the state which, if built, will mitigate the concern with having only one pipeline company. These three companies – Coastal Corporation (Gulfstream), Duke Energy (Sawgrass), and Williams-Transco (Buccaneer) – have filed, or plan to file, separate applications with the Federal Energy Regulatory Commission (FERC) seeking approval to construct new gas pipelines into the state. All three lines are expected to be placed in commercial service by the end of 2002 if approved by FERC.

DECLINING COST-EFFECTIVENESS OF DEMAND-SIDE MANAGEMENT PROGRAMS

The cost-effectiveness of utility demand-side management (DSM) programs has declined in recent years due to the decline in utility avoided costs— that is, the cost of generation avoidable by DSM. In order to maintain DSM program cost-effectiveness, utilities have been forced to reduce incentive levels paid to participating customers. If, ultimately, customer participation decreases as a result of incentive level reductions, utilities may need to modify their *Plans* to accelerate the construction of planned capacity resources to offset their DSM deficits and, therefore, meet their reliability requirements.

ENVIRONMENTAL COMPLIANCE

Evolving environmental regulations may cause electric utilities to bear additional significant compliance costs in the future. To comply with existing and proposed environmental regulations, utilities must stay informed on evolving environmental legislation to perform cost-effective compliance planning.

EXECUTIVE SUMMARY






SUMMARY OF RESOURCE ADDITIONS

Table 1 on the next page, and Figures 2, 3, and 4 on pages 14 and 15, summarize the aggregate plans for the State of Florida's utilities. These illustrations show the total planned resource additions by type, as well as planned major transmission lines, over the next ten years.

EXECUTIVE SUMMARY

THE 1999 UTILITY STATEWIDE PLAN

TABLE 1
RESOURCE ADDITIONS / (REDUCTIONS) IN THE NEXT TEN YEARS

RESOURCE TYPE	Winter Capacity (MW)
 COMBINED CYCLE UNITS ¹	6,684
 COMBUSTION TURBINE UNITS	4,342
 CONSERVATION AND DEMAND-SIDE MEASURES ²	1,554
 COAL UNITS ¹	238
 COGENERATION ³	-185
FOSSIL AND NUCLEAR STEAM UNITS ¹	-601
TOTAL <u>NET</u> RESOURCE ADDITIONS	12,032
FIRM PEAK DEMAND INCREASE	8,452

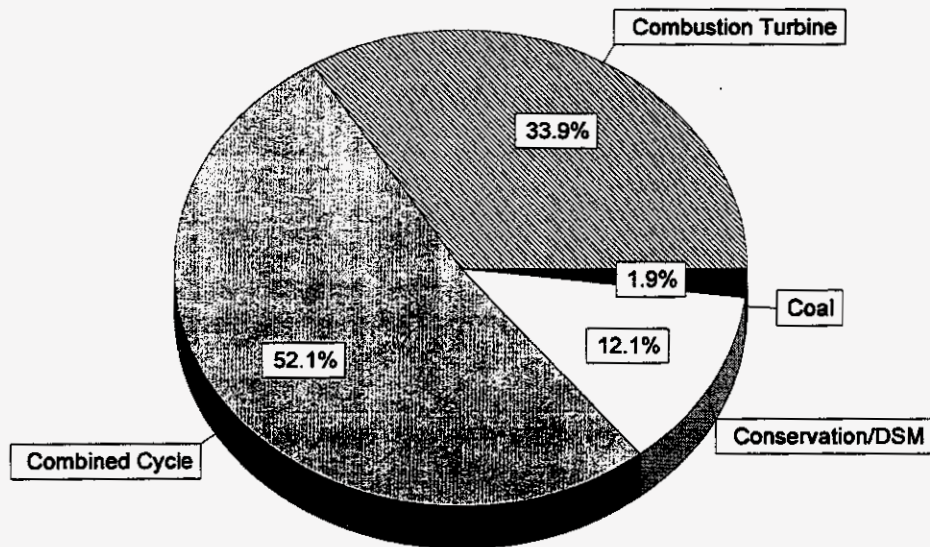
¹ Includes new unit additions, existing unit capacity increases or decreases, and unit retirements.

² Load management (247 MW), interruptible service (128 MW), and conservation programs (1179 MW).

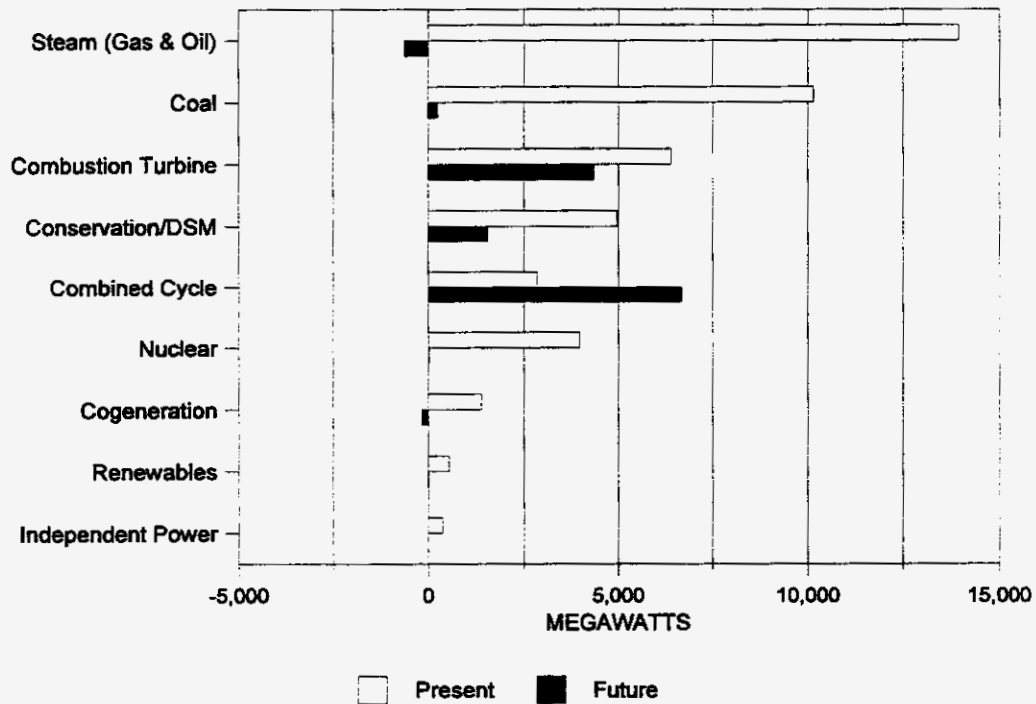
³ Three firm capacity contracts are set to terminate over the next ten years, with a total capacity reduction of 185 MW. No new qualifying facilities are proposed.

EXECUTIVE SUMMARY

**FIGURE 2
UTILITY RESOURCE ADDITIONS IN THE NEXT TEN YEARS**

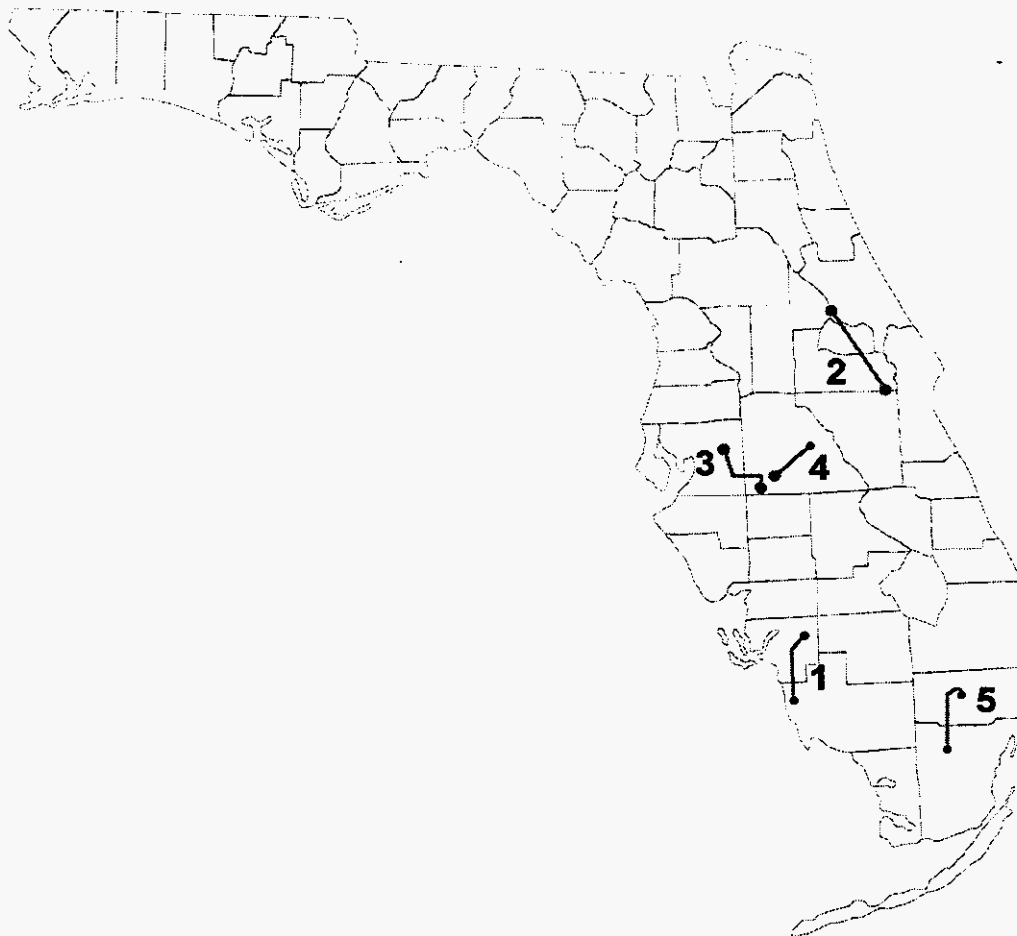


**FIGURE 3
UTILITY RESOURCE MIX BY PLANT TYPE -- PRESENT AND FUTURE**



EXECUTIVE SUMMARY

**FIGURE 4
PROPOSED MAJOR TRANSMISSION LINES ⁴**



	UTILITY	TERMINALS	LENGTH (MILES)	IN-SERVICE DATE	VOLTAGE (kV)
1	FPL	Collier - Orange River	36	Dec. 1999	230
2	FPL	Poinsett - Sanford (2 lines)	45	June 2002	230
3	TECO	Polk - Lithia (2 lines)	28	June 2003 June 2004	230
4	FPC	West Lake Wales - Hines	21	May 2006	230
5	FPL	Conservation - Levee	36	June 2007	500

⁴The Conservation - Levee line was previously certified under the Transmission Line Siting Act.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

INTEGRATED RESOURCE PLANNING

Integrated resource planning (IRP) is a utility process that includes a cost-effective combination of demand-side resources (e.g., conservation measures) and supply-side resources (e.g., generating units or capacity purchases). Many view IRP as a sharp contrast to traditional utility planning, which focused primarily on the construction of utility-owned supply-side resources to meet system demand. While the specific approaches to IRP for each utility vary, they are all consistent with a process that has five steps:

Update Assumptions

All assumptions and system performance data are updated. This includes the assumptions that must change based on Commission decisions in various dockets as well as other input assumptions of demographics, financial parameters, generating unit operating characteristics, etc. At this step, the load forecast excludes future DSM installations.

Conduct Reliability Analysis

A reliability analysis is conducted to determine when resources may be needed to meet expected load. Utilities generally use two reliability criteria: deterministic [reserve margin] and probabilistic [loss of load probability (LOLP) and expected unserved energy (EUE)].

Determine Need for New Resources

Based on the reliability analysis, the magnitude and timing of new resources needed is determined. At this step, it is undetermined whether the need will be met by supply-side or demand-side resources. Only the timing and amount of capacity needed are known.

Compare Supply-Side and Demand-Side Measures

An initial screening of demand-side and supply-side resources is performed to find candidates to meet the expected resource need. Then, the demand-side and supply-side resources compete against each other to decide which combination meets the need most cost-effectively.

Review Results

Utility management reviews the results of the previous steps, and a final IRP plan is adopted. The utility's IRP plan may require Commission approval, such as in a power plant need determination proceeding. In addition, after reviewing the plan the Commission may, on its own motion, open proceedings to address any part of the plan.

Although Florida Statutes and Commission Rules do not specifically define IRP, they do provide a solid framework for flexible, cost-effective utility resource planning. The following statutes and rules are the basis for electric utility integrated resource planning in Florida.

Florida Statutes

Section 366.04(2)(c), 366.04(5), and 366.05(8). Commonly known as the "grid bill", its purpose is to ensure the development and maintenance of a reliable and coordinated statewide power grid.

Section 366.80 - 366.85. Known as the Florida Energy Efficiency and Conservation Act

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

(FEECA), originally enacted in 1980. FEECA requires the setting of goals for reduction in the growth rates of peak demand and energy use.

Section 403.519. Statute that makes the Commission the exclusive forum for the determination of need for an electrical power generating plant as defined by the Power Plant Siting Act (Section 403.501 - 403.517).

Section 403.537. Need determination statute for transmission lines as defined by the Transmission Line Siting Act (Section 403.52 - 403.536).

Section 186.801. Statute requiring utilities to submit *Plans* to the Commission for review.

Rules (Florida Administrative Code)

Rule 25-22.070 - 25-22.072. Addresses the content, submission, and review of the *Plan*.

Rule 25-17.001 - 25-17.015. Addresses conservation goals and related matters. Rule 25-17.001 requires that utilities "aggressively integrate non-traditional sources of power generation into the various utility service areas to the extent cost-effective." Rule 25-17.0021 addresses the setting of numeric DSM goals and requirements for monitoring utility progress in meeting those goals.

Rule 25-22.080 - 25-22.082. Governs power plant need determinations and requires detailed information on viable generating and non-generating alternatives to the proposed plant. Rule 25-22.082 is the Commission's bidding rule.

Rule 25-22.075. Addresses transmission line need determinations and requires information on alternatives to construction of the line.

Rule 25-17.080 - 25-17.091. Governs utility obligations with regard to cogenerators and small power producers.

The *Plan* summarizes the results of a utility's IRP process. The final *Plan* adopted by utility management is reviewed by the Commission, and appropriate action is taken to address any concerns. Comments made by the Commission and other review agencies on this year's *Plan* filings should be incorporated by the utilities into next year's *Plans*. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day operations to utility management.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

LOAD FORECAST

The first step in developing an integrated resource plan is the load forecast. Load forecasting is the process used by electric utilities to estimate future energy needs. From these estimates, utilities determine how much, and when, additional generating capacity may be needed.

The Commission evaluates a utility's load forecast based upon three types of analyses. The first involves reviewing the load forecasting methodology to ensure that it uses reasonable models and assumptions. The second examines the historical forecast accuracy to determine whether or not the forecasting process has performed well in the past. The third compares forecasted values to historical growth patterns. Taken together, these evaluation procedures can either lend credibility to a forecast or cast doubt on its reliability.

EVALUATION OF LOAD FORECASTING METHODOLOGY

Although each reporting utility has developed its own distinct forecasting process, there are four steps which all forecast methodologies have in common. These steps are discussed below.

Collection of Historical Data

Historical data forms the foundation for utility load and energy forecasts. This data includes energy usage patterns, number of customers, economic, demographic, and weather data for the utility's service territory, and appliance-specific saturation and energy consumption characteristics. The Commission reviewed these data sources for their timeliness, reliability and accuracy.

Derivation of Forecast Model Parameters

The parameters of a forecast model quantify the relationship between the economic and demographic data of a utility and the energy usage patterns of its customers. These parameters must be updated periodically to ensure that forecasts produced by the model reflect current customer energy consumption patterns.

Assembly of Forecast Assumptions

Forecast assumptions represent utility expectations of future economic, weather, technological, and demographic conditions in their service territory. Overly optimistic assumptions can cause the resulting load forecast to be too high; likewise, overly pessimistic assumptions can cause the forecast to be too low. In evaluating forecast assumptions, the Commission reviewed the sources from which the assumptions were drawn, the consistency of those assumptions with other economic and demographic projections, and the validity of any adjustments made to those assumptions arising from known changes in a utility's service territory.

Calculation of Forecast

The load forecast is calculated by inputting forecast assumptions into the forecast model. The mathematical result may be adjusted to reflect the professional judgement of the forecaster, or to reflect the impact of conservation programs or other events not already quantified by the model parameters or the forecast assumptions. The Commission reviewed any adjustments made to the utility forecasts to determine if these adjustments were appropriate.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

EVALUATION OF HISTORICAL FORECAST ACCURACY

Reviewing the past results of a load and energy forecasting methodology reveals whether that methodology has produced accurate forecasts. A pattern of over- or under-forecasting is indicative of past forecast error that could be carried forward into current forecasts.

For each reporting utility, the Commission reviewed the historical forecast accuracy of total retail energy sales for the five-year period from 1994-1998. This review compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, actual 1998 energy sales were compared to the projected 1998 forecasts made in 1993, 1994, and 1995. These differences, expressed as a percentage error rate, were used to calculate two measures of a utility's historical forecast accuracy. The first measure, *average absolute forecast error*, is an average of the percentage error rates calculated by ignoring the positive and negative signs that result when a forecast over- or under-estimates actual values. This calculation provides an overall measure of the accuracy of past utility forecasts. The second measure, *average forecast error*, is an average of the percentage error rates calculated without removing the positive and negative signs. This measure indicates a utility's tendency to over-forecast (positive values) or under-forecast (negative values).

The Commission evaluated the historical forecast accuracy of total retail energy sales for each reporting utility except Florida Municipal Power Agency and Kissimmee Utility Authority, as there was insufficient historical data to analyze these two utilities. This evaluation is summarized in Table 2 below. A detailed discussion of individual utility retail sales forecasts is contained later in this report.

UTILITY	Average ABSOLUTE Forecast Error	Average Forecast Error
Florida Power Corporation (FPC)	2.33%	1.30%
Florida Power & Light Company (FPL)	2.44%	-2.44%
Gulf Power Company (Gulf)	3.52%	-2.21%
Tampa Electric Company (TECO)	2.49%	-1.81%
Gainesville Regional Utilities (GRU)	2.13%	-2.13%
Jacksonville Electric Authority (JEA)	5.79%	-5.79%
City of Lakeland (LAK)	3.57%	-3.40%
City of Tallahassee (TAL)	3.45%	-2.87%
Seminole Electric Cooperative (SEC)	3.84%	-1.44%
ALL REPORTING UTILITIES	3.28%	-2.31%

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

Consistency of Forecasts with Historical Trends

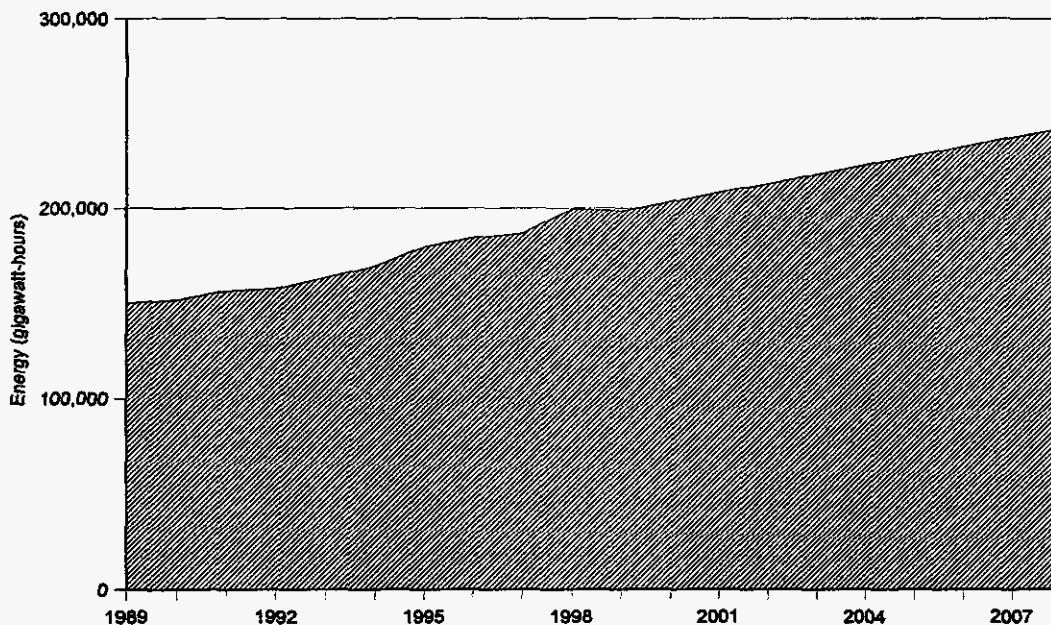
As a final check of the projections, the Commission compares the forecasts to historical growth patterns as well as past load forecasts. Unexpected changes in forecasted growth rates not explicitly accounted for in the forecast methodology may indicate that the load forecast does not properly reflect past consumer behavior, and the forecast likely is in error. As shown in Table 2 on the prior page, all reporting utilities except Florida Power Corporation have a tendency to under-forecast retail energy sales. This apparent trend may aggravate the Commission's concerns with low reserve margins in Peninsular Florida.

Summary of Load Forecast Evaluation Process

A detailed discussion of individual utility load forecasts is contained later in this report. In general, the load forecasting procedures used by the reporting utilities provide reliable forecasts of Florida's future energy needs. However, the aggregate summer and winter peak demand forecasts for Peninsular Florida utilities have increased since last year. The current forecast for 2000 and 2007 summer peak demand has increased by 423 MW and 992 MW, respectively over last year's forecast. Similarly, the current forecast for winter peak demand for 2000/2001 and 2007/2008 has increased by 498 MW and 113 MW, respectively over last year's forecast. This apparent trend increases the Commission's concerns with low reserve margins in Peninsular Florida.

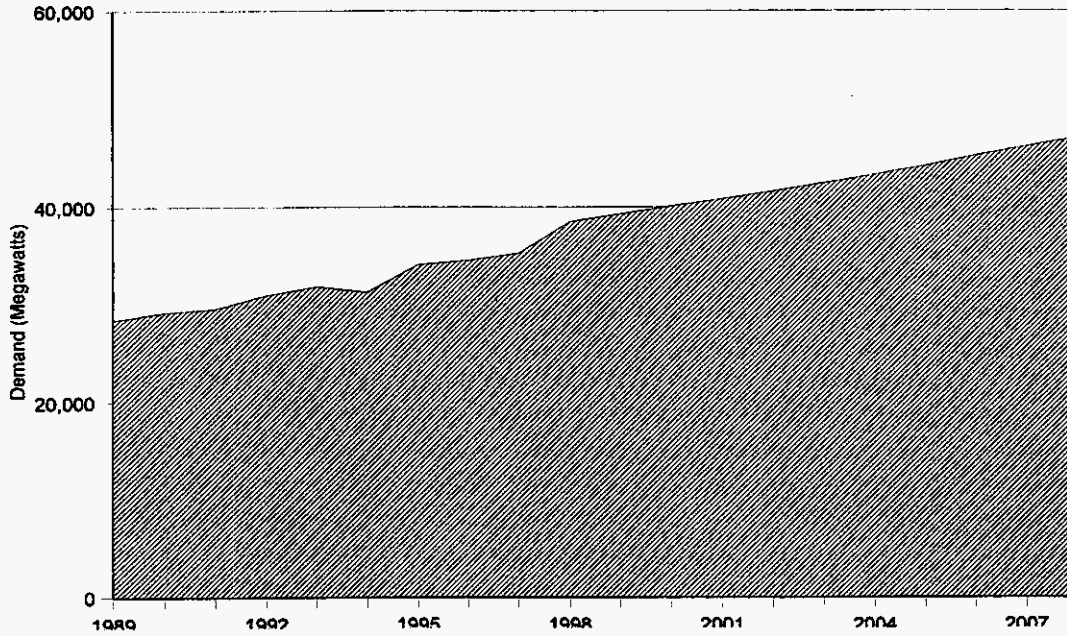
Figure 5, shown below, illustrates forecasted aggregate net energy for load (NEL) for the state of Florida. Figures 6 and 7, on the next page, illustrate forecasted aggregate summer peak demand and winter peak demand, respectively.

**FIGURE 5
ANNUAL NET ENERGY FOR LOAD
STATE OF FLORIDA -- HISTORY & FORECAST**

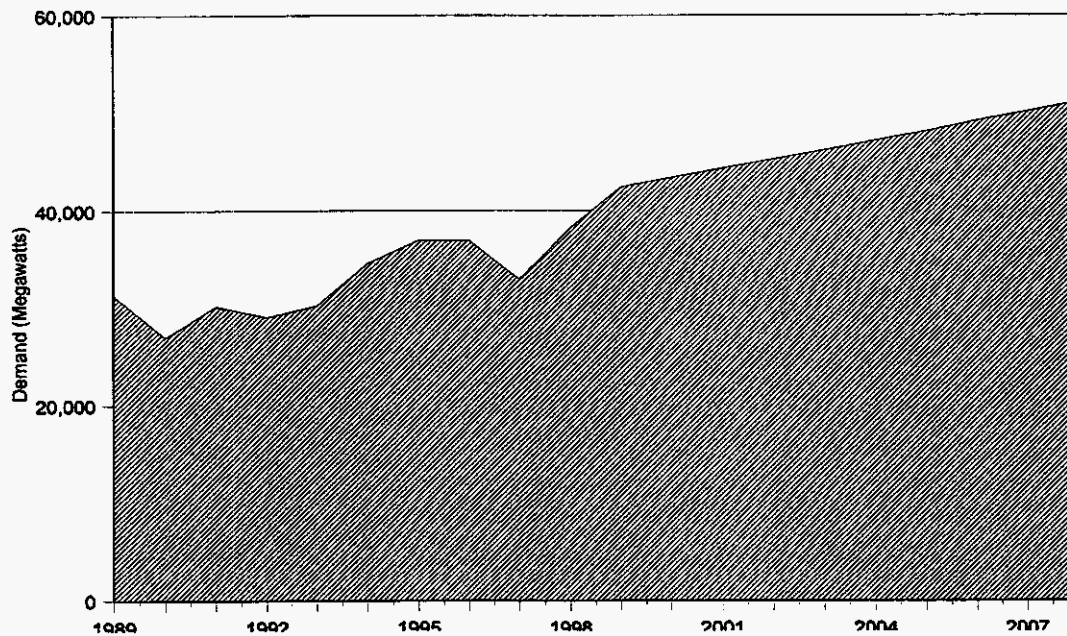


REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

**FIGURE 6
SUMMER FIRM PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST**



**FIGURE 7
WINTER FIRM PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST**



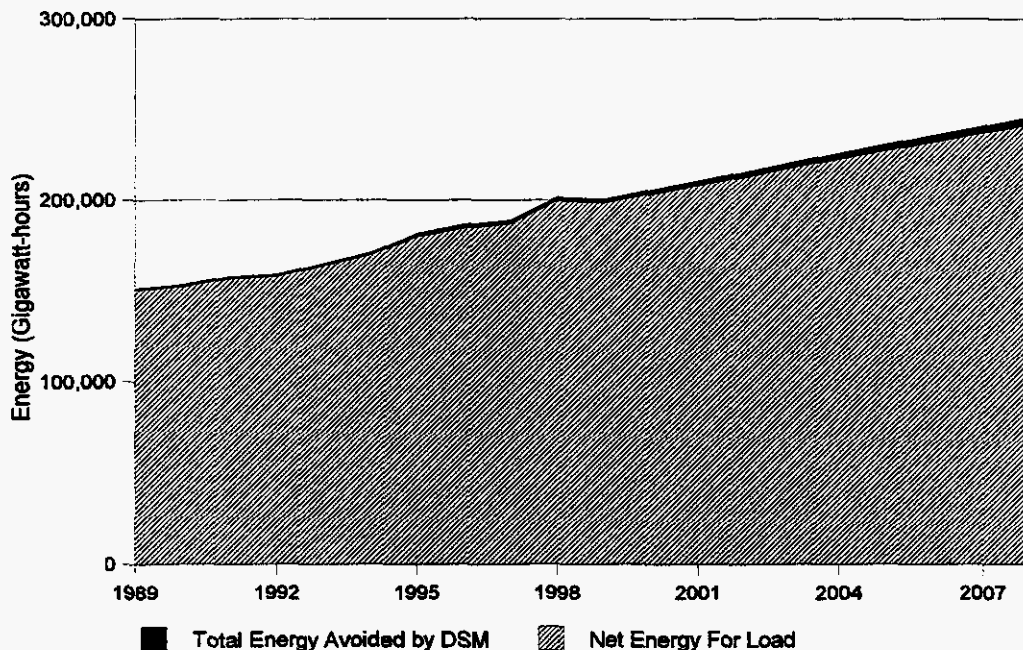
REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) is an integral part of each utility's integrated resource plan. DSM reduces customer peak demand and energy requirements, and has avoided or deferred the construction of new generating units. Florida's electric utilities were among the first in the nation to promote energy conservation practices. Conservation and DSM programs have been offered since 1980 as a result of the Florida Legislature's enactment of the Florida Energy Efficiency and Conservation Act (FEECA). The Commission's broad-based authority over electric utility conservation measures and programs is embodied in Rules 25-17.001 through 25-17.015, Florida Administrative Code.

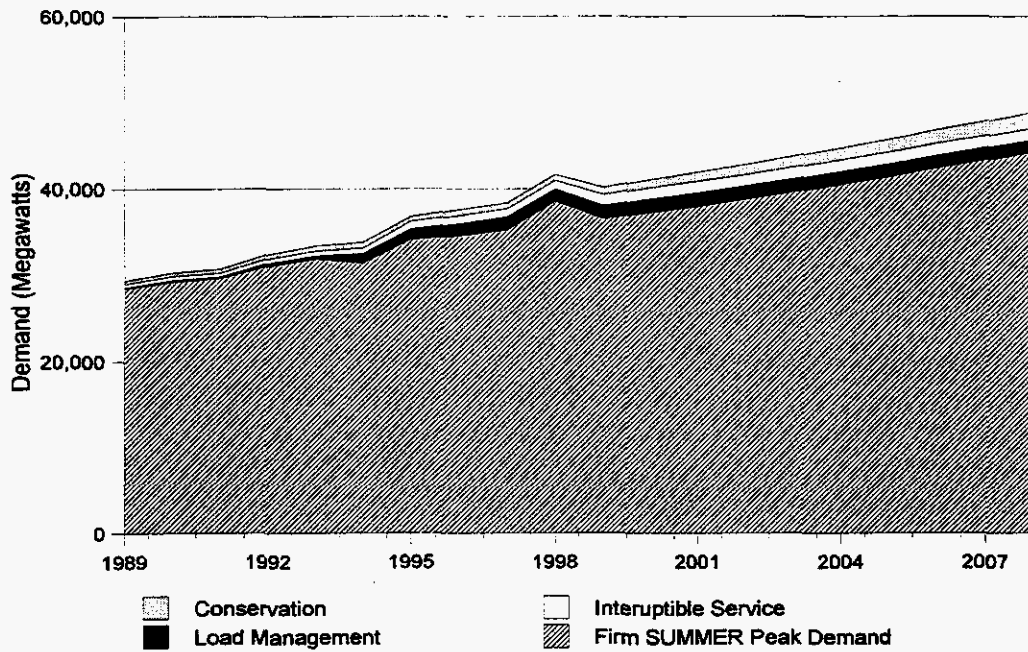
FEECA places emphasis on reducing the growth rates of weather-sensitive peak demand, reducing and controlling the growth rates of electricity consumption, and reducing the consumption of expensive resources such as petroleum fuels. To meet these objectives, the Commission sets DSM goals, and the utilities develop and implement DSM programs designed to meet the goals. As a whole, Florida's electric utilities have been successful in meeting the overall objectives of FEECA. *Dispatchable* (e.g., load management and interruptible service) and *non-dispatchable* conservation programs (e.g., attic insulation and energy-efficient lighting) have reduced statewide summer peak demand by an estimated 3092 MW, winter peak demand by an estimated 4976 MW, and energy consumption by an estimated 2175 GWh. By 2008, DSM programs are forecasted to reduce aggregate summer peak demand by an estimated 4662 MW, winter peak demand by an estimated 6530 MW, and energy consumption by an estimated 4194 GWh. These demand and energy savings are illustrated in Figures 8, 9, and 10.

**FIGURE 8
ESTIMATED IMPACT OF DSM ON NET ENERGY FOR LOAD
STATE OF FLORIDA -- HISTORY & FORECAST**

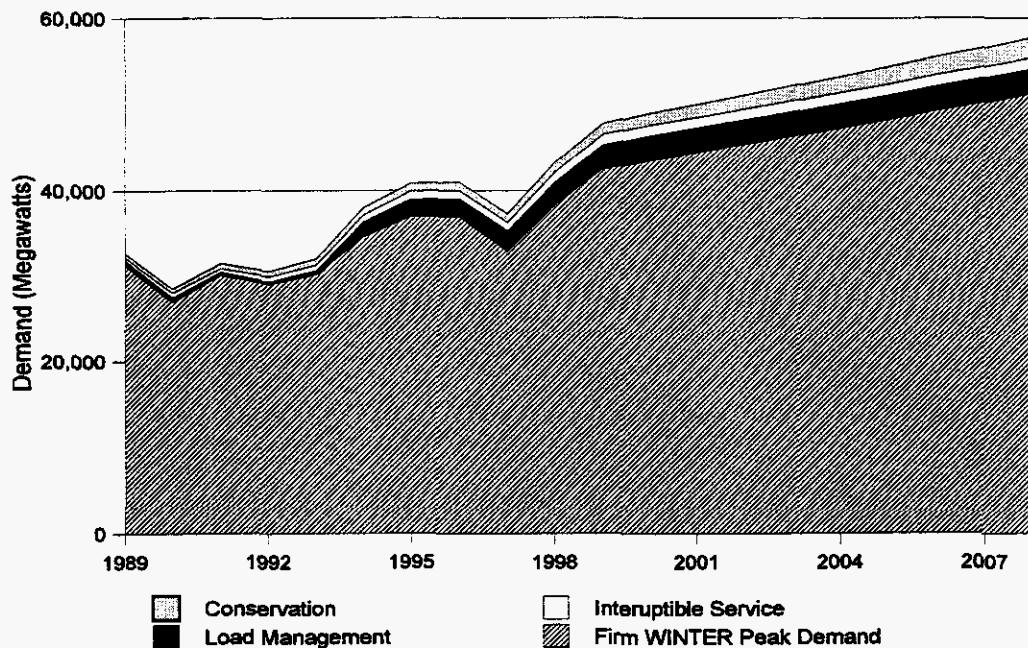


REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

**FIGURE 9
ESTIMATED IMPACT OF DSM ON SUMMER PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST**



**FIGURE 10
ESTIMATED IMPACT OF DSM ON WINTER PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST**



REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

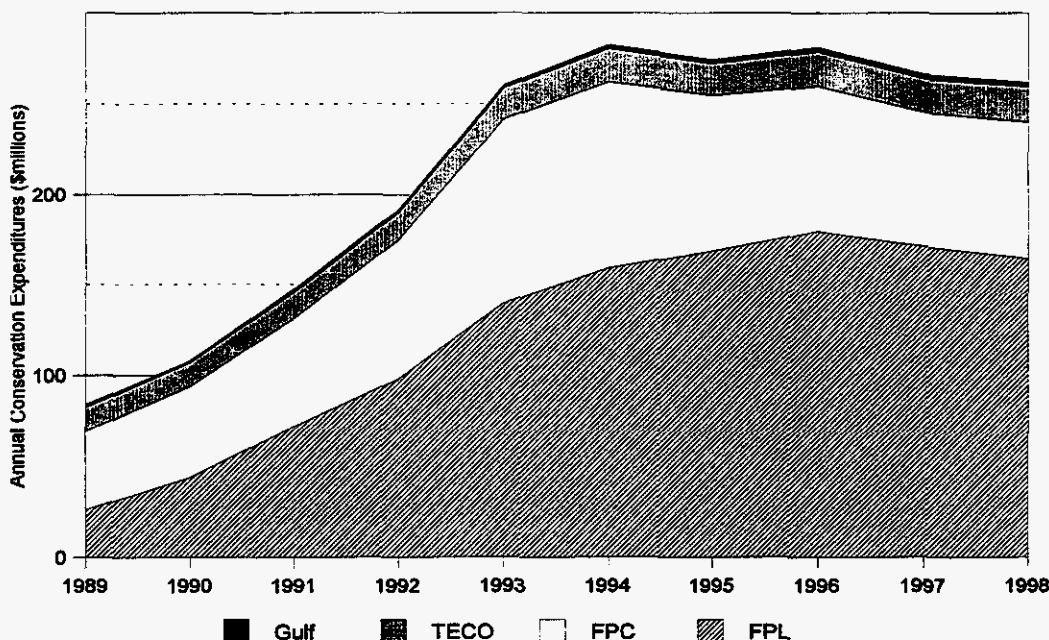
It is not clear whether dispatchable DSM is sustainable over the planning horizon given the current low level of Peninsular Florida's reserve margins. Furthermore, if a utility relies on DSM rather than constructing a generating unit, the utility may also forego opportunity sales. Finally, there may be continued decline on DSM cost-effectiveness because the cost of new generating capacity continues to decrease.

ENERGY CONSERVATION COST RECOVERY CLAUSE

Florida's investor-owned utilities have spent a vast amount of money to implement DSM programs. This money has been collected from utility ratepayers through the Energy Conservation Cost Recovery Clause (ECCR). The ECCR clause allows investor-owned utilities to recover, on an annual basis, prudently incurred expenses associated with the implementation of Commission-approved conservation programs.

Since 1981, Florida's investor-owned utilities have collected over \$2.7 billion through the ECCR clause. As shown in Figure 11 below, annual DSM expenditures increased substantially during the period from 1989 through 1994 due primarily to the expansion of FPL's and FPC's load management programs during this time. However, total DSM expenditures have leveled off since 1994 due to program saturation and to declining DSM cost-effectiveness because of the lower overall cost of new gas-fired combined cycle and combustion turbine generating units.

**FIGURE 11
CONSERVATION EXPENSES RECOVERED THROUGH
THE ENERGY CONSERVATION COST RECOVERY CLAUSE**



REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

CHANGES TO FEECA

When FEECA was enacted by the Florida Legislature in 1980, every electric utility in the state was subject to its requirements. After FEECA was first revised in 1989, the statute applied only to those electric utilities with annual energy sales of more than 500 GWh. The twelve utilities that exceeded this threshold at that time comprised approximately 94% of all electricity consumed in Florida. When FEECA was revised again in 1996, the minimum sales threshold was increased to 2000 GWh. As a result, FEECA's requirements now apply only to the five investor-owned utilities and two municipal utilities, JEA and OUC. These utilities, in aggregate, generate approximately 87% of all electricity consumed in Florida.

DEMAND-SIDE MANAGEMENT GOALS

The Commission set new numeric demand and energy DSM goals for FPL, FPC, Gulf, and TECO in August, 1999. These four utilities are currently scheduled to file DSM plans to meet their goals on December 29, 1999.

The Commission set numeric DSM goals for Florida Public Utilities Company (FPUC) and the large municipal and cooperative utilities in April, 1995. The Commission subsequently approved the DSM plans for these utilities. However, only the DSM plans filed by JEA, OUC, and the investor-owned utilities can be enforced because the 1996 FEECA revisions exempted the remaining utilities in the state. While the now-exempt utilities are no longer subject to FEECA's requirements, these utilities have committed to continuing their conservation efforts.

The Commission plans to set new DSM goals for JEA, OUC, and FPUC in April, 2000. Docket Nos. 990720-EG, 990721-EG, and 990722-EG have been opened by the Commission for the purpose of setting new DSM goals for these utilities.

STATE COMPREHENSIVE PLAN

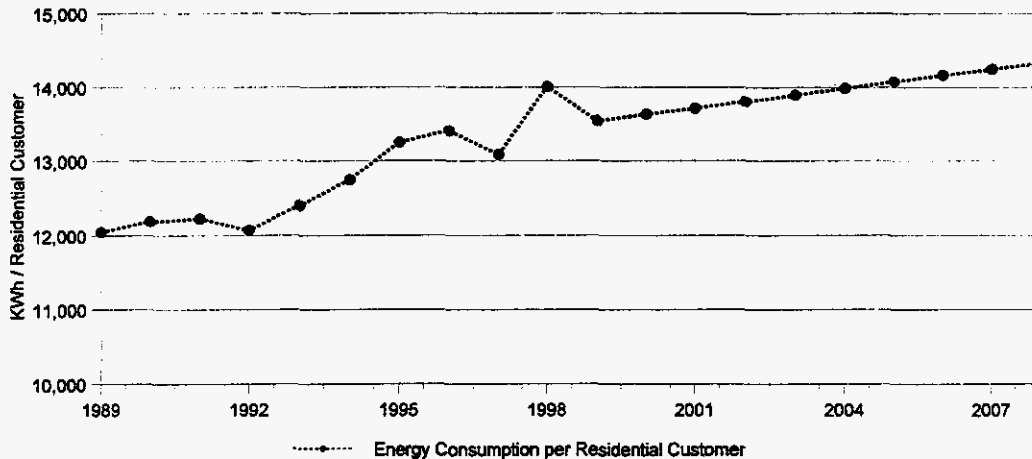
Energy conservation is a component of the State Comprehensive Plan. Section 187.201(12)(a), Florida Statutes, contains the State Comprehensive Plan's goal concerning energy:

"Florida shall reduce its energy requirements through enhanced conservation and efficiency measures in all end-use sectors, while at the same time promoting an increased use of renewable energy resources."

To meet this goal, the State of Florida has implemented policies to reduce per-capita energy consumption through the development and application of end-use efficiency alternatives, renewable energy resources, efficient building code standards, and by informing the public of energy conservation measures through active media campaigns. The Commission set DSM goals and approved DSM plans for electric utilities. The Commission's Bureau of Consumer Information and Conservation Education promotes end-use efficiency and customer-induced conservation. The Commission continues to work with the Department of Community Affairs (DCA) to ensure a building code that results in the most energy-efficient, cost-effective new construction. These activities have the effect of promoting end-use efficiency and reducing per-capita energy consumption from what it otherwise would have been. These activities will continue in the future.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

**FIGURE 12
ENERGY CONSUMPTION PER RESIDENTIAL CUSTOMER
STATE OF FLORIDA -- HISTORY & FORECAST**



However, in spite of the Commission's efforts, Figure 12 shows that residential per-capita energy consumption has consistently risen over the past ten years, and is expected to continue to increase each year over the planning horizon. The rate of increase in per-capita consumption is expected to be less over the forecast period than what has occurred during the past ten years. This is due largely to the replacement of older household appliances with newer, more energy-efficient models. However, past and projected increases may also be attributed to factors beyond the Commission's control, such as:

- the nominal cost of electricity has remained relatively stable for over a decade;
- natural gas, used by many residents nationwide for heating, water heating, and cooking, is relatively unavailable in parts of Florida;
- the average home size has increased over time; and
- there are many more electricity-consuming appliances in the home today than in past years.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

RELIABILITY REQUIREMENTS

RELIABILITY CRITERIA

Utilities plan their electric system to meet peak demand plus allow for planned maintenance and forced outages at generating units, as well as variation from base-case assumptions. To determine when additional future resources are required, utilities generally use two types of reliability criteria: *deterministic* and *probabilistic*. The reliability criteria used by each utility who filed a *Plan* are shown below in Table 3.

Deterministic Criteria

Most all utilities use a deterministic reliability criterion. The main criteria, *reserve margin*, is the amount of capacity that exceeds firm peak demand. This value may be expressed in megawatts or as a percentage above firm peak demand. Reserve margin is comprised of demand-side resources (e.g., non-firm load) and supply-side resources (e.g., generating units or firm capacity purchases). Some utilities employ a secondary criterion, *supply-side reserve margin*, which means that a certain percentage of reserves will be made up of generating units or firm capacity purchases. However, reserve margin indicates the degree of reliability of a utility's system only at the single peak hour of the summer and winter season. Thus, it cannot capture the impact of random events occurring throughout the year, such as a forced outage of a generating unit.

UTILITY	RESERVE MARGIN		PROBABILISTIC CRITERIA	
	Percent	Season	LOLP	EUE/NEL
Florida Power Corporation (FPC) *	15%	Sum/Win	0.1	—
Florida Power & Light Company (FPL) *	15%	Sum/Win	0.1	—
Gulf Power Company (Gulf)	13.5%	Sum	—	—
Tampa Electric Company (TECO) *	15% (7% supply-side)	Sum/Win Sum	—	1%
Florida Municipal Power Agency (FMPPA)	18%	Sum/Win	—	—
Gainesville Regional Utilities (GRU)	15%	Sum/Win	—	—
Jacksonville Electric Authority (JEA)	15%	Sum/Win	—	—
Kissimmee Utility Authority (KUA)	15%	Sum/Win	—	—
City of Lakeland (LAK)	15%	Sum/Win	—	—
Orlando Utilities Commission (OUC)	15%	Sum/Win	—	0.5%
City of Tallahassee (TAL)	17%	Sum	—	—
Seminole Electric Cooperative (SEC)	15%	Sum/Win	—	1%

* FPC, FPL, and TECO agreed to a 20% reserve margin criterion starting in Summer, 2004.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

Probabilistic Criteria

Because of the limitations of reserve margin, many utilities also use probabilistic reliability criteria. The most common one is *loss of load probability* (LOLP), expressed in days per year. The LOLP criterion used for planning purposes is typically 0.1 days per year, meaning that, on average, a utility will likely be unable to meet its daily firm peak load on one day in ten years. The LOLP criterion allows a utility to calculate and incorporate its ability to import power from neighboring utilities. However, LOLP does not account for the magnitude of a forecasted capacity shortfall. A second probabilistic method, *expected unserved energy* (EUE), accounts for both the probability and magnitude of a forecasted energy shortfall. Utilities that use the EUE criterion usually calculate a ratio of expected unserved energy to net energy for load (EUE/NEL), and the typical criterion is 1% EUE/NEL. This means that, on average, a utility will likely be unable to serve 1% of its annual net energy requirements in a given year.

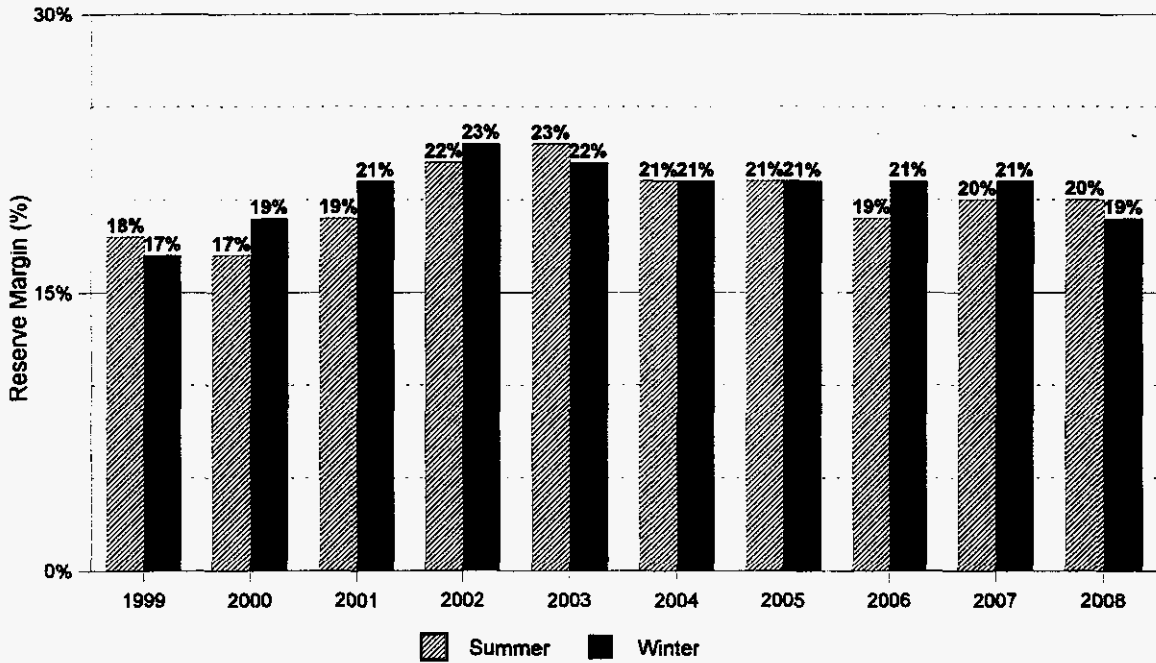
Once reliability criteria are established, a utility compares its load forecast to existing system resources. Reliability concerns arise if a utility's reserve margin falls below established criteria or the LOLP exceeds one day in ten years. The utility must build or purchase additional capacity (supply-side options) or reduce peak load through the promotion of additional cost-effective conservation programs (demand-side options). An integrated resource plan is developed by combining supply-side and demand-side options to satisfy the utility's reliability criteria. This fact implies that reliability criteria decide the timing of a utility's planned resource additions.

Figures 13 and 14, on the next page, show the aggregate forecast of reserve margin over the next ten years, both statewide and for Peninsular Florida's utilities. Figure 14 shows that Peninsular Florida's aggregate reserve margin is not forecasted to drop below the FRCC standard of 15% in any year, either summer or winter season, over the planning horizon. As stated on page 40 of this report, the Commission's concern with the viability of FRCC's 15% reserve margin criterion is mitigated in part by the expected addition of approximately 3,100 MW of new merchant plant capacity over the next five years. Florida's utilities should purchase power from merchant plants if such a purchase is the least-cost alternative available. Thus, during periods of capacity shortages, merchant plants may enhance the reliability of Peninsular Florida's grid.

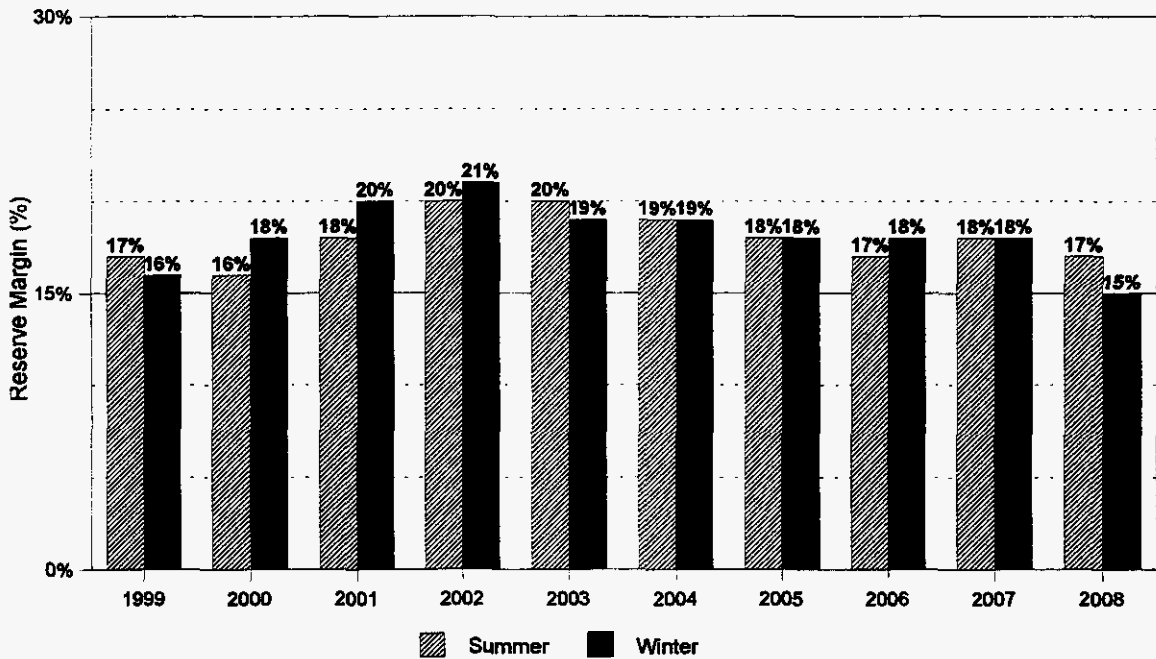
There is another factor which mitigates the Commission's concern with FRCC's 15% reserve margin criterion. Pursuant to an agreement approved by the Commission on November 30, 1999 in Docket No. 981890-EI, FPC, FPL, and TECO have agreed to adopt a 20% reserve margin planning criterion starting in the summer of 2004. Based on this year's *Plans*, TECO is the only investor-owned utility that does not meet the 20% criterion in 2004. Municipal and cooperative electric utilities are not part of this agreement, and can therefore carry their current level of reserves. If all municipal and cooperative utilities were to carry exactly a 15% reserve margin while FPC, FPL, and TECO, pursuant to the agreement, each carry a 20% reserve margin, the weighted average reserve margin for Peninsular Florida would be approximately 19%. However, Florida's municipal and cooperative utilities typically carry reserves exceeding 20% in most years.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

**FIGURE 13
UTILITY FORECASTED RESERVE MARGIN -- STATE OF FLORIDA**



**FIGURE 14
UTILITY FORECASTED RESERVE MARGIN -- PENINSULAR FLORIDA**



REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

POTENTIAL IMPACT OF MERCHANT PLANTS ON RELIABILITY

There appears to be considerable interest in constructing *merchant plants* in Florida. Merchant plant developers are attracted to Florida due to the expected high growth in electricity demand, limited import capability (approximately 3,600 MW) from other states, and relatively high incremental fuel costs for Florida's utilities. It is likely that merchant plant developers will build natural gas-fired combustion turbine or combined cycle generators. Recent technological improvements, combined with the current low price of natural gas, results in low production costs for these types of generators, giving merchant plant owners an opportunity to sell electricity in the wholesale market. Unless specific contracts exist, load-serving Florida utilities have no obligation to purchase electricity from merchant plants. Likewise, absent specific contracts, merchant plant have no obligation to sell electricity to load-serving Florida utilities.

Florida's utilities should purchase power from merchant plants if such a purchase is the least-cost alternative available. Thus, during periods of capacity shortages, merchant plants may enhance the reliability of Peninsular Florida's grid without putting retail ratepayers at risk for the costs of the facility. When a merchant plant is unavailable due to planned or forced outages, or uneconomical to operate due to high fuel costs, the merchant plant's owners bear the costs rather than retail customers.

Several companies have announced plans to construct merchant plants in Florida over the next five years. These merchant plant additions are summarized in Table 4 below. Only Duke Energy New Smyrna Beach and Okeechobee Generating Company require certification under the Power Plant Siting Act. The Commission has already approved a determination of need for the 514 MW combined cycle unit proposed by Duke New Smyrna. This decision is being appealed to the Florida Supreme Court. The Commission is currently evaluating the need for Okeechobee's proposed 550 MW combined cycle unit. Four other merchant plants have recently been announced through press releases or trade magazine articles.

Entity	Unit (Type)	In-Service Date
Duke Energy New Smyrna Beach	Volusia County (514 MW CC unit)	10/01
Okeechobee Generating Company	Okeechobee County (550 MW CC unit)	4/03
Constellation	Brevard County (5 CT units totaling 850 MW)	7/01
Reliant Energy	Osceola County (3 CT units totaling 460 MW)	12/01
IMC-Agrico	Polk County (400 MW CC cogen unit)	unknown
IPS Avon Park	Pasco County (2 CT units totaling 340 MW)	unknown

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

FUEL FORECAST

Florida's electric utilities consider several strategic factors such as fuel mix, fuel availability, and environmental compliance prior to selecting a supply-side resource. However, the fuel price forecast is the primary factor affecting the type of generation resource addition. The reporting utilities produced base-case fuel price forecasts for several fuels: coal, natural gas, residual and distillate oil, petroleum coke, nuclear, and refuse-derived fuel. Additionally, several utilities produced high-case and low-case price sensitivities.

Although each utility has its own unique method for forecasting fuel prices, all utilities generally perform the following steps:

- (1) Specific knowledge of contractual relationships with fuel vendors is typically combined with reasonable assumptions of future events which the utility cannot control.
- (2) Additional forecast sensitivities may be performed by adjusting the assumptions used to test the utility's generation expansion plan under various economic and technical scenarios.
- (3) To test their reasonableness, utility-specific fuel price forecasts are compared to several outside sources such as the U.S. Energy Information Administration (EIA), the Gas Research Institute, the American Gas Association, and DRI/McGraw-Hill.

The Commission has compared each utility's fuel price forecast with the respective EIA forecast. EIA's comprehensive fuel price forecasts fall within a reasonable range of forecasts provided by the other outside sources. Table 5, on the next page, shows the annual average growth rate (AAGR) for the forecast horizon (1999-2008) for each fuel, as forecasted by the reporting utilities and by EIA.

COAL

Nationwide, coal-fired electric generation has historically represented between 45% and 55% of all electric utility generation. This is due to low-cost domestic reserves and advancements in mine productivity. In 1998, the nation's electric utilities consumed approximately 918 million tons of coal, an increase of around 2% from 1997 levels. EIA attributes this increase to a vibrant economy, less hydroelectric generation, and a warmer than normal summer. Over the next ten-years, coal-fired electric generation is expected to increase by only 1% per year due to environmental concerns with its use, the availability of economical natural gas, and lengthy construction lead times for new coal-fired generating units.

In 1998, Florida's electric utilities consumed an estimated 28.3 million tons of coal. Utility consumption of coal is expected to increase at an average annual growth rate (AAGR) of just under 1% over the next ten years, as utilities plan to add approximately 340 MW of coal-fired capacity during that time. The primary planned coal-fired capacity addition, and the only new coal-fired unit, is Lakeland's McIntosh Unit 4, a 238 MW fluidized bed coal unit to be built using assistance from the U.S. Department of Energy's Clean Coal Technology Program. The remaining increase is expected from small capacity increases at existing units at FPC's Crystal River site and at TECO's Gannon and Big Bend sites.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

**TABLE 5
FUEL PRICE FORECAST -- AVERAGE ANNUAL GROWTH RATE
(1999 - 2008)**

UTILITY	COAL	RESIDUAL OIL	DISTILLATE OIL	PETCOKE	NATURAL GAS	NUCLEAR
EIA	1.30%	3.70%	3.20%	NA	3.60%	3.03%
City of Tallahassee	1.90%	7.23%	9.97%	NA	0.41%	NA
Florida Power Corporation	-0.11%	3.28%	3.03%	NA	-1.59%	2.89%
Florida Power & Light	1.64%	7.57%	6.39%	1.81%	4.06%	-0.12%
Florida Municipal Power Agency	2.09%	4.56%	4.53%	NA	1.78%	2.45%
Gainesville Regional Utilities	0.75%	4.30%	3.32%	NA	3.14%	2.82%
Gulf Power Company	-3.07%	NA	4.27%	NA	2.92%	NA
Jacksonville Electric Authority	1.13%	3.00%	3.00%	2.00%	3.00%	NA
Kissimmee Utility Authority	1.92%	4.10%	4.85%		3.68%	2.63%
City of Lakeland	2.21%	1.92%	2.44%	2.21%	1.52%	NA
Orlando Utilities Commission	2.70%	3.65%	NA	4.64%	3.17%	2.50%
Seminole Electric Cooperative	0.99%	2.20%	1.83%	NA	2.01%	2.12%
Tampa Electric Company	2.47%	3.83%	4.46%		3.26%	NA

Continuing the downward trend of the last 15 years, the average U.S. delivered cost of coal in 1998 decreased to \$1.25 per million Btu (MMBtu), down \$0.02 per MMBtu from 1997. EIA attributes this downward trend to the expiration, renegotiation, and buyout of older high-priced coal contracts, improvements in efficiency in coal mining and transportation, and the presence of excess coal mining capacity. Through 2008, EIA forecasts that delivered coal prices will increase at a rate of approximately 1.3% per year.

PETROLEUM

Utilities primarily consume three types of petroleum-derived products: *distillate*, or light (#2) oil; *residual*, or heavy (#6) oil; and *petroleum coke* (petcoke). After lighter fuel oils such as distillate are removed during the refining process, the remaining heavier fuel oil is refined into residual, petcoke, and other petroleum products. While distillate oil is typically burned in peaking units, utilities normally burn residual oil and petroleum coke in baseload or cycling units.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

Nationwide, petroleum-fired generation currently comprises only 2% of all electric utility generation. Electric utilities consumed approximately 171 million barrels of petroleum-derived products in 1998, a substantial increase of 53 million barrels over 1997 levels. This short-term increase is attributed to the competitive cost of petroleum compared to natural gas. However, EIA projects that petroleum-fired generation will decrease at an average annual rate of 5.5% over the next ten years.

Historically, Florida has relied on petroleum products to meet a substantial part of its electric generation requirements. As recently as 1980, petroleum-fired generation accounted for nearly 50% of all electricity consumed in the state. At that time, Florida's utilities began to displace petroleum with coal and natural gas because of uncertainty with worldwide oil reserves, technological advances in recovering coal and natural gas, OPEC's market influence, and increasing environmental concerns over petroleum consumption. By 1998, petroleum's share of Florida's electric utility generation declined to just under 20%; by 2008, this share is forecasted to drop to just under 5%. This is indicative of plans, by Florida's utilities, to decrease petroleum-derived capacity by approximately 390 MW over the next ten years.

Florida's utilities have undertaken many projects in an attempt to reduce reliance on petroleum. The Commission had an oil backout cost recovery clause in which utilities could recover costs associated with cost-effective construction or conversion projects that economically displaced oil-fired generation. The Commission approved two oil-backout projects: FPL's two 500 kV transmission lines from Georgia; and TECO's Gannon Plant re-conversion from oil to coal. In 1995, the Commission repealed the oil backout cost recovery clause rule because Florida's utilities were no longer heavily dependent on oil-fired generation. However, utilities may still seek cost recovery for individual projects expected to result in fuel savings for ratepayers. The Commission decides on a case-by-case basis whether these costs are recoverable through the fuel adjustment clause.

Residual Oil

EIA reports that the average U.S. delivered cost of residual oil in 1998 was \$2.08/MMBtu, down from \$2.79/MMBtu in 1997. Through 2008, EIA anticipates that long-term residual oil prices will increase at approximately 3.7% per year. Florida's utilities as a whole expect a 12% per year decrease in residual oil consumption at their generators, to 16.3 million barrels by 2008.

Distillate Oil

EIA reports that the average U.S. delivered cost of distillate oil in 1998 was \$3.30/MMBtu, down from \$4.49/MMBtu in 1997. Through 2008, EIA anticipates that long-term distillate oil prices will increase at approximately 3.2 percent per year. Florida's utilities as a whole expect a 4.3% per year decrease in distillate oil consumption at their generators, to 1.96 million barrels by 2008.

Petroleum Coke

Utilities in Florida have recently begun using pet coke as a viable boiler fuel. Fuel grade pet coke typically exceeds 14,000 Btu/lb and contains high levels of sulfur and vanadium. With the proper emission control technology, however, utilities can blend pet coke with coal to achieve fuel cost savings as compared to an all-coal fuel stock. Florida utilities which currently use pet coke forecast increased consumption from approximately 500,000 tons annually to 2,625,000 tons annually during the planning horizon.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

NATURAL GAS

Since enactment of the 1990 Clean Air Act Amendments, U.S. utilities have increasingly turned to natural gas to comply with emission restrictions placed on power plants. Utilities can burn this low-sulfur fuel cleanly with great efficiency and minimal capital investment. Nationwide, natural gas consumption totaled 3,100 billion cubic feet (Bcf) in 1998, up 335 Bcf from 1997 levels. EIA expects natural gas-fired generation to increase at a rate of 4.5% per year during the forecast horizon due to nuclear plant retirements and the relative lack of new coal-fired units being planned. Even under a low economic growth sensitivity, nationwide natural gas-fired generation is still expected to increase at a rate of 4.0% per year.

Florida's utilities forecast natural gas-fired generation to increase by approximately 8.7% per year over the next ten years, to a level of 632 Bcf by 2008. This is a substantial increase over consumption levels projected just last year, and is due to the increased number of new natural gas-fired combustion turbine and combined cycle units planned over the next ten years.

The Commission examined the status of proven natural gas reserves at both the national and regional level. If sufficient quantities of natural gas are not available, prices may rise to prohibitively expensive levels which may cause natural gas-fired generation to be more costly than other types of generation. At the end of 1997, EIA estimated that U.S. proven natural gas reserves were approximately 167 trillion cubic feet (Tcf), a slight (0.4%) increase over year-earlier estimates. However, most natural gas consumed in Florida originates either from the Gulf of Mexico or from states adjacent to this region. EIA estimated, at the end of 1997, that proven natural gas reserves in the region were approximately 81 Tcf, a 0.5% decrease from year-earlier estimates. EIA also estimated natural gas production in this region at approximately 12 Tcf.

The average nationwide cost of natural gas was \$2.38/MMBtu in 1998, down \$0.38/MMBtu from 1997 levels. Fluctuations in natural gas price forecasts are due to several uncertainties, such as: natural gas availability; storage levels; short-term fluctuations in petroleum prices; and weather implications. However, EIA expects natural gas prices to rise at 3.6% per year through 2008. Long-term natural gas price forecasts are sensitive to EIA's economic growth scenarios. Depending on these economic growth scenarios, natural gas prices could rise between 2.8% and 5.0% per year.

NUCLEAR

Nationwide, nuclear-fired units account for an estimated 100,000 MW of capacity. Florida's five nuclear units have a current combined capacity of 3,963 MW. These units are located at FPL's St. Lucie site (2 units) and Turkey Point site (2 units), and at FPC's Crystal River site (1 unit).

EIA expects that nuclear units will meet a diminishing share of the nation's electricity needs by 2015. EIA assumes that by the year 2015, nationwide nuclear capacity will drop by 38% due to the expected retirement of 50 nuclear units. Although most nuclear units are expected to operate until the end of their 40-year license from the Nuclear Regulatory Commission, some nuclear units may be retired prematurely due to relatively high (4.0 cents/kWh) operating costs. However, both FPL and FPC expect their nuclear units to operate throughout the ten-year planning horizon.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

Spent nuclear fuel disposal is a primary concern to both FPL and FPC. The U.S. DOE has been collecting a 0.1 cents/kWh fee on nuclear-fired generation to finance the management and disposal of spent nuclear fuel. Nationwide, utilities pay approximately \$600 million per year into the DOE's Nuclear Waste Fund. FPL and FPC pay a combined total of nearly \$25 million per year into the fund. However, DOE has yet to begin accepting spent nuclear fuel, and utilities nationwide may incur significant costs to build additional on-site spent fuel storage capacity. If DOE removal of spent nuclear fuel from reactor sites does not occur, an estimated 80% of the utilities' spent fuel pools will reach capacity by 2010. Pending legislation would direct DOE to site an interim storage facility at Yucca Mountain, Nevada to begin acceptance of spent nuclear fuel by 2003 and, ultimately, to dispose of spent nuclear fuel by 2010.

RENEWABLES

Renewable sources comprise four broad categories: *solar, wind, water, and biomass*. Through tax incentives, legal mandates, and technical assistance going back nearly 25 years, federal and state governments have attempted to increase the amount of electricity derived from renewable sources. Because of relatively high capital and operating costs, energy from renewable sources has historically comprised a negligible share of total utility electric generation in Florida. Since 1980, renewable sources have consistently supplied only 0.2% of the state's total electricity.

In Florida, renewable energy is currently generated at four sites: 1) TAL has three hydropower units at its Corn Station with a combined capacity of 11 MW; 2) LAK and OUC supplement the 334 MW coal-fired McIntosh Unit 3 with refuse-derived fuel; 3) OUC is capable of burning landfill methane gas in both units at its 884 MW Stanton site; and 4) JEA burns landfill methane gas at its 3 MW Girvin Landfill facility. Additionally, non-utility generators sell approximately 800 MW of renewable capacity to the grid.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

GENERATION SELECTION

A balanced utility system typically includes capacity from different generation types. Florida's utilities supply electricity from many generating unit types, including nuclear. Additional nuclear power plants are not considered a viable option in Florida's future primarily because of their high construction cost. The advantages and disadvantages of each of the viable generating unit types are discussed below:

- **Combustion turbine (CT)** units are the least capital-intensive unit type to build and do not require permitting under Florida's Power Plant Siting Act. CT units burn natural gas or oil, but they have high operating costs because they are generally the least fuel-efficient unit type. For this reason, CT units are typically used to meet peak load needs.
- **Combined cycle (CC)** units are extremely efficient units that use the exhaust gases of one or more CT units to create steam and, in turn, generate additional electricity. CC units burn natural gas or oil, and are less capital-intensive than coal units. CC units typically serve intermediate or baseload capacity needs, and can be built in stages to more closely track a utility's load growth.
- **Pulverized coal** units utilize a low-cost, abundant, domestic fuel source but are capital-intensive. Overall cost savings may not occur until several years in the future. Coal units primarily serve baseload capacity needs.
- **Integrated coal gasification combined cycle (IGCC)** units are a variation of combined cycle technology. IGCC units use a coal gasifier that chemically manufactures gas from coal. The gas is cleaned to improve (minimize) emissions, then is used as a fuel for the combined cycle unit. IGCC units are capital-intensive but allow fuel flexibility because these units can also burn natural gas. IGCC units typically serve a utility's baseload capacity needs.

GENERATION SELECTION PROCESS

A utility's generation selection process typically begins with a financial analysis of the present worth revenue requirements (PWRR) of each option under consideration. Combinations of unit types are added to the system in years when the utility forecasts a need for capacity. This process enables the utility to calculate incremental capacity costs and total system fuel costs. The choice that minimizes system PWRR is normally chosen by the utility for construction.

When analysis of resource alternatives yields options whose PWRR may be nearly the same, other factors may be considered in making the final unit selection. These other factors include consideration of existing generation mix, environmental concerns, regulatory policy, and the flexibility of the *Plan* to changing conditions. The objective is to include, in the generating unit selection process, factors other than solely cost-effectiveness. The result of incorporating these non-cost factors is a robust integrated resource plan that ensures fuel/capital cost flexibility.

Alternative scenarios, which result from analysis of these non-cost factors, were considered in each utility's decision-making process. However, the non-cost factors do not appear to be the primary factor driving any utility's generating unit selection.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

The reporting utilities' Plans include proposed generating units which either do not require certification under the Power Plant Siting Act, or have yet to be certified. The next-planned, non-certified generating unit for each reporting utility is contained below in Table 6.

Utility	Unit (Type)	In-Service Date
GRU	none planned	---
KUA	none planned	---
OUC	none planned	---
TAL	none planned	---
SEC	unknown (150 MW CT unit)	11/00
FPL	Ft. Myers site (180 MW portion of expansion and repowering to CC unit)	1/01
JEA	Brandy Branch GT1-2 (two 186 MW CT units)	1/01
TECO	Polk 2 (180 MW CT unit)	1/01
LAK	McIntosh 4 (238 MW fluidized bed coal unit)	5/04
FPC	Hines 2 (567 MW CC unit)	11/04
FMPA	Cane Island 4 (80 MW CT unit)	1/07
Gulf	Crist 1-3 (180 MW repowering to CC unit)	6/07

FLORIDA'S GENERATION MIX

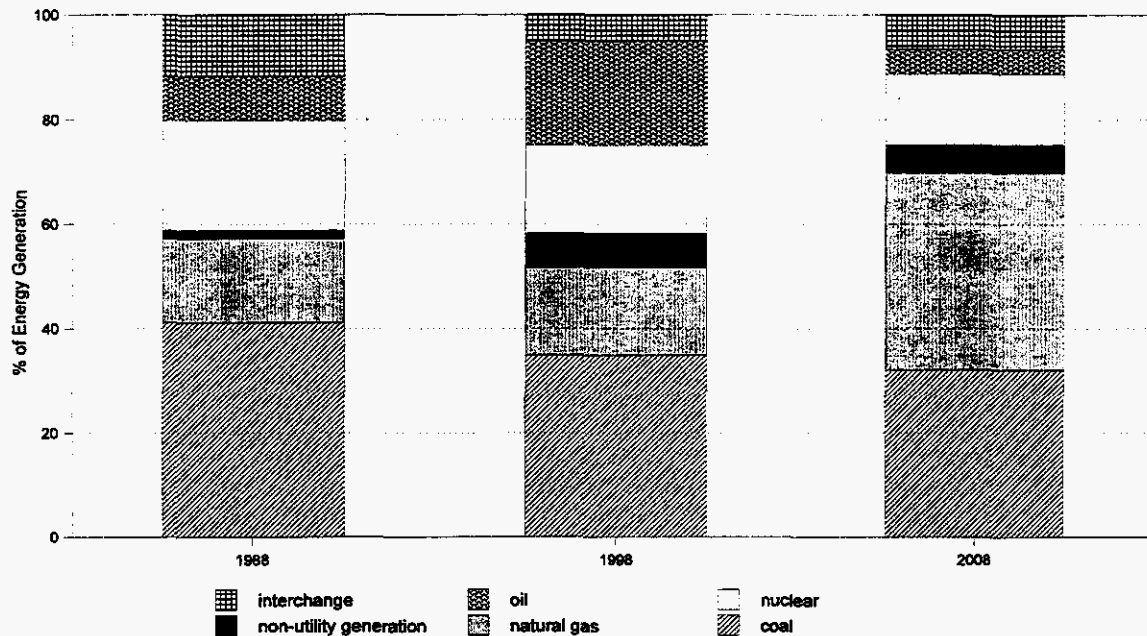
Prior to the early 1970's, utility generating units in Florida were fueled primarily by oil. While oil-fired generation still comprises 19% of Florida's electricity generation at present, the oil embargoes of the 1970's forced utilities to turn more to domestic fuels such as coal, nuclear, and natural gas. There are no current or future plans to build new nuclear generating units in Florida. As shown in Figure 15 on the next page, natural gas-fired generation is expected to increase substantially over the next ten years as the emphasis shifts away from oil-fired and coal-fired generating units.

Natural Gas

Peninsular Florida's utilities project a substantial increase in natural gas-fired generation over the next ten years, from approximately 14% to 38% of all energy generated. The projected increase is due primarily to planned combined cycle and combustion turbine unit additions. In addition, all proposed unit repowerings and unit additions by non-utility generators, are expected to use natural gas as a primary fuel. Projections of increased natural gas consumption do not include the proposed new merchant plants which have been announced this year.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

**FIGURE 15
ENERGY GENERATION BY FUEL TYPE -- HISTORY & FORECAST**



Coal

Coal generation increased substantially during the 1980's in response to the oil price increases of the 1970's. Coal plants have traditionally been justified based on low forecasts of coal prices relative to oil or natural gas. However, coal plants are capital-intensive, and there are increased concerns surrounding the emissions of coal plants that may lead to stricter regulations that further increase capital investments at coal plants. As a result, coal-fired energy is forecasted to remain stable, comprising approximately 32% to 35% of all energy produced in Peninsular Florida.

Coal Gasification

Coal gasification technology appears to provide flexibility needed to meet potential environmental restrictions and address concerns over the high initial capital investment if the combined cycle portion of the facility is constructed first. If the price differential of oil and natural gas compared to coal widens, the savings from coal gasification might justify additional capital investment at that time. As a result, for power plant siting purposes, it is important to consider whether a site can support a coal gasification plant and all the implications to the local transportation infrastructure. At this time, no utility in Florida is currently planning to construct a coal gasification plant.

Hydroelectric

While existing hydroelectric generating units continue to make a minute contribution (less than 0.1%) to Peninsular Florida's generation mix, there are no plans to construct new units due to the absence of a feasible location for such a unit. Florida's flat terrain does not lend itself to hydroelectric power.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

Interchange Purchases

Peninsular Florida's utilities continue to rely on capacity and energy purchases from out-of-state utilities. Interchange purchases are typically short-term purchases of excess capacity and energy between utilities. The maximum amount of power that Florida can import over the Southern Company-Florida interconnection is approximately 3600 MW. Florida's utilities forecast a slow decline in interchange power purchases over the next ten years, from a current level of 7.8% to 6.6% in ten years. This decrease is primarily because load growth in Southern Company's territory is expected to use much of the excess capacity and energy currently available for resale. While the amount of interchange power is projected to decrease, some capacity from Southern Company should remain for economy and emergency transactions.

Purchases from Non-Utility Generators

Non-utility generators (NUGs) build and operate power plants to satisfy contractual requirements with retail-serving electric utilities. NUGs sell firm capacity to some Florida utilities under long-term purchase contracts. NUGs do not serve retail customers. The amount of NUG electricity purchased by Peninsular Florida's utilities is expected to dip slightly, from 7.6% to 5.4% of total energy consumed, over the next ten years due to the expiration of three firm capacity NUG contracts during that time.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

CRITICAL CONCERNS

The Commission has identified two primary areas of concern which may impact the reliability and cost-effectiveness of the *Plans*. These concerns are the *methodology and conclusions of the FRCC 1999 Reserve Margin Analysis* and the *amount of reserves provided by non-firm resources*. Because of these concerns, the Commission conducted an investigation, in Docket 981890-EI, of Peninsular Florida's reserve margins.

FRCC 1999 RESERVE MARGIN ANALYSIS

The FRCC recently published the *1999 Reserve Margin Analysis*, which contains the results of its reliability study of Peninsular Florida's electric grid. In the study, the FRCC assessed the adequacy of Peninsular Florida's reserve margin standard and the projected reserve margins for Peninsular Florida's electric grid. The study was performed using base case assumptions and sensitivities related to non-coincident peak demand, generating system availability, load forecast accuracy, and a combination of all sensitivities. Under base case assumptions, the FRCC concluded that Peninsular Florida's utilities, as a whole, plan to meet or exceed a minimum 15% winter and summer reserve margin over the entire ten-year planning period from 1999 to 2008. There were some violations of the 15% planning reserve margin criterion under the various planning sensitivities. FRCC also concluded that Peninsular Florida's utilities plan not to exceed the maximum 0.1 days per year loss of load probability (LOLP) criterion.

The Commission has numerous concerns with the assumptions underlying the FRCC's conclusions in its *1999 Reserve Margin Analysis*:

- (1) Base case loss of load probability (LOLP) values for 1999, like those forecasted in 1998, are extremely low. These low LOLP values are driven by high forecasted unit availabilities. If unit availabilities degrade to levels seen a decade ago, Peninsular Florida's utilities will likely experience capacity shortages. If utilities reduce maintenance on existing units to minimize costs, or if they hesitate to build new needed generating units, capacity shortages may become a certainty in the near future.
- (2) The generally accepted 0.1 days per year LOLP criterion appears to translate to a Peninsular Florida reserve margin of approximately 6% to 8%. The FRCC agrees that a 6% to 8% reserve margin is unrealistically low; therefore, reserve margin is the criterion driving the need for additional capacity in Peninsular Florida. Yet, Florida's utilities have no real-time experience with which to test the adequacy of a 15% reserve margin planning criterion.
- (3) A planning reserve margin criterion of 15% can have a substantial adverse impact on operating reserves. A *capacity alert* occurs when Peninsular Florida's operating reserves are small enough such that the loss of the largest unit or major transmission line would cause a capacity shortfall. The Commission has identified five separate occasions since 1998 where Peninsular Florida's operating reserves could have triggered a capacity alert situation had planning reserves been at 15%.
- (4) Analysis of winter and summer peak reserve margin does not account for reliability concerns during off-peak periods. Many units are out of service for maintenance during

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

the spring and fall months. There is an indication that Peninsular Florida has come close to losing firm load during these off-peak months because of weather-related increases in peak demand. The FRCC 1999 *Reserve Margin Analysis* does not address the coordination of maintenance outages during off-peak periods. Such coordination may alleviate the Commission's concerns with off-peak reliability.

The Commission is also concerned that the adequacy of winter reserves may be negatively affected by extreme low winter temperatures. This concern dates back to the events occurring in December, 1989 where much of Peninsular Florida was blacked out due to unusually high demand coupled with low generating unit availability. It is estimated that approximately 4,700 MW of load was not served at the height of the December, 1989 outage. Individual utilities attempt to minimize unit maintenance during peak periods. However, if the FRCC does not closely monitor and coordinate unit maintenance for Peninsular Florida's utilities, a repeat of the December, 1989 weather conditions could result in an even greater amount of unserved load.

The FRCC's 1999 *Reserve Margin Analysis* also contains FRCC's review of the suitability of an aggregate 15% reserve margin criterion for Peninsular Florida. This study covered the major components which comprise reserve margin. Each component was adjusted to reflect how closely past forecasts compared to actual data. For example, if load forecasts were historically 5% less than actual load for the same period, the load forecast for the ten-year planning horizon would be adjusted by a factor of 1.05. Once all adjustments are made, the projected reserve margins are revised to reflect the historical accuracy of utility projections. If the resulting adjusted reserve margin is greater than zero, it may be assumed the originally planned reserve margin is sufficient. If the result is less than zero, the reserve margin criterion is not sufficiently high enough to withstand historical inaccuracies.

The Commission has concerns that the methodology and data used by the FRCC to adopt its 15% reserve margin criterion yields questionable results. For the summer peak period, the FRCC found that a 13% reserve margin would adequately cover all adjustments due to forecast errors. The FRCC determined that a -3% (minus three percent) reserve margin would adequately cover the winter peak period. The FRCC explains the negative value as meaning that forecast errors cause a decrease in base-case winter peak demand.

The 1999 *Reserve Margin Analysis's* LOLP methodology yields unprecedented low reserve margins, and the new reserve margin methodology produces questionable results. This leaves the Commission in a dilemma. Without a tested reserve margin methodology, the FRCC cannot determine whether Peninsular Florida's existing and planned generating resources will be reliable enough to satisfy growing power demands. The state's economic well-being depends on a reliable electricity supply.

The Commission's concern with the viability of FRCC's 15% reserve margin criterion is mitigated in part by the expected addition of approximately 3,100 MW of new merchant plant capacity over the next five years. The Commission has already approved a determination of need for the 514 MW combined cycle unit proposed by Duke Energy New Smyrna Beach. This decision is being appealed to the Florida Supreme Court. The Commission is currently evaluating the need for a 550 MW combined cycle unit proposed by Okeechobee Generating Company. Four other merchant plants have recently been announced through press releases or trade magazine articles. All

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

proposed new merchant plant facilities are listed in Table 4 on page 30. There are arguments in favor of including merchant plant capacity in a reserve margin calculation – the 3,100 MW of announced capacity should cause aggregate peninsular reserve margins to exceed 20%. There are also arguments opposing the inclusion of merchant plant capacity in reserve margin – the capacity is defined as non-firm unless there exists a firm power purchase contract with a utility.

AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

The reserve margin for some of Peninsular Florida's utilities is currently comprised largely of non-firm resources such as load management and interruptible service. This appears to be primarily a near-term concern, as Peninsular Florida's utilities are expecting to rely slightly less on non-firm resources as reserves over the ten-year planning horizon. As shown in Figure 16 at right, non-firm load makes up 70% of Peninsular Florida's 1999/2000 winter reserves and 47.5% of 1999 summer reserves. These values are slightly lower than what was forecast last year, indicating that utilities are planning in future years to rely more on generation than on non-firm load. However, it is still not clear whether this large dependence on non-firm resources is sustainable if, in the future, the frequency of interruptions increases due to low supply-side reserves.

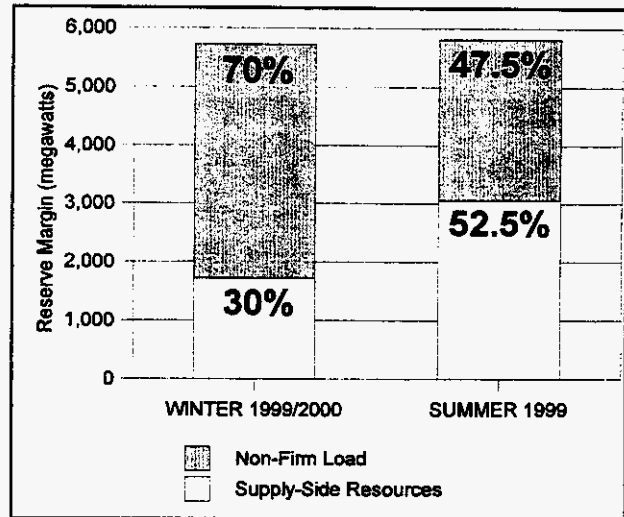


FIGURE 16
RESERVE MARGIN COMPONENTS -
1999

TECO and FPC are the utilities most affected by their reliance on non-firm load for reserves. For 1999, TECO forecasts 71% winter / 75% summer reliance on non-firm load for reserve margin. These ratios are expected to drop during the planning horizon since, during 1999, TECO adopted a new 7% supply-side reserve margin criterion. For 1999, FPC forecasts non-firm load to make up 89% winter / 69% summer of its reserve margin. In 1998, FPC lost nearly 70,000 load management program participants (8% of total) due to the utility's use of load control measures during extremely hot weather conditions in the summer of 1998. Because residential customers can give the utility less than 30-days notice to leave the program, customer flight from load management can cause sudden near-term reliability problems. Both FPC and TECO have had complaints from large, non-firm customers regarding the increased frequency and duration of service interruptions.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

RESERVE MARGIN INVESTIGATION (DOCKET NO. 981890-EI)

The Commission has had an ongoing concern with the level of Peninsular Florida's reserve margins and with the amount of non-firm resources which currently make up these reserve margins. In response to these concerns, on December 17, 1998 the Commission opened Docket No. 981890-EI to investigate the adequacy of reserve margins for Peninsular Florida's utilities. Gulf was not included in the Commission's investigation because Gulf's service territory is not contained in Peninsular Florida.

Many of Peninsular Florida's utilities filed direct testimony in Docket No. 981890-EI supporting the use of a 15% reserve margin planning criterion. As part of the Commission's investigation, the staff performed a vast amount of discovery on the FRCC and each of Peninsular Florida's generating utilities. As a result of the discovery, the Commission staff filed testimony on August 31, 1999 which criticized the continued use of a 15% planning reserve margin criterion for Peninsular Florida utilities. Many utilities filed rebuttal testimony which continued to support the use of a 15% reserve margin planning criterion.

On October 28, 1999, the three investor-owned utilities which were part of the investigation – FPC, FPL, and TECO – filed a proposed agreement in this docket. Pursuant to this agreement, FPC, FPL, and TECO agreed to adopt a 20% reserve margin planning criterion starting in the summer of 2004. The agreement also calls for the Commission to hold workshops to address the appropriate level of non-firm load for Peninsular Florida's utilities, and to address the use of distributed generation as a resource. Based on this year's *Plans*, TECO is the only investor-owned utility that does not meet the 20% criterion in 2004. FPC, FPL, and TECO combined make up approximately 75% of Peninsular Florida's generation.

The Commission determined that the agreement proposed by FPC, FPL, and TECO would mitigate many of the concerns underlying the level of reserves in Peninsular Florida. Municipal and cooperative electric utilities are not part of this agreement, and can therefore carry their current level of reserves. If all municipal and cooperative utilities were to carry exactly a 15% reserve margin while FPC, FPL, and TECO, pursuant to the agreement, each carry a 20% reserve margin, the weighted average reserve margin for Peninsular Florida would be approximately 19%. However, Florida's municipal and cooperative utilities typically carry reserves exceeding 20% in most years.

The Commission approved the agreement on November 30, 1999. The Commission will close this docket upon issuance of the final order.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

RISKS AFFECTING PLANS

Because the future is uncertain, any utility's long-range plan will contain risks that affect the viability of the *Plan*. The major elements of risk are *competition, natural gas availability, declining cost-effectiveness of demand-side management programs, and environmental compliance*. The following discussion identifies the major elements of risk associated with the *Plans*.

COMPETITION

As noted by some reporting utilities, the national debate on electric utility restructuring and retail competition is causing utilities to defer power plant construction and rely more on power purchases whose source is uncertain. Further, the cost of electric generating capacity, particularly natural gas-fired combined cycle and combustion turbine units, has dramatically decreased in recent years. As a result, self-service generation may become more attractive to large industrial retail customers. Utilities have become more cost-conscious in order to reduce rates to these large-use customers.

At present, a form of competition exists at the wholesale level in Florida. Utilities which purchase wholesale electricity, either to meet resource requirements or for economic purposes, can currently choose their electricity supplier. In April, 1996, the Federal Energy Regulatory Commission (FERC) issued *Order 888*, which requires electric utilities to provide comparable, open transmission access for all entities – utilities, non-utility generators, and power marketers.

The possibility of retail competition may already have impacted long-term generation planning for Florida's utilities. According to some utilities, the threat of retail competition is driving utilities to wait until the last possible moment to commit to building a new power plant. Waiting may allow utilities to minimize potential stranded costs due to new power plant construction. However, to ensure system reliability, utilities may be forced to choose an alternative that does not necessarily result in a least-cost resource plan.

In the future, utilities may need to build new power plants on short notice to address declining reserve margins caused by the utilities' hesitancy to commit to new power plants in advance. These new units will likely be gas-fired combustion turbines requiring approximately 24 months of lead time to build. Building new generating units on short notice would address reliability concerns. However, if dual fuel capability with oil is not maintained and natural gas prices increase, utility ratepayers may be locked into higher electric bills than what they otherwise would have been because of this lack of fuel diversity.

NATURAL GAS AVAILABILITY

Current national policies, such as the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992, promote the consumption of natural gas over other fossil fuels. Because natural gas is domestically produced, its increased consumption by electric utilities decreases Florida's dependence on foreign oil.

Figure 17, shown on the next page, illustrates current natural gas consumption by end-user. Natural gas vehicles, fuel cells, and gas air conditioning currently represent less than 1% of the total

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

natural gas usage in Florida. While consumption by these uses should increase in the future, even rapid increases will not materially change natural gas usage for several years. On the other hand, the reporting electric utilities project a 143% increase in natural gas usage during the next ten years. Much of this forecasted increase (83%) is expected to occur between 2001 and 2003.

The State of Florida continues to rely on a single gas transportation pipeline company, Florida Gas Transmission (FGT), to supply direct customers and electric utility fuel requirements. Therefore, the feasibility of using natural gas for future electric generation is directly dependent on FGT's available pipeline capacity. Currently, FGT's system pipeline capacity is approximately 1.455 billion cubic feet per day (Bcf/day). There is no unsubscribed capacity at this time. Nearly 80% of FGT's capacity is used for electric utility and NUG generation purposes. Conservative estimates indicate that future natural gas needs exceed FGT's current capacity. To meet the forecasted needs of electric utilities and NUGs, as well as the expansion of natural gas distribution utilities, an additional 0.8 Bcf/day may be required over the next ten years.

On December 1, 1998, FGT filed an application with the Federal Energy Regulatory Commission (FERC) to obtain approval for its proposed Phase IV Expansion. This proposed expansion, consisting primarily of compression, would increase the average daily delivery capacity by 0.272 Bcf/day, to a total of approximately 1.727 Bcf/day. Eight shippers signed 20-year firm commitments for this capacity, but the anchor shipper is Florida Power & Light (FPL) which sought the gas deliveries for its repowering project at the Fort Myers site. The planned in-service date of this expansion is May, 2001. The FERC issued a preliminary determination on the non-environmental aspects of FGT's Phase IV application on June 30, 1999.

With FERC reviewing FGT's Phase IV application, FGT held a five-week open season for its proposed Phase V expansion. The open season, which closed on April 30, 1999, garnered enough interest for FGT to indicate that it will submit a certificate application to FERC late in 1999 to meet a projected in-service date of mid-2002. The anchor customers for this expansion are FPL and Gulf Power Company (Gulf). FPL will use the capacity to serve its planned repowering project at the Sanford site in Volusia County, while Gulf plans to use its share to fuel a new gas-fired combined-cycle unit at the Lansing Smith site near Panama City. Early estimates indicate that the completion of both Phase IV and Phase V will raise FGT's capacity to nearly 2.0 Bcf/day by mid-2002. This is sufficient capacity to meet the anticipated demand of 1.8 Bcf/day for 2003, but is 0.25 Bcf/day less than the forecasted need of 2.25 Bcf/day for 2008.

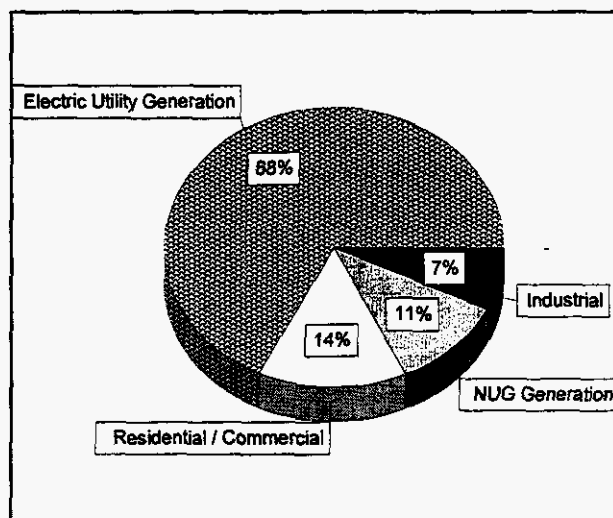


FIGURE 17
NATURAL GAS CONSUMPTION BY
END-USER -- 1999

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

In addition to FGT's proposed Phase IV and Phase V expansion projects, three companies are competing to bring new pipeline capacity into the state.

- Coastal Corporation plans to construct the 700-mile long Gulfstream Natural Gas pipeline. As proposed, the 1.0 Bcf/day pipeline will extend from near Mobile, Alabama, across the Gulf of Mexico, to near Port Manatee. Once on shore, the pipeline will proceed east to a terminus near the Okeechobee Generating Company's proposed merchant plant. The Gulfstream pipeline has an expected in-service date of June, 2002. Coastal filed an application with the FERC on October 15, 1999.
- Duke Energy's Sawgrass pipeline project has two pipeline segments representing different ownership interests. The first segment will extend from the Dauphin Island Gathering Partnership processing plant near Coden, Alabama to a termination point in Panama City, Florida. The proposed in-service date is 2001. The other pipeline will extend from the Coden plant (through expansion of the Enron-Duke Energy system) into Peninsular Florida. This segment, as proposed, will have a capacity of 0.7 Bcf/day at its November, 2002 in-service date. Duke Energy plans to file an application with the FERC in early 2000.
- The proposed 420-mile long Williams-Transco Buccaneer pipeline is a 1.0 Bcf/day project which will extend from a processing plant in Mobile County, Alabama, across the Gulf of Mexico to the west coast of Florida just north of Tampa, and continue onshore in a easterly direction. The Buccaneer pipeline has an expected in-service date of April, 2002. Williams filed an application with the FERC on October 28, 1999

While some utilities have pursued the secondary market to secure pipeline capacity, this market may only provide capacity for short intervals. Since the majority of FGT's pipeline capacity is used for electric generation, the peak throughput on the pipeline occurs in the summer months. Capacity is difficult, at times impossible, to obtain during this period. To assure that ample capacity is available to supply the necessary natural gas requirements, electric utilities will need to arrange for natural gas capacity for new generating units, or identify a contingency plan to obtain transportation capacity. While the timing of the additional demand for capacity may change, the amount of additional capacity needed is presumed to be accurate.

DECLINING COST-EFFECTIVENESS OF DEMAND-SIDE MANAGEMENT PROGRAMS

The cost of new generating units has declined in recent years. Consequently, the cost of an avoided unit -- that is, the cost of a generating unit avoidable by DSM -- continues to decrease. The result is that the cost-effectiveness of utility DSM programs has also declined in recent years.

Although the investor-owned utilities revised their DSM programs as recently as March, 1995, the decrease in avoided cost rendered many DSM programs not cost-effective. The Commission has recently approved several utility requests to modify these programs to restore their cost-effectiveness. These modifications usually consist of reducing the incentive level paid to participating customers. If, ultimately, customer participation decreases as a result of incentive level reductions, utilities may not meet their Commission-approved DSM demand and energy goals. Further, the utilities may need to modify their *Plans* to add capacity resources to offset their DSM deficits and, therefore, meet their reliability requirements.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

ENVIRONMENTAL COMPLIANCE

Table 7 shows the forecasted base-case composite emission rates of Florida's electric utilities. Most utilities forecast declines in their emission rates compared to 1998 estimates. Most of this decline is due to gas-fired repowering projects, while fuel switching and retirement of small oil-fired units account for the rest. Natural gas is clearly the fuel of choice for new generation. Not only have there been improvements in natural gas generation technology, but natural gas-fired generation produces no ash and almost no sulfur dioxide (SO₂) air pollution. Utilities owning coal-fired facilities are contending with air emission restrictions on SO₂, nitrogen oxides (NO_x), volatile organic compounds (VOCs) and particulates.

Ambient air quality in the major metropolitan areas is a public concern. Utilities operating power plants located near or in these highly urbanized areas are likely to experience more scrutiny now than in the past. Retrofit emission controls may be needed to comply with improved air quality standards. The utility is then faced with increased operating costs for existing and proposed units. There is no current legislation at the state or federal level on pollutants such as carbon dioxide (CO₂) and mercury, although there may be some level of future regulation contributes to uncertainty in long-term utility planning.

The use of fossil fuels for electricity generation results in unavoidable emissions. Some emission reduction technologies for one pollutant can increase emissions of another. For example, the limestone used in an SO₂ scrubber releases CO₂ and may increase CO₂ emissions by as much as 3%. Therefore, the combination of complex chemistry, uncertain long term environmental regulations, and each utility's perception of the changes in the national electric utility industry creates uncertainty for environmental compliance planning.

However, the Clean Air Act Amendments of 1990 created the SO₂ allowance (one ton of SO₂ air pollution) and allowance auctions. Each year, EPA is required to hold an auction of SO₂

**TABLE 7
BASE CASE COMPOSITE EMISSION RATES FOR INVESTOR-OWNED
ELECTRIC UTILITIES**

Pollutants	Projected Emissions (Tons per GWh)	
	2000	2007
Sulfur Dioxide (SO ₂)	2.8	2.0
Nitrogen Oxides (NO _x)	1.6	1.3
Particulates	0.2	0.1
VOCs	0.02	0.01
Carbon Dioxide (CO ₂)	570	601
Mercury	0.00001	0.00001

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

allowances. EPA's 1999 spot auction resulted in the sale of 152,510 allowances at prices ranging from \$41.16 to \$230.00 with a clearing price of \$200.55. EPA's seven-year advance auction saw the sale of 125,000 allowances first usable in 2006. These allowances were sold at prices ranging from \$110.31 to \$220.51 with a clearing price of \$167.55. None of Florida's electric utilities purchased SO₂ allowances at either auction. However, it should be noted that other auctions, sales, and trading of SO₂ allowances occur.

The remaining air pollutants are subject to site-specific rate emission caps which DEP and local governments review and set.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

FLORIDA POWER CORPORATION (FPC)

FPC's generating system currently has a winter capacity of 7,727 MW. The system consists of four coal-fired steam turbine units (2,276 MW), four oil-fired steam turbine units (1,270 MW), four natural gas-fired steam turbine units (360 MW), 44 combustion turbine units (2,838 MW), one combined cycle unit (236 MW), and a 90.4% (755 MW) ownership share of the Crystal River 3 nuclear unit. In addition, FPC currently purchases firm capacity from two investor-owned utilities (469 MW) and 19 qualifying facilities (831 MW).

On April 26, 1999, Hines Unit 1, a 470 MW combined cycle unit, was placed into service. FPC also plans to add 300 MW of combustion turbine capacity at the existing Intercession City site by December 2000. Hines Units 2 and 3, each a 470 MW gas-fired combined cycle unit, have projected in-service dates of 2004 and 2006, respectively. FPC also plans capacity additions at the Crystal River site totaling 75 MW. FPC plans to retire 12 generating units with a total generating capacity of 413 MW. The following sites will be affected: Higgins (148 MW), Suwanee (147 MW), Avon Park (64 MW), Turner (36 MW), and Rio Pinar (18 MW). FPC plans to convert three oil-fired steam turbine and two oil-fired combustion turbine units to natural gas.

FPC plans resource additions on its system to meet a dual reliability criteria of 15% summer and winter peak reserve margin and a 0.1 days per year loss of load probability (LOLP). Winter peak demand is driven primarily by low temperatures. FPC's base case winter load forecast assumes a low winter temperature of 34.2°F.

LOAD FORECAST

FPC identifies and justifies its load forecast methodology via its models, variables, data sources, assumptions, and informed judgments. The Commission believes that all of these factors have been accurately documented. A combination of econometric and end-use models provide a sound foundation for planning purposes. The variables used were obtained from reputable sources and are representative of a valid load forecast model.

FPC has traditionally been a winter-peaking utility. FPC's base-case winter peak demand forecast for the next ten years is projected to increase at an average annual growth rate (AAGR) of 1.33%, lower than the 1989-1998 AAGR of 2.06%. However, the Commission is concerned that FPC's base-case summer peak demand forecast shows an AAGR of 0.95%. This projected rate significantly differs from that of other utilities in the state.

FPC's 1994-1998 retail sales forecasts have an absolute percent error of 2.33%, which is lower than the 3.28% numeric average for the nine reporting utilities in the state with sufficient available historical data. For the same five-year period, FPC's retail sales forecasts have an average forecast error of +1.30%, which shows a tendency to over-forecast. FPC justifies its lower projected energy and demand growth rates to the loss of a wholesale contract with Seminole Electric Cooperative, slower population growth, less rapid economic expansion, and improved appliance efficiencies in electric end-uses.

Overall, FPC's load forecast model is appropriate. The Commission encourages FPC to continue its efforts towards accurate forecasts given FPC's major role as an energy provider in the state.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

CONSERVATION

The Commission set new DSM goals for FPC on August 17, 1999. These goals call for a cumulative reduction of 163 MW of summer peak demand, 426 MW of winter peak demand, and 204 GWh of energy consumption over the next ten years. By the end of this year, FPC is scheduled to file a new DSM Plan to meet its new goals.

FPC's DSM Plan consists of 14 programs -- four residential, nine commercial/industrial, and one research and development. FPC also has a low income pilot program offered in conjunction with the Department of Community Affairs. In total, FPC's DSM programs are forecasted to reduce 2007 winter peak demand by 2008 MW (18%).

Much of FPC's forecasted savings are attributed to interruptible service tariffs (255 MW) and the Residential Energy Management program (1179 MW), one of the largest load control programs in the country. Other substantial savings are forecasted to come from FPC's non-dispatchable conservation programs (363 MW).

However, non-firm resources such as interruptible service and load management also make up a substantial part of FPC's reserve margin. For 1999, non-firm resources comprise approximately 89% of FPC's winter reserves and 69% of summer reserves. The Commission is concerned that a drop-off in customer participation in non-firm resource programs may reduce forecasted DSM program demand savings, resulting in an unacceptably low reserve margin. This concern is exacerbated by events occurring during unusually hot, dry weather occurring during the summer of 1998. FPC experienced a loss of approximately 70,000 customers (8% of total) in load management program participation due to customers being load controlled during the hot weather. FPC estimates that these lost participants accounted for 70-80 MW of winter reserves.

ENVIRONMENTAL COMPLIANCE

FPC is not subject to sulfur dioxide (SO₂) compliance restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). All known requirements of Phase II of the CAAA are integrated into FPC's resource planning process. FPC's long-term compliance strategy, like most other utilities, is to increase reliance on natural gas and switch to lower sulfur coals and oils. FPC's secondary compliance methods include environmental dispatch and allowance purchases. Environmental compliance and coordination with respective regulatory agencies are discussed in FPC's *Plan* to the extent that those issues are addressed in the site certification process.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on FPC's *Plan*. Complete comments are contained in Volume 2.

East Central Florida Regional Planning Council

The Planning Council noted that the FPC's Intercession City Site contains a significant regional wildlife corridor. Therefore the proposed addition should be done with adequate consideration given to avoiding impacts to this natural system.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

Florida Department of Community Affairs (DCA)

DCA provided general comments on FPC's *Plan* and stated that the Hines facility is consistent with applicable local land use and zoning ordinances..

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

Southwest Florida Water Management District

All proposed plant expansions are on existing sites or have already undergone site certification. The District's water resource concerns were addressed during the certification process .

Tampa Bay Regional Planning Council

The Planning Council provided general comments and found FPC's *Plan* to be consistent with the Tampa Bay Regional Planning Council's *Strategic Regional Policy Plan*.

SUITABILITY

Forecasted reserve margins are expected to be at or above FPC's criterion of 15% for each seasonal peak throughout the planning horizon. Pursuant to the Commission's decision in Docket No. 981890-EI, FPC will use a 20% reserve margin planning criterion beginning in 2004. FPC's *Plan* is suitable for planning purposes. By classifying FPC's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

FLORIDA POWER & LIGHT COMPANY (FPL)

FPL's generating system consists of four nuclear units totaling 3,013 MW; six gas-fired combined cycle units totaling 2,354 MW; 17 residual oil-fired steam turbines totaling 6,545 MW; four gas-fired steam turbines totaling 1,871 MW; three coal-fired units totaling 927 MW; 36 gas-fired combustion turbines totaling 1,371 MW; 12 distillate oil-fired combustion turbines totaling 690 MW; and five distillate oil-fired internal combustion units (12 MW).

FPL expects to increase its generating resources by approximately 3,600 MW during the planning horizon. A significant part of FPL's expansion plan is the repowering of existing Ft. Myers and Sanford generating units. By replacing existing boilers with state-of-the-art combustion turbines while using the same steam cycle at these two plants, FPL will gain more than 2,000 MW of winter generating capability beginning in the year 2002. FPL also plans to add three combined cycle units in 2006, 2007, and 2008.

FPL's *Plan* identified 19 proposed transmission line additions during the planning horizon. Two planned 45-mile, 230 KV lines from Poinsett to Sanford will require certification under the Transmission Line Siting Act. Certification will also be required for a planned 500 KV line from Conservation to Levee.

Prior to 1998, FPL planned resource additions on its system to meet a dual reliability criteria of 15% summer peak reserve margin and a 0.1 days per year loss of load probability (LOLP). FPL added a third reliability criterion, 15% winter peak reserve margin, for last year's *Plan*. As a result, FPL's 1999 *Plan* forecasts higher winter reserves than past plans. The winter reserve margin criterion is the driving force behind the repowering projects at Ft. Myers and Sanford.

LOAD FORECAST

FPL develops its residential load forecast via the Residential End-Use Energy Planning Model (REEPS), an integrated end-use/econometric forecasting model. This method simulates acquisitions and usage of nine major household appliances and residual electricity use by means of selecting a representative sample of households. Following an analysis of appliance stock, prices, and other factors, electricity consumption is then aggregated across all households to generate a forecast for total residential sales. In addition, REEPS simulates appliance stock in new and existing homes by taking energy, weather, and conservation measures into consideration.

FPL adequately identifies and describes the models, variables, data sources, assumptions, and informed judgements used to generate the demand and energy forecasts in this year's *Plan*. The forecasting analysis is thorough and incorporates quantitative rigor and sophistication. The Commission believes that all of these factors have been accurately documented and that the data sources relied upon are credible.

FPL has traditionally been a summer-peaking utility. FPL's base-case summer peak demand forecast for the next ten years is projected to increase at an AAGR of 1.37%, less than the 2.06% AAGR for the 1989-1998 period. FPL's 1999 base-case summer peak demand forecast is higher than its 1998 forecast by an average of 194 MW per year over the forecast horizon.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

FPL's 1999 base-case winter peak demand forecast for the next ten years is projected to increase at an AAGR of 1.89%, similar to last year's 1998-2007 AAGR projection of 1.73%. However, the Commission noted in last year's review that FPL's 1998 base-case winter peak demand forecast was lower than that from its 1997 *Plan* by an average of 144 MW per year over the forecast horizon. This year, the difference between the 1999 and 1998 base-case projections has widened to an average of 337 MW per year. The Commission is concerned that the actual data figures are becoming increasingly different on a year-to-year basis and FPL has not fully addressed the reasons that justify these revisions.

FPL's 1994-1998 retail sales forecasts have an absolute percent error of 2.44%, which is lower than the 3.28% numeric average for the nine reporting utilities in the state with sufficient available historical data. For the same five-year period, FPL's retail sales forecasts have an average forecast error of -2.44%, which shows a tendency to under-forecast.

Overall, FPL's load forecast is appropriate. The Commission encourages FPL to continue its efforts towards accurate forecasts given the Company's major role as an energy provider in the state.

CONSERVATION

The Commission set new DSM goals for FPL on August 17, 1999. These goals call for a cumulative reduction of 765 MW of summer peak demand, 505 MW of winter peak demand, and 1287 GWh of energy consumption over the next ten years. By the end of this year, FPL is scheduled to file a new DSM Plan to meet its new goals.

FPL currently offers six residential and eight commercial/industrial DSM programs to its customers. These programs are forecast to reduce winter peak demand by 1,812 MW in 2007, representing approximately 9% of FPL's total winter peak demand. These programs are also projected to reduce FPL's system annual energy usage by 1,335 GWh (1%) in 2007. FPL's non-firm resources – interruptible service tariffs and load management – make up approximately 41% of 1998 winter reserves and 36% of 1998 summer reserves.

In 1997, FPL revised many of its existing DSM programs. These programs were revised to maintain their cost-effective conservation during times of ever-decreasing avoided costs. FPL also received Commission approval in 1997 to offer a new program, BuildSmart, designed to encourage the design and construction of energy efficient homes.

ENVIRONMENTAL COMPLIANCE

FPL is not subject to sulfur dioxide (SO₂) compliance restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). All known requirements of Phase II of the CAAA are integrated into FPL's resource planning process. FPL's long-term compliance strategy, like most other utilities, is to increase reliance on natural gas and switch to lower sulfur coals and oils. FPL's secondary compliance methods include environmental dispatch and allowance purchases. Environmental compliance and coordination with respective regulatory agencies are discussed in FPL's *Plan* to the extent that those issues are addressed in the site certification process.

FPL's 1999 projection of air emission rates is lower than forecasts performed in recent past years.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

Reduced emissions forecasts are due primarily to unit repowerings planned at Ft. Myers and Sanford, which will be large natural gas consumers. FPL performed two emission sensitivities: *high fuel prices with low demand*, and *low fuel prices with high demand*. These sensitivities show that with low demand and high price forecasts for natural gas and light oil, FPL's system will emit more SO₂, NO_x, particulates and VOCs but less CO₂ compared with the base case. The converse is also true. FPL's analysis demonstrates some of the benefits of lowering demand as well as aggressively pursuing low natural gas prices.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on FPL's *Plan*. Complete comments are contained in Volume 2.

East Central Florida Regional Planning Council

The Council provided general comments on the positive environmental impacts of FPL's proposed Sanford unit repowering. However, the Council noted that strict impact avoidance is necessary if the site requires additional gas lines.

Florida Department of Community Affairs (DCA)

DCA stated that FPL should coordinate with environmental agencies during the planning of the Ft. Myers repowering to minimize impact to endangered species. DCA also noted that a mitigation plan dealing with the loss of isolated wetlands at the Martin plant site was discussed in FPL's 1997 *Plan*, but is not mentioned in this year's *Plan*. DCA also expressed general concerns regarding the Cape Canaveral and Port Everglades sites, which were identified as potential sites in FPL's *Plan*.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

South Florida Regional Planning Council

Since planned transmission lines are limited to existing utility easements and are necessary for economic growth, the Council is not concerned that these lines conflict with the regional plan. FPL's *Plan* is consistent with the goals and policies of the regional plan.

Southwest Florida Regional Planning Council

Generally commented on FPL's plans to repower the Ft. Myers site.

Southwest Florida Water Management District

All proposed plant expansions are on existing sites or have already undergone site certification. The District's water resource concerns were addressed during the certification process.

Tampa Bay Regional Planning Council

FPL's *Plan* is consistent with regional policies.

Volusia County

Supports FPL's repowering project at the Sanford site and is encouraged by the potential positive impact on air quality due to the proposed use of natural gas.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

SUITABILITY

Forecasted reserve margins are expected to be at or above FPL's criterion of 15% for each seasonal peak throughout the planning horizon. Pursuant to the Commission's decision in Docket No. 981890-EI, FPL will use a 20% reserve margin planning criterion beginning in 2004. FPL's *Plan* is suitable for planning purposes. By classifying FPL's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

GULF POWER COMPANY (Gulf)

Gulf relies heavily upon coal-fired generation capacity to meet its customers' electricity demand. Gulf currently has full or partial ownership (with other Southern Company members) of 11 coal-fired steam turbine units (2,103 MW of winter capacity), three natural gas-fired steam turbine units (83 MW), and four combustion turbine units (54 MW).

Gulf plans to rely on purchases from the Southern system to meet its reserve criterion through 2001. Reserve requirements for 2002 will be met with a planned 540 MW combined cycle unit at the existing Lansing Smith site. The Commission approved Gulf's petition for a need determination for the Lansing Smith combined cycle unit in June, 1999. Gulf also plans to repower its existing Crist Units 1, 2, and 3, with an expected in-service date of 2007. Gulf also plans to retire a 40 MW combustion turbine at the Lansing Smith site in 2006.

Gulf plans to meet short-term deficiencies in its reserve margin by making a series of power purchases over the next four years. Although the Southern Company's target reserve margin is 13.5%, Gulf's reserve margin at winter peak is well below 13.5% for each of the next four years. Therefore, Gulf is expected to be a net buyer of capacity from the Southern Company pool.

LOAD FORECAST

Gulf uses different methods to produce its short term forecasts (0-2 years) and intermediate/long term forecasts (3-25 years). Short term forecasts are the aggregate of district projections performed by district personnel for each revenue class, based upon a variety of forecasting methods. The core economic assumptions (service territory growth, electricity price, and weather patterns) are not explicitly annotated in the analysis. Gulf's intermediate and long-term forecasts use models that integrate end-use and econometric methods. They include the Residential End-Use Energy Planning System (REEPS) and Commercial End-Use Model (COMMEND). Data sources were not specifically identified, and sensitivity analysis (low- and high-band forecasts) were not provided.

In Gulf's 1997 *Plan*, the 2005 customer forecast included 13,567 fewer customers than the 2005 forecast from the 1996 *Plan*. At that time, Gulf cited an update of the 1990 Census and fewer military installations in Gulf's service territory as the reasons for this adjustment. For the 1998 and 1999 *Plans*, Gulf's population projections were revised upward, and the most recent 2006 population forecast is 24.5% higher than that 1997 forecast for the same year.

Gulf is a summer-peaking utility. Gulf's base-case summer peak demand for the next ten years shows an AAGR of 1.41%, which is exactly half of the 2.82% historical growth rate. The base-case winter peak demand over the forecast period is the lowest in the state, 0.97%. This compares to an AAGR of 1.97% in winter peak demand over the past ten years. The 1999 base-case summer and winter peak forecasts are fairly consistent with those filed in Gulf's 1998 *Plan*.

In response to a 1997 Commission inquiry regarding the substantial decrease in forecasted demand growth rates compared to historical growth rates, Gulf stated that the stabilization of appliance saturation rates and appliance efficiencies are the main factors driving this low-growth forecast. Gulf used the REEPS to model winter demand for the residential sector, which accounts for such appliance saturations and efficiencies. Another factor contributing to a suppression in demand

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

growth is residential conservation programs. Without the growth in such programs, the forecasted AAGR would have been 1.60%. Considering both the forecasted customer growth rate and historical trend in winter demand, the Commission believes that the REEPS model, as employed by Gulf, may underestimate the future winter demand growth rate.

Gulf's 1999 *Plan* shows smaller increases in the forecasted growth rate of both demand and energy than Gulf's 1998 *Plan*. This is a concern due to Gulf's revised service territory population estimates. These growth projections are significantly higher than those from two years ago, but demand and energy forecasts are very similar and the reasons for this inconsistency is not specifically stated.

CONSERVATION

The Commission set new DSM goals for Gulf on August 17, 1999. These goals call for a cumulative reduction of 221 MW of summer peak demand, 235 MW of winter peak demand, and 143 GWh of energy consumption over the next ten years. By the end of this year, Gulf is scheduled to file a new DSM Plan to meet its new goals.

Most of Gulf's forecasted demand savings are expected to result from the Good Cents Home program and the Advanced Energy Management program. In 1996, Gulf implemented Solar for Schools, a green pricing pilot program which obtains funding for the installation of solar technologies in participating schools. All of Gulf's existing and new DSM programs are expected to reduce the 2007 winter demand by an estimated 547 MW (20%) from what it would have been without DSM.

Gulf does not have an interruptible service tariff or any dispatchable load management on its system. As a result, none of Gulf's 1999 winter and summer reserves are comprised of non-firm resources.

ENVIRONMENTAL COMPLIANCE

Gulf's compliance strategy is a subset of the overall Southern Company compliance strategy. Gulf's 1999 emissions projections show a general downward trend in most pollutants relative to 1998 projections. This change is consistent with Gulf's plan to add the new Smith combined cycle unit. Estimates of CO₂ emissions, however, substantially increase due to Gulf's expectation of economic dispatching the new natural gas facility at high load factors.

To date, Gulf is the only Florida utility that has formally submitted a Clean Air Act Compliance Plan for approval by the Commission. Gulf continues to recover costs for precipitator changes, continuous emissions monitoring equipment, groundwater monitoring, and hazardous materials through the Environmental Cost Recovery Clause (ECRC).

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on Gulf's *Plan*. Complete comments are contained in Volume 2.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

Florida Department of Community Affairs (DCA)

DCA notes that more information is necessary to determine if the proposed repowering of the Crist units is consistent with the County's comprehensive plan.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

West Florida Regional Planning Council

Gulf's *Plan* is consistent with the Strategic Regional Policy Plan.

SUITABILITY

The Commission notes that Gulf's reserve margin does not satisfy its 13.5% planning criterion in any year, either summer or winter season, until Smith Unit 3 is placed into service in June, 2002. Gulf currently does not have sufficient firm commitments to purchase short-term capacity to meet forecasted needs. Gulf should indicate, with more certainty, the manner in which it plans to meet its capacity needs. However, because Gulf's capacity shortfall is small in magnitude in relation to the size of the Southern Company, and since Gulf is able to rely on the Southern Company to meet such small capacity deficiencies, Gulf's *Plan* is suitable for planning purposes.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

TAMPA ELECTRIC COMPANY (TECO)

TECO's system currently has a total winter generating capacity of 3,601 MW. TECO's installed capacity is dominated by coal-fired generation, which alone exceeds load requirements. As a result, TECO's interchange consists primarily of wholesale energy and capacity sales to other utilities. Ten coal-fired units supply 2,897 MW of TECO's current system capacity. TECO has small amounts of capacity from six fossil steam units (223 MW total), four combustion turbines (194 MW total) and two diesel units (34 MW total). **Polk Unit 1**, a 250 MW integrated coal gasification combined cycle (IGCC) unit, was placed into service in 1996. TECO initially plans to use gasified coal to fuel the new unit, but future plans call for TECO to burn a mixture of gasified coal and petcoke.

TECO's future generation expansion plans include the installation of six 180 MW natural gas-fired combustion turbine units at the Polk site, one each in 2001, 2003, 2004, 2005, 2007, and 2008. TECO currently plans to retire all five fossil steam units at the Hookers Point site (215 MW total) in 2003. Nine transmission line additions are proposed in TECO's *Plan*, but none appear to require certification under the Transmission Line Siting Act.

TECO plans resource additions on its system to meet a dual reliability criteria of 15% winter reserve margin and a 1% EUE/NEL ratio. Winter peak demand is driven primarily by low temperatures. TECO's base case winter load forecast assumes a low winter temperature of 31 °F.

LOAD FORECAST

TECO's energy forecast is the result of three separate forecasting methods. The most comprehensive of these is the detailed end-use model. The results of two additional models (multiple regression and trend analysis) are blended with the end-use model to form the basis of the forecast. TECO's *Plan* does not identify how these models are reconciled, although it provides a good diagram outlining TECO's customer, demand, and energy forecast process. TECO's end-use forecast method takes into account a wide range of forecast assumptions.

In addition to base case energy and demand forecasts, TECO constructed high and low band demand and energy forecasts, using explicit assumptions regarding customer growth, employment, per capita income, appliance saturation and efficiency standards, and the real price of electricity.

During the past ten years, TECO has been primarily a winter-peaking utility. Nevertheless, this was not the case in 1998 as summer peak demand exceeded 1997/1998 winter peak demand by 613 MW. TECO's base-case winter peak demand increased by an AAGR of 1.05% over the 1989-1998 period, which is significantly different than last year's 3.31% AAGR. However, the decrease is a function of a mild 1997/1998 winter as compared to prior winter seasons. TECO's base-case summer peak demand is projected to increase at an AAGR of 3.04%, which is similar to its historical growth rate of 3.17% for the 1989-1998 period.

TECO's 1994-1998 retail sales forecasts have an absolute percent error of 2.49%, which is slightly lower than the numeric average for the nine of reporting utilities in the state with sufficient available historical data. For the same five-year period, TECO's retail sales forecasts have an average forecast error of -1.81%, which shows a tendency to under-forecast..

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

Overall, TECO's load forecast criteria are adequate. The models employed are comprehensive and data sources are properly documented.

CONSERVATION

The Commission set new DSM goals for TECO on August 17, 1999. These goals call for a cumulative reduction of 71 MW of summer peak demand, 123 MW of winter peak demand, and 189 GWh of energy consumption over the next ten years. By the end of this year, TECO is scheduled to file a new DSM Plan to meet its new goals.

TECO currently offers ten DSM programs. Most of TECO's forecasted demand savings are expected to come from non-dispatchable conservation programs (winter demand reduction estimated at 703 MW in 2007) and a dispatchable load management program (482 MW). While interruptible service is forecasted to continue during the planning horizon, its contribution to TECO's winter demand savings is forecasted to decrease from 211 MW in 1998 to 192 MW by 2007. In total, TECO's DSM programs are forecasted to reduce winter peak demand by approximately 1185 MW (26.5%) in 2007.

However, non-firm resources such as interruptible service and load management make up a substantial part of TECO's reserve margin. For 1999, non-firm resources comprise approximately 71% of TECO's winter reserves and 75% of summer reserves. The Commission is concerned that a drop-off in customer participation in non-firm resource programs may reduce forecasted demand savings from DSM programs, resulting in an unacceptably low reserve margin.

ENVIRONMENTAL COMPLIANCE

TECO is subject to compliance restrictions contained in both Phase I and Phase II of the 1990 Clean Air Act Amendments (CAAA). TECO's SO₂ reduction plan is to use low-sulfur coal at Gannon and add a large scrubber which will serve both Big Bend Units 1 and 2. This is TECO's current plan to achieve the reductions by year end 2000 which has been in their projections since at least 1995. TECO projects a noticeable drop in NO_x emissions again this year, but does not explain how this reduction will be accomplished.

TECO provided four sensitivities addressing emissions due to high/low fuel prices and high/low demand. Results are somewhat similar to FPL's but lack the advantage of significant use of natural gas at its existing units.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on TECO's *Plan*. Complete comments are contained in Volume 2.

Florida Department of Community Affairs (DCA)

DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA has concerns over whether TECO plans to operate proposed combustion turbine units to serve baseload requirements. If TECO plans to use this unit addition for baseload needs, DCA would have TECO revise its *Plan* to replace the CT units with combined cycle capacity.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

Southwest Florida Water Management District

All proposed plant expansions are on existing sites or have already undergone site certification. As such, the District's water resource concerns were addressed during the certification process.

Tampa Bay Regional Planning Council

TECO's *Plan* is consistent with regional policies.

SUITABILITY

Forecasted reserve margins are expected to be at or above TECO's criterion of 15% for each seasonal peak throughout the planning horizon. Pursuant to the Commission's decision in Docket No. 981890-EI, TECO will use a 20% reserve margin planning criterion beginning in 2004. TECO's *Plan* is suitable for planning purposes. By classifying TECO's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

FLORIDA MUNICIPAL POWER AGENCY (FMPA)

FMPA is an organization that jointly manages and operates the activities of 27 municipal electric utilities. Ten member utilities currently comprise the All-Requirements Project, meaning that FMPA has committed to plan for, and supply, all power requirements for these members. FMPA has recently added four new municipalities to its All-Requirements Project: Vero Beach, Starke, Fort Pierce, and Key West. FMPA plans to add Lake Worth to the network in 2000.

FMPA's existing generation facilities include two coal-fired steam turbines (237 MW winter capacity), an ownership share in FPL's St. Lucie 2 nuclear unit (75 MW), one combined cycle unit (60 MW), and five combustion turbine units (106 MW). On September 17, 1998, FMPA and the Kissimmee Utility Authority received Commission approval to build a 250 MW combined cycle unit to be placed into service in 2001. FMPA's plans also include construction of an 80 MW combustion turbine in 2007. Both proposed units will be located at the Cane Island complex. The addition of three All-Requirements members is forecasted to increase net interchange from 362 GWh in 1997 to 2092 GWh by 2008.

The aggregate load for FMPA's members exceeds their combined capacity. To serve load that exceeds generation, FMPA purchases capacity from other utilities. FMPA's member utilities serve nearly 650,000 customers. This total includes Orlando Utilities Commission, which joined effective November 7, 1997. Member cities not involved in the All-Requirements Project are responsible for planning their own generation and transmission needs. FMPA's load and energy forecasts account for DSM savings attributable to member utilities' conservation programs.

FMPA plans resource additions on its system to meet a reliability criterion of 18% summer and winter peak reserve margin. Along with the planned additions described above, FMPA plans to purchase capacity and energy from other utilities to meet its reserve margin criterion.

LOAD FORECAST

FMPA used various econometric models to forecast sales by rate class, specific to each member utility, supplied by the All-Requirements Project. Time series and time trend modeling are also employed to forecast load. FMPA has done a better job of documenting forecasting techniques this year than in past years, but still does not identify its data sources. Some general economic and demographic assumptions are identified. Nonetheless, applying generalized economic assumptions across all member systems may not best represent the load characteristics for these geographically-dispersed municipalities. FMPA did not provide sensitivity analyses based upon varying economic and demographic assumptions. There is insufficient historical forecast data exists to compare FMPA's forecast accuracy to other utilities in the state.

FMPA has historically been a summer-peaking utility. Its base-case summer peak demand for the 1990-1998 period increased at an AAGR of 12.16%, due primarily to the addition of new member utilities. The projected AAGR for the next ten years is 2.69%. FMPA's base-case winter peak demand for the 1990-1998 period increased at an AAGR of 6.51%. Last year's AAGR for the 1990-1997 period was 1.71%. This change is due to a large increase in demand during the 1997/1998 winter season. For the ten-year planning horizon, FMPA forecasts winter peak demand to increase at an AAGR of 2.69%. Both summer and winter peak demand are forecasted to grow at rates which

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

are very close to the growth rates projected by most utilities in the state. This year's forecasts are consistent with the base-case summer and winter peak forecasts provided by FMPA in its 1998 *Plan*.

CONSERVATION

Member utilities individually promote their own conservation programs with assistance from FMPA. Originally, the only All-Requirements members having to establish numeric conservation goals were Vero Beach and Ocala. However, since the Florida Energy Efficiency and Conservation Act (FEECA) was revised to increase the annual retail sales threshold to 2,000 GWH, both Vero Beach and Ocala are now exempt. Nonetheless, FMPA's All-Requirements participants may choose from among seven conservation programs that have been evaluated to ensure cost effectiveness. These programs are forecasted to reduce the total 2007 winter load of FMPA's member utilities by 9 MW (0.7%).

ENVIRONMENTAL COMPLIANCE

None of Florida's municipal utilities are subject to restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). At this time, FMPA does not appear to be severely impacted (on a tonnage reduction basis) by Phase II of the CAAA. This is because of FMPA's participation in Orlando Utilities Commission's (OUC) Stanton Unit 2. Stanton Unit 2 is a scrubbed, coal-fired unit with precipitators to control particulate emissions and selective catalytic reduction technology to reduce NO_x. The addition of a combined cycle unit at Cane Island does not have a significant impact except to increase total emissions.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on FMPA's *Plan*. Complete comments are contained in Volume 2.

Florida Department of Community Affairs (DCA)

DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA has concerns over whether FMPA plans to operate a proposed combustion turbine unit to serve baseload requirements. If FMPA plans to use this unit addition for baseload needs, DCA recommends that FMPA include the conversion of this unit to combined cycle operation as capacity needs increase in the future.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

East Central Florida Regional Planning Council

FMPA's *Plan* contains little information on possible environmental impacts of Cane Island Unit 3.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

SUITABILITY

Forecasted reserve margins are expected to be at or above FMPA's criterion of 18% for each seasonal peak throughout the planning horizon. FMPA's *Plan* is **suitable** for planning purposes. By classifying FMPA's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

GAINESVILLE REGIONAL UTILITIES (GRU)

GRU's electric generating system currently has a winter capacity of 563 MW. The system consists of a 228 MW coal-fired steam turbine unit, three gas-fired steam turbine units (158 MW), six combustion turbine units (166 MW), and an 11 MW ownership share of FPC's Crystal River 3 nuclear unit.

GRU expects to be a net seller of interchange energy until the year 2000, although its firm and non-firm interchange transactions contribute only minimally to GRU's generation mix. Most of GRU's energy generation (85%) currently comes from the single coal-fired unit, **Deerhaven 2**, since more than half of GRU's natural gas-fired capacity is used strictly for peaking purposes.

Although the capacity is not needed until 2006, GRU plans to repower **J. R. Kelly Unit 8** as a 110 MW combined-cycle unit in 2001. The Gainesville City Commission approved the early installation date to improve operating efficiency, reduce emissions, and increase capacity when reserve margin for Peninsular Florida is tight.

GRU plans resource additions on its system to meet a reliability criterion of 15% summer and winter peak reserve margin. Winter peak demand is driven primarily by low temperatures. GRU's base case winter load forecast assumes a low winter temperature of 23°F.

LOAD FORECAST

GRU uses a series of linear multiple regression models to forecast energy consumption. GRU's historical data has been obtained from reputable sources, including the Bureau of Economic and Business Research (BEBR) at the University of Florida and the U.S. Department of Commerce. GRU outlined the key assumptions of its forecast. These assumptions include normal weather conditions, declining real electricity prices, an inflation adjustment of all income and price data indexed to base year 1986, a 3.5% average annual inflation rate increase throughout the forecast horizon, and the impacts of demand-side management programs.

GRU is a summer-peaking utility. GRU's base-case summer peak demand forecast for the next ten years is projected to increase at an AAGR of 2.38%, less than the 3.36% AAGR for the 1989-1998 period. GRU's *Plan* does not specifically justify these lower growth rates. However, GRU's 1999 base-case summer peak demand forecast is consistent with that contained in its 1998 *Plan*.

GRU's 1994-1998 retail sales forecasts have an absolute percent error of 2.13%, lower than the numeric average for the nine reporting utilities in the state with sufficient available historical data. For the same period, GRU's retail sales forecasts have an average forecast error of -2.13%, which shows a tendency to under-forecast.

Overall, GRU's load forecast criteria are adequate. The statistical models used for this analysis are direct and appropriate for the purposes of this review.

CONSERVATION

GRU is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

(FEECA). However, GRU expects to continue offering conservation programs. GRU does not have a load management program or an interruptible service program. GRU offers energy audits, home fix-up programs, natural gas displacement of electric space heating and water heating, commercial lighting efficiency and maintenance services, and public information and education programs. These programs are expected to reduce GRU's winter peak demand by an estimated 28 MW (6.5%) by 2007.

In the near future, GRU plans to begin rebate programs for new commercial programs, including thermal energy storage, heat recovery, and gas-fired cooling. GRU also plans to begin two residential DSM programs to encourage the use of solar energy: a solar water heater rebate program, and a green pricing program for grid-connected photovoltaic systems installed on the roofs of homes.

ENVIRONMENTAL COMPLIANCE

None of Florida's municipal utilities are subject to restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). GRU does not appear to be severely impacted (on a tonnage reduction basis) by Phase II of the CAAA.

Deerhaven Unit 2 achieves environmental compliance strictly by purchasing compliance-quality coal because the unit does not have a scrubber. As stated last year, this may become a concern if the price for compliance coals begins to rise in the future.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on GRU's *Plan*. Complete comments are contained in Volume 2.

Alachua County Department of Growth Management

No comments are necessary at this time.

Florida Department of Community Affairs (DCA)

DCA commented that the proposed repowering of the John R. Kelly plant is consistent with the local comprehensive plan.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

North Central Florida Regional Planning Council

GRU's *Plan* is consistent with the policies of the North Central Florida Regional Policy Plan.

Suwannee River Water Management District

The District did not identify any environmental impacts or other related issues of concern in its review of GRU's *Plan*.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

SUITABILITY

Forecasted reserve margins are expected to be at or above GRU's criterion of 15% for each seasonal peak throughout the planning horizon. GRU's *Plan* is **suitable** for planning purposes. By classifying GRU's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

JACKSONVILLE ELECTRIC AUTHORITY (JEA)

JEA's generation mix consists of 1,220 MW of coal-fired capacity from its share of two units at St. John's River Power Park, in Jacksonville, and Scherer Unit 4, near Macon, Georgia. Generation from gas-and oil-fired steam units totals 1,421 MW, and gas turbine units supply 437 MW.

JEA plans to add a 168 MW combustion turbine (CT) at the Kennedy site in 2000, three 168 MW CT units in 2001 at the new Brandy Branch site, repower Northside Units 1 and 2 in 2002, convert the two Brandy Branch CT units to combined cycle operation in 2005, and build a 168 MW CT in 2007. JEA also intends to place Kennedy 10 in cold shutdown mode in 2000, and retire Southside Units 4 and 5 in 2001.

JEA also plans to purchase seasonal capacity during 2000, 2002, and 2008. JEA has entered into a partnership with the Municipal Electric Authority of Georgia and the South Carolina Public Service Authority in forming The Energy Authority (TEA). TEA will work on behalf of JEA as its power marketing group to meet purchased power needs.

JEA plans resource additions on its system to meet a reliability criterion of 15% summer and winter peak reserve margin. Winter peak demand is driven primarily by low temperatures. JEA's base case winter load forecast assumes a low winter temperature of 23°F.

LOAD FORECAST

JEA used trend analysis to evaluate base, high, and low forecasts of demand, energy, and number of customers. All of these criteria are adjusted for the JEA's assessment of the strength of the local economy. However, JEA did not specify the data sources used in its energy models, the forecast assumptions, or descriptions of the forecasting methods used to generate its forecasts.

JEA's 1994-1998 retail sales forecasts have an absolute percent error of 5.79%, the highest among all of the state's reporting utilities and nearly 2.5% over the statewide average of 3.28%. For the same period, JEA's retail sales forecasts have an average forecast error of -5.79%, which shows a strong tendency to under-forecast.

JEA has been a winter-peaking utility for the past few years. Its base-case winter peak demand forecast for the next ten years is projected to increase at an AAGR of 3.19%, which is lower than the historical winter peak AAGR of 4.75% over the past ten years. The base-case summer peak demand forecast shows an AAGR of 2.58%, which is lower than the historical summer peak AAGR of 3.08%. Both base-case seasonal peak forecasts are lower on average than those contained in JEA's 1998 *Plan* in MW terms (142 MW less for summer and 118 MW less for winter).

JEA's method of trending historical data series to derive a load forecast merely extends historical errors into future time periods. Trend forecasts do not explicitly consider the impact of projected personal income growth, population growth, and other variables which are related to electricity usage. Forecasts which are based upon multiple regression models include such variables. In addition, trending techniques ignore the detailed analyses of appliance use, efficiencies and saturations, all of which are the foundation of end-use models. Most of the state's large utilities -- those with annual energy sales greater than 10,000 GWH-- use end-use and econometric models

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

simultaneously to generate load forecasts. The Commission believes that JEA would benefit from the detailed analysis permitted by the end-use and econometric modeling techniques employed by other large utilities in the state.

CONSERVATION

JEA's conservation programs consist primarily of audits, public information and education programs, and home fix-up programs. JEA does not currently have a load management program. Nearly all forecasted demand savings are expected to come from JEA's interruptible tariffs. JEA forecasts its interruptible tariffs to reduce total winter peak demand in 2007 by 108 MW.

The Commission set residential DSM goals for JEA in 1995. JEA has no commercial / industrial DSM goals. The Commission is scheduled to set new DSM goals for JEA in 2000. Currently, JEA's residential DSM programs have yielded cumulative summer and winter demand savings which do not meet the current Commission-approved goals. However, JEA has been achieving its residential energy goal.

ENVIRONMENTAL COMPLIANCE

None of Florida's municipal utilities are subject to restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). The extent which JEA is impacted by Phase II of the CAAA is a strategic concern especially with the repowering project at their Northside facility. Emission reductions of about 10% are expected through the application of Best Available Control Technology (BACT). However, as JEA indicates, BACT for future projects is subject to change as regulations and interpretations of the regulations change.

JEA examined eight emissions sensitivities: reference plan, base case, low and high fuel prices, low and high demand, high discount rate, and self-build. None of the sensitivities forecasted a significant increase or decrease emissions above the base case.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on JEA's *Plan*. Complete comments are contained in Volume 2.

Florida Department of Community Affairs (DCA)

DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA has concerns over whether JEA plans to operate a proposed combustion turbine unit to serve baseload requirements. If JEA plans to use this unit addition for baseload needs, DCA recommends that JEA include the conversion of this unit to combined cycle operation as capacity needs increase in the future.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

Northeast Florida Regional Planning Council

The Council commented that because JEA's planned additions are at existing sites, new impacts on public facility capacities are not expected. JEA's *Plan* is not inconsistent with the City of Jacksonville's Future Land Use Element.

SUITABILITY

Forecasted reserve margins are expected to be at or above JEA's criterion of 15% for each seasonal peak throughout the planning horizon. JEA's *Plan* is **suitable** for planning purposes. By classifying JEA's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

KISSIMMEE UTILITY AUTHORITY (KUA)

KUA's electric system consists of eight gas- and oil-fired internal combustion units (19 MW) and one combined cycle unit (52 MW). KUA and FMPA each have a 50% joint ownership in **Cane Island Unit 1**, a gas-fired combustion turbine (20 MW), and **Cane Island Unit 2**, a combined cycle unit (60 MW). KUA also has an ownership interest in FPC's **Crystal River 3** nuclear unit (6 MW), OUC's **Stanton Unit 1** (21 MW), and OUC's **Indian River combustion turbine units A and B** (11 MW total). In addition, KUA has a contract to purchase 20 MW of firm capacity from OUC with an option to purchase up to an additional 50 MW.

KUA will need additional capacity by the year 2001 to maintain its 15% summer and winter reserve margin criteria. As a result, KUA, along with FMPA, jointly petitioned the Commission for a determination of need for **Cane Island Unit 3**, a 250 MW combined cycle unit with an in-service date of June 1, 2001. The Commission granted the joint need petition on September 17, 1998. KUA also plans to retire Hansel Units 8 and 14 through 18 in 2002.

LOAD FORECAST

KUA uses econometric forecast models that measure changes in electricity usage per customer class as a function of temperature, population, and income. Economic and population forecasts were obtained from the Bureau of Economic and Business Research (BEBR), and normal weather conditions were assumed for the load forecast model. There is insufficient data to measure the absolute percent error of KUA's 1994-1998 retail sales forecasts. However, KUA's methodology and assumptions are appropriate for the purposes of these projections.

KUA is primarily a summer-peaking utility. KUA's base-case summer peak demand forecast for the next ten years is projected to increase at an AAGR of 5.01%, slightly lower than the 1989-1998 AAGR of 5.13%. KUA's base-case winter peak demand forecast for 1999-2008 shows an AAGR of 5.05%, but its historical growth rate for 1989-1998 is 2.69%. KUA's base-case NEL forecast for the next ten years reflects an AAGR of 4.24%, slightly lower than the historical (1989-1998) growth rate of 5.43%.

Overall, KUA has submitted a comprehensive load forecast with good background data, assumptions, and a good summary of low-, base-, and high-case forecasts.

CONSERVATION

KUA is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). As a result, the Commission does not set numeric conservation goals for KUA. However, the utility plans to continue offering conservation programs such as energy audits and a residential load management program. The load management program is expected to reduce KUA's winter peak demand by an estimated 14 MW (5%) in 2007.

ENVIRONMENTAL COMPLIANCE

None of Florida's municipal utilities are subject to restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). At this time, KUA does not appear to be severely impacted (on a

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

tonnage reduction basis) by Phase II of the CAAA. KUA is expecting to add new natural gas-fired generation, and the emissions will increase proportionally for some pollutants. If KUA retires old diesel units within the next 2-3 years as their plan suggests, there will be decreases in VOC, SO₂, and NO_x emissions.

KUA generally stated that environmental issues are appropriately addressed in the siting process and in public board meetings. There are no environmental regulatory proposals which have a significant impact on KUA's resource expansion plan.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on KUA's *Plan*. Complete comments are contained in Volume 2.

Florida Department of Community Affairs (DCA)

DCA stated that at this time further comments on Cane Island Unit 3 are unnecessary.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, more information is necessary to predict specific impacts.

SUITABILITY

Forecasted reserve margins are expected to be at or above KUA's criterion of 15% for each seasonal peak throughout the planning horizon. KUA's *Plan* is **suitable** for planning purposes. By classifying KUA's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

CITY OF LAKELAND (LAK)

LAK's 649 MW electric system consists of four natural gas-fired steam turbine units (267 MW), one coal-fired unit (205 MW), one gas-fired combined cycle unit (124 MW), and three gas-fired combustion turbine units (48 MW). LAK's next planned capacity addition is **McIntosh Unit 5**, a 264 MW gas-fired combustion turbine unit due to enter service in 2000. LAK plans to add a 120 MW heat recovery steam generator to **McIntosh Unit 5** in 2002, thus converting it to a combined cycle unit. In 2004, LAK plans to place into service **McIntosh Unit 4**, a 238 MW fluidized bed coal unit. This unit is expected to be built with assistance from the U.S. Department of Energy's Clean Coal Technology Program. LAK's *Plan* shows 240 MW of unit retirements over the next ten years.

LAK plans resource additions on its system to meet a reliability criterion of 15% summer and winter peak reserve margin. Winter peak demand is driven primarily by low temperatures. LAK's base case winter load forecast assumes a low winter temperature of 30°F.

LOAD FORECAST

LAK's load forecast methodology includes several regression models measuring population, accounts, sales, net energy for load (NEL), and peak demand. LAK's load forecast is built from three data sources: Polk County population projections from the 1997 Annual Bureau of Economic and Business Research (BEER) forecast; the number of residential accounts in LAK's service area; and the results of LAK's 1994 Appliance Saturation Survey. The Polk County population projections are consistent with LAK's forecasted service territory population, which is currently roughly 46% of the total county estimates. However, the BEER figures are not the latest available to LAK prior to submitting this year's *Plan*, and the results of the 1998 Appliance Saturation Survey could have also been used. The Commission encourages use of the most recent available data.

LAK is a winter-peaking utility. Under base case conditions, winter peak demand is projected to increase at an AAGR of 2.83% over the next ten years, lower than the 3.14% AAGR actually experienced during the 1989-1998 period. Summer peak demand is projected to increase at an AAGR of 2.16%, which is lower than the 3.18% AAGR for the 1989-1998 period. The utility does not specifically justify these lower growth rates. However, LAK's 1999 base-case projections for summer peak demand, winter peak demand, and energy sales are all consistent with those included in its 1998 *Plan*.

LAK's 1994-1998 retail sales forecasts have an absolute percent error of 3.57%, higher than the numeric average for the nine reporting utilities in the state with sufficient available historical data. For the same period, LAK's retail sales forecasts have an average forecast error of -3.40%, which shows a tendency to under-forecast.

Overall, LAK's load forecast is appropriate. The analyses are well-documented and have been supported by data from credible sources.

CONSERVATION

LAK is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). As a result, the Commission does not set numeric conservation goals for LAK. However,

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

LAK plans to continue its research into other DSM technologies, including photovoltaic applications. Further, the utility plans to continue offering its existing conservation programs. In addition to energy audits, LAK offers two residential programs (load management and a loan program) and three commercial programs (lighting, thermal energy storage, and high-pressure sodium outdoor lighting). These programs are expected to reduce LAK's winter peak demand by an estimated 94 MW (11%) in 2007.

ENVIRONMENTAL COMPLIANCE

None of Florida's municipal utilities are subject to restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). LAK does not appear to be severely impacted (on a tonnage reduction basis) by Phase II of the CAAA. LAK's response to the Commission's supplemental data request reflects the impact of the proposed fluidized bed project, McIntosh Unit 4, coming on line in 2003. LAK anticipates a long-term reduction in both SO₂ and NO_x emissions. Other emissions appear to be tracking growth.

There are no environmental regulatory proposals which have a significant impact on LAK's resource expansion plan.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on LAK's *Plan*. Complete comments are contained in Volume 2.

Florida Department of Community Affairs (DCA)

DCA provided general comments on LAK's *Plan*.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

Southwest Florida Water Management District

All proposed plant expansions are on existing sites or have already undergone certification. As such, the District's water resource concerns were addressed during the certification process.

SUITABILITY

Forecasted reserve margins are expected to be at or above LAK's criterion of 15% for each seasonal peak throughout the planning horizon. LAK's *Plan* is suitable for planning purposes. By classifying LAK's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

ORLANDO UTILITIES COMMISSION (OUC)

OUC's generating system has a total capacity of 1,688 MW. The system consists of three coal-fired steam turbines (758 MW), three gas-fired steam turbines (619 MW), four natural gas-fired combustion turbines (246 MW), a 13 MW ownership share in FPC's Crystal River 3 nuclear unit, and a 52 MW ownership share in FPL's St. Lucie 2 nuclear unit. In October, 1999, OUC signed a contract to sell its three Indian River gas-fired steam units, totaling 619 MW, to Reliant Energy. The contract with Reliant includes a buy-back purchase power agreement to cover OUC's capacity and energy requirements. OUC has not scheduled any retirements over the planning horizon. OUC has also recently entered into an agreement to manage the City of St. Cloud's existing generation and transmission facilities, and power purchase contracts.

Historically, OUC has used a dual reliability criteria of 15% summer and winter reserve margin and a 0.5% ratio of expected unserved energy (EUE) to net energy for load (NEL). For the purposes of this year's *Plan* analysis, OUC used only the 15% summer and winter peak reserve margin criterion. These criterion are not violated during the planning horizon, even though no additional electric generation is identified in OUC's *Plan*. OUC's winter peak demand is driven primarily by low temperatures. OUC's base case winter load forecast assumes a low winter temperature of 27°F.

LOAD FORECAST

OUC uses an end-use/econometric load forecasting methodology that has been enhanced to produce loads for each hour of the year in chronological order. The Company developed a typical weather year and adjusted the data set to the model. OUC's methodology and assumptions are appropriate for the purposes of this study. There is insufficient data to measure the absolute percent error of OUC's 1994-1998 retail sales forecasts.

OUC is a summer-peaking utility. Under base case conditions, summer peak demand is projected to increase at an AAGR of 2.67% over the forecast period, lower than the 3.30% AAGR actually experienced during the 1989-1998 period. Similarly, winter peak demand is forecast to increase at an AAGR of 2.36%, much higher than the historical AAGR of 0.22% over the 1989-1998 period. This low growth rate has been mostly attributable to some recent mild winters. Similarly, OUC's base-case NEL forecast for the period of 1998-2007 shows a 3.05% AAGR, slightly higher than the 2.96% AAGR seen over the past ten years.

Overall, OUC's load forecast is satisfactory. It is supported by a sound methodology, reasonable assumptions, and results that are consistent with historical trends.

CONSERVATION

OUC offers five residential conservation programs (audit, heat pump replacement, water heating, weatherization, home energy fix-up) and three commercial programs (audit, cooling, efficient lighting). OUC does not currently have a load management program, although OUC does offer an interruptible tariff. Overall, OUC's conservation programs are expected to reduce winter peak demand by 32 MW (2.8%) in 2007.

The Commission set residential demand, as well as commercial / industrial summer demand, DSM

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

goals for OUC in 1995. The Commission is scheduled to set new DSM goals for OUC in 2000. Currently, demand and energy savings from OUC's DSM programs are not meeting any of its Commission-approved goals. One reason is that OUC's residential demand goals contemplated the addition of a new load management program. However, OUC's evaluation of the economics of load management for its system concluded that the program would not be cost-effective.

ENVIRONMENTAL COMPLIANCE

None of Florida's municipal utilities are subject to restrictions contained in Phase I of the Clean Air Act Amendments (CAAA). There are no new projects which would significantly affect OUC's emissions relative to last year.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on OUC's *Plan*. Complete comments are contained in Volume 2.

Florida Department of Consumer Affairs (DCA)

DCA provided no comments on the OUC *Plan*.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes, however, additional information is necessary to predict specific impacts.

East Central Florida Regional Planning Council

OUC plans no new generation that would require certification within the region.

Southwest Florida Water Management District

No new facilities are planned in the district.

SUITABILITY

Forecasted reserve margins are expected to be above OUC's criterion of 15% for each seasonal peak throughout the planning horizon. OUC's *Plan* is suitable for planning purposes. By classifying OUC's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

CITY OF TALLAHASSEE (TAL)

TAL's existing generation mix consists primarily of natural gas-fired units and interchange capacity purchases. TAL has five fossil steam turbines (426 MW), four combustion turbines (60 MW) and three hydroelectric units (11 MW). TAL divested its 1.333% ownership interest in FPC's Crystal River 3 nuclear unit on September, 30, 1999. TAL has agreed to purchase replacement electric capacity and energy equal to the Crystal River Unit 3 interest (11.4 MW) from FPC. In 1998, TAL relied upon purchased power to meet approximately 20% of its load requirements. This is expected to continue until the year 2000.

On May 19, 1997, the Commission approved TAL's petition to determine the need for a 233 MW gas combined cycle unit at the Purdom site. The addition of this unit, along with the early retirement of two combustion turbines at the same location, results in a net summer capacity increase of 187 MW in 2000. As a result, TAL's natural gas-fired generation is forecasted to increase to approximately 91% of load requirements by 2008. The addition of Purdom Unit 8 is expected to also cause TAL to become a net seller of electricity, whereas it has been a net buyer in past years.

TAL plans resource additions on its system to meet a reliability criterion of 17% summer peak reserve margin. TAL's *Plan* includes a reserve shortfall in years 2006, 2007, and 2008, with summer reserve margins of 15%, 13%, and 9%, respectively. TAL did not include a specific plan to meet these projected reserve shortfalls.

LOAD FORECAST

TAL employs a series of econometric-based linear regression forecasting models to develop its energy forecasts. These models rely upon an analysis of the system's historical growth, usage patterns, and population statistics. As in previous years, TAL has failed to properly document its outside sources for economic, weather and demographic data, regardless of whether it is historical or forecasted. Furthermore, TAL has not included significant assumptions or informed judgements regarding its forecasts as recommended by the Commission in previous *Plan* reviews.

TAL is a summer-peaking utility. Under base-case conditions, summer peak demand is projected to increase at an AAGR of 2.13% over the forecast period, lower than the 3.26% AAGR actually experienced during the 1989-1998 period. TAL's 1999 base-case summer peak demand forecast is consistent with that contained in its 1998 *Plan*.

TAL's 1994-1998 retail sales forecasts have an absolute percent error of 3.45%, slightly higher than the 3.28% numeric average for the nine reporting utilities in the state with sufficient available historical data. For the same period, TAL's retail sales forecasts have an average forecast error of -2.87%, which shows a tendency to under-forecast.

TAL continues to do a commendable job of addressing load forecast sensitivities.

CONSERVATION

TAL is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). As a result, the Commission does not set numeric conservation goals for TAL. However,

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

TAL does not expect to reduce its current commitment to conservation. TAL's DSM portfolio consists of five residential and five commercial programs. These programs include natural gas conversion, non-dispatchable conservation programs, public information and education programs, and home improvement programs. TAL does not have a load management program. TAL forecasts that its DSM programs will reduce winter peak demand by an estimated 51 MW (8.4%) in 2007.

ENVIRONMENTAL COMPLIANCE

None of Florida's municipal utilities are subject to restrictions contained in Phase I of the Clean Air Act Amendments (CAAA). Any new natural gas-fired generation will impact TAL's compliance with Phase II of the CAAA. All emissions are forecasted to slowly increase throughout the planning horizon, reflecting TAL's replacement of interchange purchases with the new gas-fired Purdom Unit 8.

TAL generally responded that environmental issues are appropriately addressed in the siting process and during public board meetings. There are no environmental regulatory proposals, other than the site review for the proposed Purdom Unit 8, which would significantly affect TAL's expansion plan.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on TAL's *Plan*. Complete comments are contained in Volume 2.

Apalachee Regional Planning Council

All issues of regional concern resulting from the proposed new Purdom Unit 8 have been addressed.

Florida Department of Consumer Affairs (DCA)

DCA participated in the Site Certification process for Purdom Unit 8 and, therefore, has no further comments.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

SUITABILITY

Forecasted reserve margins are expected to be at or above TAL's criterion of 17% summer reserve margin for each seasonal peak except the last three years of the *Plan* (2006-2008). Due to the short magnitude of the reserve deficiency and to TAL's proximity to the Southern Company, TAL is expected to be able to acquire reserves as needed. TAL's *Plan* is suitable for planning purposes. By classifying TAL's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

SEMINOLE ELECTRIC COOPERATIVE (SEC)

SEC currently provides full requirements to its ten distribution system members. SEC relies on owned and purchased capacity resources to meet its members' needs. SEC is obligated to serve all load up to specified capacity commitment levels and provide adequate reserves. SEC's partial requirements providers serve all load above specified capacity commitment levels. The power supply contract between SEC and previous member Okefenokee Rural Electric Membership Corporation was terminated in January, 1999.

SEC's generating resources include two 665 MW coal-fired steam turbine units and a 15 MW ownership in FPC's Crystal River 3 nuclear unit. In addition, SEC purchases full or partial requirements power from FPC, TECO, JEA, OUC, and GRU. SEC terminated its Partial Requirements agreement with FPL effective January 1, 1999. SEC plans to diversify its generation resources with the addition of the **Payne Creek Generation Station**, a 572 MW combined cycle unit, in January, 2002. SEC's *Plan* also shows the planned addition of nine combustion turbines (1350 MW) at unknown sites by 2007. Although currently non-existent within its generation mix, SEC expects natural gas to represent 28% of native generation in 2008.

SEC uses a dual reliability criteria of 15% summer and winter reserve margin and a 1% ratio of expected unserved energy (EUE) to net energy for load (NEL). SEC's forecasted reserve margins exceed these criteria in each year of the planning horizon.

TREATMENT OF HARDEE POWER STATION

Hardee Power Partners, Limited, a TECO Power Services Corporation, owns and operates two gas-fired generating units, totaling 359 MW of winter capacity, at the Hardee Power Station. Unit 1 is a 269 MW combined cycle unit, while Unit 2 is a single 90 MW combustion turbine. SEC has first priority use of this capacity as a reserve resource when its own generation is derated or incurs a forced outage or maintenance outage. TECO can purchase capacity from Hardee Power Station at times when SEC does not exercise its capacity rights. Normally, SEC does not use the capacity during the summer and winter months, therefore releasing it to TECO.

Because the Hardee Power Station is shared, there is particular interest in how this capacity is treated in each respective utility's *Plan*. SEC has first call on Hardee Power Station's capacity for backup purposes, which coincide with maintenance outages occurring during the spring and/or fall. Since SEC can also call on this capacity during emergencies occurring at any time of the year, it appears that SEC should include the Hardee Power Station capacity in a reserve margin calculation.

Traditionally, SEC has only used 1% expected unserved energy (EUE) as its sole reliability criterion due to its heavy reliance on other utilities to supply its full requirements and partial requirements capacity needs. This typically resulted in large reserve margins. However, reserve margin has become the driving reliability criterion. Accordingly, SEC has adopted a dual reliability criteria of 15% system peak reserve margin and 1% EUE.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

When determining the reliability of its system, SEC estimates the number of hours and amount of capacity it expects to purchase from Hardee Power Station based on SEC's historical use of the capacity. It appears that SEC's calculation of EUE properly accounts for its use of capacity from Hardee Power Station.

LOAD FORECAST

SEC identifies and justifies its load forecast methodology with a thorough description of econometric and end-use models, variables, data sources, assumptions, and informed judgements. SEC analyzed each member cooperative's load forecast and combined them to yield the final forecast results. SEC provided detailed statistical accounts of alternate load forecasts based on different economic and weather scenarios, including forecast models for residential, commercial, and other consumer classes. However, SEC's forecasting model incorporates 20 years of historical data which ends in 1996. More recent data through 1998 should be used to update the forecast.

SEC's 1994-1998 retail sales forecasts have an absolute percent error of 3.84%, second highest among all reporting utilities in the state. For the same period, SEC's retail sales forecasts have an average forecast error of -1.44%, which shows a tendency to under-forecast.

SEC is a winter-peaking utility. Under base case conditions, winter peak demand forecast is projected to increase at an AAGR of 3.21% over the forecast period. While the winter peak demand forecast is lower than the 3.61% AAGR actually experienced during the 1989-1998 period, it is still one of the highest winter peak growth rates in the state. SEC attributes this increase to the expectation of continued steady increases in electric space-heating appliance saturation. In spite of this, SEC's *Plan* contains no discussion of why the 1999 forecast is lower than the 1998 *Plan* forecast by an average of 341 MW per year.

Overall, SEC's load forecast criteria are adequate. The models employed are comprehensive and the level of detail provided is superior to that shown in previous years. SEC also includes data sources that are properly documented.

CONSERVATION

Member utilities individually promote their own conservation programs with SEC's assistance. Given the power supply agreements that SEC has with its members, demand reduction resulting from conservation and load management programs does not affect the operation of SEC's generating units. However, conservation reduces the amount of partial requirements purchases.

Some of SEC's member utilities have load management programs whose dispatch are coordinated by SEC. These programs provide an estimated two-thirds (243 MW) of SEC's forecasted demand savings, with the remaining savings coming from various interruptible service tariffs. The aggregate winter demand savings of SEC's members is forecasted to be 361 MW (7.4%) in 2007.

ENVIRONMENTAL COMPLIANCE

SEC is not subject to SO₂ restrictions contained in Phase I of the CAAA. However, SEC elected to be subject to the CAAA earlier than the Phase II date of January 1, 2000. SEC projects a slow

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

increase in all pollutants which seems to track the addition of proposed units. The emission sensitivities of high/low demand and high/low fuel prices are consistent with those of FPL and TECO. Lowering demand as well as aggressively pursuing low natural gas prices reduces emissions relative to the base case used for long-term planning.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on SEC's *Plan*. Complete comments are contained in Volume 2.

Florida Department of Community Affairs (DCA)

DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA has concerns over whether SEC plans to operate its proposed combustion turbine units to serve baseload requirements. If SEC plans to use these unit additions for baseload needs, DCA would have SEC revise its *Plan* to include combined cycle units solely to meet DCA policy requirements.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes. However, additional information is necessary to predict specific impacts.

East Central Florida Regional Planning Council

SEC plans no new generation within the region.

North Central Florida Regional Planning Council

The impact of SEC's planned addition of twelve new generating units cannot be determined because the location of the units is not identified in SEC's *Plan*. Therefore, the Council cannot conclude whether SEC's *Plan* is consistent with the goals and policies of the North Central Florida Strategic Regional Policy Plan.

Northeast Florida Regional Planning Council

The Council had no comments regarding SEC's *Plan* since no new facilities are planned within the northeast Florida region.

Southwest Florida Regional Planning Council

The Council provided no comments as none of SEC's generating facilities is within Southwest Florida.

Suwannee River Water Management District

The district did not identify any environmental impacts or related matters of concern.

Tampa Bay Regional Planning Council

SEC's *Plan* is consistent with regional policies.

Withlacoochee Regional Planning Council

The Council found SEC's *Plan* suitable with regard to regional goals and policies.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

SUITABILITY

Forecasted reserve margins are expected to be above SEC's criterion of 15% for each seasonal peak throughout the planning horizon. SEC's *Plan* is **suitable** for planning purposes. By classifying SEC's *Plan* as suitable, the Commission does not conclude that the 15% reserve margin criterion adopted by the FRCC for Peninsular Florida's utilities is also suitable.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY (Duke New Smyrna)

Duke New Smyrna's lone generating unit is a 514 MW gas-fired combined cycle unit in New Smyrna Beach. This unit is expected to provide 30 MW of firm capacity and energy to the Utilities Commission of New Smyrna Beach. The remaining capacity would be made available for wholesale sales to other utilities.

Duke New Smyrna's generating unit was granted a need determination by the Commission on March 22, 1999. The unit is awaiting certification by DEP under the Power Plant Siting Act. However, FPL, FPC, and TECO have protested the Commission to the Florida Supreme Court, and a decision is expected in early 2000.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following is a summary of the comments provided by review agencies on Duke New Smyrna's *Plan*. Complete comments are contained in Volume 2.

Florida Department of Community Affairs (DCA)

DCA participated in the certification process for the proposed Duke/New Smyrna combined cycle unit. Further comments are unnecessary at this time.

Florida Fish and Wildlife Conservation Commission

The Commission commented that, in general, the *Plans* are suitable for planning purposes, however, additional information is necessary to predict specific impacts.

East Central Florida Regional Planning Council

The Council reviewed the proposed Duke/New Smyrna generating unit during the certification process. No significant regional issues were identified. No further comments are necessary at this time.

Volusia County

The County commented that the proposed site is not subject to Volusia County's Comprehensive plan. However, the County is encouraged by the potential positive impact on air quality due to the proposed use of natural gas.

SUITABILITY

Duke New Smyrna's *Plan* is **suitable** for planning purposes. Duke New Smyrna's *Plan* contains no other proposed generating unit additions over the ten-year planning horizon.

APPENDIX

STATUS OF NEED DETERMINATIONS / SITE CERTIFICATIONS

Seminole Electric Cooperative -- Hardee Power Station Unit 3

The Commission granted SEC's need petition for a 440 MW combined cycle unit at the existing Hardee Power Station site in June, 1994. SEC deferred the unit's original 1999 in-service date until November, 2001. This action was possible because SEC found it more cost-effective to purchase 455 MW of firm capacity from FPC during this period rather than start construction of Unit 3.

City of Tallahassee -- Purdom Unit 8

In May, 1997, the Commission granted TAL's need petition for a 250 MW gas-fired combined cycle unit at the existing St. Marks site in Wakulla County. The Power Plant Siting Board approved TAL's site certification application in April, 1998. TAL plans to place Purdom Unit 8 into commercial service in May, 2000.

Kissimmee Utility Authority / Florida Municipal Power Agency -- Cane Island Unit 4

On September 17, 1998, the Commission granted joint need petition, by KUA and FMFA, to jointly build and operate a 250 MW gas-fired combined cycle unit at the existing Cane Island site in Osceola County. KUA and FMFA plan to start construction on Cane Island Unit 4 in October, 1999 to meet an anticipated in-service date of June, 2001.

Duke Energy Company / Utilities Commission of New Smyrna Beach -- Merchant Plant

On March 22, 1999, the Commission granted a need petition by Duke New Smyrna Beach Energy Company to build a 514 MW gas-fired combined cycle unit at a site in New Smyrna Beach. Approximately 50 MW of the proposed plant's output is expected to go to the Utilities Commission of New Smyrna Beach (NSB) pursuant to a yet-unsigned power purchase agreement, with the remainder of the capacity available for purchase by any other entity. The proposed unit is awaiting certification by DEP under the Power Plant Siting Act. However, FPL, FPC, and TECO have protested the Commission to the Florida Supreme Court, and a decision is due in early 2000.

Gulf Power Company -- Smith Unit 3

On June 6, 1999, the Commission granted Gulf's petition to build a 532 MW gas-fired combined cycle unit at the existing Lansing Smith site. This unit is expected to be placed into commercial service in June, 2002. Gulf is currently seeking DEP certification for Smith Unit 3 under the Power Plant Siting Act.

City of Lakeland -- McIntosh Unit 4

On April 1, 1999, the Commission granted LAK's petition to build a 185 MW fluidized bed coal unit using funding from the U.S. Department of Energy's Clean Coal Technology Program. The unit is expected to be placed into service in May, 2004. LAK is currently seeking DEP certification for McIntosh Unit 4 under the Power Plant Siting Act.

Okeechobee Generating Company / PG&E Generating Company -- Merchant Plant

Okeechobee Generating Company has petitioned the Commission for a determination of need for a 550 MW combined cycle unit. As proposed, the natural gas-fired unit will be located in southern Okeechobee County, just north of Lake Okeechobee. The unit's projected in-service date is April, 2003. A Commission hearing is scheduled for early 2000. The proposed unit will require certification under the Power Plant Siting Act.

APPENDIX

PLANNED, UNCERTIFIED GENERATING UNITS

Florida Power Corporation -- Hines Units 2 and 3

FPC's expansion plans reflect the planned addition of two new 470 MW, gas-fired combined cycle units at the existing Hines plant site in Polk County. Identical to the first unit at the site, Hines Units 2 and 3 are currently scheduled to be placed into commercial service in November, 2004 and November, 2006, respectively. FPC has petitioned the Commission for approval not to issue an RFP for alternatives to Unit 2 so that the unit's in-service date can be moved up to November, 2002. If FPC ultimately plans to build these units in lieu of other resource options, Hines Units 2 and 3 will require certification under the Power Plant Siting Act.

Florida Power & Light Company -- Martin Units 5 and 6

FPL's expansion plans reflect the planned addition of two new 440 MW, gas-fired combined cycle units at the existing Martin plant site in Martin County. Martin Units 5 and 6 are currently scheduled to be placed into commercial service in November, 2005 and November, 2006, respectively. If FPL ultimately plans to build these units in lieu of other resource options, Martin Units 5 and 6 will require certification under the Power Plant Siting Act.

PUBLIC WORKSHOP COMMENTS

The Commission received written comments on the *Plans* from many review agencies. Utility-specific comments were summarized previously in this document. Complete comments are contained, in their entirety, in Volume 2 of this review. Prior to its September 27, 1999 Public Workshop, the Commission received written comments from the Legal Environmental Assistance Foundation (LEAF). LEAF emphasized four general concerns with all utility *Plans*. Because of these concerns, LEAF recommended that the Commission classify all *Plans* as unsuitable. The following discussion summarizes LEAF's concerns:

- (1) The utility plans are inconsistent with the State Comprehensive Plan. In aggregate, the plans emphasize demand-reducing DSM programs such as load management at the expense of energy-reducing programs. Further, according to LEAF, the plans do not include enough renewable resources.
- (2) The utility plans overstate the need for new generation. This concern is based on LEAF's first concern that the plans do not contain enough energy-reducing DSM programs. In LEAF's opinion, additional energy-reducing DSM programs, regardless of cost-effectiveness, would reduce the need for additional generation.
- (3) The utility plans lack any apparent consideration of the aging fleet of existing plants, their potentially increased maintenance costs, and their considerable current and future environmental costs.
- (4) Assumptions that the availability of all existing units is increasing are unsupported. This concern is based on LEAF's third concern that the utilities plan to rely on an aging fleet of generators as their primary source for electricity.