CCA

REVIEW OF ELECTRIC UTILITY 1998 TEN-YEAR SITE PLANS

VOLUME 1 REVIEW AND ANALYSIS

December 31, 1998

FLORIDA PUBLIC SERVICE COMMISSION

Division of Electric and Gas
Division of Auditing and Financial Analysis

LIST OF FIGURES AND TABLES

1.0 INTRODUCTION

Section 186.801, Florida Statutes, requires generating electric utilities to submit a Ten-Year Site Plan to the Florida Public Service Commission (Commission) at least once every two years. The Ten-Year Site Plan contains projections of the utility's electric power needs for the next ten years and the general location of any proposed power plant sites and major transmission facilities. The Commission is responsible for making a preliminary study of each utility's plan and must determine whether it is "***suitable***" or "***unsuitable***."

The Commission's *Review of 1998 Ten-Year Site Plans* consists of two volumes. Volume 1 contains the Commission's review and analysis of the plans, including its ultimate conclusions on the suitability of the plans. Volume 2 contains comments from state, local, and regional government agencies as well as from other interested parties. These comments provide feedback to the utilities on any concerns that review agencies might have regarding proposed power plant sites. Both volumes of the Commission's review are forwarded to the Florida Department of Environmental Protection (DEP).

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

Section 377.703(e), Florida Statutes, requires the Commission to perform electricity and natural gas forecasts for analysis by the Florida Department of Community Affairs (DCA). This statutory requirement is fulfilled by the Ten-Year Site Plan review contained in this document.

1.1 PURPOSE -- What is the purpose of this document?

- to review and comment on the long-range generation and transmission plans of Florida's electric utilities; and

- to satisfy the requirements of Sections 186.801 and 377.703(3)e, Florida Statutes.

1.2 PUBLIC INVOLVEMENT

Pursuant to the State of Florida's policy of "government in the sunshine," all workshops and hearings at the Commission are open to the public. Members of the public may directly participate in any of the Commission's proceedings. The Commission held a public workshop on September 11, 1998 to solicit public comments on the Ten-Year Site Plans. The Commission received oral and written comments from the Legal Environmental Assistance Foundation (LEAF), a coalition led by the American Planning Association (APA), and the U.S. Generating Company. Written comments were also provided by state agencies, regional planning councils, and water management districts. These comments are summarized in Sections 4.1 through 4.12 of this document. Complete comments are contained in Volume 2 of this review.

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

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

2.0 EXECUTIVE SUMMARY

Pursuant to Section 186.801(2), Florida Statutes, the Ten-Year Site Plans are preliminary studies done for planning purposes. The Commission's classification of a utility's plan as "suitable" or "unsuitable" has no binding effect on utilities, and such a classification does not constitute a determination or finding in subsequent docketed matters before the Commission. Because the plans contain tentative data, there may not be sufficient information to allow regional planning councils, water management districts, and other review agencies to fully assess site-specific issues pertaining to their jurisdiction. When a utility files for certification under the Power Plant Siting Act or Transmission Line Siting Act, more detailed data are provided based on in-depth environmental assessments. This fact underscores the purpose of the Ten-Year Site Plan as an early notification process rather than a binding plan of action.

Table 1 briefly summarizes how the Commission has complied with the requirements contained in Section 186.801, Florida Statutes.

TABLE 1
COMMISSION COMPLIANCE WITH SECTION 186.801, FLORIDA STATUTES

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. Analysis is discussed in Sections 3.2 through 3.3 of this document.
Review possible alternatives to the proposed plant.	Reviewed DSM assumptions, fuel forecasts, and generation alternatives modeled to arrive at the projected expansion plan. Analysis is discussed in Sections 3.2 through 3.4 of this document.
Review the anticipated environmental impact of proposed power plant sites.	Since the Commission does not have expertise in this area, it requested comments from DEP and water management districts regarding environmental impacts and compliance. Comments are summarized in Sections 4.1 through 4.12 of this document. Complete comments are contained in Volume 2.
Consider the views of appropriate local, state, and federal agencies regarding water and growth management issues.	Requested comments from affected agencies. Comments are summarized in Sections 4.1 through 4.12 of this document. Complete comments are contained in Volume 2.
Determine if the Ten-Year Site Plan is consistent with the State Comprehensive Plan	Energy-related aspects of the Comprehensive Plan are discussed in Section 3.2.3. Requested comments from the Department of Community Affairs (DCA) and from regional and local planning agencies regarding growth management and Comprehensive Plan issues. Comments are summarized in Sections 4.1 through 4.12 of this document. Complete comments are contained in Volume 2.
Review the Ten-Year Site Plan for information on energy availability and consumption.	Review of load forecast data and methodologies is discussed in Sections 3.2.1 and 3.2.2 of this document.

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

The FRCC recently developed a formal reliability assessment process to annually review and assess issues that either exist currently or have the potential for developing. FRCC member utilities are expected to exchange information in both 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 formed a reliability assessment group to determine what planning and operating studies will be performed during each year to address these issues.

In 1998, the FRCC published two documents which address the reliability of Peninsular Florida's electric grid. One, the *1998 Regional Load and Resource Plan*, is essentially the *Ten Year Plan, State of Florida* from past years. This document contains aggregate data on demand and energy, capacity and reserves, and proposed new unit additions for Peninsular Florida's utilities. The second FRCC document, the *1998 Reliability Assessment*, is an aggregate study of the reliability of Peninsular Florida's electric grid. The Commission used both FRCC documents in its review of the individual utility Ten-Year Site Plan filings.

By its very nature, planning is a dynamic process. Many factors that influence utility plans are subject to change. Variations in weather, economic conditions, and population growth can impact the results of a load forecast. Improvements in technology are constantly monitored, and changes in governing regulations and laws, as well as shifts in public policy, may impact utility plans. It is the responsibility of each utility to develop and maintain its plans based on the most up-to-date information available. Because of the unsettled national debate on electric utility restructuring and retail wheeling, electric utility reserve margins have declined from prior years. Some decline may be acceptable because of higher generating unit availability due to increased unit maintenance. However, care must be taken to ensure that adequate levels of generating capacity are maintained in the state to ensure the continued provision of reliable electric service to the public.

The Commission has classified the twelve 1998 Ten-Year Site Plans as ***suitable*** for planning purposes. However, the Commission has identified some areas of concern which may impact the viability of some Ten-Year Site Plans. These concerns are discussed below:

1. FRCC's *1998 RELIABILITY ASSESSMENT*

    This document, published in August, 1998, is a reliability study of Peninsular Florida's electric grid. Over the ten-year planning horizon covered by the study, and under base case assumptions, the FRCC concluded that Peninsular Florida's utilities are expected to maintain a minimum 15% winter and summer reserve margin, as well as a loss of load probability (LOLP) significantly less than the generally accepted 0.1 days per year. The FRCC's 15% reserve margin criterion is an aggregate number. According to the FRCC, reliability of the peninsular electric system should not be adversely impacted should a single utility's reserve margin fall below this criterion. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

The Commission has numerous concerns with the analyses contained in the *1998 Reliability Assessment*: low LOLP results apparently are the result of high forecasted unit availabilities; the 0.1 LOLP value appears to correlate to an unrealistically low reserve margin of 6-8%; and there is uncertainty as to whether the Southern Company will continue to be able or willing to assist the Peninsula in the future given that they could sell power at higher prices to other parts of the country. Additionally, the Commission is concerned with how the FRCC determined the suitability of a 15% reserve margin standard for Peninsular Florida. Finally, the Commission is concerned that the level of winter reserves may be negatively affected by extreme low winter temperatures. This final concern dates back to events occurring in December, 1989 where an estimated 4,700 MW of Peninsular Florida's load was not served due to unusually high demand coupled with low generating unit availability.

2. AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

The reserve margin for some of Peninsular Florida's utilities is currently comprised largely of non-firm resources such as load management and interruptible service. During the ten-year planning horizon, it is expected that non-firm resources will comprise an even greater percentage of peninsular reserve margins, resulting in less generating capacity. This situation is of even greater concern to Florida Power Corporation, whose winter, 1998 non-firm load is greater than its winter reserves. Exacerbating this situation is the fact that FPC lost several thousand load management program participants due to the utility's use of load control measures during extremely hot weather conditions in the summer of 1998. If Peninsular Florida's reserve margins decrease even further because of customer flight from load management programs, utilities may be facing reliability problems in the near term.

In addition to these critical concerns, there are elements of risk that may influence the viability of the Ten-Year Site Plans:

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

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

3. NATURAL GAS AVAILABILITY -- Current national policies have helped to increase natural gas consumption in Florida. Florida's electric utilities continue to rely primarily on a single gas transportation pipeline company, Florida Gas Transmission (FGT), to supply direct customers and electric utility fuel requirements. Current estimates of the need for

natural gas for all sectors exceed the current pipeline capacity of FGT's system. The FRCC has been notified of FGT's ability and willingness to expand the natural gas pipeline system to meet all projected electric demand. However, electric utilities should individually identify a contingency plan if gas transportation capacity is not subscribed to in advance and, subsequently, is not available at the time needed to fuel future generation expansions.

4. UNCERTAINTY WITH THE COST-EFFECTIVENESS OF DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS -- The cost-effectiveness of utility DSM programs has declined in recent years due to the decline in utility avoided costs-- that is, the cost of generation avoidable by DSM. The result is that the cost-effectiveness of utility DSM programs has also declined in recent years. The primary remedy to this problem is for the utility to reduce the incentive level paid to participating customers. If, ultimately, customer participation decreases as a result of incentive level reductions, utilities may not meet their Commission-approved DSM demand and energy goals. Further, the utilities may need to modify their Ten-Year Site Plans to add capacity resources to offset their DSM deficits and, therefore, meet their reliability requirements.

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

The table and illustrations on pages 11, 12, and 13 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.

THE STATEWIDE PLAN

TABLE 2
RESOURCE ADDITIONS / (REDUCTIONS) IN THE NEXT TEN YEARS (1998-2007)

RESOURCE TYPE	Winter Capacity (Megawatts)
COMBINED CYCLE UNITS [1]	6,248
COMBUSTION TURBINE UNITS	3,402
CONSERVATION AND DEMAND-SIDE MEASURES [2]	1,983
COAL UNITS [1]	278
COGENERATION [3]	-152
FOSSIL AND NUCLEAR STEAM UNITS [1]	-651
TOTAL NET RESOURCE ADDITIONS	**11,108**

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

[2] Load management (874 MW), interruptible service (167 MW), and conservation programs (942 MW).

[3] Three firm capacity contracts are set to terminate during the planning horizon, with a total capacity reduction of 152 MW. No new qualifying facilities are proposed.

FIGURE 1: RESOURCE ADDITIONS IN THE NEXT TEN YEARS

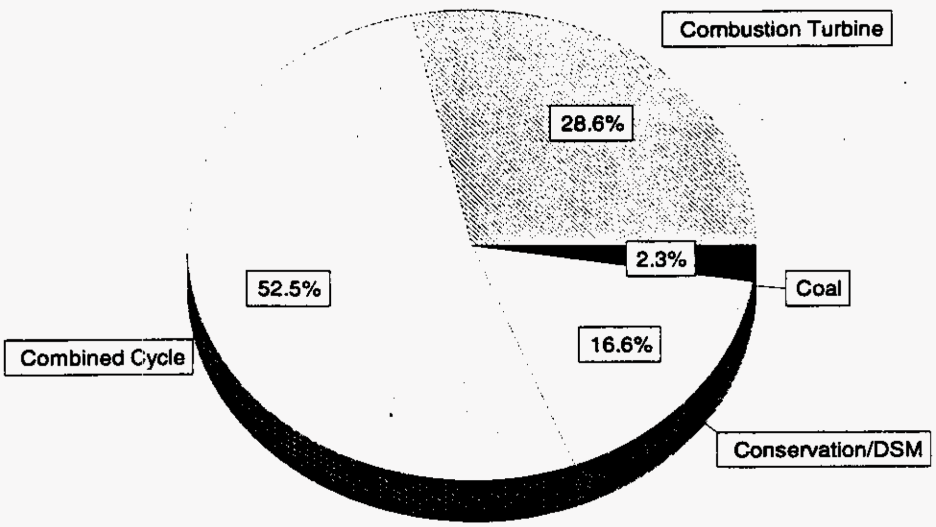


FIGURE 2: RESOURCE MIX BY PLANT TYPE – PRESENT AND FUTURE

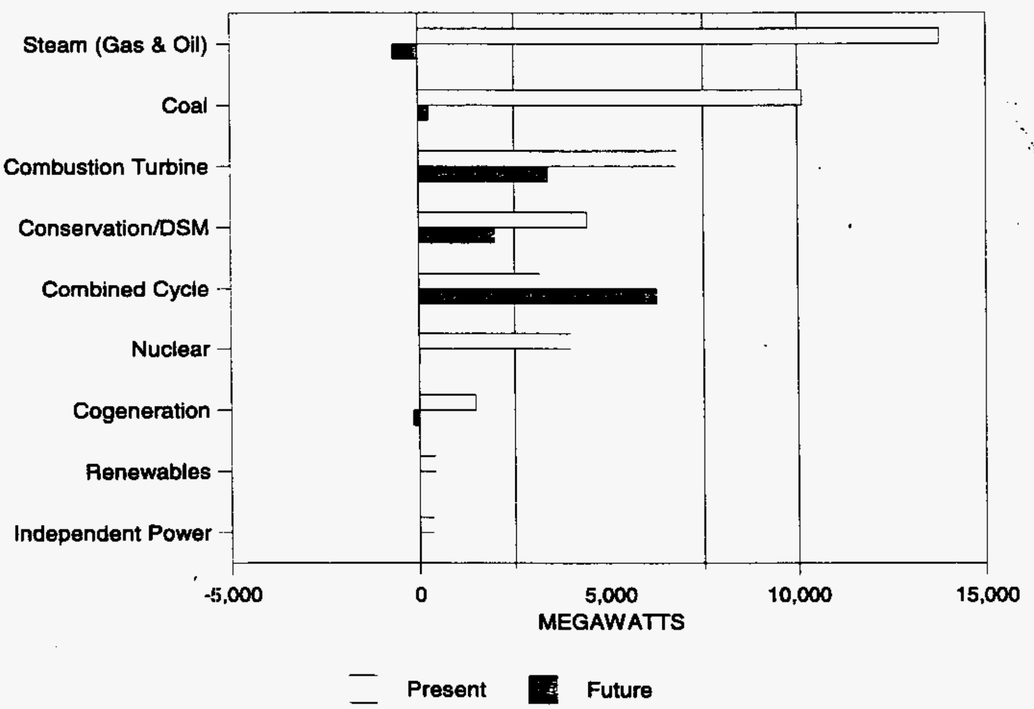
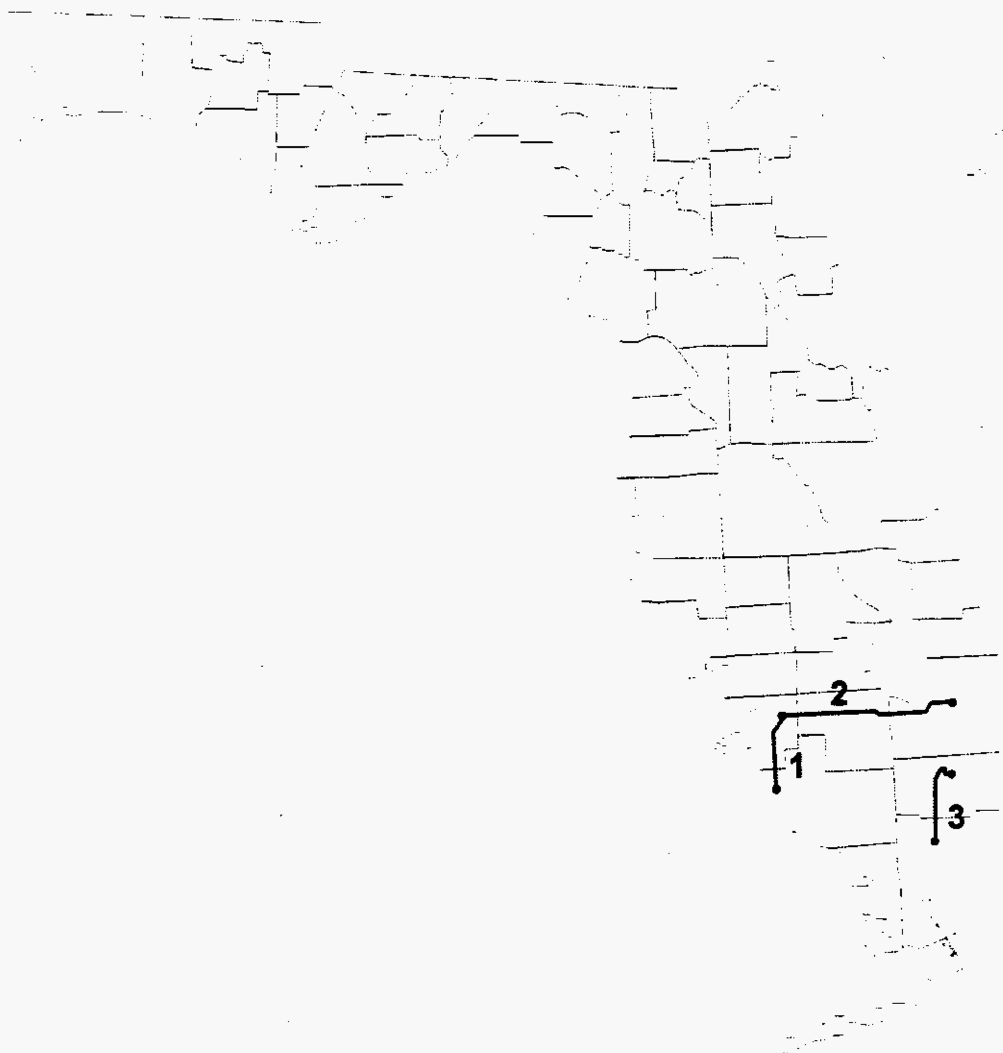


FIGURE 3: PROPOSED MAJOR TRANSMISSION LINES (1998-2007) [4]



	UTILITY	TERMINALS	LENGTH (MILES)	IN-SERVICE DATE	VOLTAGE (kV)
1	FPL	Collier - Orange River	36	Dec. 1999	230
2	FPL	Corbett - Orange River	114	Dec. 2001	500
3	FPL	Conservation - Levee	36	June 2007	500

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

3.0 REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

3.1 INTEGRATED RESOURCE PLANNING

Integrated resource planning (IRP) is a utility process that includes both demand-side resources (e.g., conservation measures) and supply-side resources (e.g., generating units) to the extent they are cost-effective. Many view IRP as a sharp contrast to traditional utility planning, which focused primarily on the construction of utility-owned supply-side resources to meet system demand.

While there is apparent agreement on the general meaning of IRP, controversy surrounds the definition of IRP specifics. Much of the debate has centered on the following questions:

- What is the appropriate definition of the term ***cost-effective***?
- How are environmental externalities to be considered, if at all?
- Should utilities be required to promote certain technologies, even if not cost-effective, to aid in promoting social goals?

3.1.1 THE IRP PROCESS IN FLORIDA

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

Statutes

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

Section 366.80 - 366.85, Florida Statutes. Known as the Florida Energy Efficiency and Conservation Act (FEECA), originally enacted in 1980. FEECA requires the setting of goals for reduction in the growth rates of peak demand and energy use.

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

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

Section 186.801, Florida Statutes. Statute requiring utilities to submit Ten-Year Site Plans to the Commission for review.

Rules

Rule 25-22.070 - 25-22.072, Florida Administrative Code. Addresses the content, submission, and review of the Ten-Year Site Plan.

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

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

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

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

While the specific approaches to IRP for each utility vary, they are all consistent with a generic process that has six broad steps:

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

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

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

(4) An initial screening of demand-side and supply-side resources is performed to find candidates to meet the expected resource need.

(5) Demand-side and supply-side resources compete against each other to decide which combination meets the need most cost-effectively.

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

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

3.2 LOAD FORECAST

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

The Commission determines the suitability of a load forecast based upon three types of analyses. The first involves reviewing the methodology used to produce the forecast to ensure that it uses reasonable models and assumptions. The second examines the historical accuracy of forecasts to determine whether or not the forecasting process has performed well in the past. The third compares the forecasted values to historical growth patterns. Taken together, these evaluation procedures can either lend credibility to a forecast or cast doubt on its reliability. The evaluation criteria used to perform each type of analysis are described below.

3.2.1 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: (1) collection of historical data upon which the forecast models are based; (2) derivation of the forecast model parameters; (3) assembly of a set of forecast assumptions; and (4) calculation of the forecasts themselves.

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

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

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

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.

3.2.2 EVALUATION OF HISTORICAL FORECAST ACCURACY

Reviewing the past results of a load and energy forecasting methodology reveals whether a 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 1993 to 1997. The analysis compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, actual 1997 energy sales were compared to the projected 1997 forecasts made in 1992, 1993, and 1994. 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 error rates) or under-forecast (negative error rates). Table 3 summarizes the historical forecast accuracy for each utility. There was insufficient historical data to analyze the forecast accuracies of Florida Municipal Power Agency, Kissimmee Utility Authority, and Orlando Utilities Commission. A detailed discussion of historical forecast errors for each reporting utility is contained in Sections 4.1 through 4.12.

TABLE 3
HISTORICAL FORECAST ACCURACY

UTILITY	Average ABSOLUTE Forecast Error	Average Forecast Error
Florida Power Corporation (FPC)	2.98%	2.98%
Florida Power & Light Company (FPL)	2.19%	-0.73%
Gulf Power Company (Gulf)	2.50%	-1.19%
Tampa Electric Company (TECO)	2.88%	0.49%
Gainesville Regional Utilities (GRU)	2.24%	-2.24%
Jacksonville Electric Authority (JEA)	3.95%	-3.63%
City of Lakeland (LAK)	3.47%	-3.21%
City of Tallahassee (TAL)	2.96%	-2.38%
Seminole Electric Cooperative (SEC)	3.14%	1.09%
ALL REPORTING UTILITIES	2.92%	-0.98%

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. The Commission compares projected energy consumption patterns to historical patterns and previous forecasts to determine if any changes in energy consumption forecasted by the utility are reasonable.

Summary of Load Forecast Evaluation Process

After analyzing the load forecasts of the twelve reporting utilities, the Commission found that the load forecasting procedures used by the utilities generally provide reliable and accurate forecasts of Florida's future energy needs. However, the summer and winter peak demand forecasts for Peninsular Florida utilities have increased since last year. The current forecast for 1999 and 2006 summer peak demand has increased by 412 MW and 590 MW, respectively over last year's forecast. Similarly, the current forecast for winter peak demand for 1999/2000 and 2006/2007 has increased by 157 MW and 604 MW, respectively over last year's forecast. A detailed discussion of each utility's load forecast is contained in Sections 4.1 through 4.12.

The following three graphs reflect forecasted aggregate peak demand, energy, number of customers, and energy consumption per residential customer. As shown in Figure 4, peak demand is expected to grow at a slightly lower rate than the number of customers. Figure 5 reveals that total energy consumption is expected to grow slightly faster than the number of customers. Figure 6 shows that per-customer energy consumption is forecasted to increase over the forecast period, although at a lesser rate than in the past. This last observation is due largely to the expectation that existing households will replace older appliances with newer, more energy-efficient models.

FIGURE 4: FIRM PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST (1988-2007)

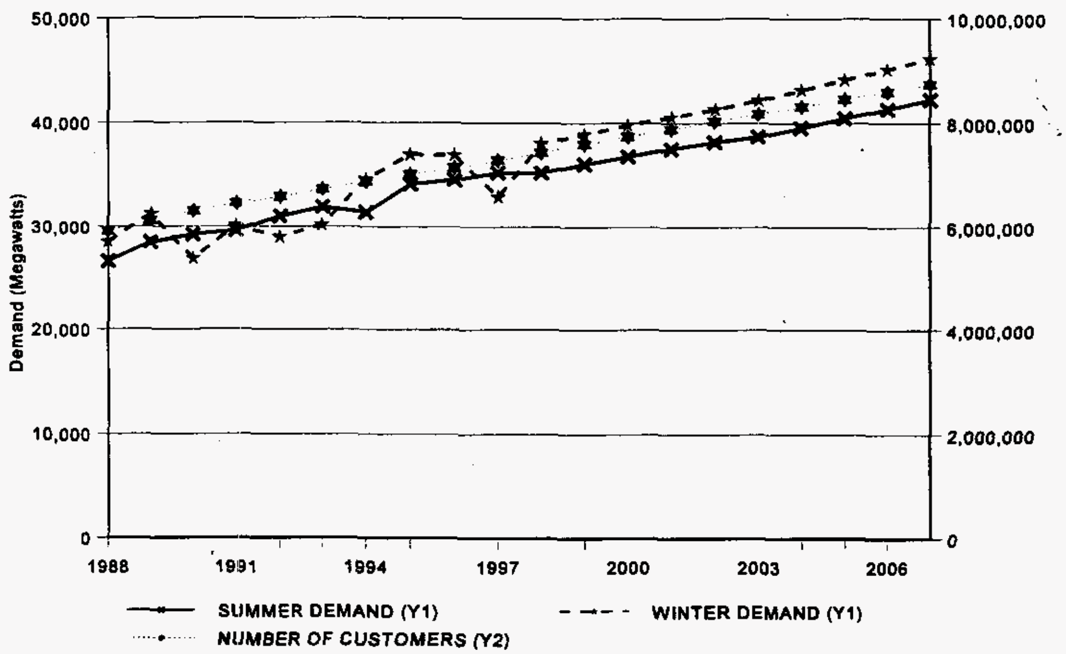


FIGURE 5: NET ENERGY FOR LOAD
STATE OF FLORIDA -- HISTORY & FORECAST (1988-2007)

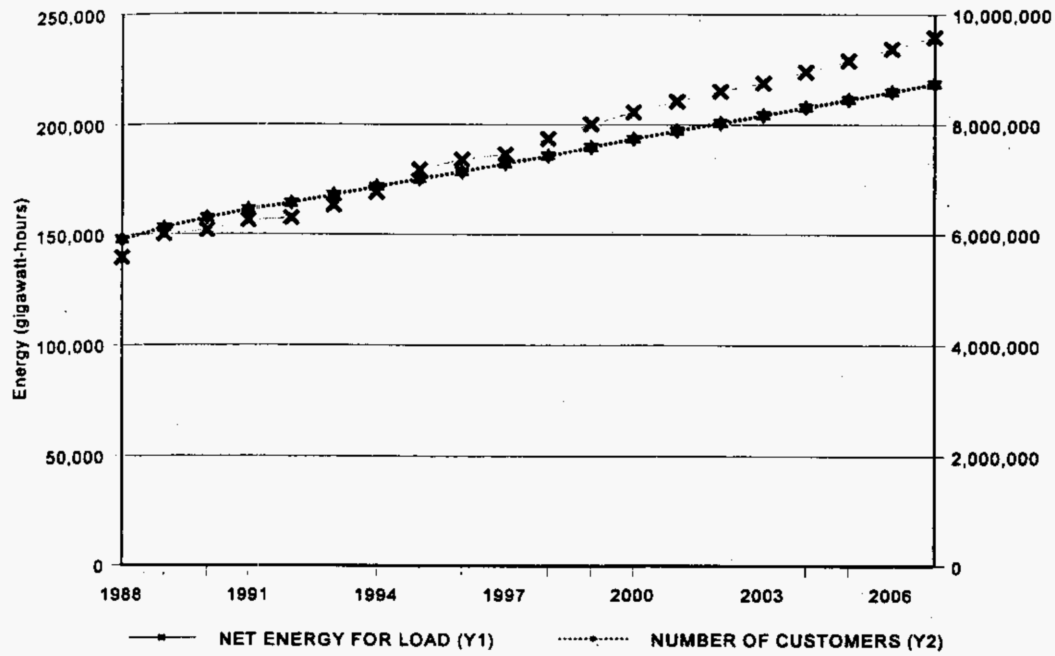
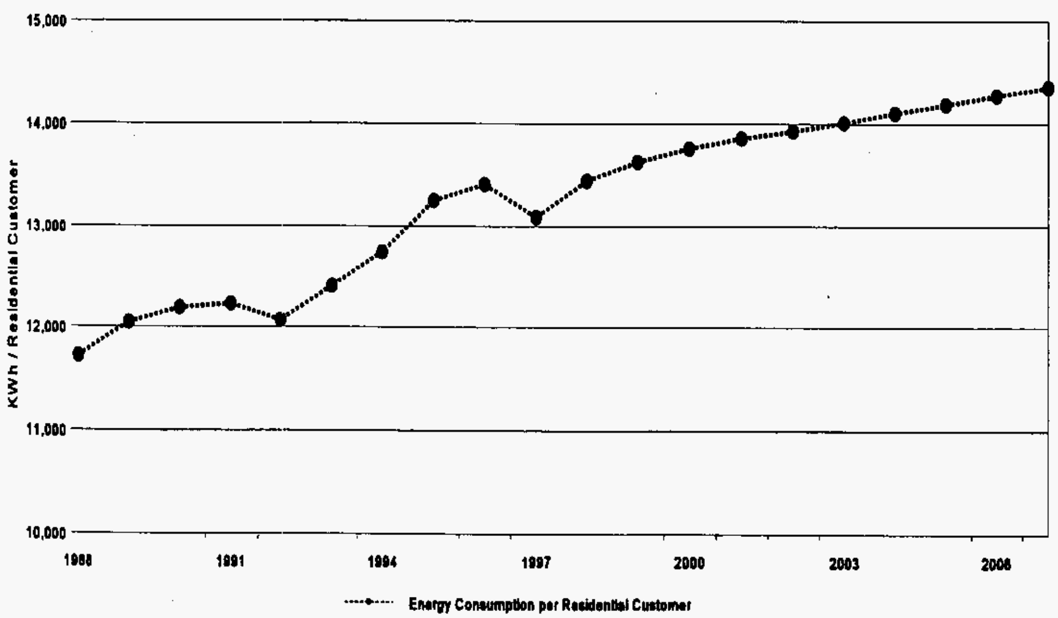


FIGURE 6: ENERGY CONSUMPTION PER RESIDENTIAL CUSTOMER
STATE OF FLORIDA -- HISTORY & FORECAST (1988 - 2007)



3.2.3 DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) is an integral part of each utility's integrated resource plan. DSM reduces customer peak demand and energy requirements, and has avoided or deferred the construction of new generating units.

Florida's electric utilities were among the first in the nation to promote energy conservation practices. Conservation and DSM programs have been offered since 1980 as a result of the Florida Legislature's enactment of the Florida Energy Efficiency and Conservation Act (FEECA). The Commission's broad-based authority over electric utility conservation measures and programs is embodied in Rules 25-17.001 through 25-17.015, Florida Administrative Code.

FEECA places emphasis on reducing the growth rates of weather-sensitive peak demand, reducing and controlling the growth rates of electricity consumption, and reducing the consumption of expensive resources such as petroleum fuels. To meet these objectives, the Commission sets DSM goals, and the utilities develop and implement DSM programs designed to meet the goals. As a whole, Florida's electric utilities have been successful in meeting the overall objectives of FEECA. ***Dispatchable*** (e.g., load management and interruptible service) and ***non-dispatchable*** conservation programs (e.g., attic insulation and energy-efficient lighting) have reduced Florida's aggregate summer peak demand by an estimated 3140 MW (8.2%), winter peak demand by an estimated 4417 MW (11.8%), and energy consumption by an estimated 2095 GWh (1.1%). By 2007, DSM programs are forecasted to reduce aggregate summer peak demand by an estimated 5115 MW (10.8%), winter peak demand by an estimated 6400 MW (12.2%), and energy consumption by an estimated 4482 GWh (1.8%). These demand and energy savings are illustrated in Figures 7, 8, and 9.

FIGURE 7: ESTIMATED IMPACT OF DSM ON NET ENERGY FOR LOAD STATE OF FLORIDA -- HISTORY & FORECAST (1988 - 2007)

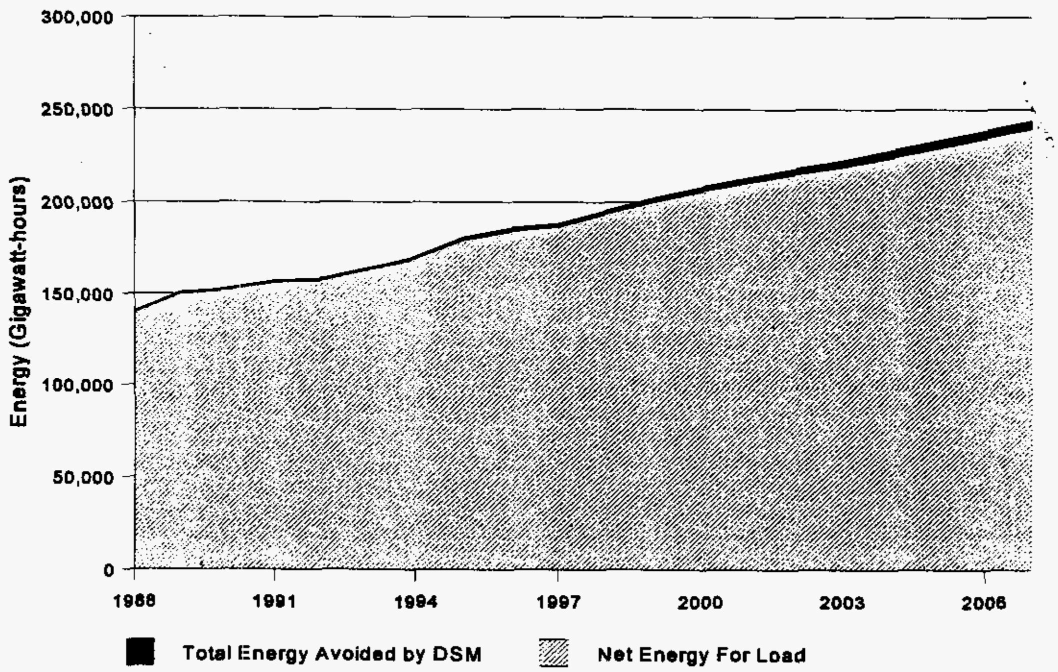


FIGURE 8: ESTIMATED IMPACT OF DSM ON SUMMER PEAK DEMAND STATE OF FLORIDA -- HISTORY & FORECAST (1988 - 2007)

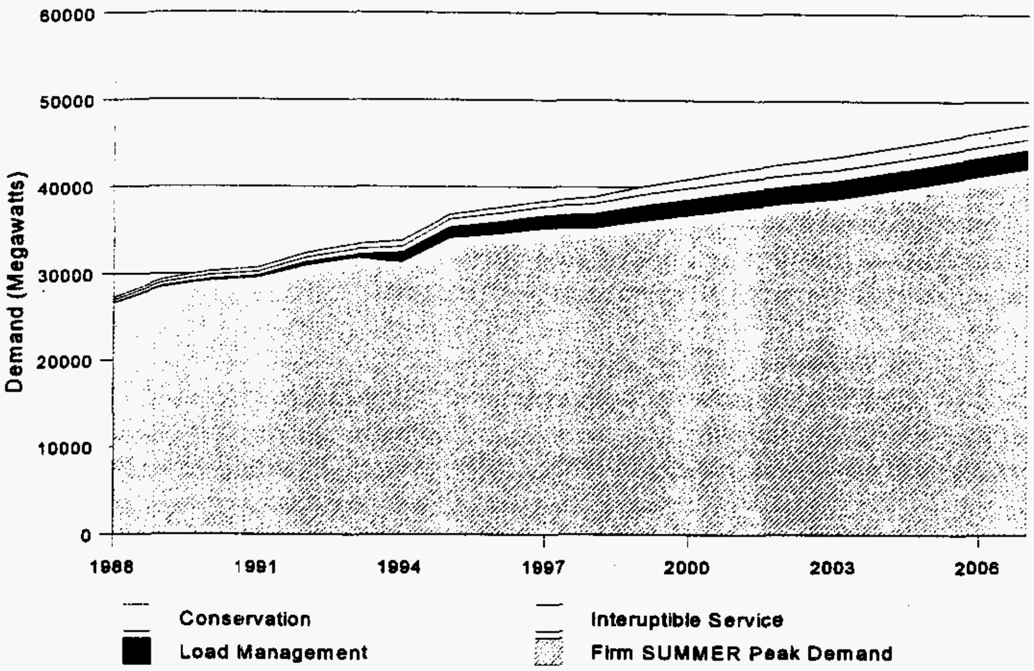
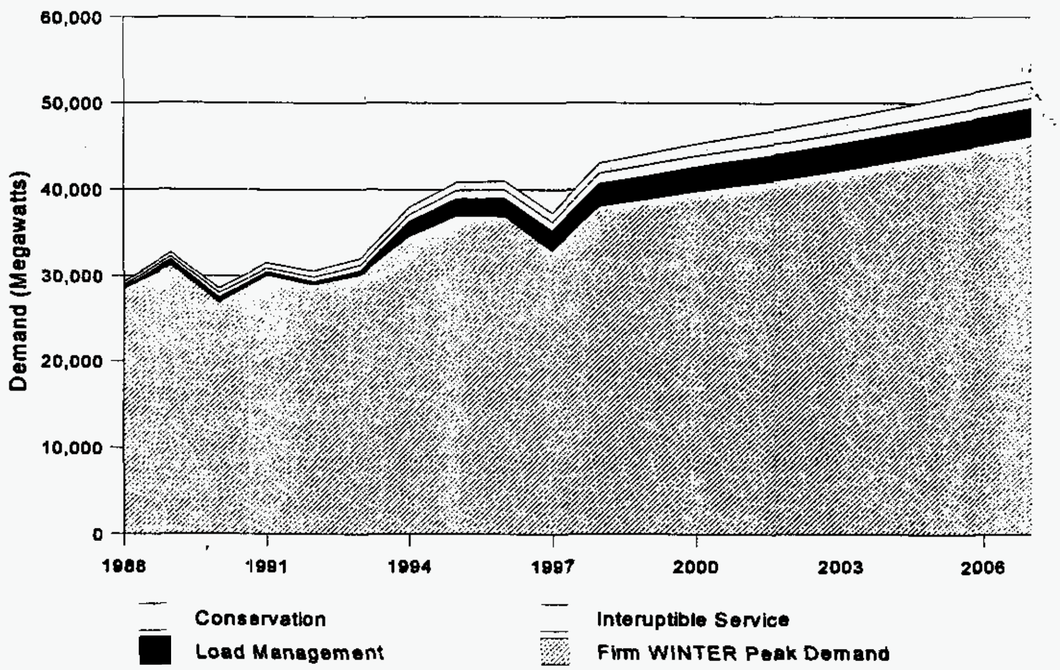


FIGURE 9: ESTIMATED IMPACT OF DSM ON WINTER PEAK DEMAND STATE OF FLORIDA -- HISTORY & FORECAST (1988 - 2007)

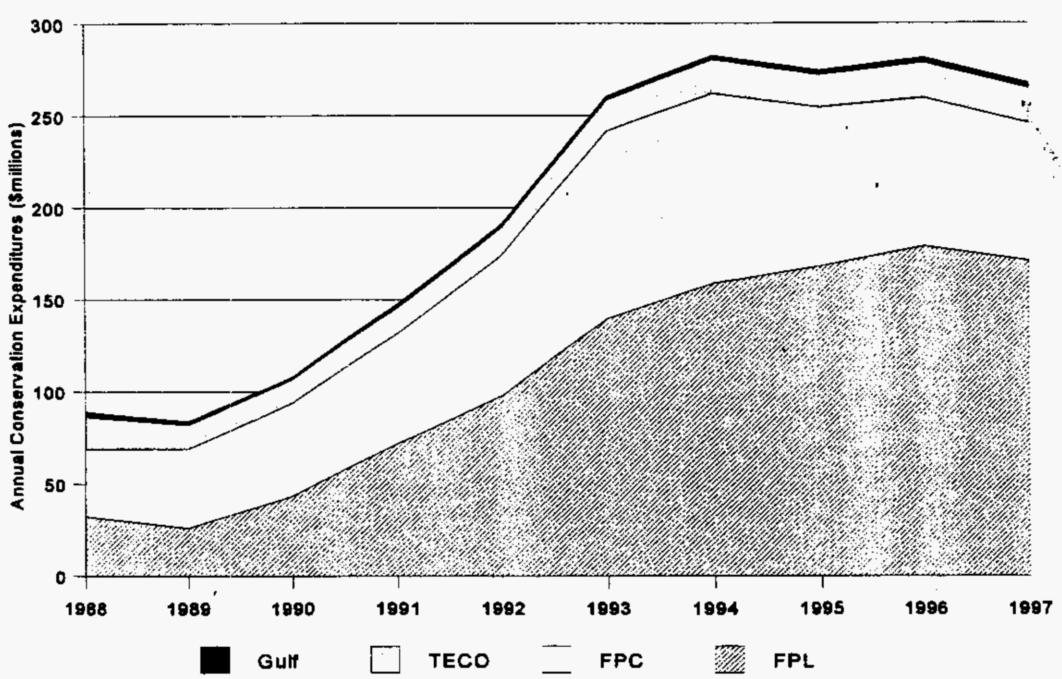


Florida's investor-owned utilities have spent a vast amount of money to implement DSM programs. This money has been collected from utility ratepayers through the Energy Conservation Cost Recovery Clause (ECCR). Since 1981, Florida's investor-owned utilities have collected over $2.4 billion through the ECCR clause, as shown in Figure 10 below.

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

It is not known at this time what impact the recent statutory revision of FEECA will have on future DSM plans and forecasts for the affected cooperative and municipal utilities that are no longer subject to FEECA's requirements. However, all former FEECA utilities who file Ten-Year Site Plans have committed to continuing their conservation efforts.

FIGURE 10: INVESTOR-OWNED ELECTRIC UTILITIES -- CONSERVATION PROGRAM COSTS RECOVERED THROUGH THE ENERGY CONSERVATION COST RECOVERY CLAUSE (1988 - 1997)



State Comprehensive Plan

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

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

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

The Commission's activities in these areas 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 these efforts, per-capita electricity consumption is projected to increase each year over the planning horizon. As shown in Figure 6, per-capita consumption is projected to grow at a lesser rate than what occurred over the past ten years. The past and projected increase may attributed to factors beyond the Commission's control, such as: (1) the nominal cost of electricity has remained relatively stable for over a decade; (2) natural gas, used by many residents nationwide for heating and cooking, is relatively unavailable in parts of Florida; (3) the average home size has increased over time; and (4) there are many more electricity-consuming appliances in the home today than in past years.

3.2.4 COMMISSION ACTIONS AFFECTING DSM

Demand-Side Management Goals and Plans

The Commission set numeric demand and energy DSM goals for the four large investor-owned utilities in October, 1994 and approved their DSM plans in June, 1995. The Commission established numeric DSM goals for Florida Public Utilities Company (FPUC) and the large municipal and cooperative utilities in April, 1995. The Commission subsequently approved the DSM plans of FPUC and the City of Tallahassee (TAL) in March, 1996; all other municipal and cooperative utility DSM plans were approved in November, 1995. However, only the DSM plans filed by JEA, OUC, and the five investor-owned utilities can be enforced because the 1996 revisions to FEECA exempted the remaining utilities in the state. While the now-exempt utilities are no longer subject to FEECA's requirements, these utilities have committed to continuing their conservation efforts.

Two utilities, Gulf Power Company (Gulf) and Tampa Electric Company (TECO), continue to fail to achieve a sufficient level of demand and energy savings to meet their Commission-approved numeric DSM goals. Gulf and TECO cite the following primary reasons for their failure to meet their DSM goals:

(1) New DSM program implementation has been delayed for various reasons; and

(2) Declining avoided generation costs have driven down the amount of customer rebates, so program participation has decreased and demand and energy savings have therefore been less than forecasted when goals were set.

The individual utility discussion of Gulf's and TECO's Ten-Year Site Plans, contained in Sections 4.3 and 4.4, respectively, has more discussion on this subject.

The Commission plans to revisit the DSM goal setting process starting in early 1999. Docket Nos. 971004-EG through 971007-EG have been opened by the Commission for the purpose of setting new DSM goals for the investor-owned utilities.

3.3 RELIABILITY REQUIREMENTS

After completing a load and energy forecast, utilities plan their electric system to meet peak demand plus allow for planned maintenance and forced outages at generating units, as well as variation from base-case assumptions. ***Reserve margin*** is the amount of capacity that exceeds firm peak demand and may be expressed in megawatts or as a percentage above firm peak demand.

However, reserve margin indicates the degree of reliability of a utility's system only at the single peak hour of the summer and winter season. Thus, it cannot capture the impact of random events occurring throughout the year, such as a forced outage of a generating unit. Therefore, many utilities also use a probabilistic reliability criterion. 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.

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.

The reliability criteria used by each utility who filed a Ten-Year Site Plan are shown in Table 4.

TABLE 4
RELIABILITY CRITERIA FOR REPORTING UTILITIES

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

Once reliability criteria are established, a utility compares its load forecast to existing system resources. Reliability concerns arise if a utility's reserve margin falls below the established criteria (for example, 15%) or the LOLP is close to or above 1 day in ten years. The utility must build or purchase additional capacity (supply-side options) or reduce peak load through the promotion of additional cost-effective conservation programs (demand-side options). An integrated resource plan is developed by combining supply-side and demand-side options to satisfy the utility's reliability criteria. This fact implies that reliability criteria decide the timing of a utility's planned resource additions.

The electric utility industry is evolving towards a competitive generation market. As this occurs, utilities may opt to make short-term firm capacity purchases in order to defer the construction of new generating units that may become future stranded investment. Competition is expected to impact the way utilities plan for generating resource additions.

The two graphs on the next page, Figures 11 and 12, show the aggregate forecast of reserve margin over the next ten years, both statewide and for Peninsular Florida's utilities. As shown in Figure 12, the aggregate reserve margin for Peninsular Florida is not forecasted to drop below 15% in any year, either summer or winter season, over the planning horizon. Thus, it appears that Peninsular Florida's utilities have planned enough generating resource additions to ensure the ability to meet customer needs for electricity over the next ten years. However, the Commission has concerns over how the Florida Reliability Coordinating Council (FRCC) performed its studies of Peninsular Florida's reliability. This concern is addressed in greater detail in Section 3.6.1 of this report.

FIGURE 11: FORECASTED RESERVE MARGIN (1998-2007) – STATE OF FLORIDA

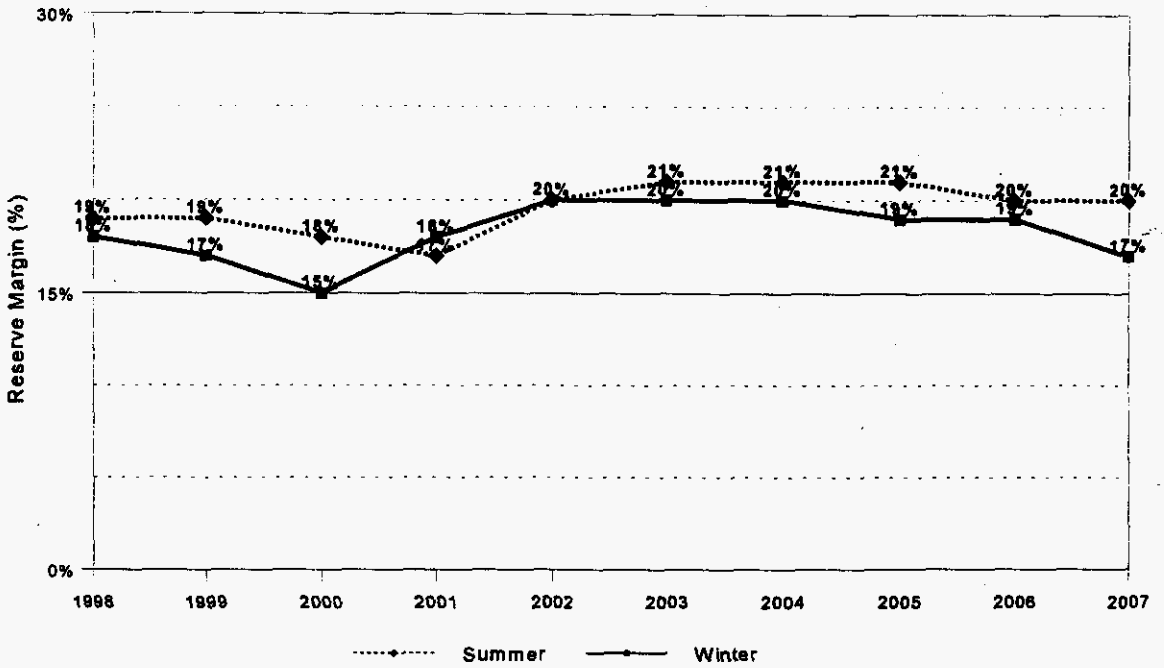
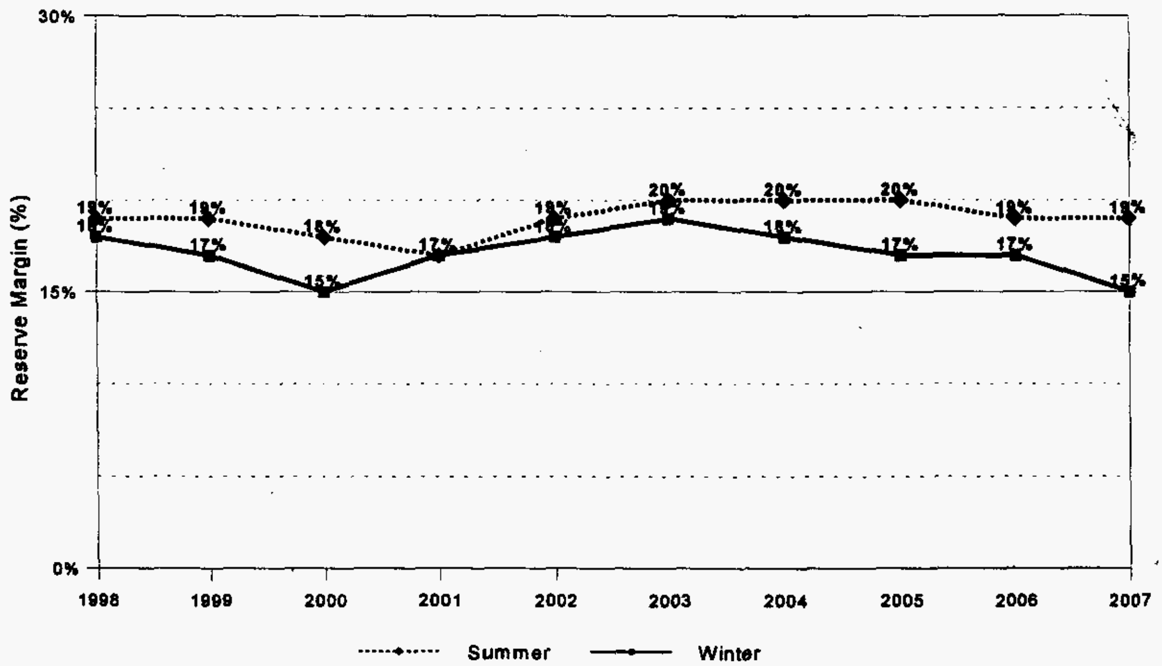


FIGURE 12: FORECASTED RESERVE MARGIN (1998-2007) – PENINSULAR FLORIDA



3.4 FUEL FORECAST

Although utilities consider several strategic factors such as fuel mix, fuel availability, and environmental compliance prior to selecting a generation resource, the fuel price forecast is the primary and potentially most volatile factor which affects the type of generation resource addition. Utilities typically apply generally accepted escalation rates, such as those published by Standard & Poor's / DRI (DRI) or the U.S. Energy Information Administration (EIA), to current fuel prices to provide a known starting point for future trends. Utilities evaluate assumptions such as inflation rates, available resources, productivity levels, and technological advances to refine a fuel price forecast. Utilities should produce several fuel price forecasts to evaluate the cost-effectiveness of potential generation plant alternatives under different economic and technical scenarios. Finally, utilities should also determine whether a project will remain cost-effective under all reasonable prices for competing fuels.

3.4.1 COAL

Coal-fired electric generation currently makes up the majority of the nation's electric generation due to low-cost domestic reserves and productivity advancements. Nationwide, electric utilities consumed approximately 900 million short tons in 1997, up approximately 2.9% from 1996 levels. According to EIA, coal-fired generation increased to offset a decrease in nuclear generation. However, this increase was tempered by increases in hydroelectric and natural gas-fired generation. Experts believe that the increase in coal-fired generation is a short-term phenomenon. Coal is expected to experience a long-term, downward trend due to its environmental concerns, available economical natural gas, and lengthy construction lead times for new coal-fired generation.

Florida's utilities have historically relied on eastern supplies of coal to meet their generation needs. Recently, utilities have increasingly used foreign and western sources for lower sulfur coal because of current and future restrictions on emission levels imposed as a result of the 1990 Clean Air Act Amendments. These alternative coal sources, which contain favorable chemical properties, allow utilities to meet load requirements and comply with emission constraints without the cost of capital-intensive scrubbers. In Florida, coal consumption for electric generation is forecasted to hold steady at approximately 27 million tons per year during the planning horizon.

Continuing the downward trend seen over the last 11 years, the average U.S. delivered cost of coal in 1997 decreased to $1.27 per million Btu (MMBtu), down $0.02 per MMBtu from 1996. EIA attributes this downward trend to the expiration, renegotiation, and buyout of older high-priced contracts; improvements in efficiency in coal production and transportation; and excess coal production capacity. Through 2020, EIA has forecasted that delivered coal prices will increase at an annual growth rate of approximately 1.8%. Florida utilities who use small quantities of coal expect prices to increase slightly faster (2.0%) during the planning horizon, and therefore have forecasted higher prices than other utilities. Utilities who use larger quantities of coal expect prices to escalate at approximately the same rate as EIA. This phenomenon was repeated for oil and natural gas as well. Depending upon specific circumstances, higher forecasted prices of a given fuel can be either the cause or the effect of a utility consuming little, if any, of the fuel for generating electricity.

Compared to last year's long-term price forecasts, coal prices at the end of the planning horizon fell an average of 4.8%. FPL and OUC have the lowest and highest coal price forecasts for 2007 with prices of $1.80 and $2.29 per MMBtu, respectively. FPL expects coal's relative share of its electric generation to drop steadily throughout the planning horizon due to the additions, repowerings, and upgrades of natural gas-fired units. OUC expects coal's relative share of its total generation to fall as load requirements increase during the planning horizon.

3.4.2 OIL

Historically, Florida has relied on oil to meet a substantial part of its electric generation requirements. Although oil currently represents a small share (12%) of the state's generation, Florida utilities consumed 39.1 million barrels in 1997, up 2.2 million barrels from 1996. Oil-fired generation also currently makes up a relatively small percentage of national load requirements. Oil consumption by electric utilities nationwide totaled 125 million barrels in 1997, up 12 million barrels from 1996. This increase goes against the trend started during the 1970's in which electric utilities reduced their use of oil as a baseload fuel. However, oil consumption in 1996 was unusually low due to intense competition from low-cost natural gas. In 1997, the average cost of oil was $2.88 per MMBtu nationwide, down $0.28 per MMBtu from 1996.

Approximately 20 years ago, Florida utilities began to explore ways to reduce their reliance on oil-fired generation. The Commission established an oil backout cost recovery clause in which utilities could recover costs associated with cost-effective construction or conversion projects that economically displaced oil-fired generation. Subsequently, the Commission approved two oil-backout projects: FPL's two 500 kV transmission lines from Georgia; and TECO's Gannon Plant re-conversion from oil to coal. In 1995, the Commission repealed the oil backout cost recovery clause rule because Florida's utilities were no longer heavily dependent on oil. However, if a utility justifies a project that will result in fuel savings for its ratepayers, the Commission will decide on a case-by-case basis whether the utility could recover the costs through the fuel adjustment clause.

A utility may equip its combustion turbine units with the ability to burn either oil or natural gas to generate electricity. This dual-fuel capability allows a utility to burn either fuel, depending on which one is more cost-effective at the time. Therefore, a utility's choice to produce oil-fired generation is largely dependent upon the relative price of oil to natural gas. During the first third of the planning horizon, Florida utilities expect oil consumption for electric generation to drop approximately 35% before increasing substantially during the remainder of the planning horizon. By 2007, Florida utilities are forecasted to consume approximately 6% more oil for electric generation than they do at the present.

One common concern with each utility's oil price forecast is that they typically include the possibility of a catastrophic event, such as the oil embargo of 1973 and Gulf War of 1990-1991. Such possibilities do exist; however, no one can accurately predict when it might happen. As a result, oil price forecasts are premised on extremely pessimistic assumptions that may neither materialize nor communicate appropriate pricing signals.

Residual Oil – EIA anticipates that residual oil prices will increase at approximately 3.9% annually through 2020. The reporting utilities project residual oil prices to increase at 3.4% annually during the planning horizon. Compared with last year's long-term fuel price forecasts, however, residual oil prices at the end of the planning horizon fell an average of 16.5%. The City of Tallahassee (TAL) projected the highest price in 2007 at $6.21/MMBtu, but TAL does not expect to use any residual oil during the planning horizon. Meanwhile, FPC projected the lowest price at $2.91/MMBtu in 2007, but expects its annual residual oil consumption to drop from its 1997 level of 9.1 million barrels to slightly less than 4.8 million barrels by 2007 due to the planned retirements of several oil-fired steam units and the conversion of other units from oil to natural gas.

Distillate Oil – EIA anticipates that distillate oil prices will increase at approximately 3.6% annually through 2020. Distillate oil is expected to remain the most expensive fuel type used for electric generation in Florida. The reporting utilities project that distillate oil prices will increase at approximately 3.25% annually during the planning horizon. Compared with last year's long-term fuel price forecasts, however, distillate oil prices at the end of the planning horizon fell an average of 11%. FPC and TAL have the lowest and highest 2007 price forecasts at $4.90 and $9.47 per MMBtu, respectively. TAL does not expect to use any distillate oil during the planning horizon. FPC uses distillate oil primarily for its peaking units.

3.4.3 NATURAL GAS

Since enactment of the 1990 Clean Air Act Amendments, U.S. utilities have increasingly turned to natural gas to comply with Phase I and II emission restrictions placed on electric generation sources. In fact, the overwhelming majority of new capacity installed by U.S. utilities in 1997 was natural gas-fired. Utilities can burn this low-sulfur fuel cleanly with great efficiency and minimal capital investment. Natural gas consumption totaled 2,968 billion cubic feet (Bcf) in 1997 nationwide, up 236 Bcf from 1996. EIA expects natural gas-fired generation to increase significantly during the forecast horizon due to nuclear plant retirements and the relative lack of new construction of coal-fired generation. In Florida, utilities expect natural gas-fired generation to increase by approximately 27% during the planning horizon to 370 Bcf in 2007. FPL, FPC, FMPA, JEA, SEC, and TAL are the driving forces behind the increased usage with proposed unit additions, conversions, and upgrades.

As indicated by historical trends, coal and distillate oil should form the floor and ceiling, respectively, for natural gas prices during the forecast horizon. The average 1997 cost of natural gas was $2.76/MMBtu nationwide, up $0.12/MMBtu from 1996. Electric utilities face uncertainties which influence natural gas price changes; these uncertainties include natural gas availability, storage levels, weather implications, and crude oil prices. EIA expects natural gas prices to rise at 3.8% per year through 2020, but the reporting utilities forecast a smaller (2.5% per year) increase during the planning horizon. Compared with last year's long-term fuel price forecasts, however, natural gas prices at the end of the planning horizon fell an average of 14.7%. FPC and FPL have the lowest and highest 2007 price forecasts at $2.50 and $3.90 per MMBtu, respectively. FPC expects to increase its natural gas-fired generation due to the addition of three combined cycle units at its Hines Energy Complex and the conversion of several units from oil to natural gas. FPL also plans to add two combined cycle units at its Martin site and repower several oil-fired steam units to gas-fired, combined cycle operation during the planning horizon.

3.4.4 ORIMULSION

Orimulsion is a coal derivative product with physical characteristics similar to oil. The Commission approved FPL's cost-recovery mechanism for the conversion of Manatee Units 1 and 2 from residual oil to Orimulsion by Order No. PSC-94-1106-FOF-EI, issued September 7, 1994. FPL would install equipment to enable the two 783 MW units to burn Orimulsion. However, on April 23, 1996, the Power Plant Siting Board (Board) voted 4-3 to deny project certification because of the potential environmental impacts of Orimulsion. On May 14, 1997, the Florida First District Court of Appeals ruled that the Board should reconsider its decision to deny certification of the proposed project.

Moreover, FPL modified the project to include the following: stricter air emission limits; improved spill prevention, containment, and cleanup systems; removal of byproducts by rail; and establishment of a $200 million trust fund for preservation and restoration of Tampa Bay. On September 30, 1997, the Board ordered the administrative law judge (ALJ) to conduct an expedited hearing and submit a supplemental recommended order on five specific issues, including the financial impact upon FPL's ratepayers from the fuel conversion during the next 20 years. On April 17, 1998, the ALJ recommended that Orimulsion be approved for use at the Manatee Plant. The ALJ found that the project meets all state and local criteria for approval. However, on June 24, 1998, the Board voted 6-1 to deny project certification because of the potential environmental impacts of Orimulsion. Subsequently, FPL announced on July 30, 1998, that it will not appeal the Board's most recent decision.

3.4.5 PETROLEUM COKE

Utilities in Florida have only recently begun using petroleum coke (pet coke) as a viable boiler fuel. Currently, only TECO, JEA, LAK, and OUC use measurable quantities of this pure carbon by-product of the oil refining process. Fuel grade pet coke typically exceeds 14,000 Btu/lb and contains high levels of sulfur and vanadium. With the proper emission control technology, however, utilities can blend pet coke with coal to achieve fuel cost savings as compared to an all-coal fuel stock. The four utilities who currently use pet coke project an aggregate five fold increase in consumption, from approximately 500,000 tons to 2,625,000 tons annually during the planning horizon.

3.5 GENERATION SELECTION

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

- **Combustion turbine (CT)** units are the least capital-intensive unit type to build and do not require permitting under Florida's Power Plant Siting Act. CT units burn natural gas or oil, but they have high operating costs because they are generally the least fuel-efficient unit type. For this reason, CT units are typically used to meet peak load needs.

- **Combined cycle (CC)** units are extremely efficient units that use the exhaust gases of one or more CT units to create steam and, in turn, generate additional electricity. CC units burn natural gas or oil, and are less capital-intensive than coal units. CC units typically serve intermediate or baseload capacity needs, and can be built in stages to more closely track a utility's load growth.

- **Pulverized coal** units utilize a low-cost, abundant, domestic fuel source but are capital-intensive. Overall cost savings may not occur until several years in the future. Coal units primarily serve baseload capacity needs.

- **Integrated coal gasification combined cycle (IGCC)** units are a variation of the combined cycle technology. IGCC units use a coal gasifier that chemically manufactures gas from coal. The gas is cleaned to improve (minimize) emissions, then is used as a fuel for the combined cycle unit. IGCC units are capital-intensive but allow fuel flexibility. IGCC units typically serve a utility's baseload capacity needs.

3.5.1 GENERATION SELECTION PROCESS

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

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

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

The Ten-Year Site Plans include proposed generating units which either do not require certification under the Power Plant Siting Act, or have yet to be certified. The next-planned, non-certified generating unit for each reporting utility is contained below in Table 5.

TABLE 5
NEXT PLANNED GENERATING UNIT ADDITION
(NOT YET CERTIFIED OR UNDER CONSTRUCTION)

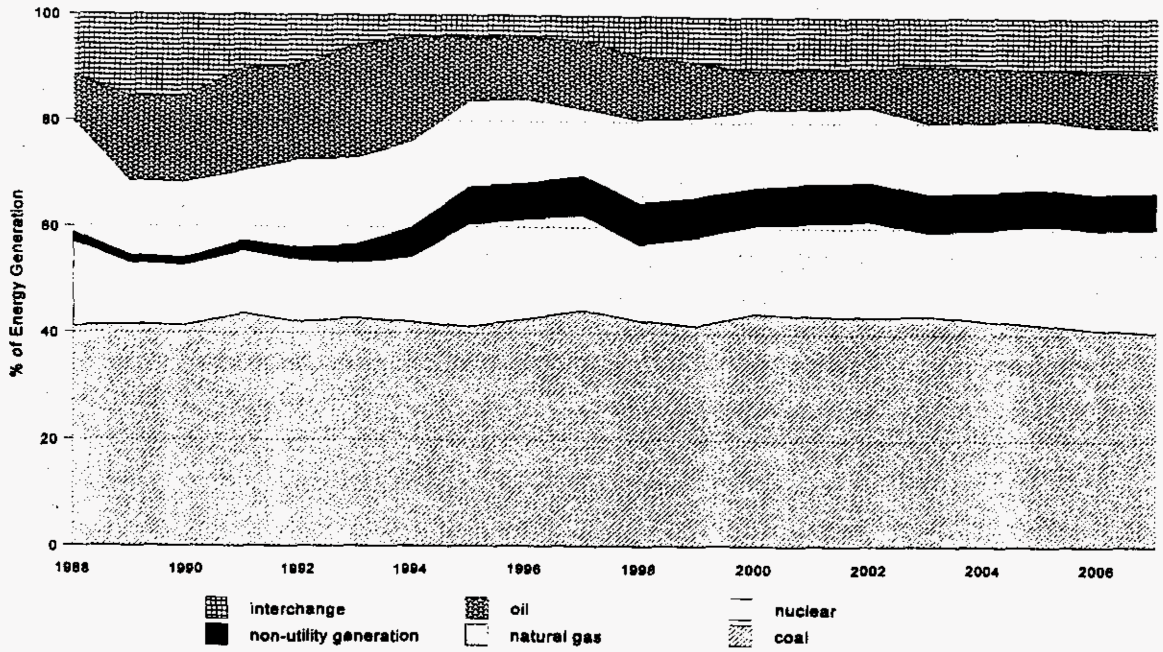
Utility	Unit (Type)	In-Service Date
GRU	none planned	—
OUC	none planned	—
TAL	none planned	—
LAK	McIntosh 5 (225 MW CT)	6/99
JEA	Kennedy GT37 (160 MW CT)	11/99
FMPA	Cane Island 3 (125 MW share of 250 MW CC)	6/01
KUA	Cane Island 3 (125 MW share of 250 MW CC)	6/01
FPL	Ft. Myers site (950 MW of CC capacity from expansion and repowering)	1/02
SEC	unknown (150 MW CT)	1/02
TECO	Polk 2 (164 MW CT)	1/02
Gulf	Lansing Smith (532 MW CC)	6/02
FPC	Hines 2 (487 MW CC)	11/04

3.5.2 FLORIDA'S GENERATION MIX: PAST, PRESENT, AND FUTURE

Prior to the early 1970's, utility generating units in Florida were fueled primarily by oil. While oil-fired generation is still expected to provide between 8% and 12% of Florida's electricity over the next ten years, the oil embargoes of the 1970's forced utilities to turn more to domestic fuels such as coal, nuclear, and natural gas. There are no current or future plans to build new nuclear generating units in Florida. As shown in Figure 13 on the next page, the generation mix of Florida's utilities is expected to remain relatively stable over the next ten years at historic levels.

Natural Gas: Florida's utilities project a slight increase in natural gas-fired generation over the next ten years, from approximately 16% to 20% of all energy generated. The projected increase is due primarily to planned combined cycle and combustion turbine unit additions. In addition, all proposed unit repowerings, as well as most unit additions by non-utility generators, are expected to use natural gas as a primary fuel.

FIGURE 13: ENERGY GENERATION BY FUEL TYPE – HISTORY & FORECAST (1988-2007)



Coal: Coal generation increased substantially during the 1980's in response to the oil price increases of the 1970's. Coal plants have traditionally been justified based on low forecasts of coal prices relative to oil or natural gas. However, coal plants are capital-intensive, and there are increased concerns surrounding the emissions of coal plants that may lead to stricter regulations that further increase capital investments at coal plants. As a result, coal-fired energy is forecasted to remain stable, comprising approximately 41% to 43% of all energy produced in the state.

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

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

Interchange Purchases: Florida's utilities continue to rely on capacity and energy purchases from out-of-state utilities. Interchange purchases are projected to provide from 8% and 10% of all energy consumed in Florida. 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. The utilities forecast a reduction in long-term firm interchange power purchases over the next ten years, 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 Qualifying Facilities: QFs sell firm capacity to some Florida utilities under long-term purchase contracts. QFs do not have an obligation to serve and, therefore, only build and operate power plants to satisfy a contractual requirement and earn a profit. The amount of QF electricity purchased by Florida's utilities is expected to dip slightly, from approximately 8% to 7% of total energy consumed, over the next ten years due to the expiration of three firm capacity QF contracts during that time.

3.6 CRITICAL CONCERNS

The Commission has identified several areas of concern which may impact the viability of some of the Ten-Year Site Plans. These concerns are discussed in greater detail below.

3.6.1 FRCC 1998 RELIABILITY ASSESSMENT

The FRCC recently performed a reliability study of Peninsular Florida's electric grid. The results of the study were published in August, 1998 in a document known as the *1998 Reliability Assessment*. The FRCC used both deterministic (reserve margin) and probabilistic (loss of load probability, or LOLP) methods to assess the adequacy of Peninsular Florida's electric grid. The study was performed using base case assumptions and sensitivities of load forecast, generating system availability, reduced assistance from the Southeastern Electric Reliability Council region, and no availability of load management or interruptible load.

Under base case assumptions, the *1998 Reliability Assessment* concluded that Peninsular Florida's utilities, as a whole, are expected to maintain a 15% winter and summer reserve margin over the entire ten-year planning period from 1998 to 2007. Further, the FRCC found that the 0.1 days per year LOLP criterion is not violated at any time. There were minimal violations of the LOLP criterion under the various planning sensitivities.

The Commission has numerous concerns with the reserve margin and LOLP analyses contained in the *1998 Reliability Assessment*:

(1) The base case LOLP values are extremely low, indicating a high degree of reliability. It appears that the low LOLP results are driven primarily by higher current and forecasted unit availabilities of more than 85%. If unit availabilities degrade to around 78% overall, a value considered the norm as recent as five years ago, Peninsular Florida's utilities would likely experience capacity shortfalls and, ultimately, blackouts. If utilities reduce maintenance on existing units to minimize costs, and if they hesitate to build new needed generating units, capacity shortages may become a reality in the near future.

(2) The generally accepted 0.1 days per year LOLP criterion corresponds to approximately a 6% to 8% reserve margin. The FRCC agrees that a 6% to 8% reserve margin is unrealistically low; hence, reserve margin is the factor driving the need for additional capacity in Peninsular Florida.

(3) There is uncertainty as to whether the Southern Company will continue to be able or willing to assist the Peninsula in the future. Southern may be able to obtain higher prices by selling emergency power to the north and Midwest during winter low temperature extremes. The Commission is concerned that the recent wholesale power price spikes experienced by Florida's utilities during the months of May, June, and July of 1998 are an indication that reserves were unusually tight during that time.

Given these concerns with the FRCC's *1998 Reliability Assessment* in particular, and with reserve margin levels in general, the Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida. It is expected that this evaluation will occur sometime in 1999.

The Commission is also concerned with how extreme low winter temperatures may adversely impact winter reserves. This concern dates back to the events occurring in December, 1989 where much of Peninsular Florida was blacked out due to unusually high demand coupled with low generating unit availability. It is estimated that approximately 4,700 MW of load was not served at the height of the December, 1989 outage. If unit availability is maintained at levels currently projected by the individual utilities, the amount of load not served is estimated to be approximately half as much (2,370 MW) as the amount of load not served in December, 1989. However, if unit availability deteriorates to historic levels, the amount of load not served is estimated to be approximately twice as much (8,225 MW) as the amount of load not served in December, 1989.

At the Commission's December 15, 1997 Internal Affairs Conference where the Commission adopted its *Review of 1997 Ten-Year Site Plans*, the FRCC stated that one of its goals for 1998 was to develop a standard reliability criterion. The *1998 Reliability Assessment* also contains FRCC's analysis of the suitability of a 15% reserve margin standard for Peninsular Florida. This study covered the major components which comprise reserve margin. Each of these components were adjusted to reflect how closely past forecasts compared to actual data. For example, if load forecasts were historically 5% less than actual load for the same period, the load forecast for the ten-year planning horizon would be adjusted by a factor of 1.05. Once all adjustments are made, the projected reserve margins are revised to reflect the historical accuracy of utility projections. If the resulting <u>adjusted</u> reserve margin is greater than zero, it may be assumed the originally planned reserve margin is sufficient. If the result is less than zero, the reserve margin criterion is not sufficiently high enough to withstand historical inaccuracies.

The Commission has concerns that the methodology and data used by the FRCC to adopt its 15% reserve margin criterion is untested. These concerns are discussed below:

(1) For both the winter and summer peak periods, the FRCC found that a 13% reserve margin is adequate for Peninsular Florida's utilities. The FRCC adopted 15% as its reserve margin criterion to be conservative and consistent with the criteria used by many of the individual utilities in Florida. However, FRCC's method averages the historical inaccuracies of the input data. Instead of using the FRCC's simple average approach, the Commission staff performed a probabilistic analysis of the input data comprising reserve margin. The Commission's analysis showed a small chance that a 15% reserve margin criterion may not be adequate to cover all possible variations in the components that make up reserve margin.

(2) The Commission questions why a 15% reserve margin criterion has been adopted when 15% is the lowest value specified in Rule 25-6.035, Florida Administrative Code, for emergency power pricing purposes. Adopting a reserve margin criterion that just barely meets the criterion for emergency power pricing suggests that planned reserve margins are razor-thin.

While the FRCC's reserve margin methodology is a good first step for evaluating Peninsular Florida's electric reliability, this methodology, as well as the Commission staff's probabilistic adaptation, needs further refinement and testing. This uncertainty leaves the Commission in a dilemma. The *1998 Reliability Assessment's* LOLP methodology yields unprecedented low reserve margins, and the new reserve margin methodology needs further evaluation and refinement. The result is that the FRCC has not yet developed a tested methodology to determine whether

Peninsular Florida's existing and planned generating resources will be reliable enough to satisfy growing power demands. With the state's economic well-being depending on a reliable electricity supply, a more prudent course would be to avoid reducing reserve margins until reliability studies yield a more definitive answer to the question: "Are planned generating unit additions sufficient to adequately supply growing power demands?"

3.6.2 AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

The reserve margin for some of Peninsular Florida's utilities is currently comprised largely of non-firm resources such as load management and interruptible service. During the ten-year planning horizon, it is expected that non-firm resources will comprise an even greater percentage of peninsular reserve margins, resulting in less generating capacity reserves. For Peninsular Florida, non-firm load makes up nearly 58% of the winter, 1998 reserves and 44% of the summer, 1998 reserves. This situation is of even greater concern to Florida Power Corporation, whose winter, 1998 non-firm load is greater than its winter reserves. Non-firm load makes up 76% of FPC's summer, 1998 reserves.

Exacerbating this situation is the fact that FPC lost nearly 70,000 load management program participants (8% of total) due to the utility's use of load control measures during extremely hot weather conditions in the summer of 1998. If Peninsular Florida's reserve margins decrease even further because of customer flight from load management programs, utilities may be facing reliability problems in the near term.

3.7 RISKS AFFECTING PLANS

Because the future is uncertain, any utility long-range plan will contain risks that affect both the reliability and cost-effectiveness of the plan. The major elements of risk are ***competition, reliability, availability of natural gas, uncertainty with the cost-effectiveness of demand-side management programs,*** and ***environmental compliance.***

The following discussion identifies the major elements of risk associated with the electric utility Ten-Year Site Plans.

3.7.1 COMPETITION

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

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

3.7.2 RELIABILITY

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

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

3.7.3 AVAILABILITY OF NATURAL GAS

Current national policies tend to promote the consumption of natural gas over other fossil fuels. Natural gas offers environmental benefits and, because it is domestically produced, decreases Florida's dependence on foreign oil. Two federal actions, the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992, greatly favor natural gas usage. These policies have assisted in increasing natural gas demand in Florida.

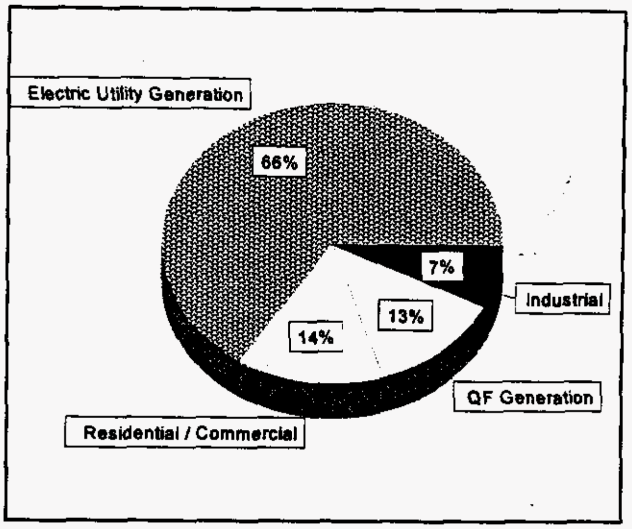


FIGURE 14: NATURAL GAS CONSUMPTION BY END-USER -- 1998

Figure 14 illustrates current natural gas consumption by end-user. Natural gas vehicles, fuel cells, and gas air conditioning currently represent less than 1% of the total natural gas usage in Florida. While consumption by these uses is expected to increase in the future, even rapid increases will not have any material bearing on natural gas consumption for several years. On the other hand, the reporting electric utilities project nearly a 47% increase in natural gas usage during the next ten years. Much of this forecasted increase (30%) is expected to occur in 2002 and 2004, with the remaining increase spread out over 2005-2007. 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. Therefore, the feasibility of using natural gas for future electric generation is directly dependent on available pipeline capacity on FGT's system.

Natural gas pipeline capacity is expressed as maximum daily throughput capability in billion cubic feet per day (bcf/day). FGT's system capacity is just under 1.455 bcf/day. Approximately 80% of Florida's natural gas pipeline capacity is used for electric and QF generation purposes. Currently, FGT does not have any unsubscribed capacity. To fuel new gas-fired, utility owned generating units included in the Ten-Year Site Plans, additional pipeline capacity may be needed by 2002. To meet the forecasted needs of electric utilities and QF's, as well as the expansion of natural gas distribution utilities, an additional 0.65 bcf/day may be required. As a result, FGT may need to increase total pipeline capacity to nearly 2.0 bcf/day by 2007.

The FGT pipelines serving Florida are located in a common corridor 15 to 30 feet apart from near the Mexican border in Texas to Orlando. Near Orlando, the lines branch out to Miami along the east coast and to the Tampa area. A line extension is being planned from the Tampa area to fuel the FPL expansion at its Ft. Myers plant. FGT indicates that an explosion on one line has never impaired another line in the corridor.

In response to the August 14, 1998 lightning-induced explosion and fire at a compressor station in Perry, Florida, FGT is implementing measures and operating procedures to reduce the possibility of interruption to all three common-corridor pipelines serving Florida. These measures and procedures include: lightning detectors at all compressor stations, redundant relay systems to prevent unnecessary gas venting, compressor station by-pass lines and valving to allow quicker shut-off should a fire occur, and switching from automatic to manual compressor station control when a thunderstorm approaches. In manual operation, a worker is called out to switch valves should a fire occur. FGT indicated that the changes will increase reliability and allow repair of a major pipeline break within 24 hours.

On October 1 of this year, FPL finalized a deal with FGT to supply natural gas to the Ft. Myers site. Hence, Florida's utilities will continue to have all natural gas pipelines in a single corridor in north Florida and be exposed to loss of all gas supplies due to a single adverse event.

FGT has indicated its willingness and ability to expand existing natural gas pipeline capacity to meet the future natural gas requirements of electric utilities. FGT can expand the capacity of its system by nearly 0.5 bcf/day with compressors at various points on the system. Additional capacity can also be acquired through minor looping, which requires a short lead time of 12 to 18 months. These actions should reduce concerns with future constrained pipeline capacity.

FGT's existing infrastructure allows flexibility to accommodate incremental growth. In August, 1997, FGT initiated a 30-day Notice of Open Season, accepting nominations for a proposed mainline expansion of its existing gas pipeline system. The proposed expansion, estimated to be placed into service in late 1999, will be accomplished through compression and minor looping. FGT has not yet committed to construct the expansion. However, it anticipates submitting an expansion project filing to the Federal Energy Regulatory Commission by year end 1998. In May 1998, FGT solicited requests for incremental firm transportation service beginning in 1999-2001. FGT also solicited offers from existing shippers to permanently release firm capacity that could reduce the need for construction of incremental facilities. Responses were due by May 31, 1998. The customers posted their offer(s) to permanently release on FGT's electronic bulletin board allowing potential acquiring parties the opportunity to bid for the capacity by June 30, 1998. Numerous parties responded, showing a desire to release a total of nearly 50,000 MMBtu/day. Until the system expansion takes place, the parties are free to temporarily release this capacity for resale on the open market. At the time of expansion FGT will take this release as permanent and factor it into the system's overall expansion, in order the decrease the amount of construction.

Currently, other utilities requiring additional natural gas capacity appear to be pursuing the secondary market. The current price of gas pipeline capacity on the secondary market reflects the demand and availability. Recently, the price in the secondary market has fluctuated between 10% and 100% of the maximum allowable rate. Such discounts suggest that capacity is available at times. However, the secondary market may only provide capacity in short intervals compared to permanent firm capacity relinquishments. Capacity obtained through the secondary market also may be subject to delivery constraints at the point of receipt.

Electric utilities will need to arrange for natural gas capacity for new generating units due to be placed into service between 2002 and 2005. If electric utilities do not subscribe for gas transportation capacity to fuel future generation expansions, they must identify a contingency plan to obtain transportation capacity. Conservative and potential maximum estimates of the need for natural gas exceed FGT's current capacity. Forecasted gas requirements include the needs of both QF's and gas distribution utilities. While timing of the additional demand for capacity may change, the amount of additional capacity need is presumed to be accurate.

3.7.4 UNCERTAINTY WITH THE COST-EFFECTIVENESS OF DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS

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

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

3.7.5 ENVIRONMENTAL COMPLIANCE

Evolving environmental regulations may cause electric utilities to bear additional significant compliance costs in the future. To comply with existing and proposed environmental regulations, utilities must stay informed on evolving environmental legislation to perform cost-effective compliance planning. The Environmental Protection Agency (EPA) is responsible for establishing national air and water pollution limits for power plants. Florida's Department of Environmental Protection (DEP) is responsible for carrying out the provisions of the Clean Air Act in Florida and establishing Florida-specific standards.

Any entity building a generating unit in Florida must comply with environmental standards established by both EPA and DEP for many pollutants. Utilities achieve compliance by building cleaner burning plants, adding pollution control equipment (e.g., scrubbers or particulate filters) to existing power plants, or burning cleaner fuels. Such compliance measures can be expensive. To keep electric rates as low as possible, utilities continuously explore alternate compliance measures and select those resulting in the lowest cost.

The most comprehensive environmental legislation affecting Florida's electric utilities is the federal Clean Air Act. The 1990 Clean Air Act Amendments (CAAA) enacted by Congress establish a national cap on total allowable sulfur dioxide (SO_2) emissions from electric power plants and require a reduction in nitrogen oxide (NO_x) emissions. CAAA Phase I required electric utilities to reduce SO_2 emissions by approximately 5 million tons below 1980 levels by January 1, 1995. Existing coal units must achieve new NO_x emission rates based on firing technologies. CAAA Phase II requires U.S. electric utilities to reduce SO_2 emissions by another 5 million tons by January 1, 2000 to achieve the national emission cap of 8.95 million tons. The NO_x emission rates are expected to achieve a target reduction of 2 million tons below 1980 levels.

In addition to SO_2 and NO_x reductions, the EPA recently proposed a significant rule change to capture more dust and soot emissions. Utilities may be faced with additional actions to trap airborne particles as small as 2.5 microns (or approximately 1/28 the diameter of a strand of hair), down from the current 10 micron requirement. These environmental requirements will decrease

TABLE 6
BASE CASE COMPOSITE EMISSION RATES FOR INVESTOR-OWNED UTILITIES

Pollutants	Projected Emissions (Pounds per kWh)	
	2000	2007
Sulfur Dioxide (SO_2)	5.2	4.0
Nitrogen Oxides (NO_x)	3.9	1.9
Particulates	0.3	0.3
VOCs	0.02	0.03
Carbon Dioxide (CO_2)	1142	1070
Mercury	0.00003	0.00002

the cost-effectiveness of older generating facilities, which primarily consume coal and residual oil.

Most of the reporting utilities are reflecting declines in their projected emission rates relative to their 1997 estimates for the regulated pollutants. Table 6 contains the projected composite emission rates for major pollutants for Florida's investor-owned utilities. While some reductions are due to unit retirements and adding of new natural gas-fired capacity, some utilities may have to retrofit coal and oil units. The extent of these retrofits may depend more on public opinion than on management or regulatory decisions.

The SO_2 allowance price appears to have started an upward climb towards $200/ton. There is some speculation that EPA's upcoming rules on dust and haze have influenced the market price. These new rules, in combination with increased allowance prices, could result in the consideration of different burner, scrubber and precipitator options.

There is a large degree of uncertainty with respect to future greenhouse gas regulation of CO_2. The problem is that fossil fuels which provide electricity have unavoidable CO_2 emissions. Some emission reduction technologies for the other pollutants increase CO_2 emissions. For example, the limestone used in a SO_2 scrubber releases CO_2 and may increase CO_2 emissions by as much as 3%. Therefore, the combination of complex chemistry and unknown future regulations creates uncertain horizons for environmental compliance planning.

4.0 REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

4.1 FLORIDA POWER CORPORATION

Florida Power Corporation's (FPC) generating system currently has a winter capacity of 7,717 MW. The system consists of four coal-fired steam turbine units (2,276 MW), eight oil-fired steam turbine units (1,630 MW), 44 combustion turbines (2,820 MW), and a 90.4% (755 MW) ownership share of the **Crystal River 3** nuclear unit. FPC recently purchased the Tiger Bay combined cycle generating facility (236 MW), transferring control of the capacity from the qualifying facility to FPC. In addition, FPC currently purchases firm capacity from two investor-owned utilities (455 MW) and 14 qualifying facilities (756 MW). The QF capacity total reflects the termination of the 75 MW standard offer contract with Panda-Kathleen, which occurred after FPC filed its Ten-Year Site Plan.

FPC plans to add three generating units to its system over the next ten years. **Hines Unit 1,** a 470 MW combined cycle unit, is due to be placed into service in November, 1998. **Hines Units 2 and 3** are identical 470 MW gas-fired combined cycle units with expected in-service dates of 2004 and 2006, respectively. FPC also plans capacity additions at the **Crystal River** site totaling 72 MW. In addition to these new units, FPC plans to retire 12 generating units with a total generating capacity of 413 MW. The following sites will be affected: Higgins (148 MW), Suwanee (147 MW), Avon Park (64 MW), Turner (36 MW), and Rio Pinar (18 MW). FPC plans to convert three oil-fired CT units to natural gas.

FPC plans resource additions on its system to meet a dual reliability criteria of 15% summer and winter peak reserve margin and a 0.1 days per year loss of load probability (LOLP). Winter peak demand is driven primarily by low temperatures. FPC's base case winter load forecast assumes a low winter temperature of 34.2°F. FPC estimates that, on average, its winter reserves will decrease to zero if the temperature in the St. Petersburg area reaches a low of 26.8°F. This has occurred three times since 1970.

4.1.1 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 within the framework of this study. A combination of econometric and end-use models provide a sound foundation for planning purposes. The variables used were obtained from reputable sources and are representative of a valid load forecast model.

The absolute percent error in FPC's 1993-1997 retail sales forecasts is 2.98%, slightly higher than the 2.92% numeric average for the nine reporting utilities in the state with sufficient available historical data. FPC's average forecast error for the same period also reflects an over-forecast of 2.98%.

FPC's winter peak demand forecast is projected to increase at an average annual growth rate (AAGR) of 1.73%, or roughly one-half of the 1988-1997 AAGR of 3.55%. The historical AAGR is considerably lower than the 7.55% AAGR from 1987-1996 due to a winter demand decrease of

21.68% from the 1996/97 to the 1997/98 winter. However, FPC's 1998-2007 winter demand forecast still projects higher net demand as compared to the 1997 Ten-Year Site Plan, even though the company assumes lower customer growth. FPC attributes these lower projected growth rates to the loss of wholesale contracts with Seminole Electric Cooperative and the City of Bartow.

4.1.2 CONSERVATION

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

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

However, non-firm resources such as interruptible service and load management also make up a substantial part of FPC's reserve margin. FPC's 1998 winter reserves are 100% comprised of non-firm resources, and these resources make up 76% of FPC's 1998 summer reserves. The Commission is concerned that a drop-off in customer participation in these programs would reduce forecasted DSM program demand savings, resulting in an unacceptably low reserve margin. This concern is exacerbated by events occurring during unusually hot, dry weather occurring during the summer of 1998. FPC experienced an 8% drop off in load management program participation due to customers being load controlled during the hot weather. FPC estimates that these lost participants accounted for 70-80 MW of winter reserves.

Despite the loss of load management participants, the cumulative demand and energy savings from FPC's DSM programs have exceeded the residential and commercial DSM goals set by the Commission in 1994. The Commission is due to set new DSM goals for FPC in 1999.

4.1.3 FUEL FORECAST

FPC has provided a base case price forecast for coal, residual oil, distillate oil, natural gas, and nuclear energy. FPC also provided a high and low price forecast for each fuel, except nuclear energy. Electric Fuels Corporation, an FPC affiliate, provided the coal price forecasts which represent its price to FPC for coal delivered to the Crystal River Plant. FPC developed the other fuel price forecasts based upon the following assumptions. Oil and natural gas prices are based on normal weather, no radical changes in the world energy markets, and stable world governments. Price forecasts for oil delivered through the Tampa Bay area include adjustments for transportation and delivery. Natural gas prices were adjusted to develop a price delivered into the Florida Gas Transmission (FGT) system. FPC assumed that high and low fuel prices are a function of global inflation trends.

Unlike most utilities, FPC expects coal and natural gas prices to converge during the planning horizon. FPC believes nuclear energy and natural gas prices will be approximately 13.4% and 10%

higher, respectively, at the end of the planning horizon as compared to the 1997 Ten-Year Site Plan. However, FPC has forecasted the lowest 2007 prices for natural gas, residual oil, distillate oil, and nuclear energy among the 12 reporting utilities. Moreover, FPC's 2007 coal price forecast is below the average 2007 coal price forecasts among the 12 reporting utilities.

4.1.4 ENVIRONMENTAL COMPLIANCE

FPC is not subject to sulfur dioxide (SO_2) compliance restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). All known requirements of Phase II of the CAAA are integrated into FPC's resource planning process. FPC's long-term compliance strategy, like most other utilities, is to increase reliance on natural gas and switch to lower sulfur coals and oils. FPC's secondary compliance methods include environmental dispatch and allowance purchases.

FPC's plan discusses environmental compliance and coordination with respective regulatory agencies to the extent that those issues are addressed in the site certification process.

FPC forecasted only base case emissions this year. FPC's plan has not substantively changed from the 1997 plan, suggesting that there is no need to look at the relative impacts of various different sensitivities.

4.1.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Community Affairs (DCA): DCA provided general comments on FPC's *Ten-Year Site Plan*.

Florida Department of Environmental Protection (DEP): DEP does not foresee any significant environmental or land use impediments for future expansion of the Hines site. However, DEP believes that FPC's *Ten-Year Site Plan* is insufficient because it lacks information concerning units scheduled for repowering.

Central Florida Regional Planning Council: The Council continues to monitor site certification activities for the Hines site. No further comment is necessary at this time.

East Central Florida Regional Planning Council: FPC plans no new generation within the region.

North Central Florida Regional Planning Council: FPC's *Ten-Year Site Plan* is consistent with the goals and policies of the North Central Florida Regional Policy Plan.

Polk County: FPC's *Ten-Year Site Plan* does not contain enough information to adequately assess the issues of compatibility, consistency, potential impacts on public facilities, and environmental concerns.

Southwest Florida Water Management District: No new facilities are planned in the district.

Tampa Bay Regional Planning Council: FPC's *Ten-Year Site Plan* is consistent with regional policies.

Volusia County: FPC plans no new generation within the County.

Withlacoochee Regional Planning Council: FPC's *Ten-Year Site Plan* is consistent with the region's goals and policies related to energy use, air quality, economic development and efficient movement of goods and services.

4.1.6 SUITABILITY

Forecasted reserve margins are expected to be at or above FPC's criterion of 15% for each seasonal peak throughout the planning horizon except for winter, 2001, when the reserve margin is forecasted to be 13%. FPC can mitigate this forecasted reserve margin shortfall by purchasing short-term capacity from other utilities. This option may be valid because Peninsular Florida's aggregate reserves could supply FPC's reserve shortfall of approximately 150 MW while maintaining the FRCC minimum 15% reserve margin criterion.

In addition to purchasing short-term capacity, FPC has other options available to it to remedy its reserve margin shortfall. These options include, but are not limited to, the following: purchases from outside Peninsular Florida; construction of a combustion turbine unit; acquisition of additional capacity from upgrades to existing units; advancement of the in-service date of an already planned unit; or, delay in the retirement date of the Suwanee River fossil steam units (147 MW) currently scheduled for April, 2000. Since these options require a short lead time to implement, FPC has adequate time to react to its reserve margin shortfall. FPC should address its chosen remedy in next year's Ten-Year Site Plan.

As discussed earlier in this report, planning is a dynamic process. The Ten-Year Site Plan is a planning document that is accurate at a point in time. FPC's forecasted 13% reserve margin for winter, 2001 does not satisfy its 15% planning criterion. However, the FRCC currently forecasts that Peninsular Florida's reserve margin, including FPC, will be above 15% in that year and could supply FPC's reserve margin shortfall if necessary. Therefore, FPC's plan is **suitable** for planning purposes.

FPC's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.2 FLORIDA POWER & LIGHT COMPANY

Florida Power & Light's (FPL) generating system consists of four nuclear units totaling 2,885 MW; six gas-fired combined cycle units totaling 2,218 MW; 17 residual oil-fired steam turbines totaling 6,547 MW; four gas-fired steam turbines totaling 1,853 MW; three coal-fired units totaling 875 MW; 36 gas-fired combustion turbines totaling 1,296 MW; 12 distillate oil-fired combustion turbines; and five distillate oil-fired internal combustion units.

FPL expects to increase its generating resources by nearly 3,000 MW during the planning horizon. This increase will come primarily from unit upgrades and fuel conversions at some of FPL's existing units. A significant part of FPL's expansion plan is the Ft. Myers repowering project. By replacing existing boilers with state-of-the-art combustion turbines while using the same steam cycle, FPL will gain more than 1000 MW of winter generating capability beginning in the year 2002. However, planned capacity additions are contingent upon FPL securing adequate natural gas supplies which are both sufficient for fueling the electrical capacity involved and economically attractive.

The Ft. Myers repowering is contingent on FPL's ability to secure adequate natural gas supplies which are economically attractive. On October 1, 1998, FPL finalized a deal with Florida Gas Transmission (FGT) to supply natural gas to the Ft. Myers site. Hence, FPL is furthering a dependence on a single gas pipeline corridor in north Florida and, therefore, is exposed to loss of all gas supplies due to a single adverse event.

Of the 12 proposed transmission lines identified in FPL's Ten Year Site Plan, only the 114-mile long Corbett-Orange River transmission line will require certification under the Transmission Line Siting Act. Construction of this line and associated facilities is expected to take as long as 36 months. If the in-service date of the natural gas pipeline to the Ft. Myers site is delayed, FPL's short-term reserves may be inadequate, particularly if sufficient backup fuel is not available.

FPL's expansion plan currently reflects the planned conversion of Plant Manatee to burn Orimulsion. This plan was denied by the Siting Board for the second time on June 24, 1998. FPL has publicly announced that it does not intend to appeal the decision. However, absent the planned conversion, FPL's capacity resources actually increase.

FPL plans resource additions on its system to meet a dual reliability criteria of 15% summer and winter peak reserve margin and a 0.1 days per year loss of load probability (LOLP). Winter peak demand is driven primarily by low temperatures. FPL's base case winter load forecast assumes a low winter temperature of 34.5°F. FPL estimates that, on average, its winter reserves will decrease to zero if the temperature in the Miami area reaches a low of 26.5°F. This has not occurred since before 1970.

4.2.1 LOAD FORECAST

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

FPL adequately identifies and describes the models, variables, data sources, assumptions, and informed judgements used to generate the demand and energy forecasts in this year's plan. The Commission believes that all of these factors have been accurately documented. Moreover, FPL's assumptions and informed judgements are reasonable and the data sources are credible. However, FPL's 1998 Ten-Year Site Plan winter demand forecast is slightly lower than its 1997 Ten-Year Site Plan forecast by an average of 144 MW per year over the forecast horizon. On a percentage terms basis, FPL's 1998 winter demand forecast for the next ten years is projected to increase at the same 1997 AAGR of 1.73%.

The absolute percent error in FPL's 1993-1997 retail sales forecasts is 2.19%, which is lower than the 2.92% numeric average for the nine reporting utilities in the state with sufficient available historical data. FPL's average forecast error for the same period is an under-forecast of 0.73%.

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

4.2.2 CONSERVATION

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

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

To date, FPL's DSM programs have yielded cumulative summer demand and annual energy savings that exceed its goals set by the Commission in October 1994. The Commission is due to set new DSM goals for FPL in 1999.

4.2.3 FUEL FORECAST

FPL provided a base case price forecast for coal, residual oil, distillate oil, and natural gas. FPL also provided a high and low price forecast for each fuel. FPL did not provide any price forecast for nuclear energy. FPL expects the anticipated increase in oil supplies from non-OPEC sources to be less than the increase in the worldwide demand for petroleum products. As OPEC's market share increases to fill the void, petroleum prices are expected to rise. FPL's natural gas forecast assumes that domestic demand will grow moderately during the planning horizon. Natural gas production should increase due to new technologies, yet the growth rate in gas demand should exceed the growth rate of gas supply.

FPL forecasts that the price differential between the delivered price of natural gas and coal will widen during the planning horizon. Residual oil, distillate oil, and natural gas prices are expected to increase annually at a faster rate than EIA's long-term forecast for these respective fuels. However, this FPL forecast puts the price of residual oil at the end of the planning horizon approximately 11.9% less than last year's forecast. FPL has forecasted the highest 2007 natural gas price forecast and the lowest 2007 coal price forecast among the 12 reporting utilities. Except for coal, FPL's 2007 fuel forecasts are above the average 2007 price forecasts of the 12 reporting utilities.

4.2.4 ENVIRONMENTAL COMPLIANCE

FPL is not subject to sulfur dioxide (SO_2) compliance restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). All known requirements of Phase II of the CAAA are integrated into FPL's resource planning process. FPL's long-term compliance strategy, like most other utilities, is to increase reliance on natural gas and switch to lower sulfur coals and oils. FPL's secondary compliance methods include environmental dispatch and allowance purchases. Environmental compliance and coordination with respective regulatory agencies are discussed in FPL's plan to the extent that those issues are addressed in the site certification process.

FPL's 1998 projection of air emission rates is lower than that from last year, primarily because of the Ft. Myers Plant repowering into a large natural gas combined cycle facility. However, FPL also assumed Orimulsion would be burned at Manatee. FPL no longer plans to pursue the Manatee Orimulsion conversion project because the Power Plant Siting Board voted to deny the project on June 24, 1998. The only likely option to Orimulsion is natural gas if FPL continues its attempts to use the plant as a base load facility. Use of natural gas at Manatee could reduce the overall emissions as long as oil usage at other units also declines.

FPL did three emission sensitivities: high fuel prices with low demand; low fuel prices with high demand; and the constant differential fuel price forecast and base case demand. These sensitivities show that with demand low and high natural gas and light oil prices, FPL's system will emit more SO_2, NO_x, particulates and VOC emissions but less CO_2 compared with the base case. The converse is also true. The constant differential fuel price sensitivity, which uses natural gas prices lower than FPL's low range, results in decreased emissions relative to the base case but slightly higher than emissions with low fuel prices and low demand. These sensitivities demonstrate some of the benefits of lowering demand as well as aggressively pursuing low natural gas prices.

4.2.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Broward County: The County had some general environmental and water-use concerns with the existing Port Everglades site. These concerns should be addressed if FPL decides to add new generating units at the site in the future.

Central Florida Regional Planning Council: Has some general environmental and water use concerns with FPL's identification of the DeSoto site as a candidate for future development.

East Central Florida Regional Planning Council: The Council provided general comments on the positive environmental impacts of FPL's proposed Sanford unit repowering.

Florida Department of Community Affairs (DCA): DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA applauds FPL for proposing to meet its baseload electricity needs with combined cycle units rather than combustion turbines.

Florida Department of Environmental Protection (DEP): Since the proposed unit additions and repowerings are all at existing sites, DEP does not foresee these projects causing any land-use conflicts. DEP is concerned that FPL's *Ten-Year Site Plan* contains no information on a proposed pipeline needed to deliver natural gas to the Ft. Myers site after repowering is complete.

Manatee County: FPL's plan includes the conversion of Manatee Units 1 and 2 to Orimulsion, which was not approved by the Florida Power Plant Siting Board. The County asks why the Manatee site cannot be converted to gas-fired generation, given that FPL's proposed repowering of the Ft. Myers site will require natural gas which may be delivered via pipelines passing through Manatee County.

North Central Florida Regional Planning Council: FPL's *Ten-Year Site Plan* is consistent with the goals and policies of the North Central Florida Regional Policy Plan.

Northeast Florida Regional Planning Council: The Council provided general comments on FPL's *Ten-Year Site Plan.*

South Florida Regional Planning Council: FPL's *Ten-Year Site Plan* is consistent with goal and policies of the regional plan.

South Florida Water Management District: Has some issues with FPL's plans to expand generation at the Ft. Myers site. These issues will be addressed during the site certification process.

Southwest Florida Regional Planning Council: Generally commented on FPL's plans to repower the Ft. Myers site.

Southwest Florida Water Management District: FPL has proposed sites which lie within the Southern Water Use Caution Area (SWUCA). The Floridian aquifer within this area has been severely stressed by past excessive withdrawals, and future access to water in this area may be restricted.

Tampa Bay Regional Planning Council: FPL's *Ten-Year Site Plan* is consistent with regional policies.

Treasure Coast Regional Planning Council: Identification of the Riviera site as a candidate for future expansion may impact residential communities, the Lake Worth Lagoon, the municipal water supply, and air quality. The Council seeks changes to regulatory policies that would urge the State of Florida and FPL to: 1) reduce reliance on fossil fuels; 2) increase conservation activities; and 3) increase solar generation.

Volusia County: Supports the conversion, from fuel oil to natural gas, planned for FPL's repowering at the Sanford site.

4.2.6 SUITABILITY

Based upon the review of FPL's Ten-Year Site Plan and the related government and public comments, FPL's plan is **suitable** for planning purposes. FPL's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.3 GULF POWER COMPANY

Gulf Power Company (Gulf) relies heavily upon coal-fired generation capacity to meet its customers' electricity demand. Gulf currently has 11 coal-fired steam turbines (2,188 MW summer capacity), three fossil steam turbines (88 MW), and one combustion turbine (32 MW) on its system.

Gulf expects to install 532 MW of combined cycle at the existing Lansing Smith site in 2002. No site has yet been chosen for an additional 60 MW of combustion turbines to be added in 2006 (30 MW) and in 2007 (30 MW). Gulf also plans to retire a 32 MW combustion turbine at the Smith site in 2006. Prior to moving forward with the certification of Gulf's 532 MW of combined cycle unit under PSC rules 25-22.080, Gulf plans to issue a request for proposals in order to solicit possible cost-effective alternatives to self-construction of the combined cycle unit.

Gulf plans to meet short-term deficiencies in its reserve margin by making a series of power purchases over the next four years. Although the Southern Company's target reserve margin is 15%, Gulf's reserve margin at winter peak is well below 15% for each of the next four years. Therefore, Gulf is expected to be a net buyer of capacity from the Southern Company pool.

4.3.1 LOAD FORECAST

Gulf uses different methods to produce its short term forecasts (0-2 years) and intermediate/long term forecasts (3-25 years). Short term forecasts are the aggregate of district projections performed by district personnel for each revenue class, based upon a variety of forecasting methods. These methods are not specifically identified in Gulf's Ten-Year Site Plan. Gulf's intermediate and long-term forecasts utilize 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 the Company did not include any sensitivity analyses results (high and low band forecasts).

The absolute percent error in Gulf's 1993-1997 retail sales forecasts is 2.50%, which is lower than the 2.92% numeric average for the nine reporting utilities in the state with sufficient available historical data. Gulf's average forecast error for the same period is an under-forecast of 1.19%.

In Gulf's 1997 Gulf Ten-Year Site Plan, the 2005 customer forecast included 13,567 fewer customers than the 2005 forecast from the 1996 Ten-Year Site Plan. Gulf cited an update of the 1990 Census and fewer military installations in Gulf's service territory as the reasons for this adjustment. For the 1998 Ten-Year Site Plan, Gulf's population projections for the next ten years were revised and the most recent 2007 population forecast is 3.87% higher than that in its 1997 Ten-Year Site Plan.

The AAGR in Gulf's winter peak demand over the forecast period is 1.16%. This compares to a 4.59% AAGR in winter peak demand over the past 10 years. In response to a 1997 Commission inquiry regarding the substantial decrease in the forecasted demand growth rates compared to historical growth rates, Gulf stated that the stabilization of appliance saturation rates and appliance efficiencies are the main factors driving this low-growth forecast. Gulf utilized the Residential End-Use Energy Planning System (REEPS) to model winter demand for the residential sector, which accounts for such appliance saturations and efficiencies. Another factor contributing to a suppression in demand growth is residential conservation programs. Without the growth in such programs, the forecasted AAGR would have been 1.60%. Considering both the forecasted customer growth rate and historical trend in winter demand, the Commission believes that the REEPS model, as employed by Gulf, may underestimate the future winter demand growth rate.

4.3.2 CONSERVATION

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

Gulf does not have an interruptible service tariff or dispatchable load management on its system. Therefore, none of Gulf's 1998 winter and summer reserves are comprised of non-firm resources.

To date, Gulf's residential DSM programs have yielded cumulative demand and annual energy savings that are less than Gulf's residential demand and energy goals set by the Commission in 1994. Gulf does not have a numeric goal for C/I winter and summer peak demand or for C/I annual energy. Gulf's failure to meet some of its DSM goals appears to be due to delays in implementing newly-approved DSM programs such as the Advanced Energy Management (AEM) program. Gulf stated that its AEM program was delayed because the equipment was unavailable for installation in customer homes until August, 1997. Gulf was farther away from meeting its numeric residential DSM goals in 1997 than it was in 1996. The Commission will continue to monitor Gulf's DSM savings to determine whether Gulf meets its Commission-approved DSM goals for 1998. The Commission is due to set new DSM goals for Gulf in 1999.

4.3.3 FUEL FORECAST

Each year, the Southern Company develops a fuel price forecast for coal, distillate oil, and natural gas which extends through Gulf's planning horizon. The forecast was developed by a panel made up of the fuel procurement managers at each of the five operating companies, with input from Southern Company Services fuel staff and outside consultants. The panel developed a set of assumptions on the supply and demand factors which influence fuel prices. These assumptions along with current market prices were utilized to produce a spot market forecast for each fuel type.

Next, internal and external forecasts and assumptions were consolidated to derive the panel's base case forecast. The panel then developed sensitivities to the price forecasts based on seasonal supply and demand assumptions. Compared with last year's forecast, Gulf's forecasted prices at the end of the planning horizon fell by approximately 11% for coal, 18% for distillate oil, and 39% for natural gas. However, Gulf still expects coal prices to increase faster than EIA's long-term coal price forecast. For distillate oil, natural gas, and coal, Gulf's 2007 price forecasts are at or below the average 2007 price forecasts among the 12 reporting utilities.

4.3.4 ENVIRONMENTAL COMPLIANCE

Gulf's compliance strategy is a subset of the overall Southern Company compliance strategy. For the 1997-1999 period, Gulf plans to switch to a lower sulfur-content coal for Crist Units 6 and 7. Gulf expects this strategy to remain in force for the foreseeable future subject to any significant regulatory changes. Gulf's estimate of emissions is only for base case assumptions, and Gulf did not provide emissions estimates for sensitivities of fuel price or demand. This is probably because Gulf's system has minimal system fuel diversity. This trend is likely to continue until Gulf makes a greater effort to use more natural gas in its units.

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

4.3.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Apalachee Regional Planning Council: The Council cannot determine yet how Gulf's proposed 532 MW Lansing Smith unit may impact regional resources and facilities.

Bay County: No comment on Gulf's proposed expansion of the Lansing Smith site.

Florida Department of Community Affairs (DCA): DCA provided general comments on Gulf's proposed combined cycle at the Smith plant site.

Florida Department of Environmental Protection (DEP): DEP believes that Gulf's *Ten-Year Site Plan* is UNSUITABLE for two reasons: (1) the plan contains no environmental or unit design information for the proposed new Smith unit; and (2) Gulf plans to begin construction of the proposed Lansing Smith unit in June, 1999 although DEP certification takes an average of 14 months to complete. If Gulf submits an application by October, 1998, the utility could start construction of the proposed unit in December, 1999 at the earliest.

West Florida Regional Planning Council: Gulf's *Ten-Year Site Plan* is consistent with the Strategic Regional Policy Plan.

4.3.6 SUITABILITY

The Commission has some concern regarding the level of Gulf's reserve margin during the ten-year planning horizon. Gulf currently does not have sufficient firm commitments to purchase short-term capacity to meet forecasted needs. Gulf should indicate, with more certainty, the manner in which it plans to meet its capacity needs. However, because of Gulf's ability to rely on the Southern Company to meet any capacity deficiencies, Gulf's Ten-Year Site Plan is **suitable** for planning purposes.

4.4 TAMPA ELECTRIC COMPANY

Tampa Electric Company's (TECO) system currently has a total winter generating capacity of 3,629 MW. TECO's installed capacity is dominated by coal-fired generation, which alone exceeds load requirements. As a result, TECO's interchange consists primarily of wholesale energy and capacity sales to other utilities. Ten coal-fired units supply 3,172 MW of TECO's current system capacity. TECO has small amounts of capacity from five fossil steam units (215 MW total), four combustion turbines (204 MW total) and two diesel units (34 MW total). **Polk Unit 1**, a 250 MW integrated coal gasification combined cycle (IGCC) unit, was placed into service in 1996. TECO initially plans to use gasified coal to fuel the new unit, but future plans call for TECO to burn gasified petcoke. TECO's future generation expansion plans include the installation of three 180 MW natural gas-fired combustion turbine units at the Polk site, one each in 2003, 2004, and 2006. TECO currently plans to retire all five fossil steam units at the Hookers Point site (215 MW total) in 2003.

Until 1996, TECO's reliability criteria were a 20% winter reserve margin and an LOLP of 0.1 days per year. TECO reduced its winter reserve margin criteria to 15%. Because LOLP is calculated based on an estimate of assistance from other utilities, TECO was unsure of how much of this assistance would be available in the future. For this reason, TECO switched to a one percent Expected Unserved Energy (EUE) criterion. TECO's winter peak demand is driven primarily by low temperatures. TECO's base case winter load forecast assumes a low winter temperature of 31°F. TECO estimates that, on average, its winter reserves will decrease to zero if the temperature in the Tampa area reaches a low of 20°F. This has occurred one time since 1970.

TECO filed a revised Ten-Year Site Plan in August, 1998. Due to the late filing date, the review agencies did not have an opportunity to comment on the revised plan. The comments of these agencies, as well as those of the Commission, are restricted to TECO's original Ten-Year Site Plan filed in April, 1998.

4.4.1 LOAD FORECAST

TECO's energy forecast is the result of three separate forecasting methods. The most comprehensive of the three is the detailed end-use model. The results of two additional models (multiple regression and trend analysis) are blended with the end-use model to form the basis of the forecast. TECO's Ten-Year Site Plan does not identify how these models are reconciled. TECO's end-use forecast method takes into account a wide range of forecast assumptions. In addition to base case energy and demand forecasts, TECO constructed high and low band demand and energy forecasts, using explicit assumptions regarding customer growth, employment, per capita income, and electricity prices.

The absolute percent error in TECO's 1993-1997 retail sales forecasts is 2.88%, which is slightly lower than the numeric average for the nine of reporting utilities in the state with sufficient available historical data. TECO's base case energy sales forecasts and base case summer and winter demand forecasts are fairly consistent with those filed in its 1997 Ten-Year Site Plan for the entire planning horizon. TECO's winter demand has historically grown at a rate of 3.31%, but is forecasted to grow at 1.66% during the forecast period.

4.4.2 CONSERVATION

TECO 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. Non-firm resources comprise approximately 70% of TECO's 1998 winter reserves; these resources make up 58% of TECO's 1998 summer reserves. The Commission is concerned that a drop-off in customer participation in these programs would reduce forecasted DSM program demand savings, resulting in an unacceptably low reserve margin.

To date, TECO's residential DSM programs have yielded demand and energy savings that are less than the goals set by the Commission in 1994. TECO's commercial/industrial programs also fail to meet its C/I summer peak demand and energy goals. TECO has met only its C/I winter peak demand goals. TECO's failure to meet most of its DSM goals appears to be caused by a decline in participation in many of TECO's programs. The Commission will continue to monitor TECO's DSM savings, and the Commission is due to set new DSM goals for TECO in 1999.

4.4.3 FUEL FORECAST

TECO provided a base case price forecast for residual oil, distillate oil, natural gas, and coal. TECO also provided a high and low case price forecast for all fuels except coal. TECO relies upon sources such as the Energy Information Administration, American Gas Association, Resource Data International, Coal Markets Weekly, and Energy Ventures Analysis, Inc., to develop its base case fuel price forecasts. TECO developed its high case fuel price forecasts by increasing its base case residual oil, distillate oil, and natural gas prices by 10% each year until 2000. TECO also decreased its base case forecast for each year by 10% for these three fuel types until 2000 to develop its low case fuel price forecasts. After 2000, the high and low case fuel price forecasts were provided by consultants who furnished a company-specific fuel market analysis.

TECO believes that the coal / natural gas price differential will narrow during the planning horizon. TECO expects coal prices to escalate faster than EIA's long-term coal price forecast. In addition, TECO has forecasted prices for residual oil, distillate oil, and natural gas at least 14% less expensive than last year's forecast. TECO's 2007 price forecasts for distillate oil and natural gas are above the average 2007 price forecasts for these fuels among the 12 reporting utilities. The Commission continues to question whether TECO's distillate oil and natural gas price forecasts will materialize.

4.4.4 ENVIRONMENTAL COMPLIANCE

TECO is subject to compliance restrictions contained in both Phase I and Phase II of the 1990 Clean Air Act Amendments (CAAA). In 1997, TECO's compliance strategy was to defer additional scrubber capital investments as long as possible by using fuel switching, base loading the Polk

IGCC unit, and through purchases of allowances. However, TECO has filed for recovery through the ECRC of a large scrubber which will reduce SO_2 emissions from both Big Bend Units 1 and 2. This is TECO's current plan to achieve the reductions by year end 2000 which has been in their projections since at least 1995. TECO projects a noticeable drop in their NOx emissions beginning in year 2001 (from 12 pounds/kWh to 8 pounds/kWh). However, TECO has not yet explained how this reduction will be accomplished.

TECO relied on various sources to base its estimate of emission levels. Estimates of total tons emitted are more sensitive to energy forecast assumptions than to fuel price. Due to their dependence on older coal-fired generation, the emission rates of both TECO and Gulf are higher than those of FPL and FPC. TECO provided four sensitivities addressing emissions due to high/low fuel prices and high/low demand. Results are somewhat similar to FPL's but lack the advantage of significant use of natural gas on its system.

4.4.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Central Florida Regional Planning Council: The Council continues to monitor site certification activities for the Polk site. No further comment is necessary at this time.

Florida Department of Community Affairs (DCA): DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA has concerns over whether TECO plans to operate a proposed combustion turbine unit to serve baseload requirements. If TECO plans to use this unit addition for baseload needs, DCA would have TECO revise its Ten-Year Site Plan to replace the CT unit with extra, unneeded capacity in the form of a combined cycle unit solely to meet DCA policy requirements.

Florida Department of Environmental Protection (DEP): DEP provided no comments on TECO's *Ten-Year Site Plan*.

Polk County: TECO's *Ten-Year Site Plan* does not contain enough information to adequately assess the issues of compatibility, consistency, potential impacts on public facilities, and environmental concerns.

Southwest Florida Water Management District: No new facilities are planned in the district.

Tampa Bay Regional Planning Council: TECO's *Ten-Year Site Plan* is consistent with regional policies.

4.4.6 SUITABILITY

Based upon the review of TECO's Ten-Year Site Plan and the related government and public comments, TECO's plan is **suitable** for planning purposes. TECO's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.5 FLORIDA MUNICIPAL POWER AGENCY

The Florida Municipal Power Agency (FMPA) is an organization of 27 municipal electric utilities that jointly manage and operate electric utility operations. Ten members currently comprise the All-Requirements Project, meaning that FMPA has committed to plan for and supply all power requirements for these members. In 1999, FMPA plans to add the City of Lake Worth as an all-requirements member.

FMPA's existing generation facilities include two coal-fired steam turbines (237 MW summer capacity), an ownership share in FPL's St. Lucie 2 nuclear unit (74 MW), two combined cycle units (69 MW), and five combustion turbines (90 MW). FMPA and the Kissimmee Utility Authority jointly petitioned the Commission for approval to install a 250 MW combined cycle unit in 2001. A joint petition for Certification of Need for this unit was granted by the Commission on September 17, 1998. FMPA's plans also include construction of an 80 MW combustion turbine in 2007. Both of these units will be located at the Cane Island complex. The addition of three all-requirements members in 1998 and the planned addition of Lake Worth in 1999 is forecasted to increase net interchange from 362 GWh in 1997 to 2233 GWh by 2007.

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

FMPA plans resource additions on its system to meet a reliability criterion of 18% summer and winter peak reserve margin. Winter peak demand is driven primarily by low temperatures. FMPA's base case winter load forecast assumes an average low winter temperature of 31.1°F. FMPA estimates that its winter reserves will decrease to zero if the average temperature in all of its member cities reaches a low of 18°F.

4.5.1 LOAD FORECAST

FMPA used various econometric models to forecast sales by rate class, specific to each system or municipality, supplied by the All-Requirements Project. Time series and time trend modeling are also employed to forecast load. However, the forecast methods and designs are not described, except in the most general way. FMPA did not identify data sources. Some general economic and demographic assumptions are identified; however, applying generalized economic assumptions across all such systems may not represent the best information for these geographically-dispersed municipalities. No discussion regarding weather assumptions is included in the plan. FMPA did not provide sensitivity analyses based upon varying economic and demographic assumptions.

Insufficient historical forecast data exists to compare FMPA's forecast accuracy to other utilities in the state. However, FMPA's summer peak demand AAGR for the 1990-1997 period is 7.20% and its expected AAGR for the next ten years is 2.94%, which is very close to the numerical average of all reporting utilities in the state. In addition to this, FMPA's winter peak demand AAGR for the

1990-1997 period is only 1.71%, but it projects an increase of 4.13% for the next ten years. These summer and winter demand forecast discrepancies as compared to historical forecast growth rates are not documented.

4.5.2 CONSERVATION

Member utilities individually promote their own conservation programs with assistance from FMPA. Originally, the only FMPA members required to establish Commission-approved 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%).

4.5.3 FUEL FORECAST

FMPA's fuel forecast is a DRI September, 1997 analysis of fuel prices and current market projections based upon Standard & Poor's South Atlantic Regional fuel price forecast study. FMPA forecasted high, base, and low case scenarios for coal, natural gas, nuclear energy, residual oil, and distillate oil. For coal, FMPA applied DRI's annual coal price escalation in 1996 dollars plus 2.5% annual inflation rate to the 1997 actual delivered cost of spot coal purchases for the Stanton Energy Center. For oil, FMPA applied DRI's annual distillate oil price escalation in 1996 dollars plus 2.5% annual inflation rate to the 1997 Florida average delivered cost of residual and distillate oil. For natural gas, FMPA applied DRI's real annual natural gas commodity price escalation in 1996 dollars plus 2.5% annual inflation rate to the 1997 average spot prices. FMPA then added applicable FTS-2 transportation charges to the forecasted commodity prices to obtain the total delivered natural gas price forecast. For nuclear energy, FMPA escalated the average 1996 fuel price for nuclear energy at FPL's St. Lucie Plant and FPC's Crystal River Plant by 2.5% annually.

FMPA expects the price differential between coal and natural gas to narrow by 2007. Compared with last year's forecasts, FMPA's price forecasts fell by over 30% for several fuels. However, FMPA still expects prices for coal, residual oil, and distillate oil to escalate faster than EIA's long-term price forecast for these fuels. Except for nuclear energy, FMPA's 2007 price forecast for the remaining fuels is near or below the average 2007 price forecast among the 12 reporting utilities.

4.5.4 ENVIRONMENTAL COMPLIANCE

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

FMPA's response to the Commission's supplemental data requests did not provide annual emission levels. FMPA generally responded that environmental issues are appropriately addressed in the siting process, and that all board meetings addressing its expansion plans are public meetings.

4.5.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Central Florida Regional Planning Council: No comment on FMPA's *Ten-Year Site Plan.*

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

Florida Department of Environmental Protection (DEP): FMPA's *Ten-Year Site Plan* contains no significant environmental information on the proposed Cane Island Unit 3.

East Central Florida Regional Planning Council: FMPA's *Ten-Year Site Plan* contains very little information on possible environmental impacts of the proposed Cane Island 3 unit.

North Central Florida Regional Planning Council: FMPA's *Ten-Year Site Plan* is consistent with the goals and policies of the North Central Florida Regional Policy Plan.

Northeast Florida Regional Planning Council: The Council provided general comments on FMPA's *Ten-Year Site Plan.*

South Florida Regional Planning Council: FMPA's *Ten-Year Site Plan* is consistent with goal and policies of the regional plan. No new facilities are planned by FMPA within the region.

South Florida Water Management District: Has some issues with FMPA's plans to expand generation at the Cane Island site. These issues will be addressed during the site certification process.

Treasure Coast Regional Planning Council: FMPA's *Ten-Year Site Plan* does not propose additional generating capacity within the Treasure Coast Region. However, the Council seeks changes to regulatory policies that would urge the State of Florida and FMPA to: 1) reduce reliance on fossil fuels; 2) increase conservation activities; and 3) increase solar generation.

Withlacoochee Regional Planning Council: FMPA plans no new proposed power plant or transmission line improvements in the region.

4.5.6 SUITABILITY

Based upon the review of FMPA's Ten-Year Site Plan and the related government and public comments, FMPA's plan is **suitable** for planning purposes. FMPA's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.6 GAINESVILLE REGIONAL UTILITIES

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

GRU expects to be a net seller of interchange energy until the year 2000, although its firm and non-firm interchange transactions contribute only minimally to GRU's generation mix. Most of GRU's energy (86%) currently comes from the single coal-fired unit, **Deerhaven 2**, since more than half of GRU's natural gas-fired capacity is used strictly for peaking purposes. This trend is expected to continue into the future, because GRU does not forecast a need for any new generation additions during the next ten years. Under a high demand and energy forecast sensitivity, GRU forecasts a generic need for 110 MW of additional capacity in the year 2005.

GRU plans resource additions on its system to meet a reliability criterion of 15% summer and winter peak reserve margin. Winter peak demand is driven primarily by low temperatures. GRU's base case winter load forecast assumes a low winter temperature of 23°F. GRU estimates that, on average, its winter reserves will decrease to zero if the temperature in the Gainesville area reaches a level well below 0°F. This has not occurred in recorded history.

4.6.1 LOAD FORECAST

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

The absolute percent error in GRU's 1993-1997 retail sales forecasts is 2.24%, lower than the numeric average for nine of the reporting utilities in the state. GRU's average forecast error for the same period is -2.24%, which shows a tendency to under-forecast. Even though GRU's sources and methodology are appropriate, the utility has not updated its econometric models for the purpose of evaluating the 1998 Ten-Year Site Plan. Moreover, its population estimates obtained from Florida Population Studies are over a year old. The February, 1998 data from that publication would have been more appropriate for the purposes of this study.

GRU's summer peak demand forecast for the next ten years is projected to increase at an AAGR of 2.18%, which is lower than the 2.87% AAGR for the 1988-1997 period. GRU does not specifically address the rationale that justifies these lower growth rates, but its 1998 summer peak demand projection is consistent with the 1997 Ten-Year Site Plan forecast.

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

4.6.2 CONSERVATION

GRU is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). However, the utility plans to continue offering conservation programs. GRU does not have a load management program or an interruptible service program. GRU offers energy audits, home fix-up programs, natural gas displacement of electric space heating and water heating, commercial lighting efficiency and maintenance services, and public information and education programs. These programs are expected to reduce GRU's winter peak demand by an estimated 28 MW (6.5%) by 2007.

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

4.6.3 FUEL FORECAST

GRU provided a base, low, and high-price forecast for all fuel types except nuclear, to which GRU only provided a base-case forecast. GRU develops a two-part fuel forecast: short-term (2-3 years) and long-term (3-20 years). The short-term forecast considers current fuel contracts, industry conditions, competitive pressures and short-term inflation rates. The long-term forecast applies the escalation factors provided by the DOE's Annual Energy Outlook. GRU projected fuel transportation prices separately and independently of fuel commodity prices. High- and low-case sensitivities are determined by applying DOE escalation rates. Future nuclear energy prices were provided by FPC.

For each fuel price forecast, GRU expects prices at the end of the planning horizon to be less than the prices that GRU had expected last year. Coal and residual oil experienced the smallest and largest decreases with falls of approximately 6% and 33%, respectively. With the exception of natural gas, GRU's 2007 prices are expected to be at or below the average 2007 fuel prices among the reporting utilities.

4.6.4 ENVIRONMENTAL COMPLIANCE

GRU is not subject to SO_2 restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). GRU does not appear to be severely impacted (on a tonnage reduction basis) by Phase II of the CAAA.

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

GRU's response to the Commission's supplemental data requests indicates that total emissions are more sensitive to GRU's demand forecast than to its fuel price forecast.

4.6.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Environmental Protection (DEP): GRU plans no new generation.

North Central Florida Regional Planning Council: GRU's *Ten-Year Site Plan* is consistent with the goals and policies of the North Central Florida Regional Policy Plan.

4.6.6 SUITABILITY

Based upon the review of GRU's Ten-Year Site Plan and the related government and public comments, GRU's plan is **suitable** for planning purposes. GRU's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.7 JACKSONVILLE ELECTRIC AUTHORITY

Jacksonville Electric Authority's (JEA) generation mix consists of 1,476 MW of coal fired capacity from its 80% share of two units at **St. John's River Power Park** and **Scherer Unit 4** near Macon, Georgia. Generation from gas-and oil-fired steam units totals 1,078 MW, and gas turbine units supply 440 MW.

JEA plans to construct a 168 MW combustion turbine (CT) at the Kennedy site in 2000, three 168 MW CT's in 2001, repower Northside 1 and 2 in 2002, and construct a 168 MW CT in each of the years 2004 and 2005. JEA's also intends to retire Southside 4 and shutdown Kennedy 10 in 2000, and retire Southside 5 in 2003. A site for the three CT's in 2001 has yet to be formally identified.

JEA also plans to purchase seasonal capacity during 1999, 2000, 2001, 2006, and 2007. JEA has entered into a partnership with the Municipal Electric Authority of Georgia and the South Carolina Public Service Authority in forming The Energy Authority (TEA). TEA will work on behalf of JEA as its power marketing group to meet purchased power needs.

JEA plans resource additions on its system to meet a reliability criterion of 15% summer and winter peak reserve margin. Winter peak demand is driven primarily by low temperatures. JEA's base case winter load forecast assumes a low winter temperature of 23°F. JEA estimates that, on average, its winter reserves will decrease to zero if the temperature in the Jacksonville area reaches a low of 15°F. This has occurred four times since 1970.

4.7.1 LOAD FORECAST

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

The absolute percent error in JEA's 1993-1997 retail sales forecasts is 3.95%, or more than 1% higher than the statewide average of 2.92%. JEA's average forecast error for the same period is -3.63%, which shows a tendency to under-forecast. JEA's 1998 Ten-Year Site Plan shows a 2.94% historical AAGR for winter peak demand. However, JEA's winter peak demand forecast shows a 5.50% AAGR. Thus, JEA's forecast is inconsistent with historical growth rates, but JEA does not provide a detailed explanation as to why this is the case. Moreover, the summer peak demand forecast shows an AAGR of 3.52%, which is higher than the historical summer peak AAGR of 2.92%.

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

4.7.2 CONSERVATION

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

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

4.7.3 FUEL FORECAST

JEA relied upon its existing long-term contracts for its short-term forecasts, and relied upon outside forecasting groups for the remainder of the planning horizon. JEA provided high, base, and low case price forecasts for the following fuels: coal at St. Johns River Power Park (SJRPP); coal at Scherer Unit 4; petroleum coke; residual oil; distillate oil; and natural gas.

JEA's price forecast for SJRPP coal is based upon the expected market price of eastern coal. JEA expects coal from eastern U.S. sources to increase at 2% per year during the planning horizon because coal production capability should exceed demand. JEA expects the average cost of coal for Scherer Unit 4 to increase at 0.8% per year during the planning horizon, because JEA believes it can extract aggressive cost reductions as long term contracts expire. Moreover, JEA expects coal at Scherer Unit 4 to be approximately 10.5% less at the end of the planning horizon as compared to last year's forecast. Because petroleum coke is less expensive than coal, JEA blends petroleum coke with coal at SJRPP to produce fuel savings. JEA expects petroleum coke to track increases in the market price of eastern coal closely, because the two fuels are close substitutes for each other.

Due to increases in the supply of crude oil and natural gas, JEA expects prices for residual oil, distillate oil, and natural gas to increase at or slightly above the projected long-term inflation rate. JEA expects residual and distillate oil prices to decline in the beginning of the planning horizon due to increased non-OPEC supply before rebounding at a 2.6% per year pace for the remainder of the planning horizon. Although JEA also expects natural gas supply to increase steadily throughout the planning horizon, JEA expects natural gas prices to increase at approximately 3% per year. As compared with last year's forecast, natural gas prices should be slightly more than 8% less at the end of the planning horizon. The expected continued construction of combined cycle and combustion turbine units is expected to cause demand for natural gas to grow faster than supply.

JEA expects that the coal and natural gas price differential should widen during the planning horizon. Finally, JEA's expected 2007 coal and natural gas prices are greater than the average 2007 price among the 12 reporting utilities for these fuels.

4.7.4 ENVIRONMENTAL COMPLIANCE

JEA is not subject to SO_2 restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). The extent which JEA is impacted by Phase II of the CAAA is a strategic concern especially with the repowering project at their Northside facility. Emission reductions of about 10% are expected through the application of Best Available Control Technology (BACT). However, as JEA indicates, BACT for future projects is subject to change as regulations and interpretations of the regulations change.

JEA's response to the Commission's supplemental data requests indicated that low load on its system is more likely to decrease emissions in the long term. Sensitivities showing emissions due to high and low fuel prices have a mixed result. Low fuel prices are expected to increase JEA's emissions beyond 2002 relative to high fuel prices and the base case. This trend is consistent with JEA's move towards increased use of solid fuels.

4.7.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

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

Florida Department of Environmental Protection (DEP): JEA plans no new units which would require certification.

Northeast Florida Regional Planning Council: The Council provided general comments on JEA's *Ten-Year Site Plan*.

4.7.6 SUITABILITY

Based upon the review of JEA's Ten-Year Site Plan and the related government and public comments, JEA's plan is **suitable** for planning purposes. JEA's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.8 KISSIMMEE UTILITY AUTHORITY

The Kissimmee Utility Authority's (KUA) electric system consists of eight gas- and oil-fired internal combustion units (19 MW) and one combined cycle unit (55 MW). KUA has a 50% joint ownership with FMPA of Cane Island Unit 1, a gas-fired combustion turbine (20 MW), and Unit 2, a combined cycle unit (60 MW). KUA also has an ownership interest in the following generating facilities: FPC's Crystal River nuclear plant (6 MW), OUC's Stanton Energy Center steam turbine Unit 1 (21 MW), and OUC's Indian River combustion turbine units A and B (11 MW). In addition, KUA currently purchases 55 MW of firm capacity from other utilities.

KUA will need additional capacity by the year 2001 to maintain its 15% summer and winter reserve margin criteria. As a result, KUA, along with FMPA, jointly petitioned the Commission for a determination of need for **Cane Island Unit 3**, a 250 MW combined cycle unit with an in-service date of June 1, 2001. The Commission granted the joint need petition on September 17, 1998. In addition to the proposed new unit, KUA also plans to retire 13 MW of gas-fired internal combustion capacity at the Hansel site – Unit 8 in 1998 and Units 14-18 in 2002.

4.8.1 LOAD FORECAST

KUA utilizes econometric forecast models that measure changes in electricity usage per customer class as a function of temperature, population, and income. KUA's economic and population forecasts were obtained from the Bureau of Economic and Business Research (BEBR) and normal weather conditions were assumed for the load forecast model. KUA's methodology and assumptions are appropriate for the purposes of these projections.

There is insufficient data to measure the absolute percent error of KUA's 1993-1997 retail sales forecasts. KUA's base-case summer peak demand forecast for the period of 1998-2007 shows a 4.28% average annual growth rate (AAGR), while its historical growth for the period of 1988-1997 was 6.10%. Similarly, the Company's base-case winter peak demand forecast for 1998-2007 shows a 4.32% AAGR, but its historical growth rate for 1988-1997 was 5.26%. KUA acknowledges these lower forecasted rates and states that previous attempts to model peak load have been unsuccessful due to a lack of data, but it does not state a specific justification for these lower projections.

KUA's base-case net energy for load (NEL) forecast for 1998-2007 is expected to increase by an AAGR of 4.12%, while its historical growth rate for the period of 1988-1997 was 6.60%. The Company states that a 1997 econometric model did not yield significant NEL accuracy, but KUA now uses a 95% efficiency factor methodology that had been a more accurate predictor of total system sales in previous years. It should be noted that KUA has presented a good summary of base-, high-, and low-case NEL forecasts. However, as in the case of peak demand, there is no specific justification for discrepancies between historical and forecasted data.

Overall, KUA has submitted a comprehensive load forecast with good background data and assumptions. However, the Commission encourages KUA to provide the necessary explanations underpinning its demand and energy sales forecasts.

4.8.2 CONSERVATION

KUA is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). However, the utility plans to continue offering conservation programs. In addition to energy audits, KUA offers a residential load management program. This program is expected to reduce KUA's winter peak demand by an estimated 14 MW (5%) in 2007.

4.8.3 FUEL FORECAST

KUA's fuel forecast is a DRI September, 1997 analysis of fuel prices and current market projections based upon Standard & Poor's South Atlantic Regional fuel price forecast study. KUA forecasted high, base, and low case scenarios for coal, natural gas, nuclear energy, residual oil, and distillate oil. For coal, KUA applied DRI's annual coal price escalation in 1996 dollars plus 2.5% annual inflation rate to the 1997 actual delivered cost of spot coal purchases for the Stanton Energy Center. For oil, KUA applied DRI's annual distillate oil price escalation in 1996 dollars plus 2.5% annual inflation rate to the 1997 Florida average delivered cost of residual and distillate oil. For natural gas, KUA applied DRI's real annual natural gas commodity price escalation in 1996 dollars plus 2.5% annual inflation rate to the 1997 average spot prices. KUA then added applicable FTS-2 transportation charges to the forecasted commodity prices to obtain the total delivered natural gas price forecast. For nuclear energy, KUA escalated the average 1996 fuel price for nuclear energy at FPL's St. Lucie Plant and Florida Power's Crystal River Plant by 2.5% annually.

KUA expects that the coal and natural gas price differential should slightly narrow during the planning horizon. Moreover, KUA expects coal, residual oil, and distillate oil to escalate faster during the planning horizon than EIA's long-term price forecast for these fuels. KUA has forecasted its 2007 prices for coal, nuclear energy, and distillate oil as higher than the average 2007 price forecast for these fuels among the 12 reporting utilities.

4.8.4 ENVIRONMENTAL COMPLIANCE

KUA is not subject to SO_2 restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA), and does not appear to be severely impacted (on a tonnage reduction basis) by Phase II of the CAAA. KUA is expecting to add new natural gas fired generation and the emissions will increase proportionally for some pollutants. If KUA retires old diesel units within the next 2-3 years as their plan suggests, then there will decreases in VOC and NOx emissions.

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

4.8.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Central Florida Regional Planning Council: No comment on KUA's *Ten-Year Site Plan*.

Florida Department of Community Affairs (DCA): DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA has concerns over whether KUA plans to operate a proposed combustion turbine unit to serve baseload requirements. If KUA plans to use this unit addition for baseload needs, DCA would have KUA revise its Ten-Year Site Plan to replace the CT unit with extra, unneeded capacity in the form of a combined cycle unit solely to meet DCA policy requirements.

Florida Department of Environmental Protection (DEP): KUA's *Ten-Year Site Plan* contains sufficient information to indicate no major environmental or land use impediments to certifying the proposed Cane Island Unit 3.

South Florida Water Management District: Has some issues with KUA's plans to expand generation at the Cane Island site. These issues will be addressed during the site certification process.

4.8.6 SUITABILITY

Based upon the review of KUA's Ten-Year Site Plan and the related government and public comments, KUA's plan is **suitable** for planning purposes. KUA's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.9 CITY OF LAKELAND

The City of Lakeland (LAK) owns 654 MW of electric generation, including five gas- and oil-fired steam turbine units (271 MW), one coal-fired unit (197 MW), one gas-fired combined cycle unit (124 MW), and two gas-fired combustion turbine units (62 MW). LAK's next planned capacity addition is **McIntosh Unit 5**, a 245 MW gas-fired combustion turbine unit due to enter service in June, 1999. In May, 2003, LAK plans to place into service **McIntosh Unit 4**, a 185 MW fluidized bed coal unit. The latter unit is expected to be built with assistance from the U.S. Department of Energy's Clean Coal Technology Program. Concurrent with the planned addition of McIntosh Unit 5 in 1999, LAK expects to retire 66 MW of steam-fired capacity.

LAK plans resource additions on its system to meet a reliability criterion of 15% summer and winter peak reserve margin. Winter peak demand is driven primarily by low temperatures. LAK's base case winter load forecast assumes a low winter temperature of 30°F. LAK estimates that, on average, its winter reserves will decrease to zero if the temperature in the Lakeland area reaches a low of 19°F. This has not occurred since before 1970.

4.9.1 LOAD FORECAST

LAK's load forecast methodology includes several regression models measuring population, accounts, sales, net energy for load (NEL), and peak demand. LAK's load forecast is built from three data sources: Polk County population projections from the 1997 Annual Bureau of Economic and Business Research (BEBR) forecast; the number of residential accounts in LAK's service area; and the results of LAK's 1994 Appliance Saturation Survey.

The absolute percent error in LAK's 1993-1997 retail sales forecasts is 3.47%, or about 0.5% higher than the numeric average for the other reporting utilities in the state. LAK's average forecast error for the same period is -3.21%, which shows a tendency to under-forecast.

LAK's 1998 winter peak demand forecast is projected to increase at an AAGR of 2.93%, which is lower than the 3.98% AAGR for the 1988-1997 period and the numeric average of 3.43% for all reporting utilities in the state. LAK's 1998 winter peak demand forecast is lower than its 1997 forecast by an average of 27 MW per year. The utility neither accounted for the lower average growth rates, nor for the current demand adjustment from last year's Ten-Year Site Plan.

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

4.9.2 CONSERVATION

LAK is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). 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 highpressure sodium outdoor lighting). These programs are expected to reduce LAK's winter peak demand by an estimated 94 MW (11%) in 2007.

4.9.3 FUEL FORECAST

LAK performed fuel price forecasts under low, base, and high price scenarios for coal, natural gas, residual oil, distillate oil, petroleum coke, and refuse-derived fuel. Commodity and transportation components of coal and natural gas were forecasted independently, then combined to arrive at the delivered price of each fuel. LAK assumed that each fuel's future price would be a combination of spot and contract prices. For its forecast of residual and distillate oil prices, LAK first projected future crude oil prices, then assumed that both residual and distillate oil prices would fluctuate with crude oil prices. Similarly, LAK assumed that petroleum coke prices would fluctuate with coal prices. The negative price of refuse-derived fuel indicates that LAK receives revenue through tipping fees by accepting the refuse from collection entities. The negative price of refuse-derived fuel is calculated based upon tipping fees established by the City of Lakeland, the amount of refuse collected, and the refuse's heating value.

LAK expects that the differential between coal and natural gas prices should widen slightly during the planning horizon. Compared with last year's forecast, LAK's forecast of prices for its four fuels in 2007 could be at least 11.6% less expensive. LAK's 2007 fuel price forecasts are below the average 2007 price forecast among the reporting utilities.

LAK also projected that residual oil and distillate oil will escalate at approximately the same rate from current levels during the planning horizon. Also, natural gas, coal, petroleum coke, and refuse-derived fuel will maintain approximately their same margins during the next ten years.

4.9.4 ENVIRONMENTAL COMPLIANCE

LAK is not subject to SO_2 restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA), and does not appear to be severely impacted (on a tonnage reduction basis) by Phase II of the CAAA. LAK's response to the Commission's supplemental data request reflects the impact of the proposed fluidized bed project coming on line in 2003. They anticipate an increase in all pollutant emission rates (ranging from 23% to 50%) except for particulates. They project annual dust emission rates will decrease about 95% over the study period. LAK generally stated that environmental issues are appropriately addressed in the siting process and in public board meetings.

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

4.9.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Central Florida Regional Planning Council: No comment on LAK's *Ten-Year Site Plan*.

Florida Department of Community Affairs (DCA): DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA is concerned because of LAK's plan to operate a proposed combustion turbine unit to serve baseload requirements. DCA would have LAK revise its Ten-Year Site Plan to replace the CT unit with extra, unneeded capacity in the form of a combined cycle unit solely to meet DCA policy requirements.

Florida Department of Environmental Protection (DEP): DEP provided general discussion of LAK's proposed new unit, McIntosh Unit 5.

Polk County: LAK's *Ten-Year Site Plan* does not contain enough information to adequately assess the issues of compatibility, consistency, potential impacts on public facilities, and environmental concerns.

Southwest Florida Water Management District: LAK has proposed sites which lie within the Southern Water Use Caution Area (SWUCA). The Floridian aquifer within this area has been severely stressed by past excessive withdrawals, and future access to water in this area may be restricted.

4.9.6 SUITABILITY

Based upon the review of LAK's Ten-Year Site Plan and the related government and public comments, LAK's plan is **suitable** for planning purposes. LAK's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.10 ORLANDO UTILITIES COMMISSION

Orlando Utilities Commission's (OUC) existing generation mix consists primarily of coal-fired capacity. The coal-fired **Stanton Units 1 and 2** supply nearly 900 MW of OUC's system capacity. Other capacity comes from four fossil steam turbines (755 MW), four combustion turbines (246 MW), an ownership share in FPC's Crystal River Unit 3 (13 MW), and an ownership share in FPL's St. Lucie Unit 2 (52 MW).

OUC has entered into a series of participation agreements in which the Florida Municipal Power Agency and the Kissimmee Utility Authority are conveyed undivided ownership interests in the Stanton and Indian River units which were constructed and are operated by OUC. OUC's dual reliability criteria of 15% summer and winter reserve margin and a 0.5% expected unserved energy (EUE) are not violated during the planning horizon, even though no additional electric generation is identified in OUC's Ten-Year Site Plan.

OUC'S winter peak demand is driven primarily by low temperatures. OUC's base case winter load forecast assumes a low winter temperature of 27°F. Because of its relatively high reserve margin, OUC estimates that its winter reserves will never decrease to zero regardless of how low the temperature in the Orlando area drops. OUC estimates that its system peak will not increase any higher once the low temperature reaches 22°F.

4.10.1 LOAD FORECAST

OUC uses an end-use/econometric load forecasting methodology that has been enhanced to produce loads for each hour of the year in chronological order. The Company developed a typical weather year and adjusted the data set to the model. In addition to this, the utility used projections that rely upon OUC and Orange County data developed through a regional economic-demographic model, entitled REGIS, which generates population, households, income, and employment projections. OUC's methodology and assumptions are appropriate for the purposes of this study.

There is insufficient data to measure the absolute percent error of OUC's 1993-1997 retail sales forecasts. OUC's base-case or most likely case summer peak demand forecast for the period of 1998-2007 shows a 2.72% average annual growth rate (AAGR), while its historical growth for the period of 1988-1997 was 3.01%. Similarly, the Company's most likely case winter peak demand forecast for 1998-2007 shows a 2.30% AAGR, but its historical growth rate for 1988-1997 is 1.91%. Given the growth of OUC's service territory, these projections are consistent with historical trends.

Similarly, OUC's most likely case net energy for load (NEL) forecast for the period of 1998-2007 shows a 3.05% AAGR, while its historical data for the period of 1988-1997 shows a 2.96% AAGR. The slight increase is mostly due to higher forecasted utility use and losses rather than higher forecasted retail energy for load.

Overall, OUC's 1998 Ten-Year Site Plan shows a satisfactory load forecast that is supported by a sound methodology, reasonable assumptions, and results that are consistent with historical trends.

4.10.2 CONSERVATION

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

In 1995, the Commission set OUC's DSM goals for residential summer and winter demand, as well as commercial / industrial summer peak demand. Currently, demand and energy savings from OUC's DSM programs are not meeting any of its Commission-approved goals. One reason is that OUC's residential demand goals contemplated the addition of a new load management program. However, OUC's evaluation of the economics of load management for its system concluded that the program would not be cost-effective.

4.10.3 FUEL FORECAST

OUC has provided fuel price forecasts under low, base, and high price scenarios for coal, natural gas, residual oil, nuclear energy, methane gas, petroleum coke, and refuse-derived fuel. OUC has used several forecasting methods when projecting fuel prices during the planning horizon. For coal and natural gas, OUC believes that fuel prices should moderately increase because supply growth should match demand growth. For residual oil, OUC believes that the price is largely dependent upon the price of West Texas Intermediate crude oil which is expected to increase 3% annually during the planning horizon. Nuclear energy is expected to increase at 2.5% which is EIA's anticipated general inflation rate for all goods and services. For petroleum coke and refuse-derived fuel burned at LAK's McIntosh Plant, OUC has used LAK's price forecast for the two fuels. The methane gas forecast is based upon a long term fixed rate contract that OUC has recently signed with DTE Biomass Energy to supply Stanton Units 1 and 2.

The coal and natural gas price differential should slightly widen during the planning horizon. Despite coal and nuclear energy representing over 90% of its load requirements by the end of the planning horizon, OUC's 2007 coal and nuclear energy price forecasts are the highest and tied for highest, respectively, among the reporting 12 utilities. Moreover, OUC's price forecasts for coal, residual oil, natural gas, and nuclear energy are greater than the average 2007 price forecast for these fuels among the 12 reporting utilities.

4.10.4 ENVIRONMENTAL COMPLIANCE

OUC is not subject to SO_2 restrictions contained in Phase I of the Clean Air Act Amendments (CAAA). There are no new projects which would significantly affect OUC's emissions relative to last year.

4.10.5 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Consumer Affairs (DCA): No comments provided since OUC plans no new generation.

Florida Department of Environmental Protection (DEP): OUC plans no new generation during the planning horizon.

East Central Florida Regional Planning Council: OUC plans no new generation within the region.

Southwest Florida Water Management District: No new facilities are planned in the district.

4.10.6 SUITABILITY

Based upon the review of OUC's Ten-Year Site Plan and the related government and public comments, OUC's plan is **suitable** for planning purposes. OUC's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.11 CITY OF TALLAHASSEE

The City of Tallahassee's (TAL) existing generation mix consists primarily of natural gas-fired units and interchange capacity purchases. TAL has five fossil steam turbines (412 MW), four combustion turbines (56 MW), three hydroelectric units (11 MW), and an ownership share in FPC's Crystal River Unit 3 (11 MW). TAL is currently negotiating to divest its 1.333% ownership interest in FPC's Crystal River Unit 3 and decommission its trust account balance to FPC. Negotiations are expected to be completed by September 30, 1998. TAL will purchase replacement electric capacity and energy equal to the Crystal River Unit 3 interest (11.4 MW) from FPC. In 1997, TAL relied upon purchased power to meet approximately 28% of its load requirements. This is expected to continue until the year 2000.

On May 19, 1997, the Commission approved TAL's petition to determine the need for a 233 MW gas combined cycle unit at the Purdom site. The addition of this unit, along with the early retirement of two combustion turbines at the same location, results in a net summer capacity increase of 187 MW in 2000. As a result, TAL's natural gas-fired generation is forecasted to increase to approximately 96% of load requirements by 2007. The addition of Purdom Unit 8 is expected to also cause TAL to become a net seller of electricity, whereas it has been a net buyer in past years.

TAL plans resource additions on its system to meet a reliability criterion of 17% summer peak reserve margin. Winter peak demand is driven primarily by low temperatures. TAL's base case winter load forecast assumes a low winter temperature of 22°F. TAL estimates that, on average, its winter reserves will decrease to zero if the temperature in the Tallahassee area reaches a level below 0°F. This has not occurred since before 1970.

4.11.1 LOAD FORECAST

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

The absolute percent error in TAL's 1993-1997 retail sales forecasts is 2.96%, or slightly higher than the 2.92% numeric average for the state's reporting utilities. TAL's average forecast error for the same period is -2.38%, which shows a tendency to under-forecast.

TAL's summer peak demand forecast for the next ten years is projected to increase at an AAGR of 1.99%, which is lower than the 3.12% AAGR corresponding to the 1988-1997 period and the 2.69% numerical average for all of the state's reporting utilities. TAL does not specifically address the rationale for these decreases, but its 1998 summer peak demand forecast is consistent with the one included in its 1997 Ten-Year Site Plan. TAL continues to do a commendable job of addressing load forecast sensitivities, especially the planning needs that account for reserve margins and the timing of new resource additions.

4.11.2 CONSERVATION

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

4.11.3 FUEL FORECAST

Except for nuclear fuel, TAL provided a price forecast for all fuel types, including high and low price scenarios. TAL's base natural gas price forecast was developed internally in December, 1995. The high and low natural gas forecasts were developed by maintaining the relative spread between high, base, and low prices as projected in ICF Resources, Inc.'s most recent natural gas price forecast prepared for TAL. ICF Resources's most recent price forecast for residual oil, distillate oil, and coal price forecasts were also used.

TAL did not make any changes to its forecasts for residual oil, distillate oil, and coal. However, TAL expects natural gas prices to be approximately 8% higher at the end of the planning horizon as compared with last year's forecast. Also, TAL expects prices for residual oil, distillate oil, coal, and natural gas to increase faster than EIA's long-term price forecasts for these fuels. TAL has forecasted the highest 2007 prices for residual oil and distillate oil among the 12 reporting utilities. In addition, except for natural gas, TAL's 2007 price forecasts for the remaining fuels are significantly above the average 2007 price forecast among the 12 reporting utilities.

In its need determination for Purdom Unit 8 (Order No. PSC-97-0659-FOF-EM), TAL assured the Commission that it could obtain natural gas supply for the proposed unit at a cost significantly less than that paid by most other utilities in Florida. The Commission approved TAL's self-build option for Purdom Unit 8 based partially on the projected fuel savings. If TAL cannot obtain natural gas supply for the proposed unit at these prices, then the overall cost effectiveness of Purdom Unit 8 compared to other available options may be jeopardized.

4.11.4 ENVIRONMENTAL COMPLIANCE

TAL is not subject to SO_2 restrictions contained in Phase I of the Clean Air Act Amendments (CAAA). Any new natural gas-fired generation will impact TAL's compliance with Phase II of the CAAA. Projected emissions reflect the addition of Purdom Unit 8, a new natural gas-fired combined cycle unit. All emissions are forecasted to initially decline, then begin to grow reflecting TAL's replacement of interchange purchases with new generation from its own units.

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Apalachee Regional Planning Council: All issues of regional concern resulting from the proposed new Purdom Unit 8 have been addressed.

Florida Department of Consumer Affairs (DCA): DCA participated in the Site Certification process for Purdom Unit 8 and, therefore, has no further comments.

Florida Department of Environmental Protection (DEP): Purdom Unit 8 was certified in 1998. No additional sites are planned at this time.

4.11.5 SUITABILITY

Based upon the review of TAL's Ten-Year Site Plan and the related government and public comments, TAL's plan is **suitable** for planning purposes. TAL's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

4.12 SEMINOLE ELECTRIC COOPERATIVE

1998

Seminole Electric Cooperative (SEC) provides full requirements to its eleven distribution system members. SEC currently relies on owned and purchased capacity resources to meet its members' needs. SEC is obligated to serve all load up to specified capacity commitment levels and provide adequate reserves. SEC's partial requirements providers serve all load above the specified capacity commitment levels. By 2007, SEC expects to introduce natural gas into its generation mix with a combined cycle unit (451 MW) and ten combustion turbines (1500 MW). Although currently non-existent within its generation mix, SEC expects natural gas to represent 22% of its native generation in 2007.

SEC's generating resources include two 625 MW coal-fired steam turbine units and a 15 MW ownership in Florida Power Corporation's (FPC) Crystal River 3 nuclear unit. SEC purchases full or partial requirements power from FPC, Florida Power & Light Company (FPL), Tampa Electric Company (TECO), Jacksonville Electric Authority (JEA), and Gainesville Regional Utilities (GRU). Though not reflected in its Ten-Year Site Plan, SEC has decided to terminate its Partial Requirements agreement with FPL effective January 1, 1999.

SEC plans to diversify its generation resources with the addition of Hardee Power Station Unit 3 in January, 2002 (451 MW combined cycle unit) and ten combustion turbines (1500 MW) by 2006. Additionally, in response to a request for proposals in 1997, SEC entered into a contract with FPC for 150 MW of firm capacity for the period 2000 through 2002 and an additional 150 MW for the period 2001 through 2002. SEC is also evaluating other bids for up to 1000 MW of capacity and energy to replace existing contracts.

On January 1, 2003, SEC's purchase contract of 145 of capacity from TECO's Big Bend 4 unit expires. Though this contract may be replaced at SEC's option with an additional 145 MW CT at the Hardee site, SEC has indicated it does not anticipate exercising this option.

Based on its 15% reserve margin criterion, SEC's capacity resources appears to be questionably adequate for reliability purposes. As proposed, SEC's system will be at or below a 15% winter reserve margin in the year 1999 and 2003. More importantly, system reliability is dependent on SEC securing 150 MW of capacity by the year 2000 to offset the termination of the existing FPL PR agreement. SEC's plan does not address the specifics of this resource, rather SEC merely declares that it is in the process of firming up seasonal short term purchases to meet this requirement.

SEC's winter peak demand is driven primarily by low temperatures. SEC's base case winter load forecast assumes a low winter temperature ranging from 19°F in Tallahassee to 37°F in Ft. Myers. SEC estimates that its winter reserves will decrease to zero if the temperature reaches a low ranging from 3°F in Tallahassee to 21°F in Ft. Myers. This has not occurred since before 1970.

4.12.1 TREATMENT OF HARDEE POWER STATION

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

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

Traditionally, SEC has only used 1% expected unserved energy (EUE) as its sole reliability criterion due to its heavy reliance on other utilities to supply its full requirements and partial requirements capacity needs. This typically resulted in large reserve margins. However, beginning in the year 2000, reserve margin begins to be the driving reliability criterion. Accordingly, SEC has adopted a dual reliability criteria of 15% system peak reserve margin and 1% EUE.

When determining system reliability, SEC estimates the number of hours and amount of capacity it expects to purchase from Hardee Power Station based on SEC's historical use of this capacity. It appears that SEC's calculation of EUE properly accounts for its use of capacity from Hardee Power Station. However, if the state experiences another extended hard freeze, such as during the Christmas of 1989, a critical issue may arise on whether SEC or TECO has first call on Hardee Power Station's capacity.

4.12.2 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 began its analysis with separate, individual load forecasts for each member cooperative, and these were then combined to yield the final forecast results. Within the analysis, SEC provided detailed statistical accounts of alternate load forecasts based upon different economic and weather scenarios, including forecast models for residential, commercial, and other consumer classes.

The absolute percent error in SEC's 1993-1997 retail sales forecasts is 3.14%, which is one of the highest among all reporting utilities. SEC's average forecast error for the same period is an over-forecast of 1.09%. SEC's winter peak demand forecast for the next ten years is projected to increase at an AAGR of 3.61%, which is lower than the 5.26% AAGR for the 1988-1997 period. SEC justifies the difference by addressing Florida's population growth rate, which recently slowed down to below 2%. In addition to this, the cooperative's residential growth membership has also slowed down considerably, and commercial consumer growth has not fully recovered from its early 1990's setback. SEC's 1998 winter peak demand forecast is consistent with its 1997 Ten-Year Site Plan.

Overall, SEC's load forecast criteria are adequate. The models employed are comprehensive and include data sources that have been properly documented.

4.12.3 CONSERVATION

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

Some of SEC's member utilities have load management programs which 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.

4.12.4 FUEL FORECAST

SEC provided a base case price forecast for coal, distillate oil, residual oil, natural gas, and nuclear energy. SEC also provided high and low price scenarios for each fuel, except nuclear energy. SEC's base case fuel price forecasts assume continued technological improvements should allow the growth in fuel supply to exceed growth in fuel demand. Thus, annual increases in fuel prices should be kept at or below increases in the overall price level. If these technological improvements should end, then SEC's high case scenarios forecast fuel prices rising at a slightly faster rate than the base case. On the other hand, if the pace of technological improvements should accelerate, then SEC's low case scenarios forecast fuel prices rising at a slightly slower rate than the base case.

SEC expects that the coal and natural gas price differential should widen during the planning horizon. SEC expects its 2007 price forecast for natural gas and nuclear energy to be greater than the average 2007 price forecast among the 12 reporting utilities for these fuels. For residual oil, distillate oil, and coal, SEC expects its 2007 price forecast to be less than the average 2007 price forecast.

4.12.5 ENVIRONMENTAL COMPLIANCE

SEC is not subject to SO_2 restrictions contained in Phase I of the CAAA. SEC does not appear to be severely impacted (on a tonnage reduction basis) by Phase II of the CAAA. Natural gas-fired unit additions will contribute to Phase II SO_2 compliance flexibility. However, this may not be an issue for SEC because it projects having approximately 200 to 2,000 excess SO_2 allowances annually.

SEC elected to be subject to the CAAA earlier than the Phase II date of January 1, 2000. Response to the Commission's supplemental data requests showed that not all of SEC's emission rates are projected to decline gradually as was the case in 1997. Their NOx emission rate will decrease about 13% over the study period. The reported CO_2 emissions are significantly higher than last year's because SEC began using consistent emission estimating factors for all reports they send to the various federal and state agencies. If last year's factors had been used again, we would not see a significant change relative to last year's CO_2 emission estimates.

4.12.6 STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Central Florida Regional Planning Council: The Council continues to monitor site certification activities for the Hardee site. No further comment is necessary at this time.

Florida Department of Community Affairs (DCA): DCA believes that combined cycle units are more suited for baseload needs than combustion turbine units. DCA has concerns over whether SEC plans to operate its proposed combustion turbine units to serve baseload requirements. If SEC plans to use these unit additions for baseload needs, DCA would have KUA revise its Ten-Year Site Plan to include combined cycle units solely to meet DCA policy requirements.

Florida Department of Environmental Protection (DEP): DEP notes that SEC will need to extend its Prevention of Significant Deterioration (PSD) permit by January, 2000 for Hardee Unit 3.

East Central Florida Regional Planning Council: SEC plans no new generation within the region.

Hardee County: SEC's *Ten-Year Site Plan* substantially complies with local codes.

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

Northeast Florida Regional Planning Council: The Council provided general comments on SEC's *Ten-Year Site Plan*.

South Florida Water Management District: SEC plans no transmission lines or other facilities within the district.

Tampa Bay Regional Planning Council: SEC's *Ten-Year Site Plan* is consistent with regional policies.

Withlacoochee Regional Planning Council: The Council finds SEC's *Ten-Year Site Plan* UNSUITABLE because it provides no information on the likely location of SEC's proposed new generating plants.

4.12.7 SUITABILITY

Based upon the review of SEC's Ten-Year Site Plan and the related government and public comments, SEC's plan is **suitable** for planning purposes. SEC's Ten-Year Site Plan is part of an aggregate Peninsular Florida plan that is based on a reserve margin methodology that needs refinement. Whether Peninsular Florida's planned generating resources will result in adequate reserves is as yet uncertain. The Commission will be looking further at the appropriate reserve margin levels for Peninsular Florida.

5.0 APPENDIX

5.1 STATUS OF NEED DETERMINATIONS AND SITE CERTIFICATIONS

Florida Power Corporation -- Hines Energy Complex Unit 1
In January, 1992, the Commission granted FPC's need petition for two 235 MW combined cycle generating units to be built in Polk County. The Governor and Cabinet, acting as the Power Plant Siting Board, approved FPC's site certification application in January, 1995. Subsequent to the Board's approval, FPC combined the construction of these two units into a single 470 MW unit which was placed into commercial service in November, 1998.

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

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

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

5.2 PLANNED, UNCERTIFIED GENERATING UNITS

Duke Energy Company / Utilities Commission of New Smyrna Beach -- Merchant Plant
Duke Energy Company plans to build a 500 MW gas-fired combined cycle unit at a site in New Smyrna Beach (NSB). Approximately 50 MW of the proposed plant's output is expected to go to NSB pursuant to a yet-unsigned power purchase agreement, with the remainder of the capacity available for purchase by any other entity. The Commission held a hearing on December 2-4, 11, and 18, 1998 to consider the plant. If approved by the Commission, the proposed unit will require certification under the Power Plant Siting Act.

Gulf Power Company -- Lansing Smith
Gulf plans to build a 532 MW gas-fired combined cycle unit at the existing Lansing Smith site. This unit is expected to be placed into commercial service in June, 2002. Gulf currently plans to issue a Request for Proposals (RFP) later this year. If Gulf ultimately decides to build rather than purchase capacity, the proposed unit will require certification under the Power Plant Siting Act.

City of Lakeland -- McIntosh Unit 4
LAK plans to build a 185 MW fluidized bed coal unit using funding from the U.S. Department of Energy's Clean Coal Technology Program. The unit is expected to be placed into service in May, 2004. If LAK ultimately plans to build rather than purchase capacity, McIntosh Unit 4 will require certification under the Power Plant Siting Act.

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

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

5.3 PUBLIC WORKSHOP COMMENTS

The Commission received written comments on Ten-Year Site Plans from many review agencies. Utility-specific comments were summarized previously in Sections 4.1 through 4.12 of this document. At its September 11, 1998 Public Workshop, the Commission received oral and written comments from the Legal Environmental Assistance Foundation (LEAF), a coalition led by the American Planning Association (APA), and the U.S. Generating Company (USGC). These comments are summarized in the next paragraph. All comments are contained, in their entirety, in Volume 2 of this review.

LEAF emphasized four general concerns with the Ten-Year Site Plans:

(1) The utilities emphasize demand-reducing DSM programs such as load management at the expense of energy-reducing programs. LEAF recommended that the Commission find the Ten-Year Site Plans ***unsuitable*** because they focus on load management rather than reduction of per-capita energy consumption.

(2) Both FPC and FPL do not forecast any incremental demand and energy savings after 2003. TECO's Ten-Year Site Plan forecasts DSM amounts that do not equal the DSM goals set by the Commission in 1994.

(3) The Ten-Year Site Plans reflect minimal investment in solar energy programs.

(4) Florida's utilities continue to operate older generating units. These units are less efficient, resulting in increased maintenance and environmental costs.

The coalition led by APA generally commented that Florida's utilities should begin the transition from fossil-fueled electric generation to conservation and renewable energy options. APA stated its belief that the Ten-Year Site Plans are not consistent with the State Comprehensive Plan with respect to energy consumption and promotion of solar technologies and other renewables. As a result, APA called on the Commission to require the utilities to amend their Ten-Year Site Plans to address these concerns.

USGC generally commented that the Commission should encourage competition among utility and non-utility generating companies. USGC stated that it should be given the opportunity to build new power plants in Florida to meet forecasted demand.