REVIEW OF ELECTRIC UTILITY 2000 TEN-YEAR SITE PLANS

December, 2000

FLORIDA PUBLIC SERVICE COMMISSION

Division of Safety and Electric Reliability
Division of Economic Regulation
Division of Competitive Services

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INTRODUCTION

Section 186.801, Florida Statutes, requires that all major generating electric utilities in Florida submit a ***Ten-Year Site Plan (TYSP)*** to the Florida Public Service Commission (Commission) for review. Each *TYSP* contains projections of the utility's electric power needs for the next ten years and the general location of proposed power plant sites and major transmission facilities.

In accordance with Section 186.801, Florida Statutes, the Commission is responsible for making a preliminary study of each utility's *TYSP* and must determine whether it is "***suitable***" or "***unsuitable***." The Commission's *TYSP* review is forwarded to the Florida Department of Environmental Protection (DEP).

To fulfill the statutory requirement of Section 186.801, Florida Statutes, the Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code. In particular, Rule 25-22.071, Florida Administrative Code, requires the *TYSP* to be submitted annually by April 1. However, utilities whose existing generating capacity is less than 250 megawatts (MW) are exempted from the requirements of this rule unless they propose to build a new generating unit larger than 75 MW.

The *TYSP* review contained herein also fulfills the requirement of Section 377.703(e), Florida Statutes, which requires the Commission to analyze and provide electricity and natural gas forecasts for analysis by the Florida Department of Community Affairs (DCA). The Commission's *TYSP* review is forwarded to DCA.

Since the purpose of a *TYSP* is to give state and local agencies advance notice of proposed power plants and transmission facilities, the *TYSP* is not intended to be a binding plan of action on electric utilities. As such, the Commission's classification of a utility's *TYSP* as ***suitable*** or ***unsuitable*** also 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 *TYSP* raises a concern that requires Commission action, such action is formally undertaken after a public hearing.

Because the *TYSP* is a planning document containing 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 jurisdictions. 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 *TYSP* as an early notification process rather than a binding plan of action.

INTRODUCTION

Table 1 briefly summarizes the criteria used by the Commission to review the *TYSPs*, as set out in Section 186.801, Florida Statutes, and the action taken by the Commission to comply with these statutory criteria.

TABLE 1
STATUTORY CRITERIA FOR REVIEWING TEN-YEAR SITE PLANS

REQUIREMENT	ACTION
Review the need for electrical power in the area to be served	Reviewed load forecasts, demand-side management (DSM) assumptions, and reliability criteria.
Review possible alternatives to the proposed Plan	Reviewed DSM assumptions, fuel forecasts, and sensitivities to the base-case expansion plan.
Review anticipated environmental impact of proposed power plant sites	Solicited comments from DEP regarding environmental impact and compliance. Comments are summarized within this report.
Consider views of local and state agencies regarding water and growth management issues	Solicited comments from the Department of Community Affairs (DCA), water management districts, and regional planning councils. Comments are summarized within this report.
Determine consistency of Plan with the State Comprehensive Plan	Evaluated energy-related aspects of the Comprehensive Plan. Reviewed comments provided by DCA and by regional and local planning agencies on growth management and Comprehensive Plan issues. Comments are summarized within this report.
Review Plan for information on energy availability and consumption	Reviewed load forecast data and methodologies used to arrive at load and energy forecasts.

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 August 30, 2000 to solicit public comments on the *TYSPs*. Several state, local, and regional government agencies submitted written comments on the *TYSPs* prior to the workshop. All comments are summarized herein. A complete copy of the comments is available from the Commission upon request.

EXECUTIVE SUMMARY

FLORIDA RELIABILITY COORDINATING COUNCIL

A region of the North American Electric Reliability Council (NERC), the Florida Reliability Coordinating Council (FRCC) was formed in 1996 to ensure electric reliability in Peninsular Florida. Prior to 1996, Peninsular Florida's utilities were members of the Southeastern Electric Reliability Council.

The FRCC has a formal reliability assessment process to annually review and assess existing and potential issues. FRCC member utilities 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 that decides which planning and operating studies will be performed to address these issues.

The FRCC annually publishes two documents which address the reliability of Peninsular Florida's electric grid. The ***2000 Regional Load and Resource Plan*** contains aggregate data on demand and energy, capacity and reserves, and proposed new unit additions for the FRCC region as well as statewide. The ***2000 Reliability Assessment*** is an aggregate study of the future reliability of Peninsular Florida's electric grid. The Commission used both FRCC documents to supplement its review of the *TYSPs* filed by the utilities.

SUITABILITY

The Commission has reviewed *TYSPs* filed by twelve(12) reporting utilities and four (4) merchant plant companies. The Commission has determined that 11 of the 12 *TYSPs* filed by the utility companies are ***suitable*** for planning purposes. The Commission has determined that the *TYSP* filed by the City of Tallahassee (TAL) is ***conditionally suitable*** for planning purposes for two reasons: (1) TAL failed to specify future supply resources; and (2) reserve margins are forecasted to fall below TAL's 17% summer reserve margin criterion in 2001 and each year between 2004 and 2009. Furthermore, by 2009, TAL's capacity deficiency – below the 17% reserve margin criterion – is forecasted to grow to near 90 MW. However, TAL is currently conducting a comprehensive planning study to identify future supply resources. The Commission makes no determination on the suitability of the merchant plant filings.

EXECUTIVE SUMMARY

CRITICAL CONCERNS

The Commission has identified two primary areas of concern which may impact the reliability and cost-effectiveness of the *TYSPs*. These concerns are discussed in detail later in this report but are summarized below.

FRCC 2000 REGIONAL LOAD AND RESOURCE PLAN

The Commission is concerned that the FRCC's ***2000 Regional Load and Resource Plan*** does not contain complete information on all generating units proposed over the ten-year planning horizon. Several combustion turbine "merchant" plants have been proposed but are not included in this document. These units do not require certification under the Power Plant Siting Act and, therefore, can be constructed once the Department of Environmental Protection (DEP) issues all environmental permits. While these CT merchant plants do not contribute to Peninsular Florida's reserve margins unless firm capacity is sold to utilities, the merchant plants may enhance reliability by increasing operating reserves and may place downward pressure on wholesale rates.

AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

Reserve margins for some Florida utilities are made up largely of non-firm resources such as load management and interruptible service. **This appears to be a near-term concern**. Florida's utilities forecasted a slight decrease in their reliance on non-firm resources over the planning horizon, thus indicating a greater reliance on supply-side resources (generation, firm capacity purchases) in future years.

EXECUTIVE SUMMARY

EXTERNAL FACTORS AFFECTING THE PLANS

Because the future is uncertain, there are external factors that may affect the viability of the *TYSP*. Three potential factors are discussed below.

ELECTRIC UTILITY RESTRUCTURING

Several federal actions have resulted in a restructuring of the electric industry nationwide. The ***Energy Policy Act of 1992 (EPAct)*** requires transmission-owning utilities to transmit power from wholesale entities. Federal Energy Regulatory Commission (FERC) Order No. 888 required functional unbundling, a process by which generation and transmission functions within a single company are separated. FERC Order No. 889 required the development of an ***open-access same-time information system (OASIS)***, an interactive database system which provides instantaneous information on the availability and price of transmission links between generation and load. Finally, FERC Order No. 2000 encouraged the development of ***regional transmission organizations (RTOs)***. Peninsular Florida's major utilities filed an RTO proposal on October 15, 2000 with the FERC.

FLORIDA ENERGY 2020 STUDY COMMISSION

Pursuant to Executive Order No. 2000-127, Governor Jeb Bush established the ***Florida Energy 2020 Study Commission*** (Study Commission) on May 3, 2000 to propose an energy plan and strategy for Florida. Consisting of 20 persons with various areas of expertise, the Study Commission first met in September, 2000 to study the major issues affecting the future of the electric industry in the state. In accordance with the Governor's executive order, the Study Commission is to submit its recommendations to the Senate, the House of Representatives, and the Governor by December, 2001.

NATURAL GAS AVAILABILITY

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. Conservative estimates indicate that future natural gas requirements will exceed FGT's current capacity. To meet these forecasted requirements, an additional 1.0 Bcf/day may be required over the next ten years. FGT has asserted to the FRCC that it is able and willing to expand the natural gas pipeline system to meet all projected electric demand. However, the Commission believes that electric utilities should individually identify a contingency plan in case gas transportation capacity is not available when needed to fuel future electric generation expansion.

Two competing companies -- Gulfstream Natural Gas System, LLC (Gulfstream) and Williams-Transco (Buccaneer) -- currently plan to construct new pipelines into the state and place them into commercial service by June, 2002. The construction of either of these two lines would mitigate the Commission's concern with having only one pipeline company.

SUMMARY OF RESOURCE ADDITIONS

Table 2 on the next page, and Figures 1, 2, and 3 on pages 11 and 12, 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.

TABLE 2

PLANNED NEW GENERATING UNIT ADDITIONS, CHANGES IN CAPACITY AT EXISTING SITES, AND UNIT RETIREMENTS (2000 - 2009)

	SUMMER CAPACITY (MW)	WINTER CAPACITY (MW)
NEW ELECTRIC UTILITY GENERATING UNIT ADDITIONS		
Combined Cycle	8,485	9,406
Combustion Turbine	3,401	3,986
Coal	288	288
TOTAL	**12,174**	**13,680**
CAPACITY CHANGES AT EXISTING ELECTRIC UTILITY SITES (repowering, fuel conversion, cold standby)		
Combined Cycle	2,180	2,521
Combustion Turbine	101	52
Coal	-517	-581
Oil & Gas Fossil Steam	-350	-403
TOTAL	**1,414**	**1,589**
ELECTRIC UTILITY UNIT RETIREMENTS		
Combustion Turbine	-273	-314
Oil & Gas Fossil Steam	-813	-826
TOTAL	**-1,086**	**-1,140**
EXPIRATION OF ELECTRIC UTILITY FIRM CAPACITY CONTRACTS (with non-utility generators)		
Cogeneration [1]	-376	-376
Independent Power Producers [2]	-593	-593
TOTAL	**-969**	**-969**
TOTAL *NET* ELECTRIC UTILITY ADDITIONS	**11,533**	**13,160**

[1] Nine firm capacity cogeneration contracts (376 MW total) are set to terminate over the next ten years. No new cogenerators are proposed. As these contracts expire, the capacity becomes uncommitted (merchant) capacity.

[2] OUC's purchased power contracts with Reliant - Indian River Units 1-3 are set to expire by 2004. At that time, the capacity becomes uncommitted (merchant) capacity.

Figure 1

ELECTRIC UTILITY RESOURCE ADDITIONS (2000 - 2009)

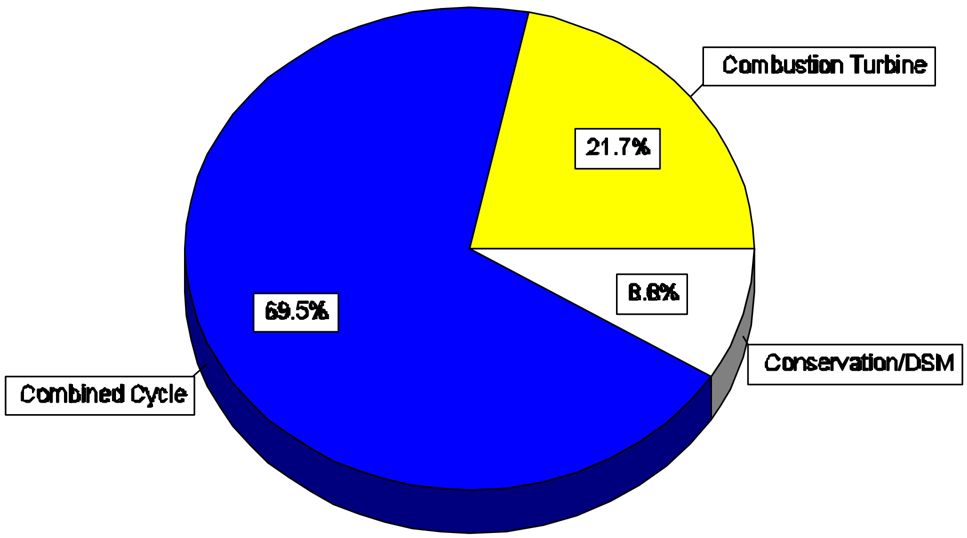


Figure 2

ELECTRIC UTILITY RESOURCE MIX BY PLANT TYPE -- PRESENT AND FUTURE

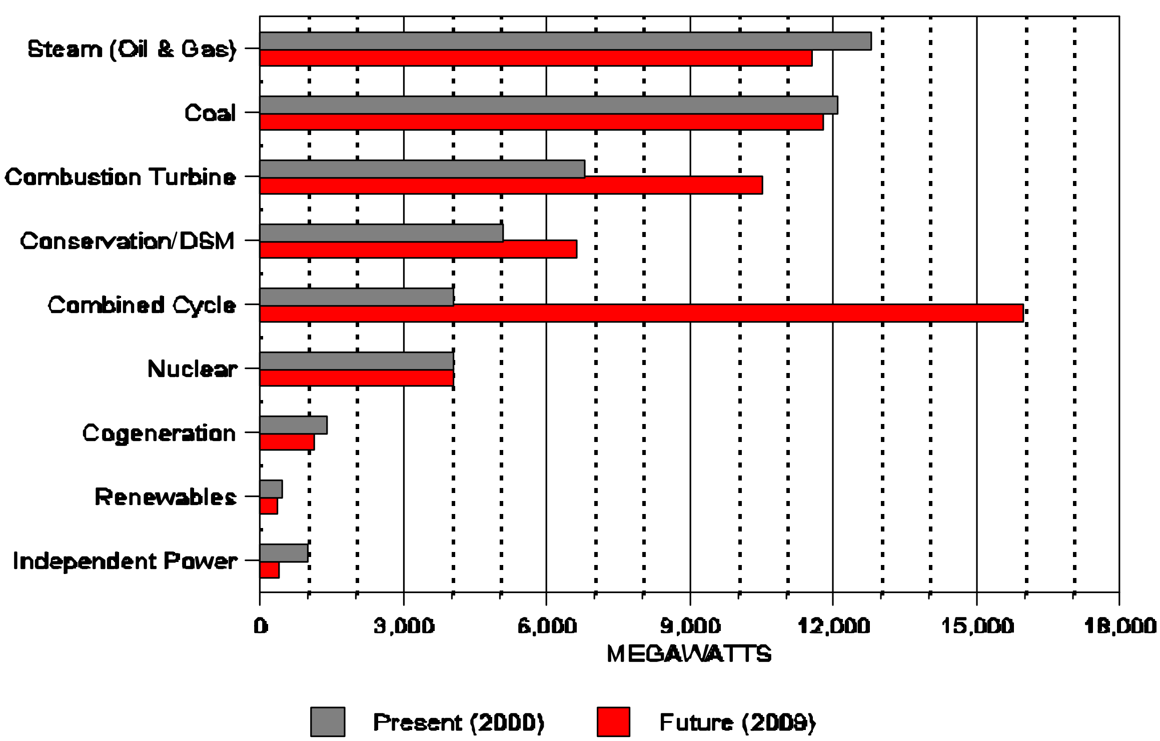
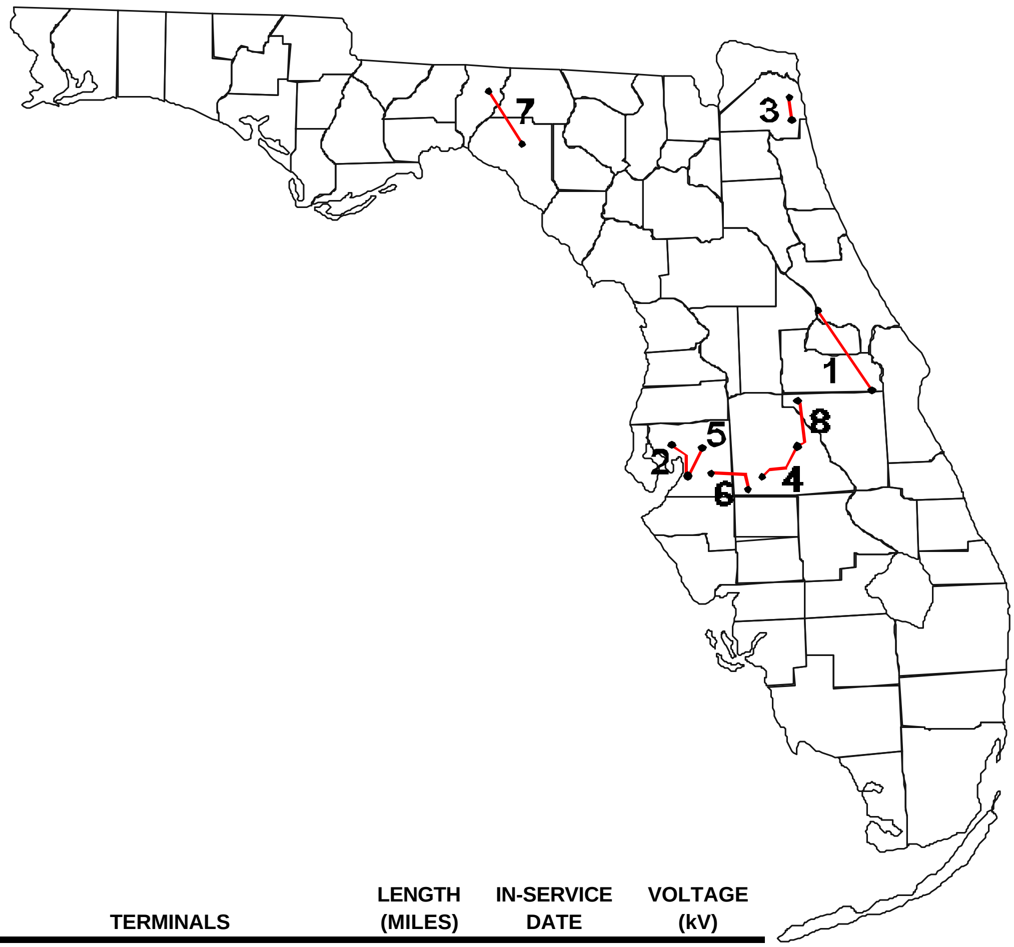


Figure 3

PROPOSED MAJOR TRANSMISSION LINES (2000 - 2009)



	UTILITY	TERMINALS	LENGTH (MILES)	IN-SERVICE DATE	VOLTAGE (kV)
1	FPL	Poinsett - Sanford (2 lines)	45	June, 2001	230
2	TECO	Gannon - Juneau	15	June, 2003	230
3	JEA	Center Park - Greenland	19	Nov., 2003	230
4	FPC	Hines - W. Lake Wales (2 lines)	21	May, 2005 May, 2009	230
5	TECO	Gannon - Davis	15	June, 2005	230
6	TECO	Polk - Lithia [3]	22	Oct., 2006	230
7	FPC	Perry - Drifton	35	May, 2007	230
8	FPC	Intercession City - W. Lake Wales	30	May, 2007	230

[3]The **Polk - Lithia** line will likely require certification under the Transmission Line Siting Act (TLSA).
All other proposed transmission lines in this table are exempt from the TLSA for one of three reasons: (1) the utility already owned the right-of-way prior to enactment of the TLSA in 1983; (2) the line is not proposed to cross a county line; or, (3) the line is proposed to be located in existing right-of-way.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

CRITICAL CONCERNS

Although the Commission has classified 11 of the 12 utility *TYSPs* as ***suitable***, the Commission has identified two primary areas of concern which may impact the reliability and cost-effectiveness of the *TYSPs*. These concerns, discussed below, are the ***FRCC 2000 Regional Load and Resource Plan*** and the ***amount of reserves provided by non-firm resources***.

FRCC 2000 REGIONAL LOAD AND RESOURCE PLAN

The Commission is concerned that the FRCC's ***2000 Regional Load and Resource Plan*** does not contain complete information on all generating units proposed over the planning horizon. As shown in Table 5 on page 29, several combustion turbine merchant plants totaling approximately 5,370 MW have been proposed in the state. However, none of these units are included in the FRCC document. Because CT units do not have any steam capacity, these units do not require certification under the Power Plant Siting Act. Therefore, the CT merchant plants can be constructed once the Department of Environmental Protection (DEP) issues all environmental permits.

The Commission recognizes that CT merchant plants do not contribute to a traditional calculation of Peninsular Florida's firm reserve margin. However, CT merchant plants may enhance reliability of the electric grid by increasing the level of operating reserves and may place downward pressure on wholesale rates. Therefore, so that the Commission can keep abreast of all proposed generating unit additions in the state which may enhance reliability, the Commission believes that CT merchant plants should be included in the ***2000 Regional Load and Resource Plan*** as potential sources of additional capacity.

AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

For some Florida utilities, reserve margins consist largely of non-firm, non-generating resources such as load management and interruptible service. Because residential customers can give just thirty days' notice to a utility to leave its load management program, customer flight from this program can cause sudden near-term reliability problems.

As shown in Figure 4 non-firm resources currently comprise 58% of Peninsular Florida's winter reserves and 52% of summer reserves. **The reliance on non-firm resources appears to be a near-term concern**, as the current level of non-firm reserves is lower than forecasted just last year. This indicates that Peninsular Florida's utilities plan to rely increasingly on supply-side resources (generation and firm capacity purchases) rather than on non-firm resources.

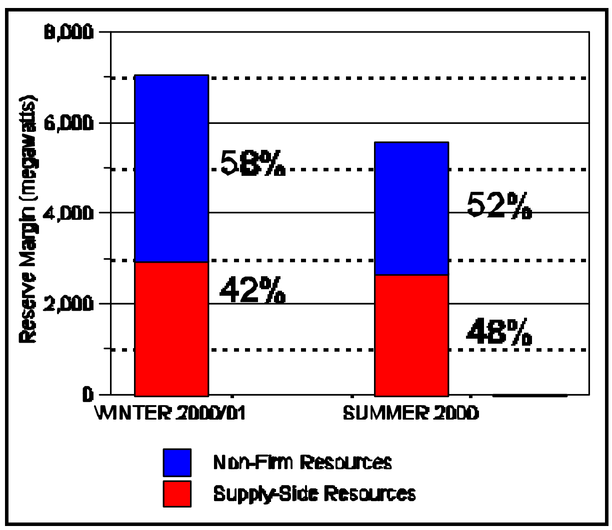


Figure 4
COMPONENTS OF RESERVE MARGIN

TECO and FPC rely primarily on non-firm resources for reserves. For 2000, TECO forecasts 87% winter (75% summer) reliance on non-firm resources for reserve margin. For 2000, FPC forecasts non-firm resources to make up 84% winter (59% summer) of its reserve margin. Like Peninsular Florida as a whole, both TECO and FPC forecast that non-firm reserves will decline over the planning horizon as new supply-side resources are added.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

EXTERNAL FACTORS AFFECTING THE PLANS

Because the future is uncertain, there are external factors that may affect the viability of the *TYSP*. Three potential factors are ***electric utility restructuring***, the ***Florida Energy 2020 Study Commission***, and ***natural gas availability***. The following discussion elaborates on these factors.

ELECTRIC UTILITY RESTRUCTURING

Several federal actions have encouraged a restructuring of the electric industry nationwide. These actions are discussed below.

In 1992, Congress enacted the ***Energy Policy Act of 1992 (EPAct)***. The EPAct authorized the Federal Energy Regulatory Commission (FERC) to order utilities to transmit, over their own transmission lines, power from wholesale entities. The EPAct also requires that a utility refusing to provide wholesale transmission service must show good cause for such refusal. EPAct is considered to be the catalyst for current restructuring of the electric utility industry.

In April, 1996, FERC issued Order No. 888 which required that all transmission-owning public entities make their facilities available to any user in a fair, non-discriminatory manner. Open access transmission was facilitated by utilities through ***functional unbundling***, a process by which generation and transmission functions within a single company are separated. FERC intended that Order No. 888 also encourage the development of ***independent system operators (ISOs)*** to manage the real-time actions of transmission systems.

In response to concerns over the transparency of real-time information, FERC issued Order No. 889 which required the development of an ***open-access same-time information system (OASIS)***. OASIS is an interactive database system designed to provide instantaneous information on the availability and price of transmission links between generation centers and load centers. The FRCC implemented Peninsular Florida's OASIS, known as FLOASIS, in November, 1996.

In December, 1999, FERC issued Order No. 2000, which encouraged the development of ***regional transmission organizations (RTOs)***. In Order No. 2000, FERC concluded that RTOs would offer advantages over the present system because they will lead to enhanced regional reliability and speed the development of a competitive, wholesale electricity market. FERC also expects that RTOs will remove any potential for discriminatory transmission system access.

On October 16, 2000, Peninsular Florida's three major utilities – FPC, FPL, and TECO – filed a joint ***RTO*** proposal with the Federal Energy Regulatory Commission (FERC). A supplemental filing containing more detail is scheduled to be filed on December 15, 2000.

FLORIDA ENERGY 2020 STUDY COMMISSION

Pursuant to Executive Order No. 2000-127, Governor Jeb Bush established the ***Florida Energy 2020 Study Commission*** (Study Commission) on May 3, 2000 to propose an energy plan and strategy for Florida. Consisting of 20 persons with various areas of expertise, the Study Commission first met in September, 2000 to study the major issues affecting the future of the electric industry in the state. In accordance with the Governor's executive order, the Study Commission is to submit its recommendations to the Senate, the House of Representatives, and the Governor by December, 2001.

NATURAL GAS AVAILABILITY

Florida's electric utilities continue to rely primarily on a single gas transportation pipeline company, **Florida Gas Transmission (FGT)**, to supply natural gas. FGT's system pipeline capacity, which is fully subscribed at this time, is nearly 1.5 billion cubic feet per day (Bcf/day). As shown in Figure 5, nearly 81% of the existing pipeline capacity is used for utility and non-utility electric generation. This trend is expected to continue, as electric utilities project a 143% increase in natural gas usage over the next ten years. Much of this increase (46%) is forecasted to occur between 2002 and 2004.

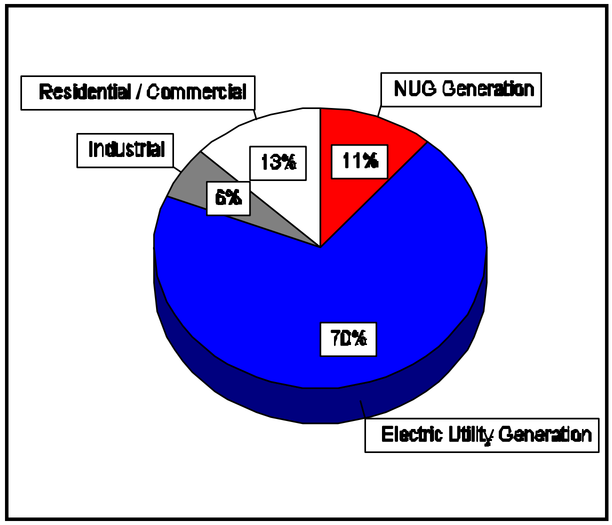


Figure 5

NATURAL GAS CONSUMPTION BY END-USER -- 2000

Conservative estimates indicate that future natural gas requirements will exceed FGT's current capacity. To meet forecasted requirements, an additional 1.0 Bcf/day may be needed over the next ten years. FGT has asserted to the FRCC that it is able and willing to expand its natural gas pipeline system to meet all forecasted electric demand. However, the Commission believes that electric utilities should identify a contingency plan in case gas transportation capacity is not available when needed for future electric generation expansion.

Future FGT Expansion

On February 28, 2000, the Federal Energy Regulatory Commission (FERC) approved FGT's proposed Phase IV Expansion project. The project, consisting of compression upgrade and approximately 140 miles of new pipeline, will increase the average daily delivery capacity to a total of 1.727 Bcf/day. Construction began in May, 2000, and the planned in-service date is April, 2001.

While FGT's Phase IV project was undergoing FERC review, FGT held a five-week open season for a proposed Phase V expansion. The open season, which closed on April 30, 1999, garnered enough interest that FGT submitted a certificate application to FERC on December 1, 1999 for a compression upgrade and approximately 190 miles of new pipeline. If approved, FGT plans to begin construction in April, 2001 to meet a projected in-service date of May, 2003. Upon completion in 2003, the Phase V expansion is expected to raise FGT's capacity to nearly 2.0 Bcf/day. This capacity is sufficient to meet anticipated demand for 2003 but not the forecasted need of 2.41 Bcf/day for 2009.

Other Proposed Pipelines

Two companies are competing to construct new pipelines into the state. The total estimated pipeline capacity of these two lines is approximately 2.13 Bcf/day. The construction of either proposed line would mitigate the Commission's concern with having only one pipeline company serving the state.

! On October 15, 1999, Gulfstream Natural Gas System, L.L.C. **(Gulfstream)** applied for FERC approval to construct and operate a new 744-mile interstate natural gas pipeline. As proposed, the 1.13 Bcf/day pipeline will extend from near Mobile, Alabama, across the Gulf of Mexico, to near Port Manatee, Florida. On April 28, 2000, the FERC issued a preliminary determination on non-environmental issues. In August, 2000, the FERC issued a Draft Environmental Impact Statement, the first of two environmental approvals needed before the optional certificate is issued. Gulfstream anticipates that the entire approval process will be completed by February, 2001, with an in-service date of June, 2002.

! On October 28, 1999, Williams-Transco applied for FERC approval to construct and operate a new 674-mile interstate natural gas pipeline known as the Buccaneer pipeline project **(Buccaneer)**. On April 28, 2000, the FERC issued a preliminary determination on non-environmental issues. As proposed, the pipeline 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. As proposed, the pipeline will have a capacity of 1.0 Bcf/day. In August, 2000, the project received the first of two environmental approvals necessary to obtain an optional certificate. Buccaneer anticipates an in-service date of April, 2002. However, because of the line's proposed route through Pasco County, Florida, residents in the area have expressed opposition to the line's construction.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

LOAD FORECASTS

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. In evaluating a utility's forecast, the Commission uses 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.

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.

STEP	DESCRIPTION
Collection of Historical Data	Historical data forms the foundation for utility load and energy forecasts. These data include 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 energy consumption patterns.
Assembly of Forecast Assumptions	Forecast assumptions represent utility expectations of future economic, weather, technological, and demographic conditions in their service territory. 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

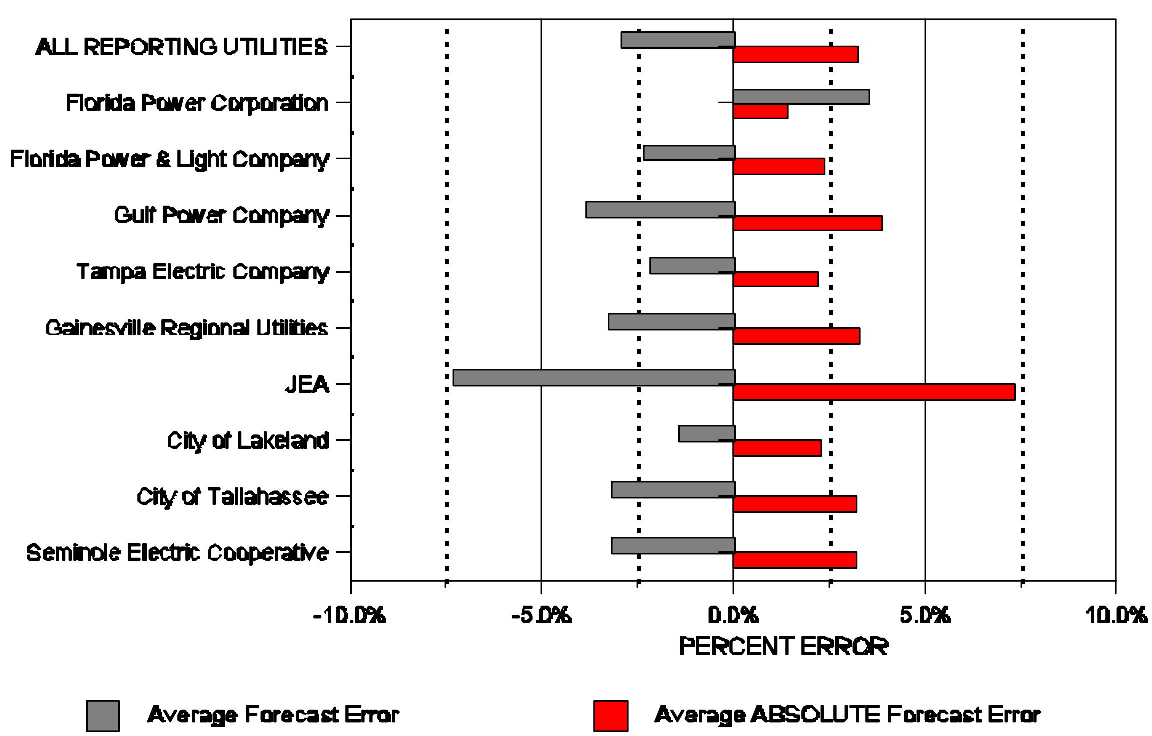
Reviewing the past results of a load and energy forecasting methodology reveals whether that methodology has produced accurate forecasts. A pattern of over- or under-forecasting is indicative of past forecast error that could be carried forward into current forecasts.

For each reporting utility, the Commission reviewed the historical forecast accuracy of total retail energy sales for the five-year period from 1995-1999. This review compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, actual 1999 energy sales were compared to the projected 1999 forecasts made in 1994, 1995, and 1996. 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 nine of the twelve reporting utilities. There was insufficient historical data to analyze the historical forecast accuracy of the Florida Municipal Power Agency, Kissimmee Utility Authority, and Orlando Utilities Commission. The Commission's evaluation is summarized in Figure 6. A detailed discussion of individual utility retail sales forecasts is contained later in this report.

Figure 6

TOTAL RETAIL ENERGY SALES – HISTORICAL FORECAST ACCURACY



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 Figure 6 n the prior page, all reporting utilities except FPC have a tendency to under-forecast retail energy sales.

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.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) reduces customer peak demand and energy requirements, and has avoided or deferred the construction of new generating units. 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 has set DSM goals, and the utilities have developed and implemented DSM programs designed to meet these goals. The DSM programs developed by Florida's electric utilities can be generally grouped into two types: ***dispatchable*** (e.g., load management and interruptible service), which are controlled by the utility; and ***non-dispatchable*** (e.g., attic insulation and energy-efficient lighting), which are permanent measures installed in a dwelling.

ESTIMATED IMPACT OF DSM ON DEMAND AND ENERGY CONSUMPTION

Florida's electric utilities have been successful in meeting the overall objectives of FEECA. As seen at right, utility conservation programs have reduced statewide summer peak demand by an estimated 3209 MW, winter peak demand by 5059 MW, and energy consumption by 2280 GWh. By 2009, DSM programs are forecasted to reduce aggregate summer peak demand by 4712 MW, winter peak demand by 6577 MW, and energy consumption by 4065 GWh. These DSM savings are also illustrated in Figures 7, 8, and 9 on the next two pages.

Estimated savings from Florida Utilities' DSM programs

	To Date	By 2009
Summer Peak Demand	3209 MW	4712 MW
Winter Peak Demand	5059 MW	6577 MW
Energy Consumption	2280 GWh	4065 GWh

CHANGES TO FEECA

When FEECA was enacted in 1980, every electric utility in the state was subject to its requirements. After its first revision in 1989, FEECA applied only to twelve electric utilities whose annual energy sales exceeded 500 GWh. Those twelve utilities provided 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 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 subsequently filed new DSM plans to meet their goals. The Commission approved all four DSM plans in April, 2000. The Commission set new numeric demand and energy DSM goals for FPUC in April, 2000. FPUC's DSM Plan was approved in September, 2000. The Commission set numeric goals of **zero** for JEA and OUC in April, 2000 because these two utilities could not identify any cost-effective DSM programs to offer.

Figure 7

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

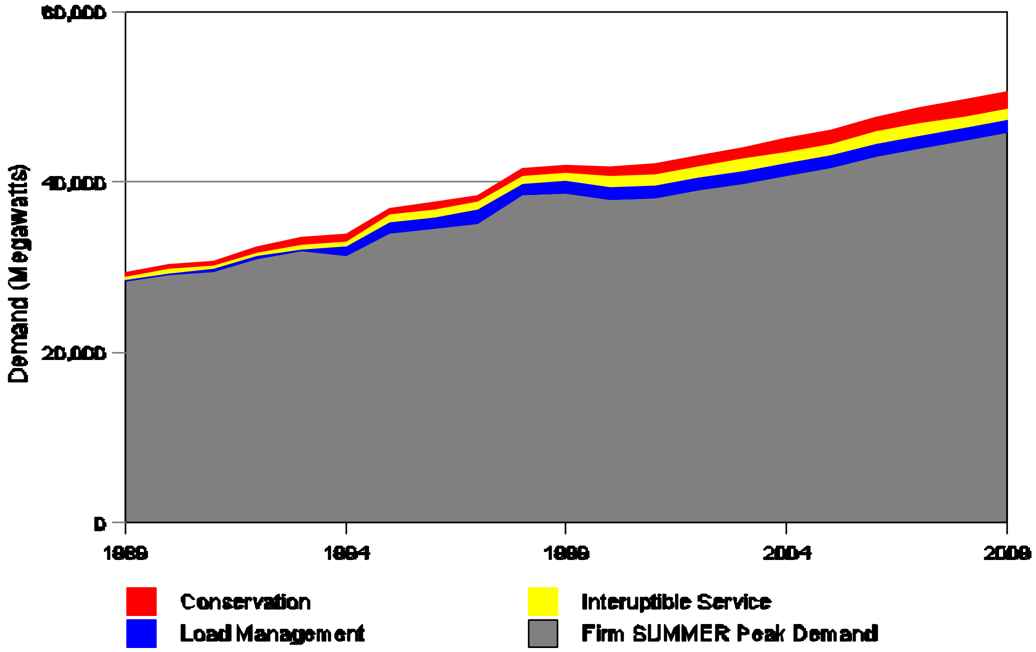


Figure 8

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

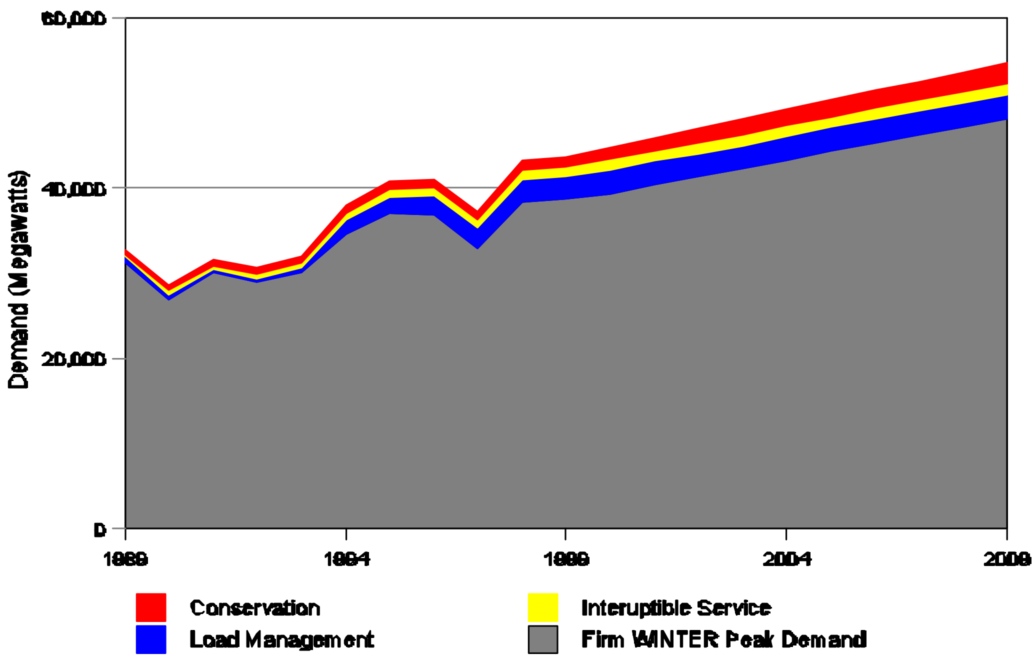
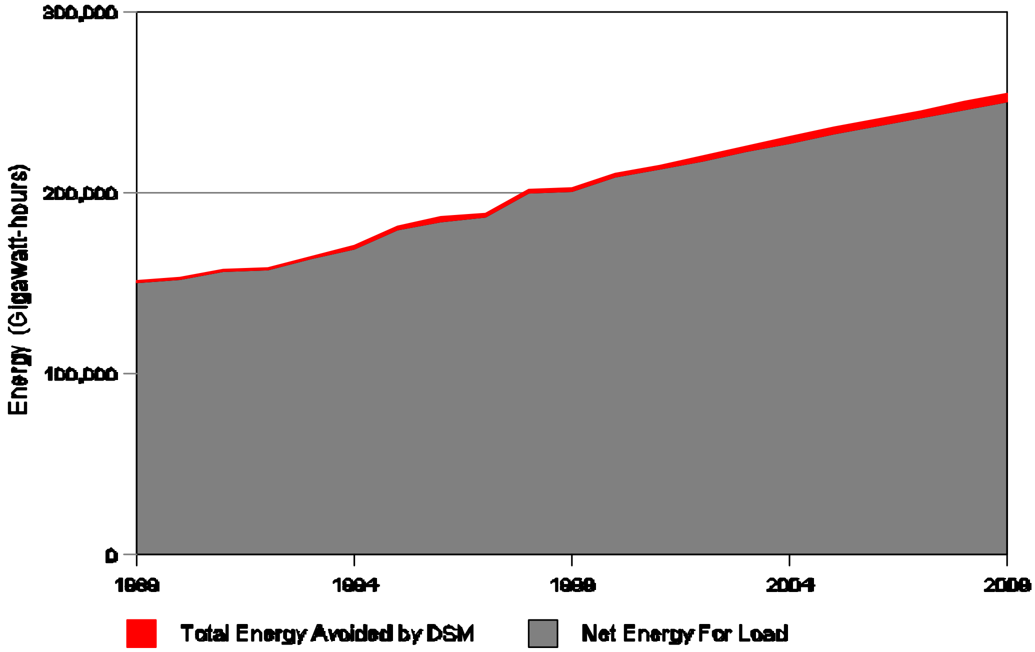


Figure 9

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



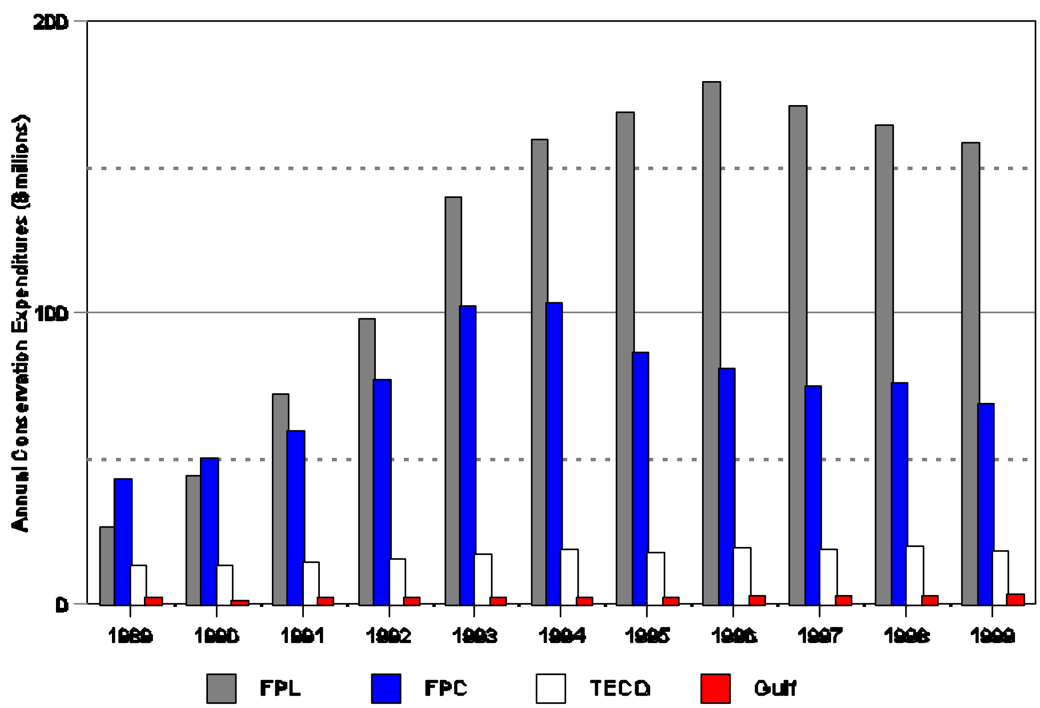
ENERGY CONSERVATION COST RECOVERY CLAUSE

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 DSM programs.

Since 1981, Florida's investor-owned utilities have collected over $2.7 billion through the ECCR clause. As shown in Figure 10 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 10

CONSERVATION EXPENSES RECOVERED THROUGH THE ENERGY CONSERVATION COST RECOVERY CLAUSE



REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

STATE COMPREHENSIVE PLAN

> *"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."*

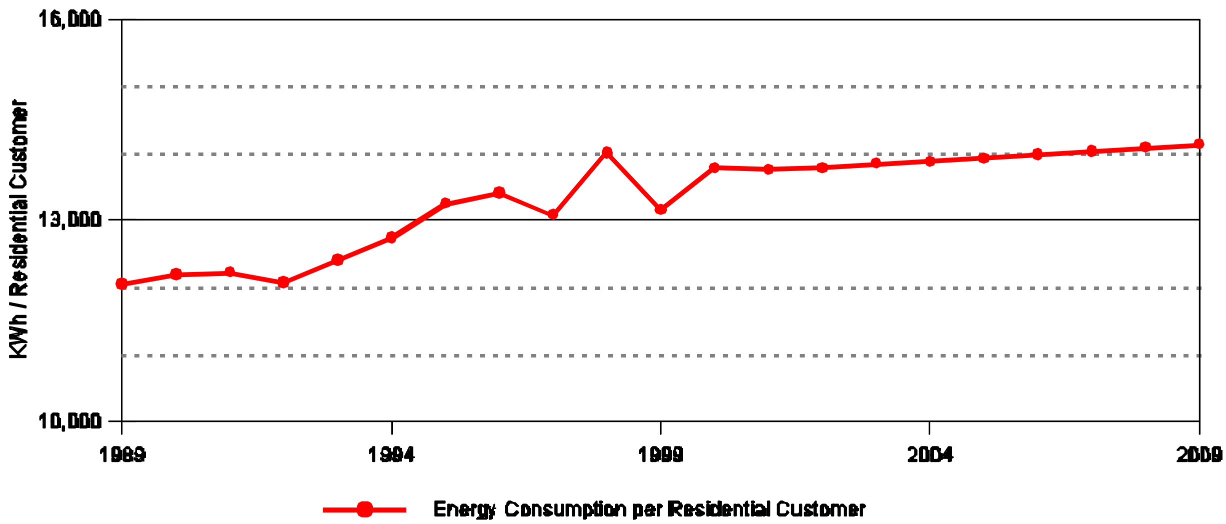
Energy conservation is a component of the State Comprehensive Plan. Section 187.201(12)(a), Florida Statutes, contains the State Comprehensive Plan's goal concerning energy as stated at right.

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. The Commission set DSM goals and approved DSM plans for electric utilities, and continues to work with the Department of Community Affairs (DCA) to ensure a building code that promotes 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.

However, in spite of the Commission's efforts, 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. As seen in Figure 11 below, the rate of increase in per-capita consumption is expected to be less over the forecast period 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 the following factors: 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, many more electricity-consuming appliances exist in the home today than in past years.

Figure 11

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



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 of generating units, as well as variation from base-case weather or forecasting 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 *TYSP* are shown in Table 3 on the next page.

Deterministic Criteria

Most all utilities use a deterministic reliability criterion. The primary criterion, ***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 indicates the level of reserves that are to 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 or winter season. Thus, it cannot capture the impact of random events occurring throughout the year, such as a forced outage of a generating unit.

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.

ROLE OF RELIABILITY CRITERIA IN RESOURCE PLANNING

Once reliability criteria are established, a utility applies its load forecast to its 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. In those instances, the utility must build or purchase additional capacity (supply-side options) or reduce peak load through 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 in a cost-effective manner. This underscores the fact that reliability criteria decide the **timing** of planned resource additions.

It should be noted that as recently as ten years ago, a 15% reserve margin criterion was approximately equivalent to an LOLP of 0.1 days per year. Currently, utility studies show that the 15% reserve margin correlates to questionable LOLP values much lower than 0.1 days per year. It is believed that these questionable LOLP values result from the high unit availability / low forced outage rates experienced by today's newer generating units. Therefore, reserve margin has become the primary criterion driving the need for additional capacity.

TABLE 3
RELIABILITY CRITERIA FOR REPORTING UTILITIES

UTILITY	RESERVE MARGIN		PROBABILISTIC CRITERIA	
	Percent	Season	LOLP	EUE/NEL
Florida Power Corporation (FPC)	15% [4]	Sum/Win	0.1	---
Florida Power & Light Company (FPL)	15% [4]	Sum/Win	0.1	---
Gulf Power Company (Gulf)	13.5% [5]	Sum	---	---
Tampa Electric Company (TECO)	15% [4] (7% supply-side) [6]	Sum/Win Sum	---	1%
Florida Municipal Power Agency (FMPA)	18%	Sum	---	---
Gainesville Regional Utilities (GRU)	15%	Sum/Win	---	---
JEA	15%	Sum/Win	---	---
Kissimmee Utility Authority (KUA)	15%	Sum/Win	---	---
City of Lakeland (LAK)	20% 22%	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%

Figures 12 and 13, on the next page, show the aggregate forecasted reserve margin over the next ten years, both statewide and for Peninsular Florida's utilities. Figure 13 shows that Peninsular Florida's aggregate reserve margin is forecasted to exceed the FRCC standard of 15% in all ten years of the planning horizon, both the summer and winter season.

[4]Pursuant to the stipulation in the reserve margin investigation (Docket No. 981890-EU, FPC, FPL, and TECO have agreed to increase their reserve margin planning criterion to 20% starting in Summer, 2004.

[5]Gulf will increase its reserve margin planning criterion to 15% starting in 2003.

[6]TECO's 7% summer supply-side reserve margin criterion becomes effective in Summer, 2004.

Figure 12

UTILITY FORECASTED RESERVE MARGIN -- STATE OF FLORIDA

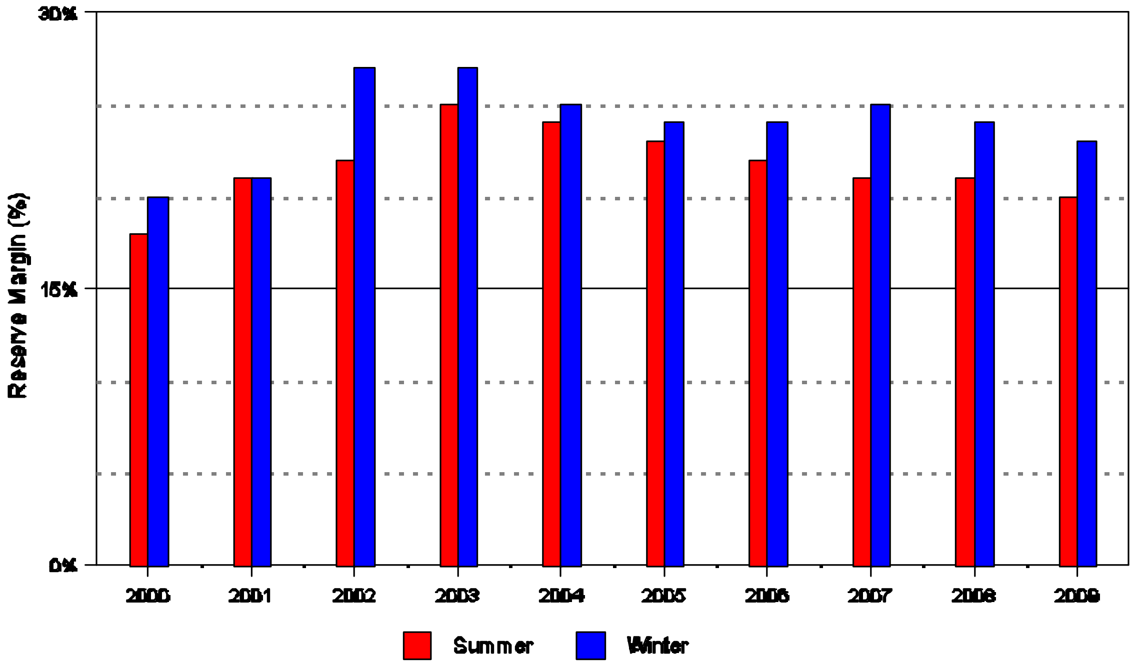
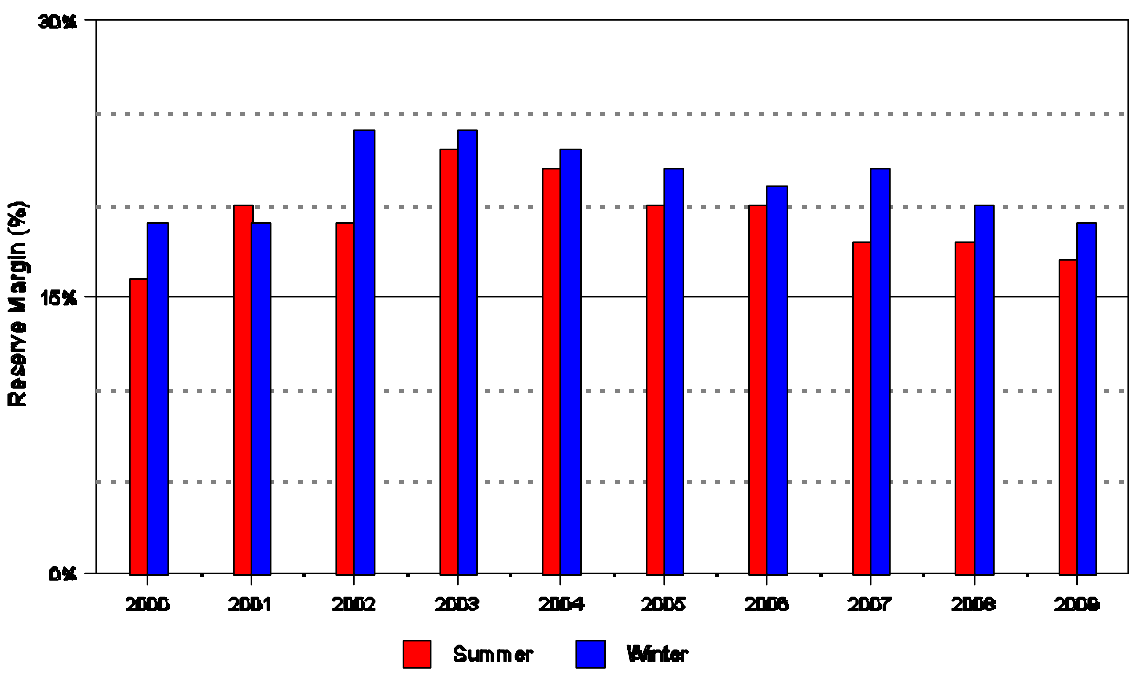


Figure 13

UTILITY FORECASTED RESERVE MARGIN -- PENINSULAR FLORIDA



REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

COMMISSION ACTIONS AFFECTING RELIABILITY

In recent years, the Commission had an ongoing concern with the decreasing level of reserve margins forecasted by Florida's utilities and the impact of these reserve margins on reliability. However, much of the Commission's concerns on reliability have been mitigated by two actions:

Reserve Margin Agreement (FPC, FPL, and TECO)

The Commission opened Docket No. 981890-EU to investigate the adequacy of reserve margins for Peninsular Florida's utilities. All generating utilities in Peninsular Florida were part of the investigation. Gulf was not included in the investigation because Gulf's service territory is not contained in Peninsular Florida.

The Commission concluded its reserve margin investigation when, on November 30, 1999, it approved an agreement by FPC, FPL, and TECO to adopt a 20% reserve margin planning criterion starting in the summer of 2004. The reserve margin agreement does not extend to municipal and cooperative electric utilities, who can therefore carry their current level of reserves. However, since FPC, FPL, and TECO make up approximately 75% of Peninsular Florida's generation, all municipal and cooperative utilities could carry exactly the FRCC minimum 15% reserve margin and the weighted average reserve margin for Peninsular Florida would still be nearly 19% due to the increased 20% reserve margins carried by FPC, FPL, and TECO. It should be noted that Florida's municipal and cooperative utilities typically carry reserves exceeding 20% in most years.

Announcement of New Merchant Plant Capacity in Florida.

There is considerable interest in constructing merchant plants in Florida. Merchant plant developers almost always plan to build natural gas-fired combustion turbine or combined cycle generators. Recent technological improvements, combined with the 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 plants have no obligation to sell electricity to load-serving Florida utilities. As a practical matter, most merchant plant sales will likely be made in-state because of transmission line constraints on the Southern Company-FRCC interface and the low marginal cost of coal-fired electricity in the Southern Company region.

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 is uneconomical to operate due to high fuel costs, the merchant plant's owners bear the costs rather than retail customers.

The Commission approved a determination of need for the 514 MW combined cycle unit proposed by Duke New Smyrna. This decision was overturned by the Florida Supreme Court, which stated that the Commission does not have jurisdiction to grant a Determination of Need for generating units whose capacity is not fully committed to the retail load of an electric utility. The Commission petitioned the Supreme Court for a rehearing on its decision. On September 28, 2000, the Supreme Court reaffirmed its order overturning the Commission's decision.

Several companies have announced plans to construct, over the next five years, combustion turbine merchant plants in Florida totaling approximately 5,370 MW. These units, which do not require certification under the Power Plant Siting Act, are summarized in Table 4 on the next page. Many merchant plant companies have also requested interconnection studies from investor-owned utilities.

As noted previously on pages 8 and 13, the FRCC did not include any CT merchant plant additions in its ***2000 Regional Load and Resource Plan***. Therefore, the Commission has compiled a listing of announced CT merchant plant additions. If the owners of these CT merchant plants were to sign firm capacity contracts to sell the entire 5,370 MW to load-serving utilities, Peninsular Florida reserve margins could potentially increase from 19% to 34% (summer, 2002) and from 24% to 38% (winter, 2002/03).

TABLE 4
ANNOUNCED COMBUSTION TURBINE MERCHANT PLANT ADDITIONS

Owner	Size (MW)	Location	In-Service Date
Reliant Energy	537	Osceola County	2001
Calpine	100	Polk County (Auburndale)	2001
El Paso	680	Hardee County	2001
El Paso	480	Pasco County	2001
Constellation	900	Brevard County	2002
Dynegy, Inc.	500	Osceola County	2002
IPS Avon Park	510	DeSoto County (Avon Park)	2002
Decker Energy	510	Polk County (Ft. Meade)	2002
Duke Energy Ft. Pierce	640	St. Lucie County (Ft. Pierce)	unknown
Granite Power Partners II	510	Hardee County	unknown
TOTAL	**5,367**		

FUEL FORECASTS

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 generating unit added. The reporting utilities produced base-case fuel price forecasts for several fuels. Additionally, some 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) Apply specific knowledge of contractual relationships with fuel vendors to reasonable assumptions of future events which the utility cannot control.

(2) Perform forecast sensitivities by modifying base-case assumptions to test the utility's generation expansion plan under various economic and technical scenarios.

(3) Compare utility-specific fuel price forecasts to several outside sources such as the U.S. Energy Information Administration (EIA).

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 forecasted annual average growth rate (AAGR) in price for each fuel, as forecasted by the reporting utilities and by EIA.

Florida's investor-owned utilities forecast fuel prices to increase at a more moderate pace during the planning horizon than EIA. EIA believes that prices for residual and oil, distillate oil, and, to some extent, natural gas, are correlated to the world price for crude oil. Recently, the world price for crude oil has doubled due to increased demand and stagnant supply. Unlike EIA, Florida's utilities anticipate that recent oil price increases are a short-term phenomenon, and that market forces will push world oil prices down to near previous levels. Prices for residual oil, distillate oil, and natural gas should also experience similar declines.

The Commission also recognizes that each utility's fuel price forecast reflects assumptions made about relevant factors that affect fuel prices. The Commission encourages each utility to periodically review these assumptions so that they accurately reflect real-world conditions. If the utility's assumptions are no longer consistent with real-world conditions, the Commission would expect to see a corresponding change in the utility's fuel price forecast.

COAL

The average U.S. delivered cost of coal in 1999 decreased to $1.22 per million Btu (MMBtu), down $0.03 per MMBtu from 1998. 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 2009, EIA forecasts that delivered coal prices will increase at a rate of approximately 1.0% 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 and in cycling units.

TABLE 5
FUEL PRICE FORECAST -- AVERAGE ANNUAL GROWTH RATE (2000 - 2009)

UTILITY	COAL	RESIDUAL OIL	DISTILLATE OIL	NATURAL GAS	NUCLEAR
EIA	0.96%	5.47%	6.39%	4.65%	NA
Florida Power Corporation	-0.05%	3.39%	3.40%	0.38%	1.75%
Florida Power & Light	-1.45%	1.59%	2.88%	1.16%	0.44%
Gulf Power Company	2.78%	NA	4.25%	1.69%	NA
Tampa Electric Company	0.43%	3.53%	4.67%	2.91%	NA
Florida Municipal Power Agency	NA	NA	NA	NA	NA
Gainesville Regional Utilities	0.77%	7.74%	6.41%	3.53%	2.90%
JEA	0.12%	4.38%	0.91%	2.44%	NA
Kissimmee Utility Authority	1.52%	1.91%	2.76%	2.54%	2.48%
City of Lakeland	1.79%	5.48%	6.27%	4.37%	NA
Orlando Utilities Commission	2.48%	1.32%	NA	3.35%	NA
City of Tallahassee	NA	4.19%	4.17%	1.36%	NA
Seminole Electric Cooperative	0.49%	1.73%	3.57%	2.01%	2.46%

Residual Oil

EIA reports that the average U.S. delivered cost of residual oil in 1999 was $2.44/MMBtu, up from $2.08/MMBtu in 1998. Through 2009, EIA anticipates that long-term residual oil prices will increase at approximately 5.5% per year. Florida's utilities have anticipated residual oil prices rising from 1.3% to 7.7% per year during the planning horizon.

Distillate Oil

EIA reports that the average U.S. delivered cost of distillate oil in 1999 was $3.90/MMBtu, up from $3.21/MMBtu in 1998. Through 2009, EIA anticipates that long-term distillate oil prices will increase at approximately 6.4% per year. Florida's utilities have anticipated distillate oil prices rising from 0.9% to 6.4% per year during the planning horizon.

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 over the sole use of coal. Florida utilities expect to increase pet coke consumption from approximately 685,000 tons annually to 3,156,000 tons annually during the planning horizon.

NATURAL GAS

The average nationwide cost of natural gas in 1999 was $2.62/MMBtu, up nearly 9% over 1998 costs. Several factors influence short-term natural gas prices: gas availability, storage levels, short-term fluctuations in residual and distillate oil prices, and weather implications. However, EIA expects the price of natural gas to increase by 4.7% per year through 2009.

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 1998, EIA estimated that U.S. proven natural gas reserves were approximately 164 trillion cubic feet (Tcf), a slight (1.8%) 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 1998, that proven natural gas reserves in the region were approximately 78.5 Tcf, a 3% decrease from year-earlier estimates. EIA also estimated natural gas production in this region at approximately 11.5 Tcf in 1998.

NUCLEAR

EIA expects that energy generation from nuclear will decrease by 0.6% per year during the planning horizon. By the year 2015, EIA assumes that 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 ¢/kWh) operating costs. However, both FPL and FPC expect their nuclear units to operate throughout the ten-year planning horizon.

Spent nuclear fuel disposal is a primary concern to both FPL and FPC. The U.S. DOE has been collecting a 0.1 ¢/kWh fee on nuclear-fired generation to finance the management and disposal of spent nuclear fuel. Nationwide, ratepayers pay approximately $600 million per year into the DOE’s Nuclear Waste Fund. FPL and FPC ratepayers 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 accounted for only 0.2% of the state’s total energy consumption.

In Florida, renewable energy is currently generated at five utility-owned sites: (1) TAL has 11 MW of hydroelectric capacity from its Corn Station units; (2) LAK and OUC use refuse-derived fuel to supplement the coal-fired generation at McIntosh Unit 3; (3) OUC can burn landfill methane gas in both coal units at the Stanton site;(4) JEA burns landfill methane gas at its 3 MW Girvin Landfill facility; and (5) TECO uses biomass to supplement the coal-fired generation from at Gannon station. Additionally, non-utility generators sell approximately 800 MW of renewable capacity to the grid.

GENERATION SELECTION

Florida's utilities supply electricity from many generating unit types. However, generating units in Florida were fueled primarily by oil prior to the early 1970's. While oil-fired generation still provides 19% of Florida's electricity at present, the oil embargoes of the 1970's forced utilities to turn more to domestic fuels such as coal, nuclear, and natural gas over the last 20 years.

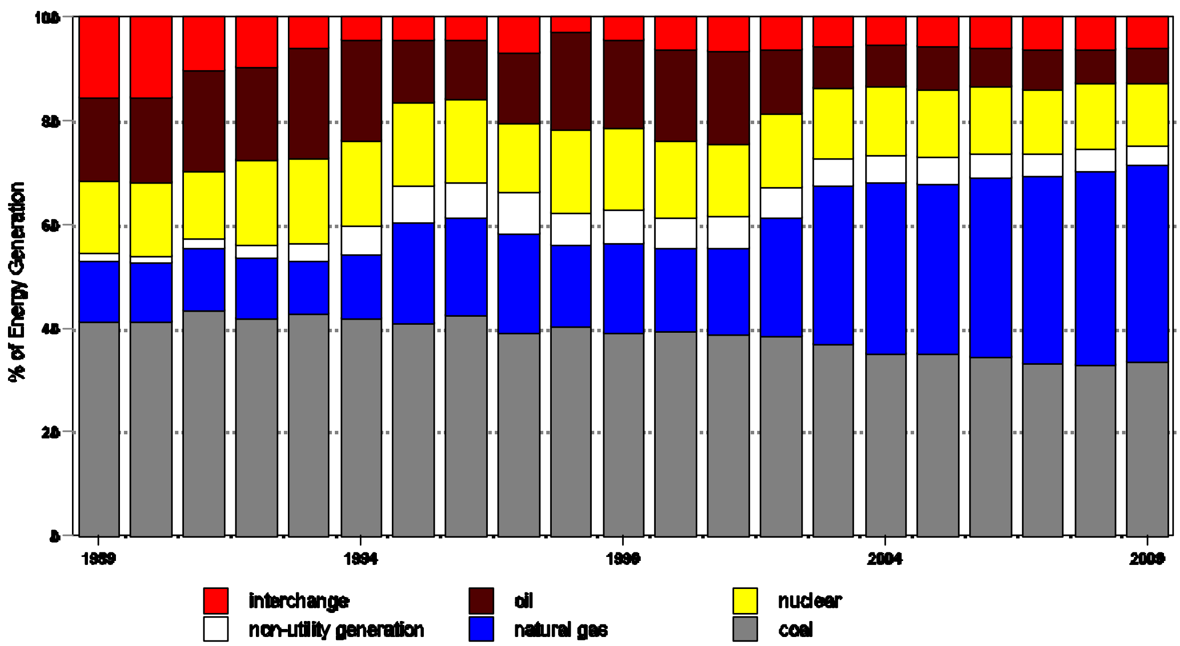
Figure 14 illustrates the historical and forecasted energy generation mix by fuel type for Florida's electric utilities. Over the next ten years, Florida's utilities are forecasting a substantial increase in natural gas-fired generation as the emphasis shifts away from oil-fired and coal-fired generating units. Nearly all of this capacity is expected to come from efficient, gas-fired combined cycle and combustion turbine units. Coal-fired generating units are not considered a viable option for most of Florida's electric utilities because of high construction costs, although Lakeland has one in its *TYSP*. Likewise, additional nuclear power plants are not considered a viable option in Florida's future primarily because of high construction costs and uncertainty over spent fuel disposal.

NATURAL GAS

Peninsular Florida's utilities project a substantial increase in natural gas-fired generation over the next ten years, from approximately 17% to 40% of all energy generated. The 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. Projections of increased natural gas consumption do not include the proposed new merchant plants which have been announced this year.

Figure 14

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, Peninsular Florida's utilities forecast that coal-fired energy will slowly decrease, from a current level of 34% down to 29% of all energy produced over the next ten years.

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. No Florida utility currently plans to build a new coal gasification plant.

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. Of the total interface, approximately 2600 MW is currently reserved for firm sales, leaving approximately 1000 MW available for non-firm, economy transactions.

Florida's utilities forecast a slow decline in interchange power purchases over the planning horizon. Interchange purchases are forecasted to comprise 5.8% of all energy consumed in ten years, down from a current level of 6.2%. 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 8.3% to 6.4% of total energy consumed, over the next ten years due to the expiration of approximately 970 MW of firm capacity NUG contracts during that time.

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 planned new units due to the absence of a feasible location. Florida's flat terrain does not lend itself to hydroelectric power.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

STATUS OF NEED DETERMINATIONS AND SITE CERTIFICATIONS

The Commission has granted a Determination of Need for several generating units in recent years. Some of these units have also been certified under the Power Plant Siting Act by the Governor and Cabinet, acting as the Power Plant Siting Board.

The following is a summary of those generating units that have received a Determination of Need from the Commission but have yet to be placed into commercial operation.

UTILITY-OWNED GENERATING UNITS

Seminole Electric Cooperative -- Payne Creek Generating 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. This unit was certified under the Power Plant Siting Act in August, 1995 and originally was to be in service by 1999. However, SEC deferred construction of the unit until January, 2002 in order to purchase cost-effective firm capacity from FPC.

Kissimmee Utility Authority / Florida Municipal Power Agency -- Cane Island Unit 3

In September, 1998, the Commission granted joint need petition, by KUA and FMPA, to jointly build and operate a 250 MW gas-fired combined cycle unit at the existing Cane Island site in Osceola County. Cane Island Unit 3 was certified under the Power Plant Siting Act in November, 1999. Construction began immediately thereafter on the proposed plant to meet an anticipated June, 2001 in-service date.

Gulf Power Company -- Smith Unit 3

In June, 1999, the Commission granted Gulf's petition to build a 532 MW gas-fired combined cycle unit at the existing Lansing Smith site in Bay County. Smith Unit 3 was certified under the Power Plant Siting Act in July, 2000. Gulf began construction on the unit in November, 2000 to meet an in-service date of June, 2002.

City of Lakeland -- McIntosh Unit 5

In April, 1999, the Commission granted LAK's petition to build a 120 MW steam turbine portion of a 365 MW combined cycle unit at the McIntosh site in Polk County. The steam turbine portion of McIntosh Unit 5 was certified under the Power Plant Siting Act in June, 2000. Construction began immediately thereafter to meet an anticipated January, 2002 in-service date.

MERCHANT PLANTS

Duke Energy Company / Utilities Commission of New Smyrna Beach

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 Duke unit has been awaiting certification by DEP under the Power Plant Siting Act. However, the Florida Supreme Court overturned the Commission's approval. The Court stated that the Commission does not have jurisdiction to approve the need for generating units whose capacity is not fully committed to retail load. The Commission petitioned the Supreme Court for a rehearing on its decision. On September 28, 2000, the Supreme Court reaffirmed its order overturning the Commission's Duke decision.

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

PLANNED UTILITY-OWNED GENERATING UNITS REQUIRING CERTIFICATION

The *TYSPs* filed by the reporting utilities contain proposed generating units which will require certification under the Power Plant Siting Act prior to their construction. The following is a summary of these proposed units.

Florida Power Corporation -- Hines Units 2, 3, 4, and 5

FPC's expansion plans reflect the planned addition of four new 567 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 2-5 are currently scheduled to be placed into commercial service in 2003, 2005, 2007, and 2009, respectively. FPC has petitioned the Commission for a Determination of Need for Hines Unit 2. A Commission decision is anticipated early in 2001. All four of the proposed Hines units will require certification under the Power Plant Siting Act.

Florida Power & Light Company -- Martin Units 5 and 6 (plus three Unsited combined cycle units)

FPL's expansion plans reflect the planned addition of two new 429 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 June, 2006. These units will require certification under the Power Plant Siting Act.

FPL also plans to build three 429 MW gas-fired combined cycle units at a yet-to-be determined site. These units have planned in-service dates of 2007, 2008, and 2009, respectively. If they are ultimately built, these units will require certification under the Power Plant Siting Act.

JEA – Brandy Branch Unit 4 (plus an Unsited combined cycle unit)

JEA's expansion plans reflect the addition of a 191MW heat recovery steam generator (HRSG) at the proposed Brandy Branch site in Duval County. The HRSG, with an anticipated June, 2003 in-service date, will be fitted to two 191 MW combustion turbine units already placed into service in January, 2001, forming a 573 MW combined cycle unit. JEA plans to file a Determination of Need petition for the HRSG with the Commission later this year. The HRSG will require certification under the Power Plant Siting Act.

JEA also plans to build a new 284 MW gas-fired combined cycle unit at a yet-to-be determined site. The proposed unit, with a June, 2006 in-service date, will require certification under the Power Plant Siting Act.

City of Lakeland -- McIntosh Unit 4

LAK's expansion plans reflect the planned addition of a 288 MW pressurized fluidized bed coal unit at the existing McIntosh plant site in Polk County. This unit was formerly a candidate for funding from the U.S. Department of Energy's Clean Coal Technology Program. LAK plans to file a Determination of Need petition with the Commission later this year to meet an anticipated June, 2005 in-service date. This unit will require certification under the Power Plant Siting Act.

Orlando Utilities Commission – Stanton Unit 3

OUC's expansion plans reflect the planned addition of a 585 MW gas-fired combined cycle unit at the existing Stanton site in Orange County. OUC plans to file a Determination of Need petition with the Commission later this year to meet an anticipated November, 2004 in-service date. This unit will require certification under the Power Plant Siting Act.

FLORIDA POWER CORPORATION (FPC)

GENERATION SELECTION

FPC's system currently has a total winter capacity of 9,577 MW. Of this total, 8,277 MW comes from FPC-owned generation. The remainder is purchased via interchange and from non-utility generators. The table at right shows the breakdown of FPC's capacity.

FPC plans to add four 567 MW gas-fired combined cycle units at the **Hines** site in 2003, 2005, 2007, and 2009, respectively. FPC has begun construction of **Intercession City Units 12-14**, three peaking units with a total winter capacity of 282 MW. These three units are expected to go into service in December, 2000. FPC plans to retire 12 units with a total generating capacity of 392 MW. The following sites will be affected: **Higgins** (134 MW), **Suwannee** (146 MW), **Avon Park** (64 MW), **Turner** (32 MW), and **Rio Pinar** (16 MW). Additionally, FPC will lose approximately 175 MW due to the expiration of five cogeneration contracts.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Combustion Turbine	2775	MW
Coal	2316	MW
Fossil Steam	1642	MW
Firm Non-Utility Generation	831	MW
Nuclear	792	MW
Firm Purchases	469	MW
Combined Cycle	752	MW
TOTAL existing capacity	**9577**	**MW**

NEXT UNIT ADDITION		
Combustion Turbine (3 units)	282	MW

RELIABILITY CRITERIA

FPC currently 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). Pursuant to a stipulation reached in the Commission's reserve margin investigation (Docket No. 981890-EU), FPC has agreed to raise its reserve margin to 20% starting in the summer of 2004. Current plans call for FPC to retain its LOLP planning criterion. FPC is a winter-peaking utility.

LOAD FORECAST

FPC identifies and justifies its load forecast methodology via its models, variables, data sources, assumptions, and informed judgements. The Commission believes that all of these factors have been accurately documented. A combination of short-term econometric models and an hourly and annual peak and energy end-use forecasting system 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's base-case winter firm demand forecast for the next ten years is projected to increase at an average annual growth rate (AAGR) of 0.51%, considerably below the actual 1990-1999 AAGR of 4.05%. FPC's base-case summer firm demand forecast for the 2000-2009 period is an AAGR of 0.76%. FPC attributes much of the slow demand growth to an expected decline in phosphate mining. FPC forecasts the lowest growth rate of all reporting utilities.

FPC's 1995-1999 retail sales forecasts have an absolute percent error of 1.4%, which is lower than the 3.22% 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 0.35%, which shows a slight tendency to over-forecast.

DEMAND-SIDE MANAGEMENT

The Commission set new DSM goals for FPC in August, 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. FPC's DSM Plan was approved by the Commission in April, 2000.

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 non-dispatchable conservation programs (363 MW), interruptible service tariffs (255 MW), and load management(1179 MW).

However, non-firm resources such as interruptible service and load management make up a substantial part of FPC's reserve margin. For 2000, non-firm resources comprise approximately 84% of FPC's winter reserves and 59% of summer reserves. In recent years, the Commission has been 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. FPC has closed its existing, year-round load management program to new customers and replaced this program with a winter-only program. Attrition from the old program is expected to reduce summer demand savings and reduce FPC's reliance on non-firm resources.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

East Central Florida Regional Planning Council

The 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. Believes that FPL's *TYSP* could contain more detailed information on conservation and on gas supply to the Sanford site.

Florida Department of Community Affairs (DCA)

DCA provided general comments on FPC's *TYSP*. Stated that the Hines and Intercession City facilities are consistent with applicable local land use and zoning ordinances.

Florida Department of Environmental Protection (DEP)

DEP found that FPC's *TYSP* is adequate for planning purposes.

South Florida Water Management District

The District does not have any adverse comments regarding the suitability of the proposed sites.

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 .

SUITABILITY

Forecasted reserve margins are expected to be at or above FPC's criterion of 15% for each seasonal peak through the summer of 2004, after which time forecasted reserve margins are expected to be at or above the new 20% criterion. FPC's *TYSP* is ***suitable*** for planning purposes.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

FLORIDA POWER & LIGHT COMPANY (FPL)

GENERATION SELECTION

FPL's system currently has a total winter capacity of 19,439 MW. Of this total, 17,234 MW comes from FPL-owned generation. The remaining 2,205 MW is purchased via interchange and from non-utility generators. The table at right shows the breakdown of FPL's capacity.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Fossil Steam	8703	MW
Nuclear	3013	MW
Combined Cycle	2544	MW
Combustion Turbine	2308	MW
Firm Purchases	1319	MW
Firm Non-Utility Generation	886	MW
Coal	666	MW
TOTAL existing capacity	**19439**	**MW**

NEXT UNIT ADDITION		
Combined Cycle (initial phase / repowering at Ft. Myers)	543	MW

FPL plans to add approximately 4,800 MW of supply-side resources 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 2,500 MW of winter generating capability between January, 2001 and May, 2003. These unit repowerings were exempt from the Power Plant Siting Act and have had no pre-approval from the Commission.

FPL also plans to build two 181 MW combustion turbines at the **Martin** site, to be placed into service in June, 2001. Also proposed during the planning horizon are five 429 MW gas-fired combined cycle units: **Martin Units 5 and 6** in 2006, and one yet-to-be sited unit in each of 2007, 2008, and 2009. FPL will lose approximately 200 MW due to the expiration of four cogeneration contracts.

RELIABILITY CRITERIA

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). In 1998, FPL added a third reliability criterion, 15% winter peak reserve margin. Pursuant to a stipulation reached in the Commission's reserve margin investigation (Docket No. 981890-EU), FPL has agreed to raise its summer and winter planning reserve margin to 20% starting in the summer of 2004. Current plans call for FPL to retain its LOLP planning criterion. FPL has traditionally been a summer-peaking utility because of recent mild winter temperatures. However, FPL forecasts that winter peak demand will be higher than summer peak during the planning horizon.

LOAD FORECAST

FPL develops its residential load forecast with an integrated end-use/econometrics forecasting model. This method forecasts electricity sales in the residential sector simulating acquisitions and energy usage of eleven major residential appliances plus residual electricity use. 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, the model 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 *TYSP*. The Commission believes that these factors have been accurately documented and that FPL's data sources are credible.

FPL's base-case summer peak demand forecast for the next ten years is projected to increase at an average annual growth rate (AAGR) of 1.87%, greater than the 1.56% AAGR for the 1990-1999 period. FPL's 2000 base-case summer peak demand forecast is higher than its 1999 forecast by an average of 456MW over the forecast horizon. FPL's 2000 base-case winter peak demand forecast for the next ten years is projected to increase at an AAGR of 2.97%, substantially higher than last year's 1999-2008 AAGR of 1.89%. In FPL's last two *TYSPs*, the winter peak projections had been falling. FPL has reversed the last two years' lower demand forecasts with the 2000 *TYSP's* base-case projections being 210MW greater over the forecast horizon than the 1999 *TYSP*.

FPL's 1995-1998 retail sales forecasts have an absolute percent error of 2.35%, which is lower than the 3.22% 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 -2.35%, which shows a tendency to under-forecast.

DEMAND-SIDE MANAGEMENT

The Commission set new DSM goals for FPL in August, 1999. These goals call for a cumulative reduction of 765 MW of summer peak demand, 505 MW of winter peak demand, and 1,287 GWh of energy consumption over the next ten years. FPL's DSM Plan was approved by the Commission in April, 2000.

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.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

East Central Florida Regional Planning Council

The Council provided general comments on the positive environmental impacts of FPL's proposed Sanford unit repowering. Believes that FPL's *TYSP* could contain more detailed information on conservation and on gas supply to the Sanford site.

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 expressed general concerns regarding the planned expansion at Sanford and Martin, as well as potential use of the Cape Canaveral, Riviera, and Port Everglades sites.

Florida Department of Environmental Protection (DEP)

DEP found that FPL's *TYSP* is adequate for planning purposes.

Southwest Florida Regional Planning Council

FPL's *TYSP* is <u>Regionally Significant and Consistent</u> with adopted goals, objectives, and policies.

South Florida Water Management District

The District does not have any adverse comments regarding the suitability of the proposed sites.

St. Johns River Water Management District

All proposed projects are on existing sites and, therefore, are suitable.

Treasure Coast Regional Planning Council

The Council has previously found that expansion at the Martin site does not conflict with regional policies. Provided general comments on its belief that FPL and the State of Florida should develop new programs to reduce reliance on coal and other fossil fuels, increase conservation to offset the need for new plants, and increase reliance on photovoltaic systems to produce electricity.

SUITABILITY

Forecasted reserve margins are expected to be at or above FPL's criterion of 15% for each seasonal peak through the summer of 2004, after which time forecasted reserve margins are expected to be at or above the new 20% criterion. FPL's *TYSP* is ***suitable*** for planning purposes.

GULF POWER COMPANY (Gulf)

GENERATION SELECTION

Gulf's system currently has a total winter capacity of 2,249 MW. Gulf-owned generation has a capacity of 2,261 MW. Gulf purchases 197 MW of firm capacity via interchange and from a single non-utility generator. However, Gulf exports 209 MW of capacity to other Southern Company members. The table at right shows the breakdown of Gulf's capacity.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Coal	2123	MW
Firm Purchases	178	MW
Fossil Steam	83	MW
Combustion Turbine	55	MW
Firm Non-Utility Generation	19	MW
(minus) Firm Exports	209	MW
TOTAL existing capacity	**2249**	**MW**
NEXT UNIT ADDITION		
Combined Cycle	574	MW

Gulf plans to increase its supply-side resources by approximately 487 MW during the planning horizon. The primary unit addition in Gulf's *TYSP* is the 574 MW **Smith Unit 3**, the first gas-fired combined cycle unit on Gulf's system. This unit is expected to be placed into commercial service in June, 2002. Gulf expects to have an ownership share (150 MW total) of three combustion turbine units to be located in Southern Company's territory. These units are expected to be placed into commercial service in 2006, 2007, and 2008. Firm imports are forecasted to drop to near zero by 2002. Gulf also plans to retire a 40 MW combustion turbine at the **Smith** site in 2006. Gulf will also lose 19 MW due to the expiration of a cogeneration contract.

RELIABILITY CRITERIA

Gulf's system peak has occurred during the summer season in seven of the last ten years. Gulf's current planning criterion is a 13.5% summer reserve margin, the same as for Southern Company. Gulf's reserve margin at peak is forecasted to be well below 13.5% for each of the next three years. Therefore, Gulf is expected to be a net buyer of capacity from the Southern Company pool during this time. Both Gulf and Southern Company have adopted a 15% summer reserve margin criterion to become effective in 2003. Gulf expects to exceed this target with the addition of Smith Unit 3 in June, 2002. Gulf currently forecasts that it will not meet its 15% reserve margin criterion in each summer season starting in 2005. Again, Gulf is expected to be a net buyer of capacity from the Southern Company pool during this time.

Because Gulf's service territory is not located in Peninsular Florida, Gulf is not bound by the stipulation reached by FPC, FPL, and TECO in the Commission's reserve margin investigation (Docket No. 981890-EU).

LOAD FORECAST

Gulf uses different methods to produce its short-term (0-2 years) and intermediate/long-term (3-25 years) forecasts. Short-term forecasts are based upon a variety of forecasting methods. Customer growth estimates are made using the aggregate of district projections performed by district personnel based on their contacts with sectors of the local economy and historical trends. Short-term energy sales forecasts are developed using multiple regression analyses. 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.

Gulf's base-case summer peak demand forecast for the next ten years shows an annual average growth rate (AAGR) of 1.32%, which is about half of the 2.48% historical growth rate. The base-case winter peak demand over the forecast period is the lowest in the state, 0.93%. This compares to an AAGR of 3.02% in winter peak demand over the past ten years. Gulf has decreased the 2000 base-case summer peak forecast and increased the base-case winter peak forecast in contrast to Gulf's 1999 *TYSP*.

Gulf stated in 1997 that the stabilization of appliance saturation rates and appliance efficiencies are the main factors suppressing demand growth. Another factor is residential conservation programs. However, Gulf's projected 1.1% average annual population growth for the 1999-2004 period is substantially below the state's annual growth rate of 1.6% plus, per year.

DEMAND-SIDE MANAGEMENT

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. Gulf's DSM Plan was approved by the Commission in April, 2000.

Most of Gulf's forecasted demand savings are expected to result from the Good Cents Home program and the Advanced Energy Management program, a customer-controlled demand control program in which customers can reduce electricity consumption in response to pricing signals. All of Gulf's existing and new DSM programs are expected to reduce the 2007 winter demand by an estimated 547 MW (20%).

Gulf does not have an interruptible service tariff or any dispatchable load management on its system. As a result, none of Gulf's 2000 winter and summer reserves are comprised of non-firm resources.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA cannot comment on the proposed combustion turbine units in Gulf's *TYSP* because no location is given for these units.

Florida Department of Environmental Protection (DEP)

DEP found that Gulf's *TYSP* is adequate for planning purposes.

West Florida Regional Planning Council

Gulf's *TYSP* 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. Further, the new 15% criterion is forecasted to be violated starting in 2005. Gulf has indicated that it will continue to rely on purchases from the Southern Company pool during these times. It should be noted that Gulf's capacity shortfall is extremely small in magnitude in relation to the size of the Southern Company. Therefore, Gulf's *TYSP* is ***suitable*** for planning purposes.

TAMPA ELECTRIC COMPANY (TECO)

GENERATION SELECTION

EXISTING WINTER CAPACITY BY FUEL TYPE		
Coal	2912	MW
Firm Purchases	551	MW
Coal Gasified Combined Cycle	250	MW
Combustion Turbine	228	MW
Fossil Steam	204	MW
Firm Non-Utility Generation	46	MW
(minus) Firm Exports	314	MW
TOTAL	**3877**	**MW**

NEXT UNIT ADDITION		
Combustion Turbine	180	MW

TECO's system currently has a total winter capacity of 3,877 MW. Of this total, 3,594 MW comes from TECO-owned generation. TECO purchases 597 MW via interchange and from non-utility generators. TECO also exports 314 MW to other utilities. The table at right shows the breakdown of TECO's capacity.

TECO's installed capacity is dominated by coal-fired generation. However, TECO's supply-side additions during the planning period are expected to consist solely of gas-fired generation. Six 180 MW gas-fired combustion turbine units are included in TECO's *TYSP*, five at the **Polk** site and one at a yet-to-be determined location. TECO also plans to place **Gannon Units 1, 2, and 6** into reserve shutdown status. **Gannon Units 3, 4, and 5** will be repowered with a total of six new gas-fired combustion turbine units and renamed **Bayside Power Station Units 1 and 2**. These two new repowered units will have a net winter capacity of approximately 800 MW each and are expected to be placed into service in 2003 and 2004, respectively. Firm exports are forecasted to drop to zero by 2003.

RELIABILITY CRITERIA

TECO has been primarily a summer-peaking utility, as seven of the last ten annual peaks have occurred during summer season. However, because winter peak demands are a primary concern to utilities in Florida, TECO plans resource additions on its system to meet a 15% winter peak reserve margin. An additional criterion used by TECO is a 1% EUE/NEL ratio. Pursuant to a stipulation reached in the Commission's reserve margin investigation (Docket No. 981890-EU), TECO has agreed to raise its reserve margin criterion to 20% starting in the summer of 2004. TECO has also adopted a 7% supply-side summer reserve margin criterion to take effect in the summer of 2004.

LOAD FORECAST

TECO's retail demand and energy forecast is the result of five separate forecasting methods: ***detailed end-use*** model, ***multiregression*** model, ***trend analysis***, ***phosphate analysis***, and ***conservation*** programs. The detailed end-use model is the most comprehensive method. The first three forecasting methods are blended together to develop a demand and energy projection. Phosphate demand and energy are forecasted separately and then combined into the final forecast. The effect of TECO's conservation, load management, and cogeneration programs is incorporated by subtracting forecasted demand and energy reductions from the forecast. TECO's end-use methodology takes into account a wide range of forecast variables. In addition to base-case energy and demand forecasts, TECO constructed high- and low-case forecasts using explicit assumptions on higher or lower expected growth in the number of customers, employment, and income.

TECO's base-case summer peak demand is projected to increase at an average annual growth rate (AAGR) of 2.49%, which is lower than its summer historical growth rate of 3.23%. TECO's base-case winter peak demand is projected to increase at an AAGR of 3.13% which is higher than its winter historical growth rate of 2.79%.

TECO's 1995-1999 retail sales forecasts have an absolute percent error of 2.19%, which is lower than the numeric average for the nine reporting utilities in the state with sufficient historical data. For the same five-year period, TECO's retail sales forecasts have an average forecast error of -2.1%, with shows a tendency to under-forecast.

DEMAND-SIDE MANAGEMENT

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. TECO's DSM Plan was approved by the Commission in April, 2000.

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 2000, non-firm resources comprise approximately 87% of TECO's winter reserves and 75% of summer reserves. This is expected to be a short-term event, as TECO has adopted a 7% supply-side reserve margin criterion beginning in 2004.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

Provided general comments on the Polk and Bayside / Gannon sites.

Florida Department of Environmental Protection (DEP)

DEP found that TECO's *TYSP* is adequate for planning purposes.

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

TECO's *TYSP* 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 through the summer of 2004, after which time forecasted reserve margins are expected to be at or above the new 20% criterion and the 7% supply-side criterion. TECO's *TYSP* is ***suitable*** for planning purposes.

FLORIDA MUNICIPAL POWER AGENCY (FMPA)

FMPA is an organization that jointly manages and operates the activities of 27 municipal electric utilities, including four recently added members. Eleven member utilities currently comprise the All-Requirements Project, meaning that FMPA has committed to plan for, and supply, all power requirements for these members. Member cities not involved in the All-Requirements Project are responsible for planning their own generation and transmission needs.

GENERATION SELECTION

FMPA's All-Requirements Project currently has a total winter generating capacity of 527 MW. The table at right shows the breakdown of FMPA's capacity.

EXISTING WINTER *GENERATING* CAPACITY BY FUEL TYPE		
Coal	245	MW
Combustion Turbine	147	MW
Nuclear	75	MW
Combined Cycle	60	MW
TOTAL existing capacity	**527**	**MW**

NEXT UNIT ADDITION		
Combined Cycle (jointly owned)	125	MW

However, the combined capacity of FMPA's members is insufficient to meet aggregate load. To serve load that exceeds generation, FMPA purchases approximately 900 MW of capacity from other utilities. FMPA has partial requirements contracts with FPC and FPL whereby these two utilities agree to serve the amount of load that exceeds FMPA's own generation and capacity purchases.

FMPA plans to add 225 MW of generation during the planning period. All proposed capacity is expected to come from joint ownership shares in two new generating units: 125 MW from **Cane Island Unit 3**, a gas-fired combined cycle unit jointly owned with KUA; and 100 MW from **McIntosh Unit 4**, a fluidized bed coal unit jointly owned with LAK. These units are scheduled to be placed into service in 2001 and 2005, respectively.

RELIABILITY CRITERIA

FMPA has historically been a summer-peaking utility. As such, FMPA plans resource additions on its system to meet a reliability criterion of 18% summer peak reserve margin. Along with the planned unit additions described above, FMPA plans to purchase capacity and energy from other utilities to meet its reserve margin criterion.

LOAD FORECAST

FMPA uses several techniques to estimate All-Requirements Project member energy requirements including econometric modeling and statistical analysis techniques. Also used are incremental load analysis and informed judgement. Some general economic and demographic assumptions are identified, but only one data source is identified. Applying generalized economic assumptions across all relevant 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, but rather high- and low-bandwidth cases based on different scenarios of events. Further, FMPA has insufficient historical forecast data to enable the Commission to compare FMPA's forecast accuracy to other utilities in the state.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

FMPA's base-case summer peak demand for the 1990-1999 period increased at an average annual growth rate (AAGR) of 10.33%, due primarily to the addition of new member utilities. The projected AAGR for the next ten years is 2.52%. FMPA's base-case winter peak demand for the 1990-1999 period increased at an AAGR of 8.28%. For the ten year planning horizon, FMPA forecasts winter peak demand to increase at an AAGR of 2.36%.

DEMAND-SIDE MANAGEMENT

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%).

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA participated in the site certification process for **Cane Island Unit 3**. Therefore, no further comments are necessary.

Florida Department of Environmental Protection (DEP)

DEP found that FMPA's *TYSP* is adequate for planning purposes.

East Central Florida Regional Planning Council

Believes that FMPA's *TYSP* could contain more information on conservation achievements.

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 .

South Florida Water Management District

The District does not have any adverse comments regarding the suitability of the proposed sites.

SUITABILITY

Forecasted reserve margins are expected to be at or above FMPA's criterion of 18% for each summer peak throughout the planning horizon. FMPA's *TYSP* is ***suitable*** for planning purposes.

GAINESVILLE REGIONAL UTILITIES (GRU)

GENERATION SELECTION

GRU's electric generating system currently has a winter capacity of 475 MW. GRU currently exports 88 MW to other utilities, and GRU expects to continue to be a net seller of capacity and energy until 2004. The table at right shows the breakdown of GRU's capacity.

The only new capacity addition in GRU's *TYSP* is a planned repowering of **J. R. Kelly Unit 8** as a 110 MW combined-cycle unit. This unit as an expected in-service date of January, 2001.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Coal	228	MW
Combustion Turbine	166	MW
Fossil Steam	158	MW
Nuclear	11	MW
(minus) Firm Exports	88	MW
TOTAL	**475**	**MW**

NEXT UNIT ADDITION		
Combined Cycle	110	MW

RELIABILITY CRITERIA

GRU has historically been a summer-peaking utility. GRU plans resource additions on its system to meet a reliability criterion of 15% summer and winter peak reserve margin.

LOAD FORECAST

GRU uses a series of linear multiple regression models to forecast energy consumption. GRU's historical data have been obtained from reputable sources, and GRU outlined the key assumptions of its forecast. The assumptions include normal weather conditions, prices adjusted for inflation, a 3% average annual inflation rate throughout the forecast, and declining real electricity prices.

GRU's base-case summer peak demand forecast for the next ten years is projected to increase at an average annual growth rate (AAGR) of 1.75%, less than the 3.54% AAGR for the 1990-1999 period. GRU's *TYSP* does not specifically justify the lower projected growth rate. GRU's base-case winter peak demand forecast for the next ten years is projected to increase at an AAGR of 1.77%, which compares to the summer peak growth projection.

GRU's 1995-1999 retail sales forecasts have an absolute percent error of 3.27%, slightly higher 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 -3.27%, which shows a tendency to under-forecast.

DEMAND-SIDE MANAGEMENT

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

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Alachua County Department of Growth Management

Had general concerns on water use and discharge, load forecasting assumptions, and GRU's plans to market electric energy.

Florida Department of Community Affairs (DCA)

DCA provided general comments on the proposed repowering at the **J. R. Kelly** site. Shares Alachua County's concerns on water use and discharge.

Florida Department of Environmental Protection (DEP)

DEP found that GRU's *TYSP* is adequate for planning purposes.

St. Johns River Water Management District

All proposed projects are on an existing site and, therefore, are suitable.

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 *TYSP* is ***suitable*** for planning purposes.

JEA

GENERATION SELECTION

JEA's electric generating system currently has a winter capacity of 2,839 MW. Of this total, 2,732 MW comes from JEA-owned generation. JEA imports 552 MW via interchange but also exports 445 MW to other utilities. The table at right shows the breakdown of JEA's capacity.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Coal	1220	MW
Fossil Steam	1073	MW
Firm Purchases	552	MW
Combustion Turbine	439	MW
(minus) Firm Exports	445	MW
TOTAL	**2839**	**MW**

NEXT UNIT ADDITION		
Combustion Turbine (2 units)	382	MW

JEA placed a new 191 MW combustion turbine (CT) unit, **Kennedy Unit 7**, into service in June of this year. JEA plans to add three identical CT units at the new **Brandy Branch** site, two in January, 2001 and the third one in December, 2001. JEA also plans to repower **Northside Units 1 and 2** in 2002, and add a heat recovery steam generator to two of the Brandy Branch CT units, thus converting the block to combined cycle operation, in 2003. JEA's *TYSP* also includes a planned 284 MW combined cycle unit in 2006 and another 191 MW CT unit in 2009. Both of these units are planned for a yet-to-be-determined site.

In addition to adding new capacity, JEA also plans to retire 306 MW of fossil steam capacity at the **Kennedy** and **Southside** sites by the end of 2001. JEA forecasts that firm exports will decrease by 62 MW over the planning horizon, while firm purchases are expected to decrease by 302 MW during that time.

JEA's capacity purchases are made through a partnership with the Municipal Electric Authority of Georgia and the South Carolina Public Service Authority. This partnership, known as The Energy Authority (TEA), will work on behalf of JEA as its power marketing group to meet purchased power needs.

RELIABILITY CRITERIA

The season during which JEA's peak load occurs varies – five of the last ten peaks occurred during the winter period, four during the summer, and one year had identical summer and winter peaks. Because of these variations, JEA's reliability criterion is a 15% summer and winter peak reserve margin.

LOAD FORECAST

JEA used trend analysis based on historical data to evaluate base, high, and low forecasts of demand, energy, and number of customers. All criteria are adjusted for JEA's assessment of the strength of the local economy. 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 1995-1999 retail sales forecasts have an absolute percent error of 7.32%, the highest among all of the state's reporting utilities and 4.1 percentage points over the statewide average of 3.22%. For the same period, JEA's retail sales forecasts have an average forecast error of -7.32%, which shows a strong tendency to under-forecast.

JEA's base-case winter peak demand forecast for the next ten years is projected to increase at an average annual growth rate (AAGR) of 3.58%, which is slightly lower than the historical winter peak AAGR of

3.79% over the past ten years. The base-case summer peak demand forecast shows an AAGR of 3.17%, which is lower than the historical summer peak AAGR of 3.54%, but still an improvement over the forecast from JEA's 1999 *TYSP*.

JEA's method of trending historical data series to derive a load forecast merely extends historical error 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 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 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.

DEMAND-SIDE MANAGEMENT

The Commission set numeric goals of **zero** for JEA in April, 2000. JEA was unable to identify any cost-effective DSM programs to offer. However, JEA has agreed to continue its existing DSM programs including audits (required by FEECA), 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.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

Provided general land-use comments on JEA's proposed new units and facility repowerings.

Florida Department of Environmental Protection (DEP)

DEP found that JEA's *TYSP* is adequate for planning purposes.

Northeast Florida Regional Planning Council

JEA's planned additions are at existing sites and will not result in any new impacts on public facility capacities. Therefore, JEA's *TYSP* is not inconsistent with the City of Jacksonville's Future Land Use Element.

St. Johns River Water Management District

As part of the DEP permitting process, the District will participate in reviewing additional water use due to the Brandy Branch expansion to combined cycle operation.

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 *TYSP* is ***suitable*** for planning purposes.

KISSIMMEE UTILITY AUTHORITY (KUA)

GENERATION SELECTION

KUA's electric generating system currently has a winter capacity of 288 MW. Of this total, 190 MW comes from KUA-owned generation. KUA purchases 98 MW from other utilities. The table at right shows the breakdown of KUA's capacity.

KUA's expansion plans reflect the addition of 133 MW of combined cycle capacity from **Cane Island Unit 3** in June, 2001. This unit is jointly owned with FMPA. Firm capacity purchases are forecasted to decrease by 50 MW during the planning horizon.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Combined Cycle	112	MW
Firm Purchases	98	MW
Combustion Turbine	51	MW
Coal	21	MW
Nuclear	6	MW
TOTAL	**288**	**MW**

NEXT UNIT ADDITION		
Combined Cycle (jointly owned)	133	MW

RELIABILITY CRITERIA

KUA is primarily a summer-peaking utility. However, KUA plans its system to meet a reliability criterion of a 15% summer and winter peak reserve margin.

LOAD FORECAST

KUA's econometric forecast models 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, and normal weather conditions were assumed for the load forecast model. There is insufficient data to measure the absolute percent error of KUA's 1995-1999 retail sales forecasts. However, KUA's methodology and assumptions are appropriate.

KUA's base-case summer peak demand forecast reflects an average annual growth rate (AAGR) of 5.1%, higher than the 1990-1999 AAGR of 4.75%. KUA's base-case winter peak demand forecast for 2000-2009 show an AAGR of 5.5%, compared to its historical growth rate of 3.4%. KUA's base-case NEL forecast for the next ten years reflects an AAGR of 4.16%, lower than the historical (1990-1999) growth rate of 5.17%.

DEMAND-SIDE MANAGEMENT

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.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA participated in the site certification process for **Cane Island Unit 3**. Therefore, no further comments are necessary.

Florida Department of Environmental Protection (DEP)

DEP found that KUA's *TYSP* is adequate for planning purposes.

South Florida Water Management District

The District does not have any adverse comments regarding the suitability of the proposed sites.

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 *TYSP* is ***suitable*** for planning purposes.

CITY OF LAKELAND (LAK)

GENERATION SELECTION

LAK's electric generating system currently has a winter capacity of 624 MW. KUA owns 649 MW of winter capacity but exports 25 MW to other utilities. The table at right shows the breakdown of LAK's capacity.

LAK's expansion plans reflect the addition of a 120 MW heat recovery steam generator to **McIntosh Unit 5**. When placed into service in January, 2002, the total capacity of this combined cycle unit will be 365 MW. LAK also plans to build **McIntosh Unit 4**, a 188 MW fluidized bed coal unit with an in-service date of June, 2005.

LAK's plans also reflect the retirement of 77 MW of capacity at the **Larsen** site. Firm exports are forecasted to increase by 75 MW during the planning horizon.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Fossil Steam	267	MW
Coal	205	MW
Combined Cycle	124	MW
Combustion Turbine	53	MW
(minus) Firm Exports	25	MW
TOTAL	**624**	**MW**

NEXT UNIT ADDITION		
Heat Recovery Steam Generator	120	MW

RELIABILITY CRITERIA

LAK is primarily a winter-peaking utility. LAK recently increased its reserve margin criteria from 15% summer / winter peak to 20% summer / 22% winter peak.

LOAD FORECAST

LAK's load forecast methodology includes several regression models measuring population, accounts, sales, net energy for load, and peak demand. LAK's load forecast is built from three data sources: Polk County population projections from the 1998 Bureau of Economic and Business Research forecast; the number of residential accounts in LAK's service area; and the results of LAK's 1994 Appliance Saturation Survey. The 1994 survey is dated and may not give appropriate results for the forecast. The Commission encourages use of the most recent possible data.

Under base case conditions, winter peak demand is projected to increase at an average annual growth rate (AAGR) of 1.35%, over the next ten years, lower than the 1.85% AAGR for the 1999-2000 period. Summer peak demand is projected to increase at an AAGR of 1.97%, which is lower than the 2.80% AAGR for the 1999-2000 period. LAK does not specifically justify these lower growth rates, although the *TYSP* does note that the projections include the effect of energy conservation programs.

LAK's 1995-1999 retail sales forecasts have an absolute percent error of 2.26%, lower 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 -1.41%, which shows a tendency to under-forecast.

DEMAND-SIDE MANAGEMENT

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, 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.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA provided general land-use comments on proposed new units at the **McIntosh** site.

Florida Department of Environmental Protection (DEP)

DEP found that LAK's *TYSP* is adequate for planning purposes.

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 .

SUITABILITY

LAK forecasts that it will be 4 MW short of meeting its 20% reserve margin criterion in the summer, 2004. Otherwise, forecasted reserve margins are expected to be at or above LAK's criterion of 20% summer / 22% winter for each seasonal peak throughout the planning horizon. The 4 MW deficiency could easily be due to load forecast error. Since the deficiency is so small, LAK's *TYSP* is ***suitable*** for planning purposes.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

ORLANDO UTILITIES COMMISSION (OUC)

GENERATION SELECTION

OUC's electric generating system currently has a winter capacity of 1,224. Of this total, 1,071 MW comes from OUC-owned generation. OUC currently purchases 593 MW of firm capacity out of the **Indian River** fossil steam units purchased from OUC by **Reliant Energy** in 1999. OUC currently exports 440 MW of capacity to other utilities. The table at right shows the breakdown of OUC's capacity.

OUC's expansion plan reflects the addition of **Stanton Unit 3**, a 585 MW gas-fired combined cycle unit, in November, 2003. This unit will be added to offset the gradual reduction, to zero, of the firm purchase from **Reliant Energy** by the end of 2003. Also proposed is a 182 MW combustion turbine unit at the **Stanton** site, with an in-service date of June, 2007. Firm exports to other utilities are forecasted to decrease by 296 MW over the planning horizon.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Coal	759	MW
Firm Purchases	593	MW
Combustion Turbine	247	MW
Nuclear	65	MW
(minus) Firm Exports	440	MW
TOTAL	**1224**	**MW**

NEXT UNIT ADDITION		
Combined Cycle	585	MW

RELIABILITY CRITERIA

OUC is primarily a summer-peaking utility. OUC plans its utility system using 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).

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 staff 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 are insufficient data to measure the absolute percent error of OUC's 1995-1999 retail sales forecasts.

Under base case conditions, summer peak demand is projected to increase at an average annual growth rate (AAGR) of 2.14% over the forecast period, lower than the 3.59% AAGR actually experienced during the 1990-1999 period. Winter peak demand is forecast to increase at an AAGR of 2.44%, slightly higher than the historical AAGR of 2.15%. OUC's base case Net Energy for Load forecast for the period of 2000-2009 shows a 2.77% AAGR, slightly higher than the 2.91% AAGR seen over the past ten years.

DEMAND-SIDE MANAGEMENT

The Commission set numeric goals of **zero** for OUC in April, 2000. OUC was unable to identify any cost-effective DSM programs to offer. However, OUC will continue its existing DSM programs including five residential conservation programs (audit, heat pump replacement, water heating, weatherization, home energy fix-up) and one commercial program (audit). OUC has an interruptible tariff but no load management program. Overall, OUC's conservation programs are expected to reduce winter peak demand by 32 MW (2.8%) in 2007.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Consumer Affairs (DCA)

DCA provided general comments on the proposed unit addition at the **Stanton** site. Noted that the site was originally certified for 2000 MW of coal-fired capacity. Therefore, the proposed gas-fired combined cycle unit is not eligible for certification under the supplemental site certification provision of the Power Plant Siting Act due to a change in fuel.

Florida Department of Environmental Protection (DEP)

DEP found that OUC's *TYSP* is adequate for planning purposes.

East Central Florida Regional Planning Council

The Council is concerned that OUC's DSM goals were set at **zero** because OUC could not identify any cost-effective conservation. The Council believes that OUC should continue seeking cost-effective conservation.

St. Johns River Water Management District

All proposed projects are on an existing site and, therefore, are suitable.

SUITABILITY

Forecasted reserve margins are expected to satisfy OUC's reliability criterion (15% seasonal peak reserve margin and 0.5% EUE/NEL ratio) throughout the planning horizon. OUC's *TYSP* is ***suitable*** for planning purposes.

CITY OF TALLAHASSEE (TAL)

GENERATION SELECTION

TAL's electric generating system currently has a winter capacity of 567. Of this total, 449 MW comes from TAL-owned generation. The remaining 128 MW is purchased via interchange. TAL currently exports 10 MW of capacity to other utilities. The table at right shows the breakdown of TAL's capacity.

TAL placed **Purdom Unit 8**, a 262 MW gas-fired combined cycle unit, into service in June, 2000. No other generating units appear in TAL's *TYSP*. Firm purchases are forecasted to decrease to 11 MW during the planning horizon, while firm exports are expected to drop to zero during that time.

EXISTING WINTER CAPACITY BY FUEL TYPE		
Fossil Steam	378	MW
Firm Purchases	128	MW
Combustion Turbine	60	MW
Hydroelectric	11	MW
(minus) Firm Exports	10	MW
TOTAL	**567**	**MW**
NEXT UNIT ADDITION		
(none)	0	MW

RELIABILITY CRITERIA

TAL is primarily a summer-peaking utility. TAL plans resource additions on its system to meet a reliability criterion of 17% summer peak reserve margin. TAL is considering increasing its reserve margin criterion in the near future.

Nonetheless, TAL forecasts that its existing 17% criterion will be violated for summer, 2001 and for each summer season between 2004 and 2009. TAL's *TYSP* did not include any capacity resources or purchases to meet these projected reserve shortfalls. The *TYSP* states only that TAL will soon conduct a comprehensive planning study to identify future resources. As seen in the table below, the magnitude of TAL's reserve deficiency is forecasted to grow to 90 MW in the summer of 2009.

SUMMER SEASON (YEAR)	2001	2004	2005	2006	2007	2008	2009
FORECASTED RESERVE MARGIN (%)	14%	16%	14%	12%	10%	6%	2%
CAPACITY DEFICIENCY (MW)	14	3	14	27	42	65	90

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. TAL lists data sources and tests its load forecast sensitivities for high load growth and low load growth cases. Although all the significant forecasting assumptions were not listed, TAL did mention that it increased the assumed normal high temperature for the base case forecast from 99$^{\mathrm{F}}$ to 100$^{\mathrm{F}}$ F.

Under base-case conditions, summer peak demand is projected to increase at an average annual growth rate (AAGR) of 2.02% over the forecast period, lower than the 2.70% AAGR actually experienced during the 1990-1999 period. TAL's 2000 base-case summer peak demand forecast is consistent with that in its 1999 *TYSP.* TAL's 2000 base-case winter peak AAGR demand forecast is 1.14% compared to 2.02% for the previous ten year period.

TAL's 1995-1999 retail sales forecasts have an absolute percent error of 3.16%, slightly lower than the 3.22% 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 of -3.16%, which shows a tendency to under-forecast.

DEMAND-SIDE MANAGEMENT

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, 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.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Consumer Affairs (DCA)

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

Florida Department of Environmental Protection (DEP)

DEP found that TAL's *TYSP* is NOT adequate for planning purposes because of forecasted capacity shortfalls in 2001 and 2004-2009. DEP is concerned that this situation could lead to an emergency "which would affect the time necessary to review future certifications or modifications to existing certifications."

SUITABILITY

Forecasted reserve margins are expected to fall below TAL's criterion of 17% summer reserve margin in 2001 and in each summer season between 2004 and 2009. Due to TAL's proximity to the Southern Company, TAL expects to be able to acquire some of these reserves as needed. The Commission believes that the absence of specified supply options in the later years of TAL's *TYSP* is inconsistent with the present criteria used to determine suitability for planning purposes. However, TAL has indicated that it is conducting a comprehensive planning study to identify future resources. Therefore, TAL's *TYSP* is ***conditionally suitable*** for planning purposes. In its 2001 *TYSP*, TAL should identify, with greater certainty, the manner in which it plans to meet future resource needs.

SEMINOLE ELECTRIC COOPERATIVE (SEC)

SEC is a wholesale cooperative that provides full requirements to ten distribution system members. SEC relies on owned and purchased capacity resources to meet the needs of its member systems. SEC is obligated to serve all load up to specified capacity commitment levels and provide adequate reserves. SEC's partial requirements providers (FPC, TECO, JEA, OUC, and GRU) serve all load above specified capacity commitment levels.

GENERATION SELECTION

SEC currently has a total winter generating capacity of 1,345 MW. The table at right shows the breakdown of SEC's capacity.

EXISTING WINTER *GENERATING* CAPACITY BY FUEL TYPE		
Coal	1330	MW
Nuclear	15	MW
TOTAL existing capacity	**1345**	**MW**
NEXT UNIT ADDITION		
Combined Cycle	572	MW

However, SEC's generating capacity is insufficient to meet the aggregate load of its members. To serve load that exceeds generation, SEC purchases approximately 1,273 MW of capacity from other utilities. In addition, SEC has partial requirements (PR) and full requirements (FR) contracts with FPC and FPL whereby these two utilities agree to serve the amount of load that exceeds SEC's own generation and capacity purchases. The amount of PR and FR purchases is currently 456 MW.

SEC plans to diversify its generation resources with the addition of the **Payne Creek Generation Station Unit 3**, a 572 MW combined cycle unit, in January, 2002. SEC's *TYSP* also shows the planned addition of three combustion turbines (546 MW total), at a yet-to-be-determined site, between November, 2002 and June, 2007. SEC also plans to add two gas-fired combined cycle units (576 MW total), at a yet-to-be-determined site, between June, 2004 and November, 2006. SEC's reliance on firm purchases is expected to decrease to 550 MW during the planning horizon. However, the amount of PR and FR capacity import is forecasted to increase to 1,005 MW during this time.

RELIABILITY CRITERIA

SEC is a winter-peaking utility. 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).

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 accounts of load forecasts which are based on economic, housing, appliance, weather and hourly load data. SEC also provided a high and low growth rate forecast.

SEC expects to continue to be a winter-peaking utility primarily due to forecasted increases in electric space-heating appliance saturations. Under base case conditions, winter peak demand forecast is projected to increase at an average annual growth rate (AAGR) of 3.55% over the forecast period. While the winter peak demand forecast is lower than the 4.64% AAGR actually experienced during the 1990-1999 period, it is still one of the highest winter peak growth rates in the state. SEC's 2000 base-case summer peak AAGR demand forecast is 3.00%, lower than the AAGR of 4.90% experienced in the past ten year period.

SEC's 1995-1999 retail sales forecasts have an absolute percent error of 3.16% and , with an average forecast error of -3.16%. These results indicate SEC's tendency to under-forecast.

DEMAND-SIDE MANAGEMENT

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.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

Florida Department of Community Affairs (DCA)

DCA cannot comment on the proposed combustion turbine units in SEC's *TYSP* because no location is given for these units.

Florida Department of Environmental Protection (DEP)

DEP found that SEC's *TYSP* is adequate for planning purposes.

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 .

Hardee County

SEC's *TYSP* does not conflict with the County's comprehensive plan, natural resources, or growth management policies.

SUITABILITY

Forecasted reserve margins are expected to be above SEC's criterion of 15% for each seasonal peak throughout the planning horizon. SEC's *TYSP* is ***suitable*** for planning purposes.

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

MERCHANT PLANT COMPANIES

Four merchant plant companies filed a TYSP in 2000:

- Duke Energy New Smyrna Beach Power Company (**Duke New Smyrna**)
- Okeechobee Generating Company (**Okeechobee**)
- Oleander Power Project (**Oleander**)
- Calpine Construction Finance Company (**Calpine**)

Three of these companies – Duke New Smyrna, Okeechobee, and Calpine – filed a *TYSP* which contained only combined cycle generating units. When proposed by retail-serving utilities, these units require certification under the Power Plant Siting Act and, therefore, a determination of need from the Commission.

Duke New Smyrna was granted a need determination by the Commission In March, 1999. This decision was overturned by the Florida Supreme Court, who stated that the Commission does not have jurisdiction to approve the need for generating units whose capacity is not fully committed to retail load. The Commission petitioned the Supreme Court for a rehearing on its decision. On September 28, 2000, the Supreme Court reaffirmed its order overturning the Commission's decision.

Among other things, the Supreme Court's decision defined an electric utility under Section 403.519, Florida Statutes. Duke New Smyrna, Okeechobee, and Calpine filed *TYSPs* under the authority of this statute. Thus, the Supreme Court's decision has the effect of negating the *TYSPs* filed by these three companies.

Oleander's *TYSP* contains combustion turbine generating units. As noted on page 29 of this report, at least ten other companies have announced plans to construct combustion turbine merchant plants in the state since the start of this year. None of these companies filed a *TYSP*.