REVIEW OF ELECTRIC UTILITY 1997 TEN-YEAR SITE PLANS

December, 1997

FLORIDA PUBLIC SERVICE COMMISSION

Division of Electric and Gas
Division of Auditing and Financial Analysis

I. 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.***" As part of its review of the plans, the Commission solicits comments from federal, state, and local government agencies as well as from the public. These comments provide feedback to the utilities on any concerns that review agencies might have regarding proposed power plant sites. All comments are contained in this document, which is forwarded to the Florida Department of Environmental Protection (DEP) for consideration at any subsequent electrical power plant site certification proceeding.

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.

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.

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 August 8, 1997 to solicit public comments on the Ten-Year Site Plans. The Commission received oral and written comments from the Legal Environmental Assistance Foundation and the Project for an Energy Efficient Florida.

To submit comments on this document or request additional information on utility planning issues before the Commission, citizens may write to:
Joseph D. Jenkins, Director, Division of Electric and Gas, Florida Public Service Commission
2540 Shumard Oak Boulevard, Tallahassee, FL 32399-0850.

II. 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 is 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. Discussed in Section III.
Review possible alternatives to the proposed plant.	Reviewed DSM assumptions, fuel forecasts, and generation alternatives modeled to arrive at the projected expansion plan. Discussed in Section III.
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. Reply comments are contained in Section IV.
Consider the views of appropriate local, state, and federal agencies regarding water and growth management issues.	Requested comments from affected agencies. Reply comments are contained in Section IV.
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 III. Requested comments from the Department of Community Affairs (DCA) and from regional and local planning agencies regarding growth management and Comprehensive Plan issues. Reply comments are contained in Section IV.
Review the Ten-Year Site Plan for information on energy availability and consumption.	Reviewed load forecast data and methodologies. Requested supplemental data from utilities that provides greater detail. All data is available to the public.

In reviewing the Ten-Year Site Plan filings, the Commission relied on information provided in response to data requests made by its staff to clarify the Ten-Year Site Plan filings. The Commission also relied on its final orders in dockets pertaining to demand-side and supply-side planning matters.

The Florida Reliability Coordinating Council (FRCC) was created in October, 1996 to ensure electric reliability in the State of Florida. As a new region of the North American Electric Reliability Council (NERC), the FRCC is developing 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 has formed a reliability assessment group to determine what planning and operating studies will be performed during each year to address these issues.

Prior to its creation as a reliability council region of NERC, the FRCC was known as the Florida Electric Power Coordinating Group (FCG). In past years, the FCG occasionally performed coordinated statewide reliability studies. However, it primarily compiled individual utility data in the form of the *Ten Year Plan / State of Florida (Ten Year Plan).* The Commission relied on the *1997 Ten Year Plan* 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, the plans of some utilities may become based more on power purchases from unspecified sources and less on traditional least-cost planning.

TEN-YEAR SITE PLANS: SUITABILITY AND CRITICAL CONCERNS

The Commission has classified eight (8) 1997 Ten-Year Site Plans as ***suitable*** for planning purposes. Florida Power & Light Company (FPL) and Jacksonville Electric Authority (JEA) also filed 1997 Ten-Year Site Plans, but withdrew these plans on December 12, 1997 and December 18, 1997, respectively.

The Commission has identified some areas of concern which may impact the viability of some Ten-Year Site Plans. Due to these concerns, it may be difficult to judge whether the plans are able to withstand significant variation from base case assumptions. These concerns are discussed below:

o As shown in the FRCC's *1997 Ten Year Plan,* Peninsular Florida's utilities, in aggregate, are planning to carry declining reserve margins in the later years of the planning horizon. The *1997 Ten Year Plan* shows a forecasted 8% winter reserve margin (13% summer) in 2006 for Peninsular Florida. The FRCC *Ten Year Plan* is simply a compilation of individual utility data, and is not the result of a coordinated statewide reliability study. In response to Commission concerns on reserve margins, the FRCC performed a coordinated statewide reliability study, the *1997 Reliability Assessment.* The FRCC presented this study to the Commission at the November 17, 1997 Internal Affairs conference. The FRCC believes that Florida's utilities, in aggregate, have adequate resource expansion plans in place to meet forecasted demand and energy requirements with adequate reserves. However, as noted herein, the Commission has questioned some assumptions used by FRCC in preparing the *Reliability Assessment.*

o The Commission has concerns with Gulf Power Company's (Gulf) forecasted reserve margin. Gulf forecasts a summer reserve margin of less than 15% for each year covered by the plan. Winter reserve margin is forecasted to be at or below 9.0% each year until 2004. Southern Company, Gulf's parent company, has a target reserve margin of 15% for its members. Gulf does not have adequate firm commitments to purchase short-term capacity to meet its deficient reserve margin. This concern may be mitigated since Southern Company's members, in aggregate, expect to meet their reserve margin criteria over the planning horizon. As a result, Gulf expects to rely on interchange purchases from other Southern Company utilities. However, Gulf's *Ten-Year Site Plan* should indicate with more certainty the manner in which Gulf plans to meet its immediate capacity needs.

- When generating capacity from a single generating unit is shared by two utilities, only one utility should include that capacity in its calculation of reserve margin for the same summer or winter season. This is of particular concern when Peninsular Florida's aggregate forecasted reserve margin is lower than historic levels. Although purchasing shared capacity may allow both utilities to satisfy their reliability criteria, the issue of who has first call on the capacity becomes important during capacity shortfall events such as those occurring during the extended 1989 Christmas freeze.

TEN-YEAR SITE PLANS: RISKS

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

- 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.

- Evolving environmental regulations due to global warming concerns 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.

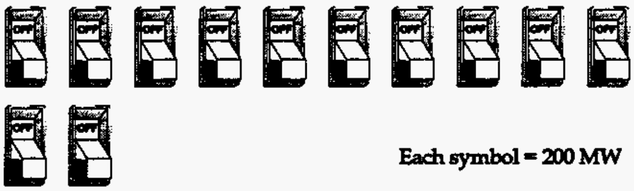
- The reserve margin for Peninsular Florida's utilities is currently comprised largely of load management and interruptible service. During the ten-year planning horizon, it is expected that load management and interruptible service will comprise an even greater percentage of peninsular reserve margins, resulting in less generating capacity reserves.

In addition to the aforementioned concerns and risks, some Ten-Year Site Plans did not include sufficient data to evaluate the robustness of the plan in light of changing conditions. To satisfy this concern, some utilities provided supplemental data at the request of the Commission staff.

The table and illustrations on the next three pages 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 (1997-2006) [1]

 Each symbol = 440 MW	COMBINED CYCLE 3338 Megawatts
 Each symbol = 200 MW	CONSERVATION AND DEMAND-SIDE MEASURES [2] 2358 Megawatts
 Each symbol = 150 MW	COMBUSTION TURBINE 1320 Megawatts
 Each symbol = 440 MW	COAL 163 Megawatts
 Each symbol = 75 MW	COGENERATION 75 Megawatts
 Each symbol = 40 MW	RENEWABLES 40 Megawatts
	STEAM (gas- or oil-fired) CAPACITY ADDITIONS OR RETIREMENTS (-389 Megawatts)
TOTAL *KNOWN* RESOURCE ADDITIONS -- 6905 Megawatts	
? ? ? ? ?	UNSPECIFIED CAPACITY PURCHASES [3] 1082 Megawatts
TOTAL RESOURCE ADDITIONS -- 7987 Megawatts	

[1]Winter resource additions.

[2]Load management (1048 MW), interruptible service (213 MW), and conservation programs (1097 MW).

[3]Includes the Ten-Year Site Plans withdrawn by FPL and JEA in December, 1997.

Figure 1: Resource Additions in the Next Ten Years [4]

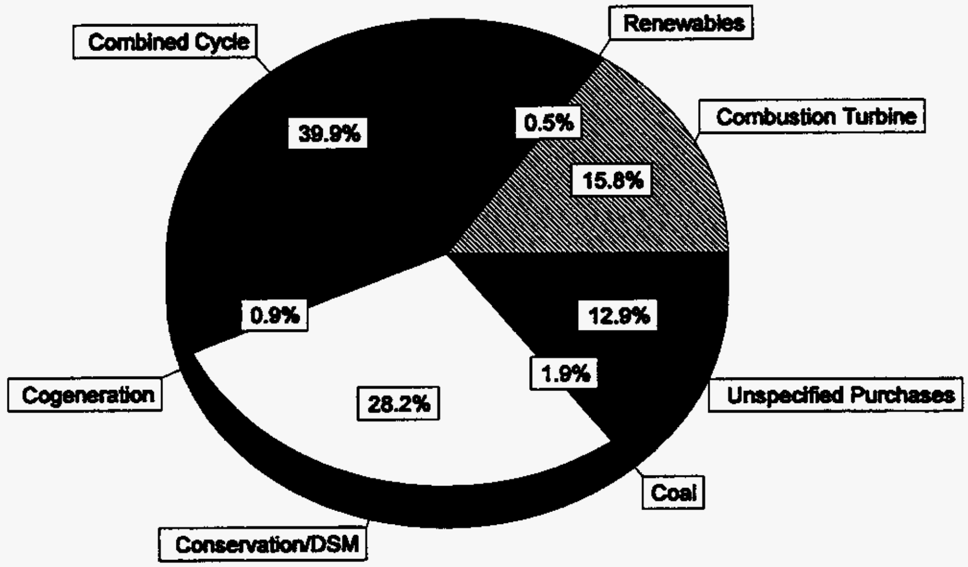
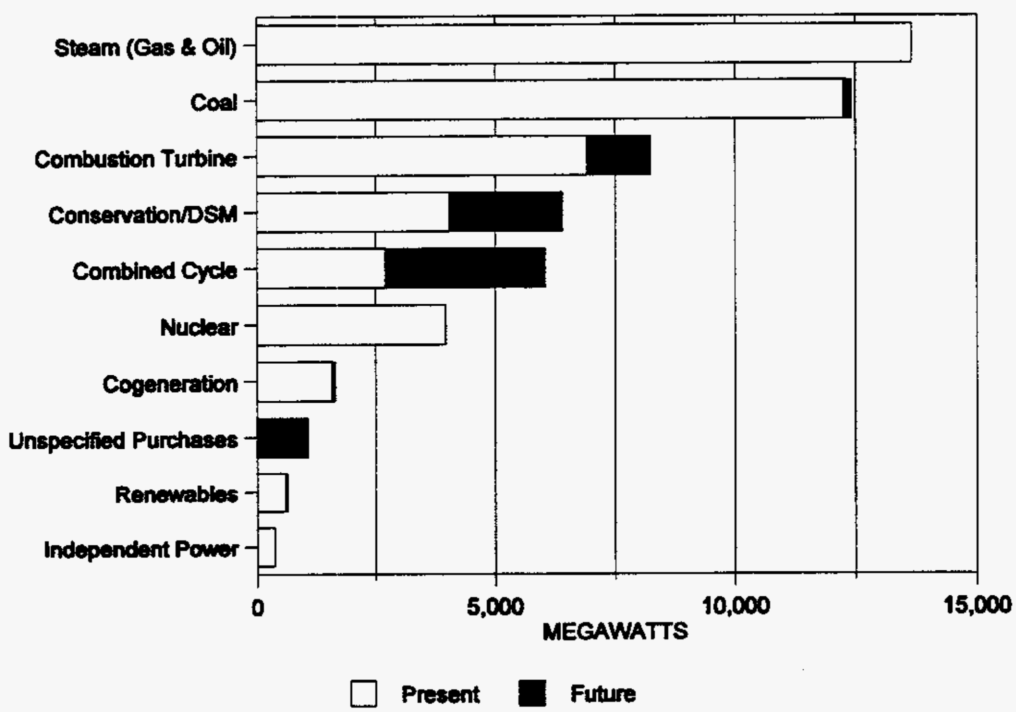


Figure 2: Resource Mix By Plant Type -- Present and Future [4]



[4] Includes the Ten-Year Site Plans withdrawn by FPL and JEA in December, 1997.

Figure 3
Proposed Major Transmission Lines (1997-2006) [5]

	UTILITY	TERMINALS	LENGTH (MILES)	IN-SERVICE DATE	VOLTAGE (kV)
1	FPL	Conservation - Corbett	57	Jan 1997	500
2	FPL	Conservation - Levee	36	June 2006	500

[5] The Conservation - Corbett line and the Conservation - Levee line were previously certified under the Transmission Line Siting Act.

III. REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

INTEGRATED RESOURCE PLANNING

Integrated resource planning (IRP) is a utility planning 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?

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 is the result 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.

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 forecast when additional capacity may be needed.

The Commission relies on three types of analyses in its review of a load forecast. The first involves reviewing the methodology used to produce the forecast to insure 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 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.

EVALUATION OF LOAD FORECASTING METHODOLOGY

Although each reporting utility has developed its own distinct forecasting process, there are 4 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 upon which utility load and energy forecasts are built. This data includes energy usage patterns, number of customers, economic, demographic, and weather data for the utility's service territory, and appliance saturation and energy consumption characteristics. The Commission reviewed these data sources for their 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; 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.

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.

TABLE 3 HISTORICAL FORECAST ACCURACY		
REPORTING UTILITY	AVERAGE ABSOLUTE FORECAST ERROR	AVERAGE FORECAST ERROR
Seminole Electric Cooperative	3.59%	+2.39%
Florida Power Corporation	3.50%	+3.50%
Tampa Electric Company	3.01%	+0.95%
Florida Power & Light Company	3.00%	+0.59%
City of Tallahassee	2.97%	-2.39%
Jacksonville Electric Authority	2.82%	-2.50%
City of Lakeland	2.32%	-2.20%
Gulf Power Company	2.02%	-0.71%
Gainesville Regional Utilities	1.91%	-1.91%
NUMERIC AVERAGE FOR ALL REPORTING UTILITIES	2.79%	-0.25%

For each reporting utility, the Commission reviewed the historical forecast accuracy of total retail energy sales for the five-year period from 1992 to 1996. The analysis compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, actual 1992 energy sales was compared to forecasts for 1992 prepared in 1987, 1988, and 1989. 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 type of average measures a utility's tendency to over-forecast (positive error rates) or under-forecast (negative error rates).

These analyses show the forecast error in each utility's three- to five-year forecasts. It is generally reasonable to assume that forecast error rates would be higher for eight- to ten-year forecasts, since accuracy is known to diminish as the forecast period expands. A summary of historical forecast accuracy for each reporting utility is contained in Table 3 (there was insufficient historical data to analyze the forecast accuracy of the Florida Municipal Power Agency). A detailed discussion of individual utility historical forecast errors is contained in Section IV.

Consistency of Forecasts with Historical Trends

As a final check of the projections, the Commission compares forecasted growth patterns to 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

TABLE 4
SEASONAL PEAK DEMAND – AVERAGE ANNUAL GROWTH RATE

REPORTING UTILITY [(W)inter or (S)ummer peak season]	HISTORICAL AAGR	FORECASTED AAGR	DIFFERENCE
Florida Power and Light (W)	3.47%	1.73%	-1.74%
Florida Power Corporation (W)	7.55%	1.16%	-6.39%
Seminole Electric Cooperative (W)	5.26%	3.86%	-1.40%
Tampa Electric Company (W)	4.70%	2.23%	-2.47%
Jacksonville Electric Authority (W)	4.50%	3.66%	-0.84%
Gulf Power Company (S)	1.72%	1.34%	-0.38%
Florida Municipal Power Agency (S)	3.90%	2.50%	-1.40%
City of Lakeland (W)	5.55%	3.27%	-2.28%
City of Tallahassee (S)	3.64%	1.88%	-1.76%
Gainesville Regional Utilities (S)	3.48%	2.25%	-1.23%
NUMERIC AVERAGE FOR ALL REPORTING UTILITIES	4.38%	2.39%	-1.99%

in energy consumption forecasted by the utility are reasonable.

Table 4 compares the average annual growth rate (AAGR) of historical peak demand (1986-1996) to forecasted peak demand (1997-2006) for each reporting utility. Each utility's forecasted peak demand is lower than actual peak demand has been historically.

Summary of Load Forecast Evaluation Process

After analyzing the load forecasts of the ten 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 significantly since last year. The current forecast for 1998 and 2005 summer peak demand has increased by 621 MW and 719 MW, respectively over what was forecasted last year. Similarly, the current forecast for winter peak demand for 1998/1999 and 2004/2005 has increased by 1,462 MW and 2,094 MW, respectively over last year's forecasts. Detailed discussions of each utility's load forecast, including the reason for the large forecasted increases in peak demand, are provided in Section IV.

The graphs on the next two pages 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 attributed largely to the expectation that households will replace older, less efficient appliances with newer, more energy-efficient models.

Figure 4: Firm Peak Demand – State of Florida
History and Forecast (1987-2006)

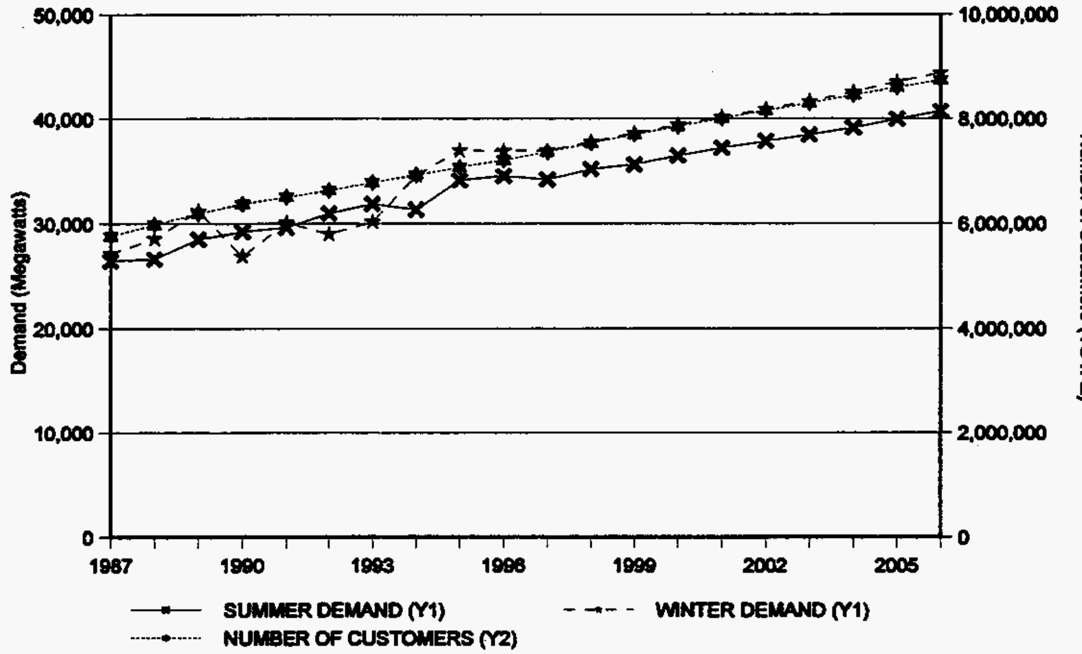


Figure 5: Net Energy for Load – State of Florida
History and Forecast (1987-2006)

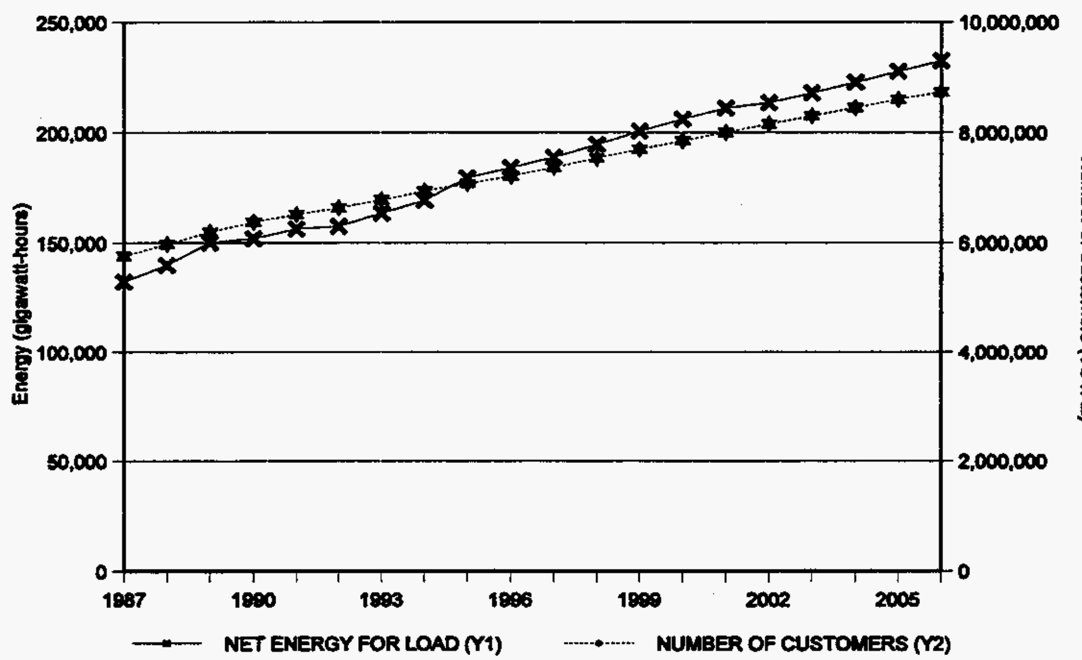
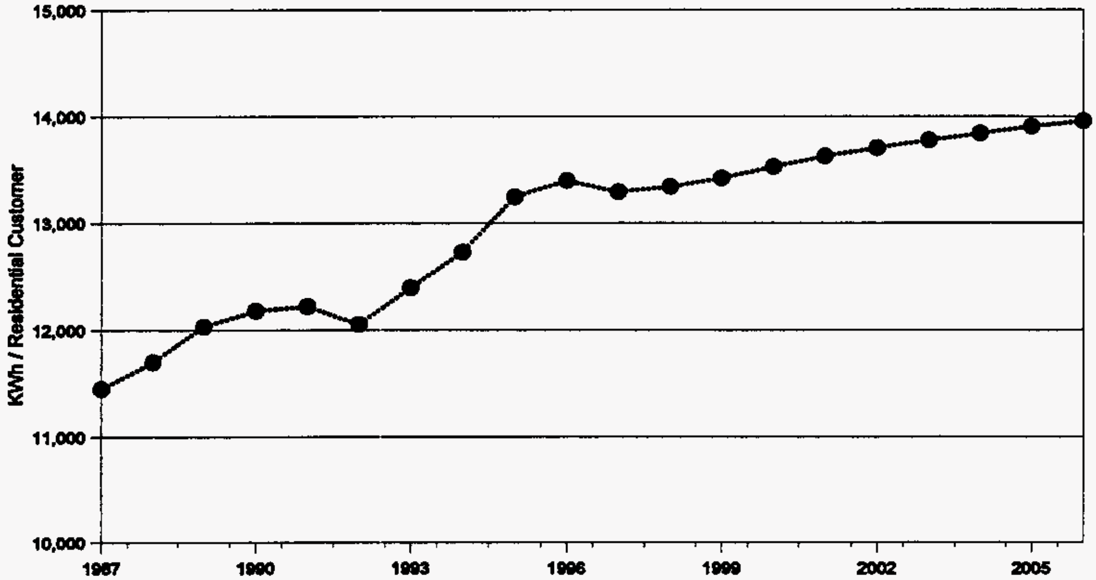


Figure 6: Annual Energy Consumption Per Residential Customer – State of Florida History and Forecast (1987 - 2006)



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 need to construct new generating units.

Florida's utilities were among the first in the nation to promote energy conservation practices. Florida's electric utilities have offered conservation and DSM programs 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 3601 MW (9.4%), winter peak demand by 4622 MW (11.1%), and energy consumption by 6088 GWh (3.2%). By 2006, DSM programs are forecasted to reduce summer peak demand by 5640 MW (12.2%), winter peak demand by 6977 MW (13.6%), and energy consumption by 8396 GWh (3.5%). These demand and energy savings are illustrated in Figures 7, 8, and 9.

Figure 7: Estimated Impact of DSM on Summer Peak Demand – State of Florida History and Forecast (1987 - 2006)

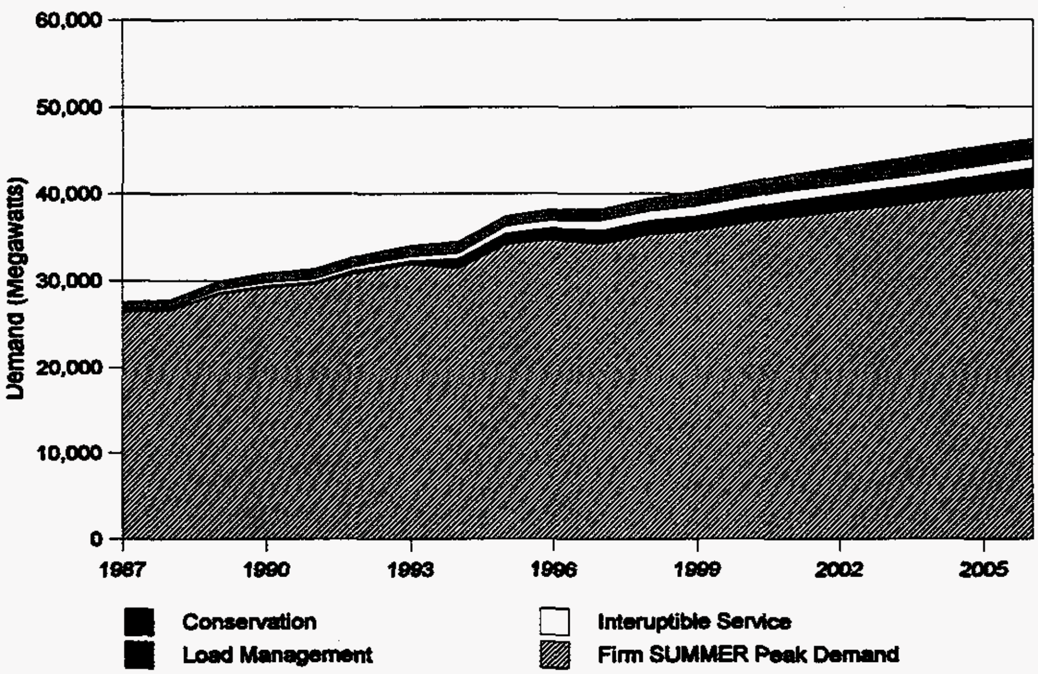


Figure 8: Estimated Impact of DSM on Winter Peak Demand -- State of Florida History and Forecast (1987 - 2006)

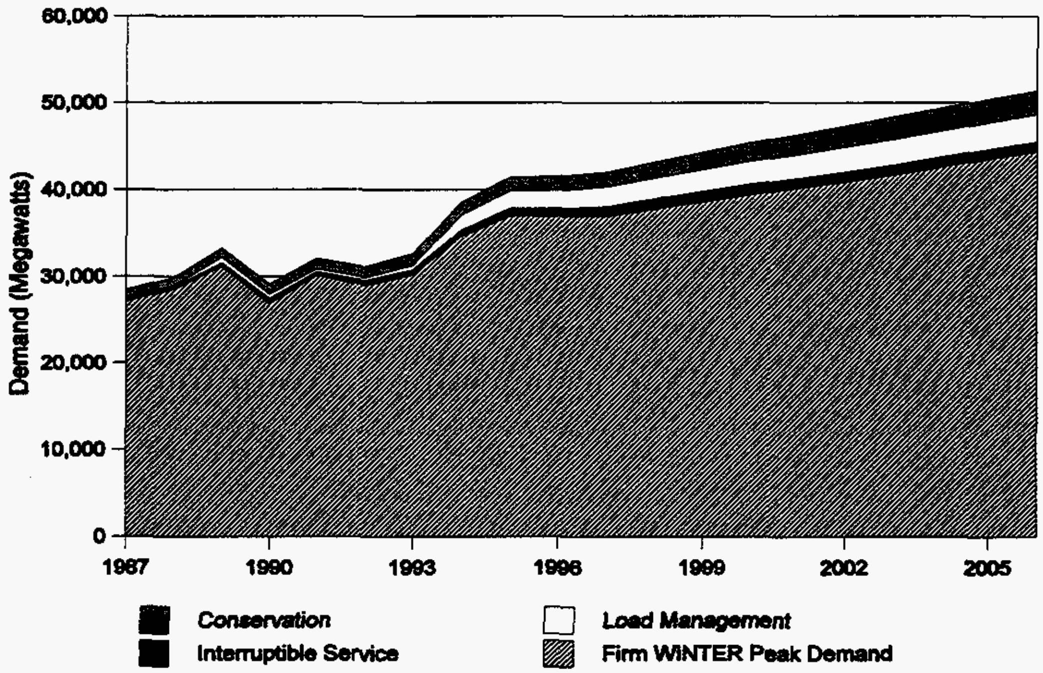
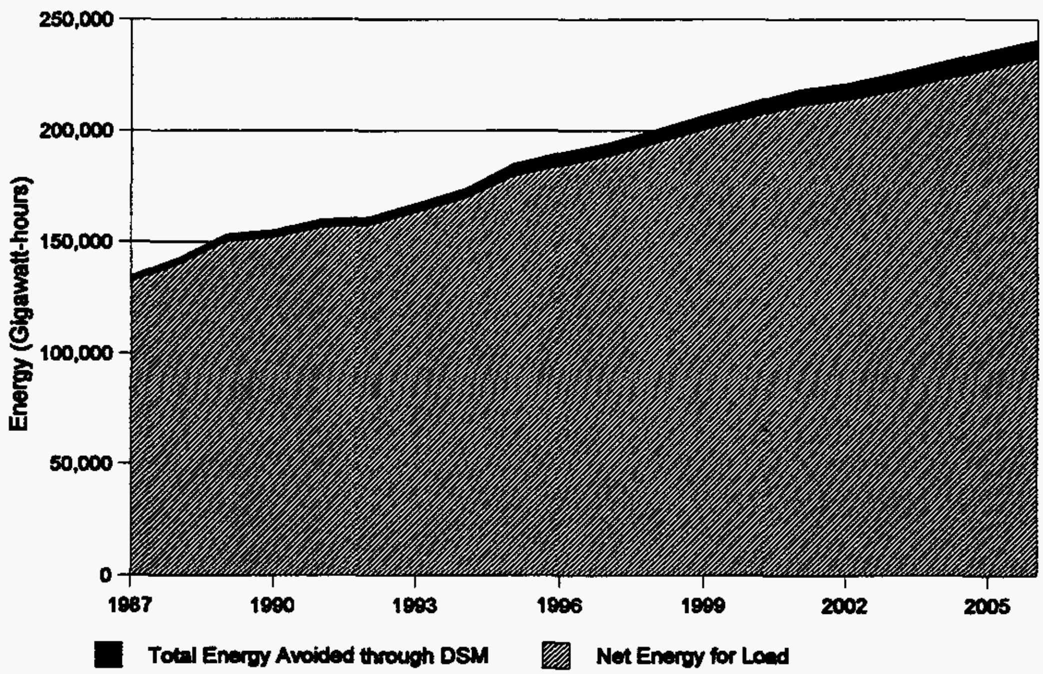


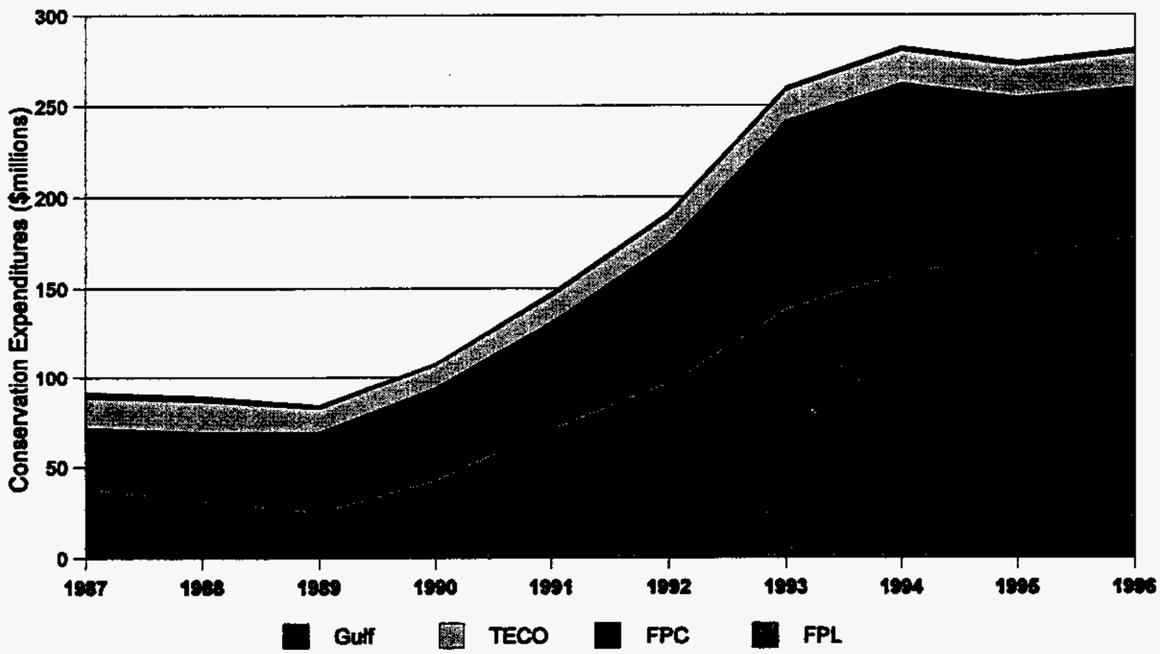
Figure 9: Estimated Impact of DSM on Net Energy For Load -- State of Florida History and Forecast (1987 - 2006)



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 nearly $1.9 billion through the ECCR clause. As shown in Figure 10 at the bottom of page, conservation-related expenditures have significantly increased since 1989.

When FEECA was enacted by the Florida Legislature in 1980, every electric utility in Florida 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 comprised approximately 94% of all electricity consumption in Florida. FEECA was revised again in 1996, and this revision increased the minimum sales threshold to 2000 GWh as of July 1, 1993. As a result, FEECA's requirements now apply only to the five investor-owned utilities and two municipal utilities, JEA and OUC. The new FEECA utilities generate approximately 87% of all energy consumed in Florida. It is not known at this time what impact the recent statutory revision will have on future DSM plans and forecasts for the affected cooperative and municipal utilities that are no longer subject to FEECA. However, all former FEECA utilities who file Ten-Year Site Plans have committed to continuing their current conservation efforts, and some expect to expand their efforts.

Figure 10: Investor-Owned Utilities -- Conservation Program Costs recovered through the Energy Conservation Cost Recovery Clause (1987-1996)



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 set forth 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 DCA to ensure a building code that results in the most energy-efficient, cost-effective new construction. This work is evidenced by the joint Commission-DCA task force which recently reviewed the cost-effectiveness of the building code. 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 may have been.

COMMISSION ACTIONS AFFECTING DSM

Demand-Side Management Goals and Plans

The Commission set demand and energy DSM goals for the four large investor-owned utilities in October, 1994 and approved their DSM plans in June, 1995. When it approved the DSM plans, the Commission made two additional decisions that may affect future DSM plans:

- The investor-owned electric utilities were ordered to conduct research and demonstration (R&D) projects on natural gas technologies for heating, cooling, water heating, and dehumidification. As part of this research, the electric utilities will gather cost-effectiveness and performance data on technologies for possible inclusion in future DSM programs. The Commission approved these natural gas R&D plans in September, 1995.

- The Commission formed a task force with DCA to examine the cost-effectiveness of the current building code. Although utilities have no direct involvement in writing building codes, the code can cause effects such as improved envelope efficiency that directly reduce a utility's load forecast. In February, 1996, the task force found that the current building code is cost-effective, and that no other actions are available to improve the current code's cost-effectiveness. No further action is anticipated at this time.

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 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.

Two utilities, Gulf Power Company (Gulf) and Tampa Electric Company (TECO), are currently not achieving a sufficient level of demand and energy savings to meet their Commission-approved DSM goals. The Commission will monitor these two utilities over the upcoming year to see if they show improvement. The individual utility discussion of TECO's and Gulf's Ten-Year Site Plan, contained in Section IV of this report, has more discussion on this subject.

The Commission plans to revisit the DSM goal setting process within the next year. 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. It has not yet been determined whether the goal-setting process will include a study on the scale of the 1993 Synergic Resources Corporation study that was used as a basis to set DSM goals in 1994.

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 variations from normal weather or base-case population projections. Defined as the amount of capacity that exceeds firm peak demand, ***reserve margin*** may be expressed either in megawatts or as a percentage of firm peak demand.

However, reserve margin cannot capture the impact of random events 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 a utility will likely be unable to meet its daily peak load on one day in a ten year planning period. 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 deficiency. A second probabilistic method, ***expected unserved energy*** (EUE), accounts for both the probability and magnitude of an energy shortfall. Utilities that use the EUE criterion typically calculate a ratio of EUE 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. Tampa Electric Company (TECO) uses the EUE/NEL ratio in addition to reserve margin; Seminole Electric Cooperative (SEC) uses the EUE/NEL ratio exclusively.

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. From a peninsular perspective, it is not clear whether utilities have adequate generating resource additions planned to ensure the ability to meet customer needs for electricity over the next ten years. Note that the aggregate winter reserve margin for Peninsular Florida's utilities is forecasted to drop to 8% by 2006. This concern is addressed in greater detail in the section "Risks Affecting Plans."

Figure 11: Forecasted Reserve Margin (1997-2006) – STATE OF FLORIDA

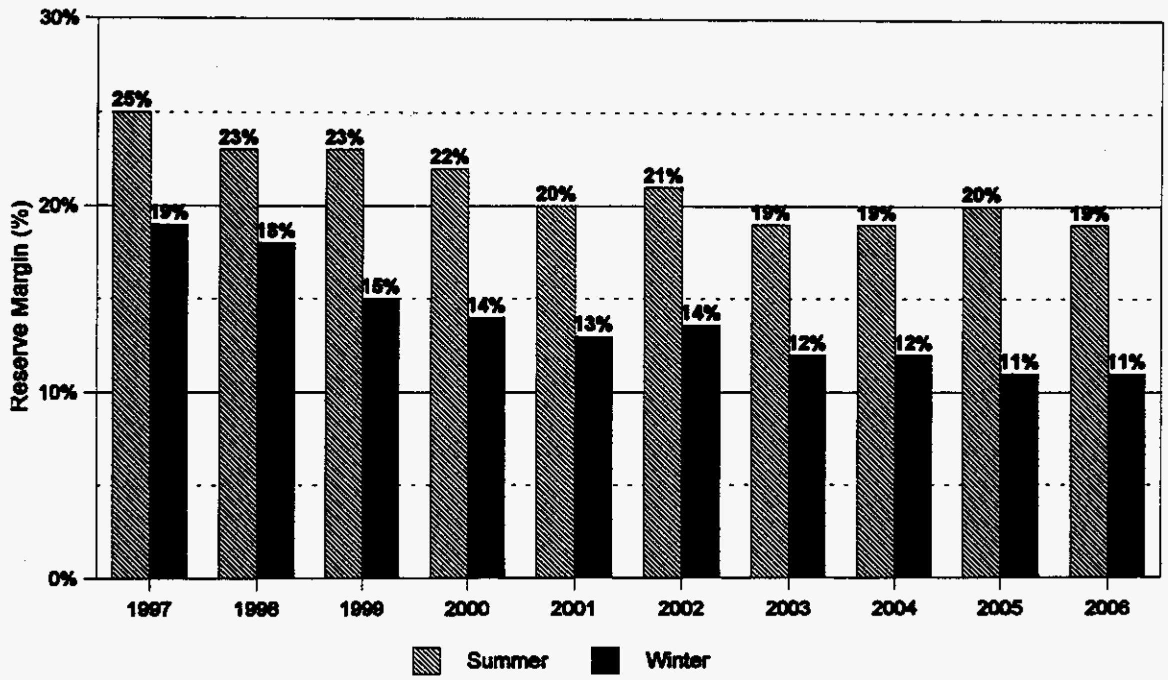
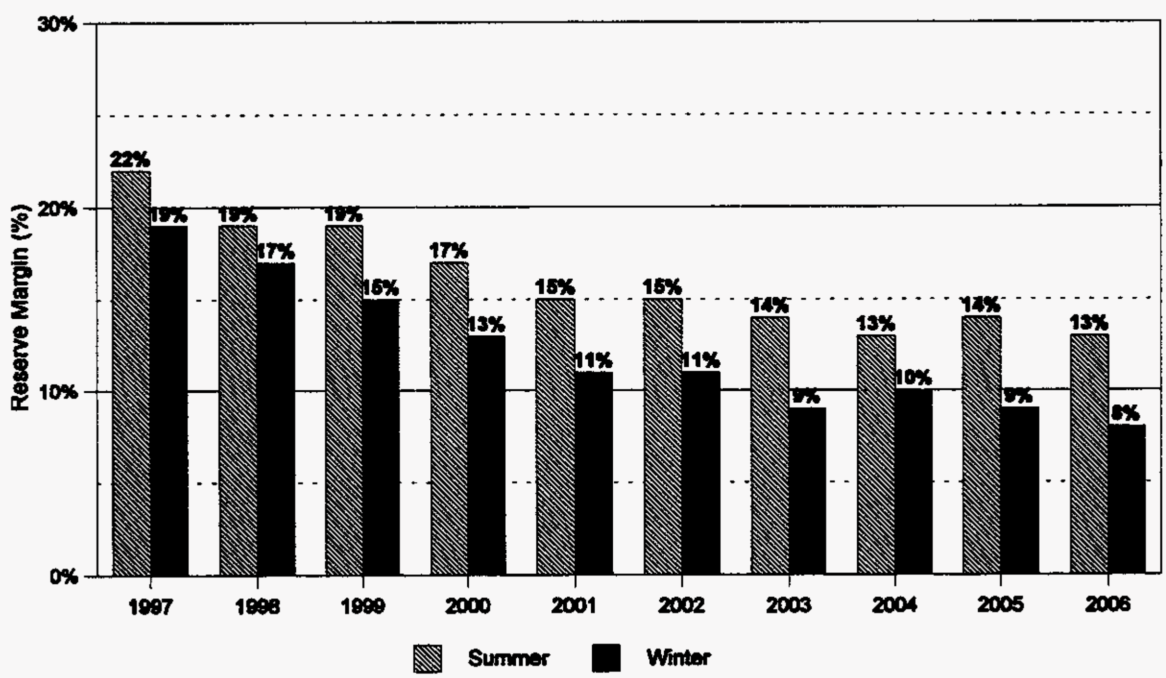


Figure 12: Forecasted Reserve Margin (1997-2006) – PENINSULAR FLORIDA



FUEL FORECAST

Although utilities must consider strategic factors such as fuel mix, fuel availability, and environmental compliance prior to selecting a generating resource, the fuel price forecast is the primary and most potentially volatile factor which affects the *type* of generating resource addition. Utilities typically apply generally accepted escalation rates, such as those of DRI/McGraw Hill or the Energy Information Administration (EIA) to current fuel prices to provide a known starting point for future pricing trends. Utilities also evaluate assumptions such as inflation rates, available resources, productivity levels, and technological advances. Moreover, utilities should produce several fuel price forecasts to evaluate the cost-effectiveness of potential generating plant expansions under different economic and technical scenarios. Finally, utilities should determine whether a project will be cost-effective under a worst-case scenario. The worst-case scenario is a check to determine whether a project will retain overall cost-effectiveness under all reasonable prices for the competing fuels.

The significance of fuel price forecast scenarios played an integral role in the Commission's 1992 decision to partially deny a joint petition by Florida Power & Light Company (FPL) and Cypress Energy Partners (Cypress) for a determination of need for two 400 MW pulverized coal power plants. FPL chose the Cypress project based in part on fuel forecasts that projected increasingly divergent prices between coal and natural gas or oil. However, historical data did not support FPL's predicted sustained divergence. While the Commission granted FPL's need for 440 MW, the specific coal units proposed by FPL were denied because the units were not found to be the most cost-effective alternative available. FPL's selection of the Cypress pulverized coal project did not follow a course that would allow for the inherent uncertainty of FPL's fuel forecast. If the forecast had proven wrong, FPL's ratepayers would have been forced to pay the high capital cost of a pulverized coal plant with minimal offsetting fuel savings.

FORECAST ANALYSIS

COAL

Across the nation, coal dominates electricity production because of low-cost domestic reserves and productivity advancements. Electric utilities nationwide burned a record 862 million tons of coal in 1996, up 35 million tons from 1995. However, Florida's generating utilities burned approximately 30.5 million tons in 1996, down from 31.4 million tons a year earlier. Independent forecasts by the EIA and the American Gas Association (AGA) estimate that coal consumption by electric utilities and independent power producers nationwide will increase between 1-2% over the next ten years. Florida's utilities project an annual increase of less than 1% for coal consumption over the forecast horizon.

Florida's utilities have traditionally relied on eastern supplies of coal to meet their generation needs. However, with current and future restrictions on toxic emission levels by the Clean Air Act Amendments, utilities are looking to both foreign and western sources of lower sulfur coal for electric generation. These alternate coal sources contain favorable chemical properties that allow the utilities to meet load requirements and comply with emission constraints while avoiding the cost of capital-intensive scrubbers.

Both EIA and AGA predict that coal prices should increase at less than the inflation rate over the forecast horizon. The reporting utilities project coal prices to escalate from an average of 170.29 cents per million Btu (MMBtu) in 1997 to 198.54 cents per MMBtu by 2006. Seminole Electric Cooperative (SEC) and the Florida Municipal Power Agency (FMPA) forecast the lowest and highest 2006 coal prices at 173.00 cents per MMBtu and 238.00 cents per MMBtu, respectively.

OIL

Approximately 20 years ago, uncertain expectations of world oil reserves, technological advances, productivity expansion, the market influence of OPEC, and increasing concerns about environmental impacts provoked Florida utilities to move away from oil-fired generation. The Commission established an oil backout cost recovery clause to protect Florida utility ratepayers from the political uncertainty and price volatility associated with oil. Utilities could recover costs associated with cost-effective construction or conversion projects that economically displace oil-fired generation. Subsequently, the Commission approved two oil-backout projects: FPL's two 500 kV transmission lines from Georgia; and Tampa Electric Company's (TECO) Gannon plant re-conversion from oil to coal.

In 1995, the Commission repealed the oil backout cost recovery clause rule, since Florida's electric utilities were no longer primarily dependent on oil. If a utility justifies a project that will result in fuel savings for its ratepayers, those costs will generally be recovered through the fuel cost recovery clause on a case-by-case basis.

Contrary to recent trends, many utilities switched from natural gas to oil as oil temporarily became more competitive in 1996. EIA reports that receipts of petroleum delivered to U.S. electric utilities totaled 106 million barrels, up from 84 million barrels in 1995. Although at a slower pace than national trends, Florida's utilities modestly increased their oil consumption in 1996 to approximately 36.9 million barrels, up from 35.1 million barrels a year earlier.

However, the reporting utilities project a long-term downward trend for oil-fired generation. Oil-fired generation among the reporting utilities is expected to decline to 14,112 GWh (22.5 million BBL) in 1999 before rebounding to 18,067 GWh (28.8 million BBL) by 2005. Nationwide, EIA forecasts a long-term downward trend in oil-fired generation, while AGA foresees a long-term upward trend.

One common concern in oil price forecasts is that each utility typically includes the possible occurrence of a catastrophic event, such as the oil embargo and price shocks of 1973. Such possibilities do exist; however, no one can accurately predict when or whether they might happen. As a result, all utility oil price forecasts are somewhat pessimistic projections that may neither materialize nor communicate appropriate pricing signals.

Residual Oil: The average residual oil price for the reporting utilities is forecasted to rise from 309.96 cents per MMBtu in 1997 to 437.85 cents per MMBtu by 2006. Although the utilities have experienced wide price swings on a year-to-year basis during the past ten years, the utilities expect prices to follow a general upward trend throughout the forecast horizon. The City of Tallahassee (Tallahassee) forecasted the highest 2006 residual oil price at 598.00 cents per MMBtu, while Gulf Power Company (Gulf) forecasted the lowest price at 216.00 cents per MMBtu. However, neither Tallahassee nor Gulf expects to use any residual oil during the planning horizon.

Distillate Oil: Prices are expected to increase at a rate similar to residual oil and natural gas. Distillate oil should remain the most expensive fuel type used for electric generation in Florida. The average price for distillate oil for the reporting utilities is forecasted to rise from 482.04 cents per MMBtu in 1997 to 708.57 cents per MMBtu by 2006. Florida Power Corporation (FPC) and FMPA have the lowest and highest 2006 price forecasts at 477.00 and 997.00 cents per MMBtu, respectively. Both utilities use distillate oil primarily for peaking units.

NATURAL GAS

Since enactment of the 1990 Clean Air Act Amendments (CAAA), Florida utilities have increasingly turned to natural gas to comply with CAAA Phase I and II emission restrictions placed on electric generation sources. Utilities can burn this low-sulfur fuel cleanly, efficiently, and with minimal capital investment. Both EIA and AGA expect natural gas-fired generation to increase significantly during the forecast horizon due to nuclear plant retirements and increasingly smaller reserve margins at coal-fired plants. Florida's utilities expect natural gas-fired generation to increase by approximately 6.4% annually to 57,115 GWh in 2006. FPC, FMPA, SEC, and Tallahassee are primarily responsible for the increased forecasted usage.

EIA reported that U.S. electric utilities burned 2,600 billion cubic feet (bcf) of natural gas in 1996, down from 3,023 bcf a year earlier. Similarly, Florida's utilities burned only 282.7 bcf in 1996, down from approximately 304 bcf in the prior year. As prices increased, natural gas became less competitive with other fuels as a fuel source for electric generation.

As indicated by historical trends, coal and distillate oil should form the floor and ceiling, respectively, for natural gas prices during the forecast horizon. Among the reporting utilities, the average price for natural gas is expected to rise from 271.30 cents per MMBtu in 1997 to 378.19 cents per MMBtu by 2006. FPC and FMPA have the lowest and highest 2006 price forecasts at 225.00 and 559.00 cents per MMBtu, respectively. FPC expects to increase its natural gas-fired generation with the addition of two combined cycle units at its Polk site and the conversion of several peaking units from oil to natural gas. FMPA also plans to add a combined cycle unit at its Cane Island site during the forecast horizon.

ORIMULSION

Orimulsion is a coal derivative with physical characteristics similar to oil. In 1994, FPL received Commission approval of a cost-recovery mechanism for the conversion of Manatee Units 1 and 2 from heavy oil to Orimulsion. The conversion project involved the installation of equipment (including scrubbers) to enable the two 783 MW units to burn Orimulsion. However, on April 23, 1996, the Governor and Cabinet, sitting as the Power Plant Siting Board, denied certification of the project, expressing concern about perceived environmental impacts related to Orimulsion. On May 14, 1997, the Florida First District Court of Appeal in Tallahassee ruled that the Power Plant Siting Board should reconsider its decision to deny certification of the proposed project. Subsequently, FPL has modified its proposal 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. Finally, on September 9, 1997, the Power Plant Siting Board voted to obtain additional information from state agencies before making a final decision. If authorized to burn Orimulsion at its Manatee units, FPL projects to burn approximately 25 million tons by 2006.

PETROLEUM COKE

Petroleum coke (petcoke) is a pure carbon by-product of the oil refining process. Fuel grade petcoke (approximately 17.5 million tons annually) typically exceeds 14,000 Btu/lb and contains high levels of sulfur and vanadium. Petcoke is marketed on long term controlled price agreements to electric utilities at prices at $0.70 per million BTU or less. Petcoke marketers must include such terms to overcome pricing and equipment modifications which have formerly precluded utility use of petcoke.

FPC, FPL, TECO, Jacksonville Electric Authority (JEA), and the City of Lakeland (Lakeland) are among several utilities nationwide that have performed test burns or are considering petcoke in their fuel mix. With the proper emission control technology, utilities could reduce future fuel costs with petcoke.

GENERATION SELECTION

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

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 calculates incremental capacity costs and total system fuel costs. The choice that minimizes system PWRR is 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 other factors is a robust integrated resource plan that ensures fuel/capital cost flexibility.

Alternative scenarios, which result from analysis of these other factors, were not included in many of the utilities' Ten-Year Site Plans. Some utilities provided scenario analyses in response to the Commission staff's supplemental data requests. Though considered in each utility's decision-making process, these 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

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

	Unit (Type)	In-Service Date
FPC	none planned	—
GRU	none planned	—
Tallahassee	Purdom 8 (260 MW CC) [Need determination granted / awaiting certification]	5/00
JEA	Southside 6 (88 MW CT)	6/00
Lakeland	McIntosh 4 (157 MW portion of 326 MW Coal)	6/00
FMPA	Cane Island 3 (40 MW share of 120 MW CT)	6/01
SEC	unknown (75 MW CT)	1/02
TECO	Polk 2 (181 MW CT)	1/03
Gulf	Scholz A (100 MW CT)	5/03
FPL	Martin 5 (448 MW CC)	8/04

have yet to be certified. The next-planned, non-certified generating unit for each reporting utility is contained in Table 5.

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

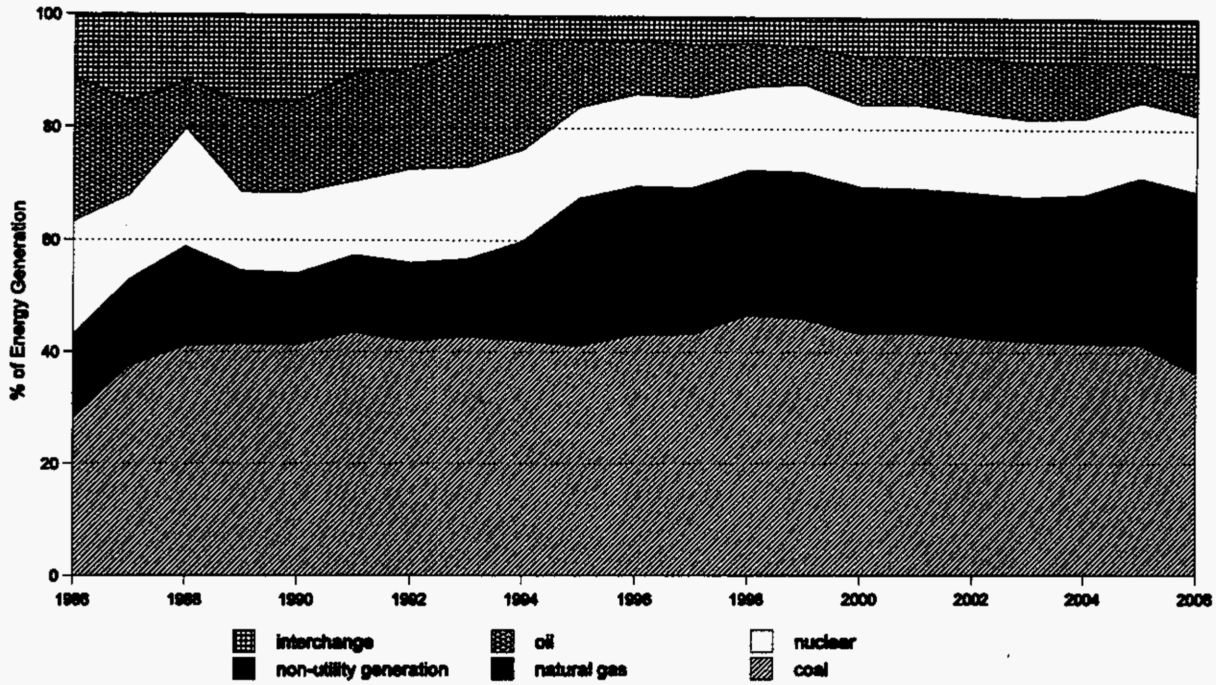
Prior to the early 1970's, utility generating units in Florida were fueled primarily by oil. The oil embargoes of the 1970's forced utilities to turn more to domestic fuels such as coal, nuclear, and natural gas. There are no current or future plans to build new nuclear generating units in Florida. As 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, primarily from planned combined cycle and combustion turbine unit additions. In addition, most new units built by non-utility generators are expected to use natural gas as a primary fuel.

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.

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

Figure 13: Energy Generation by Fuel Type (1986-2006)



consider whether a site can support a coal gasification plant and all the implications to the local transportation infrastructure.

Hydroelectric: While existing hydroelectric generating units continue to make a minute contribution 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 often purchase capacity from out-of-state utilities. Interchange purchases are typically short-term purchases of excess capacity and energy between utilities. The maximum amount of power that Florida can import over the Southern Company-Florida interconnection is approximately 3600 MW. 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 capacity purchased by Florida's utilities is expected to levelize over the next ten years.

The Commission continues to believe that utility Ten-Year Site Plans should be as flexible as possible with respect to fuel type without significantly deviating from a least-cost plan.

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, the 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.

COMPETITION

The cost of electric generating capacity, particularly natural gas-fired combined cycle and combustion turbine units, has dramatically decreased in recent years. Self-service generation may become more attractive to large industrial retail customers. Therefore, utilities have become more cost-conscious.

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.

The possibility of retail competition may already be having an impact on long-term generation planning and the forecasted reserve margins 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

TABLE 6
PROJECTED RESERVE MARGINS -- PENINSULAR FLORIDA
FROM FCG/FRCC 1993, 1994, 1995, 1996, AND 1997 TEN YEAR PLANS

YEAR	WINTER RESERVE MARGIN FORECAST FROM:					SUMMER RESERVE MARGIN FORECAST FROM:				
	1993	1994	1995	1996	1997	1993	1994	1995	1996	1997
1997	15%	21%	24%	22%	19%	22%	23%	24%	25%	22%
1998	13%	18%	23%	22%	17%	20%	21%	22%	22%	19%
1999	13%	18%	22%	19%	15%	20%	21%	23%	22%	19%
2000	12%	16%	20%	18%	13%	19%	19%	21%	20%	17%
2001	13%	15%	20%	16%	11%	18%	18%	20%	18%	15%
2002	11%	14%	17%	16%	11%	18%	18%	20%	17%	15%
2003	--	15%	16%	15%	9%	--	20%	19%	16%	14%
2004		--	16%	15%	10%		--	18%	16%	13%
2005			--	15%	9%			--	16%	14%
2006				--	8%				--	13%

alternative that does not necessarily result in a least-cost resource plan.

Because many utilities are hesitant to commit to new power plant construction far in advance, the traditional ten-year generation planning horizon has been reduced to approximately five years. As a result, the Ten-Year Site Plans filed by the reporting utilities may not contain enough committed, firm capacity to meet forecasted demand in the later years of the plans. Consequently, the aggregate reserve margin forecasted by Peninsular Florida's utilities, as shown in the FRCC's *1997 Ten Year Plan*, is expected to fall below historic levels. Table 6, on the previous page, contains aggregate reserve margin projections made in each year since 1993. This table shows illustrates that Peninsular Florida's reserve margin has steadily decreased with each year's forecast.

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, including 12 months for a bidding process. Building new generating units on short notice would address reliability concerns. However, unless dual fuel capability with natural gas and oil is maintained, utility ratepayers may be locked into higher electric bills than what they otherwise would have been.

The FRCC has excluded unspecified purchases from its calculation of Peninsular Florida's reserve margin. While there is no Peninsular Florida reserve margin planning criterion, the aggregate planned reserve margin is expected to fall below 15% starting in 2000 for winter (2003 for summer). By 2006, the end of the ten-year planning horizon, the FRCC shows an aggregate forecasted 8% winter reserve margin (13% summer) for Peninsular Florida. The Commission will maintain a close watch over the coordination of generation resource planning and reliability in Peninsular Florida.

TABLE 7
PENINSULAR FLORIDA – *PERCENT OF RESERVE MARGIN COMPRISED OF LOAD MANAGEMENT AND INTERRUPTIBLE SERVICE* FROM FCG/FRCC 1993, 1994, 1995, 1996, AND 1997 TEN YEAR PLANS

YEAR	WINTER FORECAST FROM:					SUMMER FORECAST FROM:				
	1993	1994	1995	1996	1997	1993	1994	1995	1996	1997
1997	63%	46%	41%	45%	52%	35%	34%	31%	34%	38%
1998	72%	54%	44%	47%	60%	40%	39%	35%	38%	46%
1999	75%	57%	45%	54%	71%	41%	39%	35%	40%	47%
2000	81%	64%	50%	59%	81%	43%	43%	38%	45%	53%
2001	83%	68%	52%	68%	90%	43%	46%	41%	51%	60%
2002	100%	73%	60%	69%	92%	49%	45%	42%	53%	58%
2003	–	65%	63%	72%	114%	–	41%	45%	56%	64%
2004		–	65%	72%	108%		–	45%	59%	69%
2005			–	73%	119%			–	59%	65%
2006				–	132%				–	69%

TABLE 8
RESERVE MARGIN CRITERIA AND FORECASTED SEASONAL RESERVE MARGIN

REPORTING UTILITY	CRITERIA	2006 RESERVE MARGIN	
		SUMMER	WINTER
Florida Power Corporation	15% Annual	24%	16%
Gulf Power Company	15% Summer	14%	13%
Tampa Electric Company	15% Annual	16%	16%
Florida Municipal Power Agency	20% Annual	25%	25%
Gainesville Regional Utilities	15% Annual	15%	37%
City of Lakeland	15% Annual	56%	22%
City of Tallahassee	17% Summer	17%	28%
Seminole Electric Cooperative	*(uses EUE as its sole reliability criterion)*		

Declining reserve margins pose one other major risk -- Peninsula Florida may be more susceptible to capacity shortfalls caused by severe weather, such as what occurred during the Christmas, 1989 freeze. Further exacerbating the Commission's concern is that the aggregate reserve margin of Peninsular Florida's utilities is currently comprised largely of load management and interruptible demand. In the future, it is expected that these two demand-reducing measures will contribute even more to peninsular reserve margins, resulting in less generating capacity reserves. This is of greatest concern during the winter peak season, especially when load management and interruptible demand are forecasted to make up more than 100% of available peninsular winter reserves starting in 2003. Table 7, on the previous page, illustrates how the contribution of load management and interruptible service to reserve margin has increased with each aggregate forecast performed since 1993.

To increase the availability of their generating units, most Florida electric utilities have increased the amount of unit maintenance. Additionally, the size of new generating units has decreased from the 400-600 MW range seen in the 1980's towards the 250 MW range. These two factors appear to have enabled many utilities to maintain reliability with a 15% reserve margin, rather than the 20% seen in the past.

Some of Florida's larger electric utilities use a minimum 15% reserve margin criterion for planning purposes. A comparison of each reporting utility's reserve margin criterion, along with the forecasted summer and winter reserve margin in 2006, is shown in Table 8 above. Note that this table <u>does not include</u> the Ten-Year Site Plans withdrawn by FPL and JEA.

At the August 8, 1997 workshop, the Commission voiced its concerns with the forecasted declining reserve margins. To address these concerns, the FRCC studied the reliability of Peninsular Florida's electric system. The FRCC presented its study, known as the *1997 Reliability Assessment*, to the Commission at Internal Affairs on November 17, 1997. The *Reliability Assessment* concluded that the aggregate summer reserve margin is forecasted to meet or exceed 15% for each year during the next ten years. The *Reliability Assessment* also shows that the peninsular winter reserve margin falls to 13% by 2006. Finally, the *Reliability Assessment* concluded that Peninsular Florida's assisted LOLP does not exceed 0.1 days per year during the next ten years.

The Commission is concerned with the outcome of the FRCC *Reliability Assessment*. The results show an improvement in forecasted reserves from that which was presented at the August 8, 1997 workshop. However, this improvement is due to the FRCC's addition of an estimated 1500 MW of capacity not contained in the composite *1997 Ten Year Plan* presented at the workshop.

One of the FRCC's goals during 1998 is to develop a standard criterion for reliability. The FRCC has indicated that it will include the Commission staff in this process.

AVAILABILITY OF NATURAL GAS

Current national policies promote the consumption of natural gas over other fossil fuels. Not only does natural gas offer environmental benefits, but because it is a domestic product, its usage decreases Florida's dependence on foreign oil. Two federal actions, the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992, favor natural gas usage. These policies could increase natural gas demand in Florida.

Figure 14, at right, 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 a 65% increase in natural gas usage during the next ten years. The feasibility of using natural gas for electric generation is directly dependent on available pipeline capacity on the Florida Gas Transmission (FGT) system and the price of natural gas relative to other fuels.

Natural gas pipeline capacity is expressed as maximum daily throughput capability in billion cubic feet per day (bcf/day). FGT, the only gas transportation pipeline currently serving peninsular Florida, has a capacity of just under 1.5 bcf/day. Approximately 79% of Florida's natural gas pipeline capacity is used for electric and non-utility electric generation purposes. Currently, FGT does not have any unsubscribed capacity. Thus, large future increases in gas consumption are possible only if pipeline capacity is increased.

FGT has indicated that it is willing and able to expand existing natural gas pipeline capacity, as needed, to meet the future natural gas requirements of electric utilities. Sufficient natural gas pipeline capacity can be made available to meet the needs of all capacity additions should they be replaced with gas-fired generating units. Combustion turbine units require a 2-year lead time to build. Assuming that planned reserve margins are adequate, current data indicates that construction of new power plants may have to begin by the winter of 1998 to maintain the reliability of Peninsular Florida's electric system.

FGT can expand pipeline capacity with compressors at various points on its system to accommodate increased demand. This ability, which requires a short lead time of 12 to 18

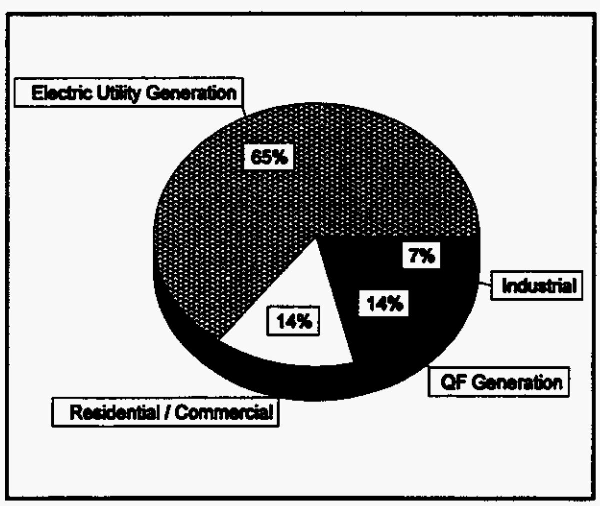


Figure 14: Natural Gas Consumption by End-User

months, should reduce concerns with constrained pipeline capacity. FGT has indicated that it may expand pipeline capacity via compression as demand for natural gas requires. To assure there is ample capacity to fuel forecasted gas-fired generating units, allow for growth on the natural gas distribution systems, and fulfill the potential needs of the unspecified capacity additions, an additional 0.5 bcf/day of capacity may be required by 2006. FGT estimates that nearly 0.5 bcf/day of additional transportation capacity can be achieved through compression.

On August 15, 1997, FGT initiated a Notice of Open Season, accepting nominations for a proposed mainline expansion of its existing gas pipeline system. The 30-day open season concluded on September 15, 1997. Estimated in-service date for the expansion is late 1999 or early 2000. FGT's existing infrastructure allows flexibility to accommodate incremental growth. The proposed expansion will be accomplished through compression and minor looping. The Open Season will also incorporate offers from existing firm shippers to permanently release firm capacity that would reduce the need for construction of incremental facilities in connection with the proposed facilities. However, at this time, FGT has not committed to construct the expansion, nor has it filed any petitions with the Federal Energy Regulatory Commission.

The secondary market also may be a viable option for electric utilities to acquire natural gas capacity. The current market 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 2000 and 2006. 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 if none is available at the time required. Forecasted gas requirements include the needs of both QF's and gas distribution utilities.

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 part of their Commission-approved DSM plans 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.

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.

Overall, electric generating units represent the largest stationary source of air pollutants in Florida. Thus, much attention has been focused on reducing power plant emissions. The Environmental Protection Agency (EPA) is responsible for establishing national air and water pollution limits for power plants. The Florida 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. 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. NO_x emission rates are expected to be established during 1997 with an ultimate 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 the cost-effectiveness of older generating facilities, which primarily consume coal and heavy oil.

Commission Activities Affecting Environmental Compliance

In 1992, the Florida Legislature enacted Section 366.825, Florida Statutes, which allows utilities to petition the Commission for approval of a plan to bring affected generating units into compliance with the CAAA. This statute was followed in 1993 by Section 366.8255, Florida Statutes, which requires the Commission to establish an environmental cost recovery mechanism to allow prudently incurred environmental compliance costs to be recovered from utility ratepayers.

To date, only Gulf has formally submitted a Clean Air Act Compliance Plan for approval by the Commission. While FPC, FPL and TECO have not filed formal plans, their compliance strategies have been the subject of discussion in other docketed proceedings such as the Environmental Cost Recovery Clause (ECRC) and Fuel Cost Recovery Clause proceedings. FPL, Gulf, and TECO currently recover costs for increased environmental constraints occasioned by the Clean Air Act through the ECRC.

IV. REVIEW AND ANALYSIS - INDIVIDUAL UTILITY PLANS

FLORIDA POWER CORPORATION

Florida Power Corporation's (FPC) generating system currently has a winter capacity of 7,341 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 (2,680 MW), and a 90.4% (755 MW) ownership share of the Crystal River 3 nuclear unit. FPC currently purchases 1,048 MW of firm capacity from 16 qualifying facilities.

FPC plans to add three generating units to its system over the next ten years. Intercession City Unit 11 is due to be placed into service in 1997. This combustion turbine unit will be jointly owned by FPC and Georgia Power Company. FPC will receive the winter capacity (167 MW), while Georgia Power will receive the summer capacity (143 MW). Polk Units 1 and 2 are identical 505 MW gas-fired combined cycle units with expected in-service dates of 1998 and 2004, respectively. In addition to these new units, FPC plans to retire 17 generating units with a total generating capacity of 581 MW. The following sites will be affected: Bayboro (232 MW), Higgins (158 MW), Suwanee (147 MW), Avon Park (64 MW), Turner (36 MW), Port St. Joe (18 MW), and Rio Pinar (18 MW). FPC plans to convert four oil-fired CT units to natural gas.

Figure 15, on the next page, contains FPC's projected generation mix by fuel type. FPC's projected increase in natural gas-fired generation, caused by the addition of the new Polk units, is reflected in this graph.

LOAD FORECAST

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

FPC's absolute percent error in its 1992-1996 retail sales forecasts is 3.50%, which is higher than the 2.79% numeric average for the ten reporting utilities in the state. FPC's average forecast error for the same period is the highest over-forecast in the state at 3.50%.

FPC's winter peak demand forecast for the next ten years is projected to increase at an average annual growth rate (AAGR) of 1.16%. This amount is considerably lower than the 7.55% AAGR during the 1987-1996 period and the 2.17% AAGR projected in the 1996 TYSP. FPC stated that lower forecasts are a direct result of an assumed loss of a short-term wholesale contract with SEC, as well as other wholesale load and energy losses not committed to FPC throughout the entire ten-year planning horizon.

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, these programs are estimated to reduce FPC's winter peak demand by 2078 MW (20.3%) in 2006.

Much of FPC's forecasted savings are due to its Residential Energy Management program, one of the largest load control programs in the country. This dispatchable DSM program is expected to account for 1267 MW of winter peak demand

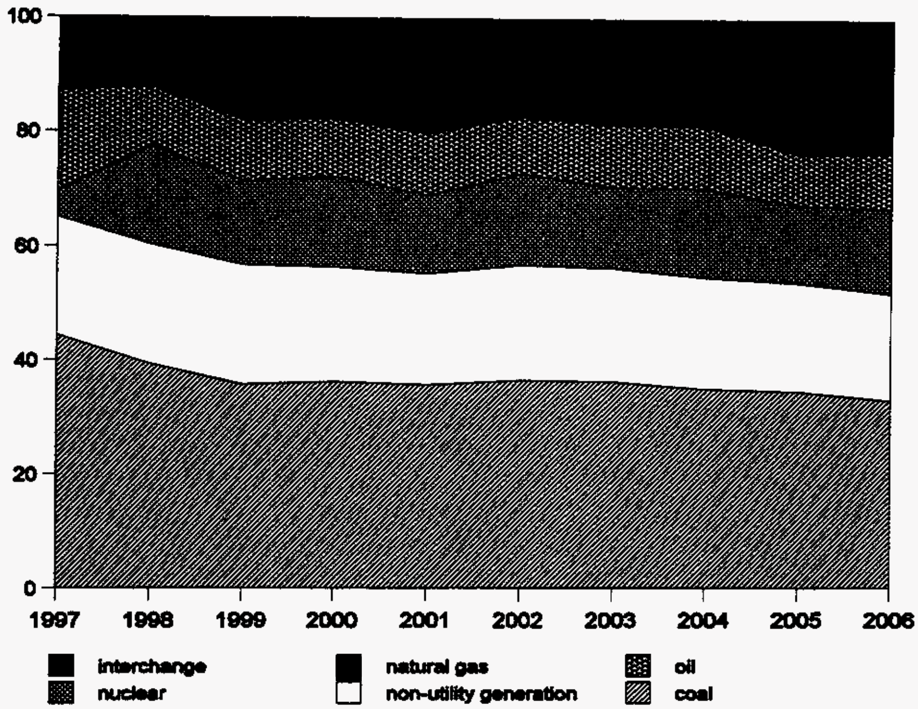


Figure 15: FPC Generation Mix - % by fuel type (1997-2006)

savings in 2006. Other substantial savings are forecasted to come from FPC's non-dispatchable conservation programs (410 MW) and its interruptible service tariffs (192 MW). Over the next ten years, FPC's DSM programs are projected to contribute nearly 30% of the aggregate winter demand savings forecasted by the state's utilities.

To date, 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.

FUEL FORECAST

FPC provided a base, low, and high-price forecast for all fuel types except nuclear, to which FPC only provided a base-case forecast. An FPC-affiliated company, Electric Fuels Corporation, provides the coal price forecasts which represent its price to FPC for coal delivered to the Crystal River plant site. 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 forecasts that all five fuel types will experience an average annual price increase of about 1% during the next ten years. FPC's 2006 price forecasts are at or below the reporting utilities' average 2006 price forecasts for the five fuel types.

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.

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

FPC forecasts are not substantively different compared to estimates from last year except for showing elevated emission levels for 1997. This is consistent with the extended outage of FPC's Crystal River Unit 3 nuclear unit which began in September of 1996. Like many other utilities, FPC's total emissions are more sensitive to demand growth assumptions than to fuel price forecast assumptions.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on FPC's *Ten-Year Site Plan*:

Florida Department of Community Affairs (DCA): DCA finds that expansion of capacity at the existing Polk County site is consistent with the State Comprehensive Plan and with applicable local comprehensive plans. DCA also reiterates past comments which expressed concern about the proximity of the planned combustion turbine at the Osceola County site to both residential areas and environmentally significant areas. DCA suggests that state policy should be reviewed regarding the export of power produced in Florida to another state.

Florida Department of Environmental Protection (DEP): DEP finds the *Ten-Year Site Plan* to be generally suitable for planning purposes, although the plan does not appear to address FPC's acquisition of the Tiger Bay cogeneration unit.

Florida Game and Fresh Water Fish Commission (GFC): GFC provided a copy of its 1992 comments on undefined adverse impacts on fish and wildlife caused by the placement of power plants at the Debary, Intercession City, and Polk sites.

North Central Florida Regional Planning Council (NCFRPC): NCFRPC finds that FPC's *Ten-Year Site Plan* is consistent with the goals and policies of the regional plan.

Southwest Florida Water Management District (SWFWMD): New withdrawals from the Floridian aquifer within the SWUCA may be restricted in the future. Utilities should work closely with SWFWMD district staff and consider alternative sources of water when planning new generation within the district.

Tampa Bay Regional Planning Council (TBRPC): TBRPC approves FPC's *Ten-Year Site Plan* as consistent with regional policies.

Withlacoochee Regional Planning Council (WRPC): WRPC finds that 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.

SUITABILITY

Based upon the review of FPC's *Ten-Year Site Plan* and the related government and public comments, FPC's plan is suitable for planning purposes.

FLORIDA POWER & LIGHT COMPANY

[NOTE: Florida Power & Light Company (FPL) officially withdrew its April, 1997 *Ten-Year Site Plan* on December 12, 1997. The following comments relate to this now-withdrawn plan. The Commission did not classify the withdrawn plan as "suitable" or "unsuitable." FPL has stated its intent to file a 1998 *Ten-Year Site Plan* by April 1, 1998.]

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on FPL's *Ten-Year Site Plan*, which was withdrawn on December 12, 1997:

Broward County: Generation expansion at the existing Port Everglades site has the potential for adverse impacts to the Port Everglades basin and Intracoastal Waterway. The Port Everglades site is listed as a petroleum contaminated site and expansion of the site should not exacerbate contamination or impede clean-up activities. FPL's description of the Port Everglades site should be amended to state that no direct barge access is available to the site.

Florida Department of Community Affairs (DCA): Additions to FPL's only preferred site, the existing Martin County site, must conform to the Planned Unit Development Agreement and that the site remains consistent with the Martin County Comprehensive Growth Management Plan. DCA also provided general land-use comments on FPL's potential sites in Brevard, Broward, DeSoto, Glades, Hardee, Highlands, Lee, Manatee, Palm Beach and Volusia counties.

Florida Department of Environmental Protection (DEP): DEP finds FPL's *Ten-Year Site Plan* to be generally suitable for planning purposes.

Florida Game and Fresh Water Fish Commission (GFC): Provided copy of its 1992 comments which reiterate past comments made regarding potential generating sites in DeSoto and Highlands counties.

Lee County: The information in FPL's *Ten-Year Site Plan* is not sufficient to adequately evaluate the plan for its environmental and land use impacts.

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 plan does not include an Orimulsion price forecast. The *Ten-Year Site Plan* should include potential impacts and mitigation proposals, particularly with regard to air quality, resulting from the Manatee conversion.

North Central Florida Regional Planning Council (NCFRPC): NCFRPC finds FPL's *Ten-Year Site Plan* is consistent with the goals and policies of the regional plan.

Northeast Florida Regional Planning Council (NEFRPC): NEFRPC finds that FPL's conservation and renewable energy plans are consistent with regional goals. Since no preferred or potential sites are located within the region, NEFRPC made no comments on the appropriateness of these sites.

South Florida Regional Planning Council (SFRPC): While locating additional generation capacity at the existing Port Everglades site is preferable to a new site, air and water quality impacts remain a concern. FPL has balanced conservation measures with the need for new generating facilities. SFRPC finds that the *Ten-Year Site Plan* is consistent with goal and policies of the regional plan.

South Florida Water Management District (SFWMD): SFWMD made no adverse comments regarding the suitability of the sites. However, SFWMD commented that no details were provided about the new facilities that may be proposed at potential sites. Also, the map depicting potential new sites does not accurately depict the Riviera Beach and Ft. Lauderdale facilities and omits the Ft. Myers facility. SFWMD stated that more specific information is needed in Ten-Year Site Plans in order to comment on water supply issues.

Southwest Florida Regional Planning Council (SWFRPC): SWFRPC offered no comments, because FPL plans no additional generation within the region.

Southwest Florida Water Management District (SWFWMD): New withdrawals from the Floridian aquifer within the SWUCA may be restricted in the future. Utilities should work closely with SWFWMD staff and consider alternative sources of water when planning new generation within the District.

Tampa Bay Regional Planning Council (TBRPC): TBRPC approved FPL's *Ten-Year Site Plan* as being consistent with regional policies.

Treasure Coast Regional Planning Council (TCRPC): Expansion of the Riviera Power Plant site may impact residential communities, the Lake Worth Lagoon, the water supply, and air quality. TCRPC urges FPL to: 1) reduce reliance on fossil fuels; 2) increase conservation activities; and 3) increase solar generation.

GULF POWER COMPANY

Gulf Power Corporation (Gulf) relies heavily upon coal-fired generation capacity to meet its customers' electricity demand. Gulf currently has 11 coal-fired steam turbines (2,220 MW summer capacity), three fossil steam turbines (88 MW), and one combustion turbine (32 MW) on its system.

Gulf expects to install 200 MW of combustion turbines at the existing Scholz site in 2003. No site has yet been chosen for the additional 200 MW of combustion turbines to be added in 2006. Gulf also plans to retire a 32 MW combustion turbine at the Smith site in 2006.

Competition in the electric industry has caused numerous uncertainties in the near future. As a result, Gulf states its belief that it is unwise to commit capital investment to build power plant facilities in the near term when it can purchase needed capacity from Southern Company and other sources. Gulf believes that this strategy will increase flexibility and decrease risk exposure under emerging competition. Gulf plans to meet short-term deficiencies in its reserve margin by making a series of power purchases over the next five 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 seven years. Therefore, Gulf is expected to be a net buyer of capacity from the Southern Company pool. This is illustrated in Figure 16 on the next page.

LOAD FORECAST

Gulf uses different methods to produce its short-term forecasts (0-2 years) and its intermediate and long-term forecasts (3-25 years). The 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 use models that integrate end-use and econometric methods. They include the Residential End-Use Energy Planning System (REEPS) and Commercial End-Use Model (COMMEND). Data sources were not specifically identified, nor did the Company include any sensitivity analysis results (high and low band forecasts). Gulf's historical forecast error rate was lower than the average error rate of the ten reporting utilities.

Gulf's customer forecast during the forecast period grows by 1.84% AAGR, while customer growth has historically been 3.11% AAGR. However, Gulf's forecast of customers in the year 2005 is less in the *1997 Ten-Year Site Plan* than in the *1996 Ten-Year Site Plan*. Gulf cited the impact of an update to the 1990 Census, as well as a forecasted reduction in the number of military installations in its service territory, as the reasons for the decrease.

Gulf's AAGR in winter peak demand over the forecast period is 0.50%, compared to a 5.20% AAGR over the last 10 years. In response to Commission inquiry regarding the substantial decrease in the forecasted demand growth rate compared to historical growth rates, Gulf cited the stabilization of appliance saturation rates and appliance efficiencies during the past several years as 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 increased residential demand-side management. Without the growth in DSM, the forecasted AAGR would have been 1.60%. Considering both the forecasted customer growth rate and historical trend in winter demand, the REEPS model, as employed by Gulf, may underestimate future growth in winter demand. Gulf forecasts larger increases in the growth rate of both demand and energy than it did last year.

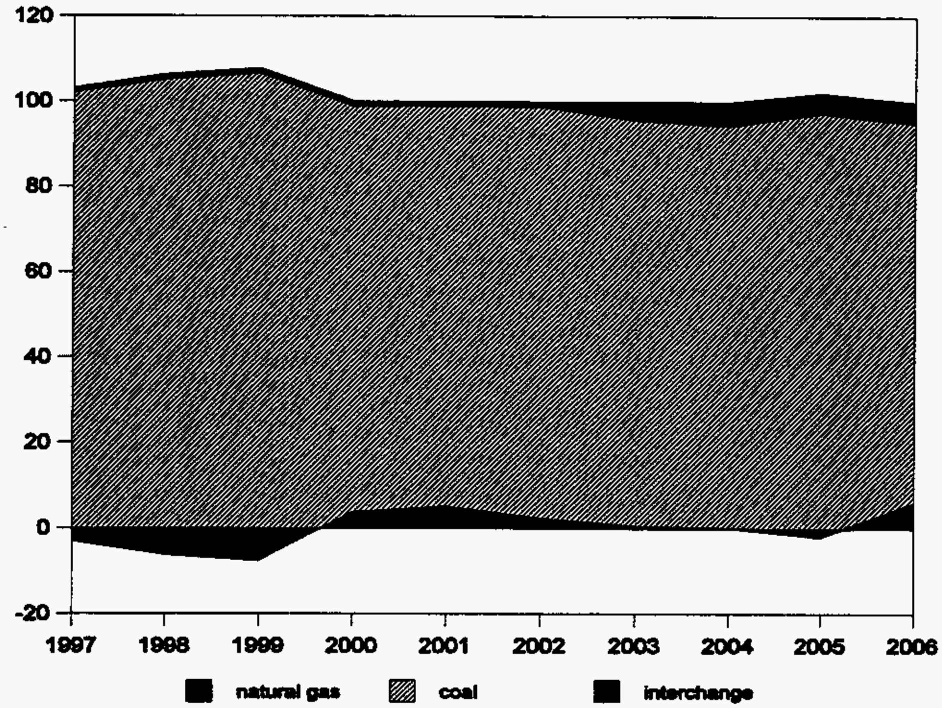


Figure 16: Gulf Generation Mix - % by fuel type (1997-2006)

CONSERVATION

Gulf does not have an interruptible service tariff. However, 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 2006 winter demand by an estimated 533 MW (21%) from what it would have been without DSM. Over the next ten years, Gulf's DSM programs are projected to contribute approximately 7.6% of the aggregate winter demand savings forecasted by the state's utilities.

To date, Gulf's residential DSM programs have yielded cumulative summer demand and annual energy savings that are less than Gulf's residential demand and energy goals set by the Commission in 1994. Further, the winter demand savings from commercial / industrial (C/I) programs have failed to meet Gulf's goal. Gulf has met only its C/I summer peak demand goal. Gulf does not have a numeric goal for residential winter 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. AEM was delayed because the equipment was unavailable for installation in customer homes until August, 1997. Gulf came closer to meeting its numeric DSM goals in 1996 than it did in 1995, and Gulf expects to catch up to its cumulative goals. The Commission will continue to monitor Gulf's DSM savings to determine whether Gulf meets its Commission-approved goals for 1997.

FUEL FORECAST

Each year, the Southern Company develops a fuel price forecast for coal, residual and distillate oil, and natural gas which extends through Gulf's planning horizon. The 1997 fuel price forecast was developed by a fuel 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 fuel 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 fuel panel's base case forecast. The fuel panel then developed sensitivities to the price forecasts based on seasonal supply and demand assumptions. For all fuel types except residual oil, Gulf's 2006 price forecasts are at or above the reporting utilities' average 2006 price forecasts.

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).

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on Gulf's *Ten-Year Site Plan*:

Apalachee Regional Planning Council (ARPC): The effect of Gulf's two 100 MW plants near Sneads on the ecological productivity of the Apalachicola River must be evaluated prior to a determination on the consistency with the Strategic Regional Policy Plan.

Florida Department of Community Affairs (DCA): DCA cautions that in view of the position taken by the State in the past, Gulf should not expect to withdraw significant amounts of water from the Apalachicola and its tributary rivers to supply additional generation at the Scholz site.

Florida Department of Environmental Protection (DEP): DEP finds the Ten-Year Site Plan to be generally suitable for planning purposes.

Florida Game and Fresh Water Fish Commission (GFC): GFC provided a copy of its 1992 comments on unspecified adverse impacts on fish and wildlife at the Scholz site.

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.

TAMPA ELECTRIC COMPANY

Tampa Electric Company's (TECO) electric system currently has a total winter generating capacity of 3,650 MW. As shown in Figure 17 on the next page, 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. Although TECO can rely on oil- and natural gas-fired generation, these fuel types currently remain minimal relative to coal-fired generation.

Ten coal-fired units at Gannon and Big Bend supply 2,950 MW of TECO's current system capacity. TECO has small amounts of capacity from five fossil steam units (212 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 last year. TECO initially plans to use gasified coal to fuel the new unit, but future plans call for TECO to fuel the unit with gasified petcoke.

TECO's future generation expansion plans include the installation of two 181 MW natural gas-fired combustion turbine units at the Polk site, one each in 2003 and 2004. TECO currently plans to retire all five fossil steam units at the Hookers Point site (212 MW total) in 2003.

Until 1996, TECO's reliability criteria were a 20% reserve margin and an LOLP of 0.1 days per year. Last year, TECO reduced its 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 an EUE/NEL criterion.

LOAD FORECAST

TECO's load 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 considers a wide range of forecast assumptions that are identified in its plan. In addition to base case energy and demand forecasts, TECO constructed high and low band energy and demand forecasts, using explicit assumptions of customer growth, per capita income, employment, and electricity price.

TECO's absolute percent error in its 1992-1996 retail sales forecasts was 3.01%, which is slightly higher than the 2.79% average for all reporting utilities. TECO's base case energy sales and summer and winter demand forecasts through 2005 are higher than the comparable base case forecasts contained in last year's *Ten-Year Site Plan*. TECO's winter demand has historically grown at a rate of 4.70%, but it is forecasted to grow at 2.23% during the forecast period.

CONSERVATION

TECO offers ten DSM programs to its customers. Most of TECO's forecasted demand savings are expected to come from non-dispatchable conservation programs (winter demand reduction estimated at 697 MW in 2006) and a dispatchable load management program (400 MW). Interruptible service is forecasted to continue its contribution to TECO's demand savings, but winter demand savings from interruptible service are forecasted to decrease from 220 MW in 1997 to 185 MW by 2006.

In total, TECO's DSM programs are forecasted to reduce winter peak demand by approximately 1186 MW in 2006 (25.6%). Over the next ten years, TECO's DSM programs and non-firm service

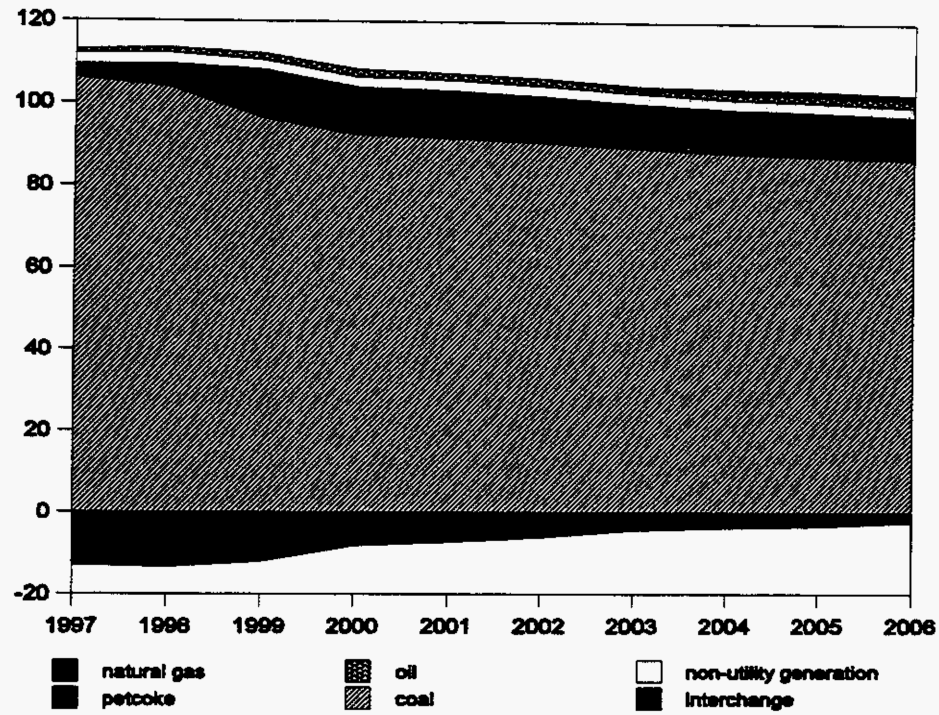


Figure 17: TECO Generation Mix - % by fuel type (1997-2006)

tariffs are projected to contribute about 17.5% of the aggregate winter demand savings forecasted by the state's utilities.

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. The energy savings from commercial/industrial programs also fail to meet TECO's C/I energy goal. TECO has met only its C/I winter and summer peak demand goals. TECO's failure to meet some DSM goals appears to be caused by delays in implementing newly-approved DSM programs. This is evidenced by the fact that TECO came closer to meeting its DSM goals in 1996 than in 1995. The Commission will continue to monitor TECO's DSM savings to determine whether TECO meets its DSM goals for 1997.

FUEL FORECAST

TECO provided a base, low, and high-price forecast for residual oil, distillate oil, and natural gas. Only a base-case fuel price forecast was provided for coal. TECO's 2006 fuel price forecast for all fuels other than coal is above the utilities' average 2006 price forecasts for these fuel types. The Commission questions whether TECO's residual oil, distillate oil, and natural gas price forecasts will materialize. TECO's projected differential between forecasted coal and natural gas prices causes concern. Additionally, the Commission strongly encourages TECO to provide high and low case price forecasts for coal so that interested parties may gauge the relative sensitivity of its generation expansion plans with respect to fuel prices.

ENVIRONMENTAL COMPLIANCE

TECO is subject to compliance restrictions contained in both Phase I and Phase II of the 1990 Clean Air Act Amendments (CAAA). TECO's compliance strategy is to defer additional scrubber capital investments as long as practical by using fuel switching, base loading the Polk IGCC unit, and through purchases of allowances. TECO has already made allowance purchases covering the period 1995 through 1999. The Polk IGCC unit is forecasted to reduce TECO's annual sulfur dioxide emission rate beginning in 2000 which would offset additional allowances required to meet retail load growth demands.

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. Because of TECO's dependence on older coal-fired generation, the emission rates of both TECO and Gulf are higher than those of FPL and FPC.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on TECO's *Ten-Year Site Plan*:

Florida Department of Community Affairs (DCA): DCA provided general comments on the expansion of the Polk site. DCA also expressed concern that TECO's planned transmission line addition in eastern Hillsborough County may impact environmentally sensitive wetlands and residential areas.

Florida Department of Environmental Protection (DEP): DEP finds the *Ten-Year Site Plan* to be generally suitable for planning purposes.

Southwest Florida Water Management District (SWFWMD): New withdrawals from the Floridian aquifer within the SWUCA may be restricted in the future. Utilities should work closely with District staff and consider alternative sources of water when planning new generation within the District.

Tampa Bay Regional Planning Council (TBRPC): TBRPC, Hillsborough County and Manatee County should be notified of any future changes to the Polk County Power Station or associated transmission lines. TBRPC approves the *Ten-Year Site Plan* as consistent with regional policies.

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.

FLORIDA MUNICIPAL POWER AGENCY

The Florida Municipal Power Agency (FMPA) is an organization of 26 municipal electric utilities that jointly manage and operate electric utility operations. Six members currently comprise the All-Requirements Project, meaning that FMPA has committed to plan for and supply all power requirements for these members. By 1998, FMPA plans to add four more all-requirements member cities: Fort Pierce, Key West, Lake Worth, and Vero Beach.

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), one combined cycle unit (54 MW), and five combustion turbines (88 MW). During the planning horizon, FMPA plans to install a 120 MW combined cycle unit in 2001. The addition of Fort Pierce, Key West, Lake Worth, and Vero Beach to FMPA's system by 1998 is forecasted to increase net interchange from 394 GWh in 1996 to 1936 GWh by 2006.

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 470,000 customers. 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.

Figure 18, on the next page, contains FMPA's projected generation mix by fuel type. The primary information gained from this figure reflects FMPA's need to rely on interchange capacity to serve its four new all-requirements member cities beginning in 1997.

LOAD FORECAST

FMPA used various econometric models to forecast sales by rate class, specific to each 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 only generally described. 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 the geographically-dispersed municipalities. The plan includes no discussion of weather assumptions. FMPA did not provide sensitivity analyses based upon varying economic and demographic assumptions. Further, insufficient historical forecast data exists to compare FMPA's forecast accuracy to other utilities in the state.

The addition of Ft. Pierce, Lake Worth, Key West, and Vero Beach to FMPA's All-Requirements Project is the main reason for the following facts:

- the 2006 customer forecast is 136% higher than 1996 actual customers;
- the 2006 NEL forecast is 144% higher than 1996 actual NEL; and
- the 2006 summer peak demand forecast is 147% higher than 1996 actual summer peak demand.

CONSERVATION

Member utilities individually promote their own conservation programs with assistance from FMPA. FMPA's all-requirements participants may choose from among seven conservation programs that have been evaluated to ensure cost effectiveness. FMPA projects these programs to reduce 2005 winter peak demand by an estimated

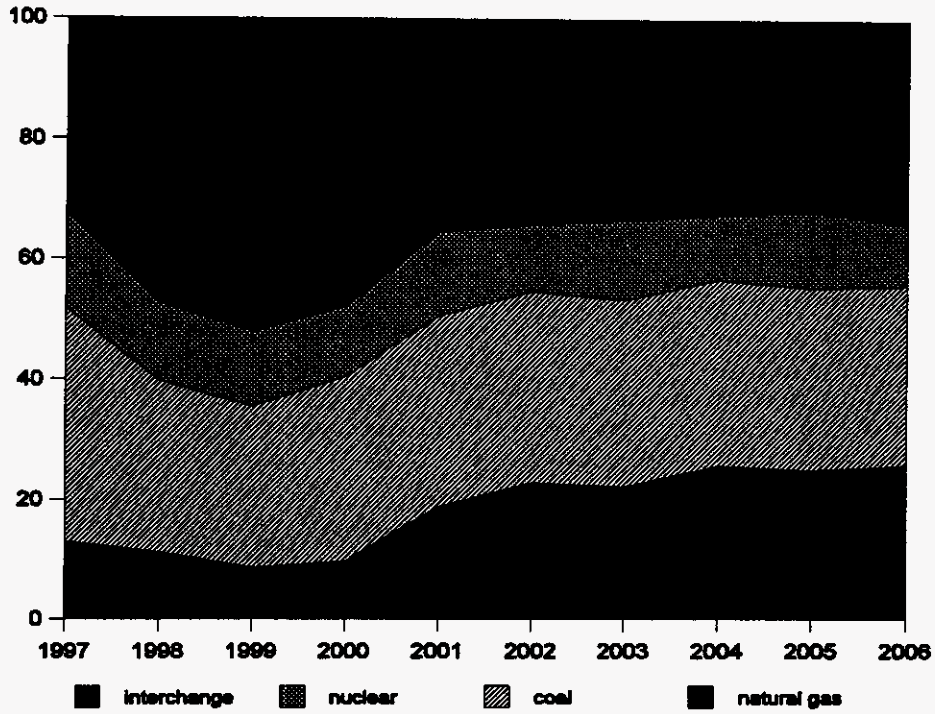


Figure 18: FMPA Generation Mix - % by fuel type (1997-2006)

9 MW (0.8% of the total winter load of FMPA's member utilities) Over the next ten years, FMPA's member utilities are projected to contribute just over 0.1% of the aggregate winter demand savings forecasted by the state's utilities. These projections may change in future Ten-Year Site Plans due to the Legislature's revision of the Florida Energy Efficiency and Conservation Act (FEECA) statute during the 1996 session.

FUEL FORECAST

FMPA provided a base-case fuel price forecast for all five fuel types. No high- and low-case price sensitivities were provided for any fuel. FMPA's 2006 price forecast for each fuel is significantly above the average for the reporting utilities. Surprisingly, FMPA's 2006 nuclear fuel price forecast is more than 60% above the average, and its 2006 distillate oil price forecast is approximately 50% higher than the average. Not surprisingly, FMPA uses distillate oil sparingly as an alternate fuel in its combustion turbines and combined cycle unit.

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.

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.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on FMPA's *Ten-Year Site Plan*:

Florida Department of Community Affairs (DCA): Due to the proximity of the new 120 MW Cane Island unit to environmentally significant areas, potential air quality and other environmental impacts should be monitored.

Florida Department of Environmental Protection (DEP): DEP finds FMPA's *Ten-Year Site Plan* to be generally suitable for planning purposes. FMPA's plan to use steam injection alone for NOx control at the proposed Cane Island unit is not likely to be considered Best Available Control Technology.

North Central Florida Regional Planning Council (NCFRPC): NCFRPC finds that FMPA's *Ten-Year Site Plan* is consistent with the goals and policies of the regional plan.

Northeast Florida Regional Planning Council (NEFRPC): NEFRPC finds that FMPA's *Ten-Year Site Plan* is consistent with regional goals regarding conservation. Since no proposed or preferred sites are located within the region, no comment were provided on these sites.

South Florida Regional Planning Council (SFRPC): SFRPC finds that 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 SFRPC region.

South Florida Water Management District (SFWMD): SFWMD provided no adverse comments on the suitability of sites. Any proposed increase in generating capacity at the Cane Island Power Park which results in increased water demands will likely require a modification in Surface Water Management and Water Use Permits. More specific information is needed in Ten-Year Site Plans in order for SFWMD to comment on water supply issues.

Southwest Florida Water Management District (SWFWMD): New withdrawals from the Floridian aquifer within the SWUCA may be restricted in the future. Utilities should work closely with SWFWMD staff and consider alternative sources of water when planning new generation within the district.

Treasure Coast Regional Planning Council (TCRPC): FMPA's *Ten-Year Site Plan* does not propose additional generating capacity within the Treasure Coast Region. TCRPC continues to urge FMPA to: 1) reduce reliance on fossil fuels; 2) increase conservation activities; and 3) increase solar generation.

Withlacoochee Regional Planning Council (WRPC): WRPC finds that the *Ten-Year Site Plan* is consistent with policies related to energy use, air quality, economic development and efficient movement of goods and services.

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.

GAINESVILLE REGIONAL UTILITIES

Gainesville Regional Utilities' (GRU) electric generating system currently has a winter capacity of 540 MW. The system consists of a 218 MW coal-fired steam turbine unit, three gas-fired steam turbine units (145 MW), six combustion turbines (166 MW), and an 11 MW ownership share of FPC's Crystal River 3 nuclear unit.

As illustrated in Figure 19 on the next page, 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 plan to build any new generation additions during the next ten years under their base demand and energy forecast. Under a high demand and energy forecast sensitivity, GRU forecasts a generic need for 55 MW of additional capacity in the year 2003.

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 also outlined the key assumptions underpinning this forecast. Among these are the following: normal weather conditions, declining real electricity prices, an inflation adjustment of all income and price figures 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.

GRU's absolute percent error in its 1992-1996 retail sales forecasts is 1.91%, lower than the numeric average for the ten reporting utilities. GRU's average forecast error for the same period is -1.91%, which shows a tendency to under-forecast.

GRU's summer peak demand forecast for the next ten years is projected to increase at an AAGR of 2.25%, less than the 3.48% AAGR for the 1987-1996 period. GRU does not specifically address the rationale that justifies these lower growth rates.

Overall, GRU's load forecast criteria are adequate. The statistical models used for this analysis are simple, yet comprehensive and very appropriate for the purposes of this study.

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, and public information and education programs. These programs are expected to reduce GRU's winter peak demand by an estimated 29 MW (5.1%) by 2006. Over the next ten years, GRU's DSM programs are projected to contribute about 0.4% of the aggregate winter demand savings forecasted by the state's utilities.

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.

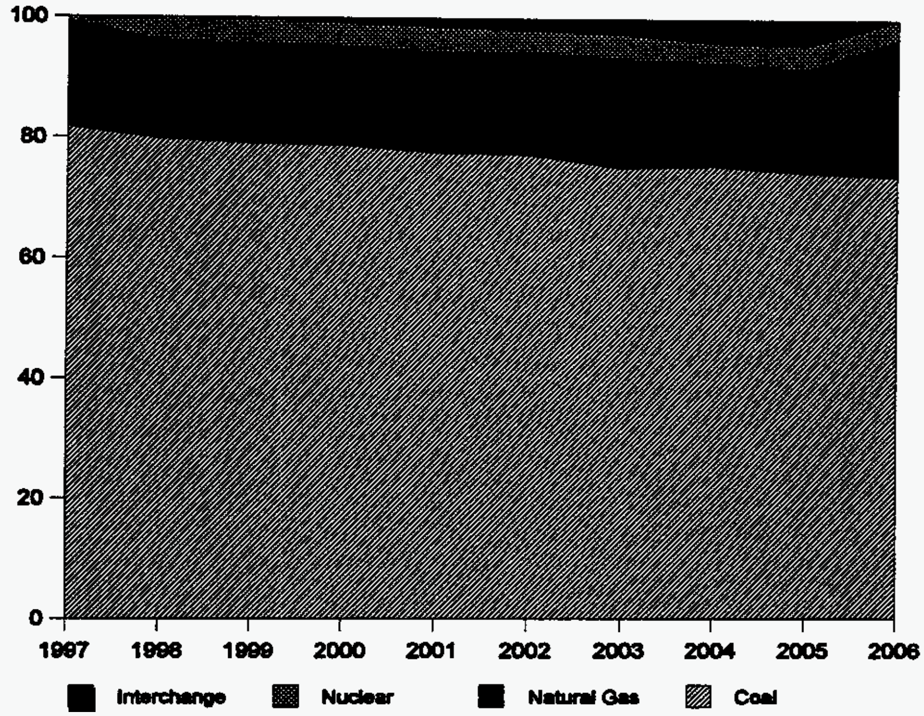


Figure 19: GRU Generation Mix - % by fuel type (1997-2006)

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.

GRU predicts that the price differential between the delivered price of natural gas and coal will widen over time. Coal is an abundant domestic fuel source that historically has had stable prices, while natural gas prices have typically been higher during the winter due to weather. Over the planning horizon, GRU expects fuel prices to escalate at an average annual rate of 2.3% for natural gas, but only 1.4% for coal. As in previous years, most utilities expect the price differential between natural gas and coal to widen during the planning horizon. This year, however, the magnitude of this differential has decreased.

GRU's 2006 coal and nuclear energy price forecasts are below the average of all reporting utilities. However, GRU forecasts residual oil, distillate oil, and natural gas prices to be significantly higher than the average of the reporting utilities.

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. 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.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on GRU's *Ten-Year Site Plan*:

Florida Department of Environmental Protection (DEP): DEP finds GRU's *Ten-Year Site Plan* to be generally suitable for planning purposes.

North Central Florida Regional Planning Council (NCFRPC): NCFRPC finds that GRU's *Ten-Year Site Plan* is consistent with the goals and policies of the regional plan.

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.

JACKSONVILLE ELECTRIC AUTHORITY

[NOTE: Jacksonville Electric Authority (JEA) officially withdrew its April, 1997 *Ten-Year Site Plan* on December 18, 1997. The following comments relate to this now-withdrawn plan. The Commission did not classify the withdrawn plan as "suitable" or "unsuitable." JEA has stated its intent to file a 1998 *Ten-Year Site Plan* by April 1, 1998.]

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on JEA's *Ten-Year Site Plan*, which was withdrawn on December 18, 1997:

Florida Department of Community Affairs (DCA): DCA finds the *Ten-Year Site Plan* contains no inconsistencies with the local comprehensive plan.

Florida Department of Environmental Protection (DEP): DEP finds that the *Ten-Year Site Plan* to be generally suitable for planning purposes.

Northeast Florida Regional Planning Council (NEFRPC): NEFRPC finds that JEA's DSM plan and use of methane gas are consistent with regional goals. JEA's plan to repower Southside Unit 3 is not inconsistent with the City of Jacksonville's Future Land Use Element.

CITY OF LAKELAND

The City of Lakeland's 654 MW electric system consists of 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). In 2001, Lakeland plans to use funds from the U.S. Department of Energy to build McIntosh Unit 4, a 157 MW fluidized bed coal unit. To ensure that this planned facility is the least-cost choice, Lakeland issued a request for proposals (RFP) for 20 years of firm capacity and energy. Responses are due later this year.

Concurrent with this planned generating resource addition, in 2001 Lakeland expects to retire 67 MW of steam-fired capacity. Lakeland plans to add two 56 MW gas-fired combustion turbine units at a yet-to-be determined site. These units are forecasted to be placed into service in 2002 and 2005. The impact of these resource additions on Lakeland's generation mix is shown in Figure 20 on the next page.

LOAD FORECAST

Lakeland's load forecast methodology includes several regression models measuring population, sales, NEL, and peak demand. Lakeland relies on Polk County population projections from the 1996 BEBR forecast. In addition, the service territory population projections are obtained via the number of residential accounts in the area and the results of the 1994 Appliance Saturation Survey.

Lakeland's absolute percent error in its 1992-1996 retail sales forecasts is 2.32%, lower than the numeric average for the ten reporting utilities in the state. Lakeland's average forecast error for the same period is -2.20%, which shows a tendency to under-forecast. Lakeland's winter peak demand forecast for the next ten years is projected to increase at an AAGR of 3.27%, which is lower than the 5.55% AAGR for the 1987-1996 period. Lakeland does not specifically address a rationale that accounts for these lower growth rates.

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

CONSERVATION

Lakeland 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, Lakeland offers two residential programs (load management and a loan program) and three commercial programs (lighting, thermal energy storage, and high-pressure sodium outdoor lighting). These programs are expected to reduce Lakeland's winter peak demand by an estimated 94 MW (11%) in 2006. Over the next ten years, Lakeland's DSM programs are projected to contribute about 1.3% of the aggregate winter demand savings forecasted by the state's utilities.

Although no longer subject to FEECA's requirements, Lakeland plans to continue its research into other DSM technologies, including photovoltaic applications. Lakeland plans to implement new conservation programs if they become cost-effective.

FUEL FORECAST

Lakeland provided fuel price forecasts under low, base, and high price scenarios for coal, natural gas, residual oil, distillate oil, petroleum coke, and refuse-derived fuel. The commodity and transportation components of coal and natural gas were forecasted independently, then added together to arrive at the delivered price of each fuel. Lakeland assumed that each fuel's future price would be a combination of spot and contract

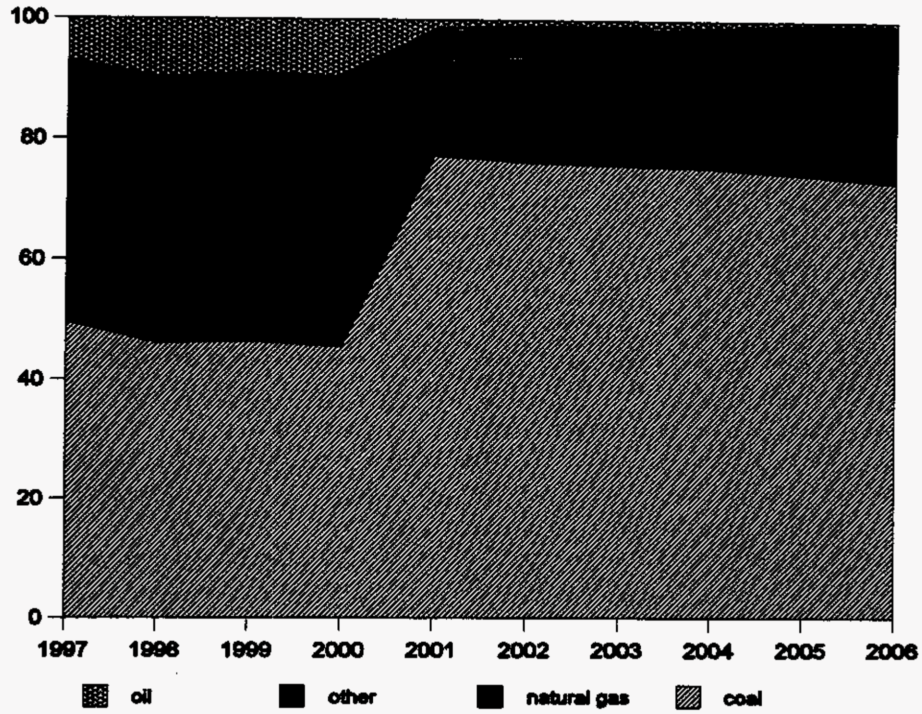


Figure 20: Lakeland Generation Mix - % by fuel type (1997-2006)

prices. Lakeland projected the prices for residual and distillate by assuming that they would fluctuate with crude oil prices. A similar assumption was made that petroleum coke prices would fluctuate with coal prices. The negative price of refuse-derived fuel (RDF) is calculated based on revenue collected the tipping fees established by the City of Lakeland, the amount of refuse collected, and the refuse's heating value.

Lakeland's fuel price forecast for residual oil, distillate oil, natural gas, and coal is near the average price forecasted by the other reporting utilities. Residual oil and distillate oil are expected to escalate at approximately the same rate from their current levels during the planning horizon. Also, natural gas, coal, petroleum coke, and RDF will maintain approximately their same margins during the next ten years.

ENVIRONMENTAL COMPLIANCE

Lakeland 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. In its response to the Commission's supplemental data request, Lakeland 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 Lakeland's resource expansion plan.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on Lakeland's *Ten-Year Site Plan*:

Florida Department of Community Affairs (DCA): DCA provided general comments on Lakeland's proposed expansion of the Macintosh site.

Florida Department of Environmental Protection (DEP): DEP finds Lakeland's *Ten-Year Site Plan* to be generally suitable for planning purposes.

Southwest Florida Water Management District (SWFWMD): New withdrawals from the Floridian aquifer within the SWUCA may be restricted in the future. Utilities should work closely with SWFWMD staff and consider alternative sources of water when planning new generation within the district.

SUITABILITY

Based upon the review of Lakeland's *Ten-Year Site Plan* and the related government and public comments, Lakeland's plan is **suitable** for planning purposes.

CITY OF TALLAHASSEE

The City of Tallahassee's (Tallahassee) existing generation mix consists primarily of natural gas-fired units and interchange capacity purchases, as shown on the next page in Figure 21. Tallahassee has five fossil steam turbines (408 MW), four combustion turbines (60 MW), three hydroelectric units (11 MW), and an ownership share in FPC's Crystal River Unit 3 (11 MW). In 1996, Tallahassee relied upon purchased power to meet approximately 39% of its load requirements.

On May 19, 1997 the Commission approved Tallahassee'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, Tallahassee's natural gas-fired generation is forecasted to increase to approximately 96% of load requirements by 2006. This new unit is expected to also cause Tallahassee to switch from a net buyer of interchange capacity to a net seller.

LOAD FORECAST

Tallahassee 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, Tallahassee has failed to properly document its outside sources for economic, weather and demographic data, regardless of whether it is historical or forecasted. Furthermore, Tallahassee has not included significant assumptions or informed judgments regarding its forecasts as recommended by the Commission in previous *Ten-Year Site Plan* Reviews.

Tallahassee's absolute percent error in its 1992-1996 retail sales forecasts is 2.97%, higher than the 2.79% numeric average for the ten reporting utilities. Tallahassee's average forecast error for the same period is -2.39%, which shows a tendency to under-forecast.

Tallahassee's summer peak demand forecast for the next ten years is projected to increase at an AAGR of 2.20%, less than the 3.64% AAGR corresponding to the 1987-1996 period. Tallahassee does not specifically address the reasons for these decreases. However, these figures are consistent with those of other electric utilities in the state.

CONSERVATION

Tallahassee is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA). However, Tallahassee does not expect to reduce its current commitment to conservation. Tallahassee'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. Tallahassee does not have a load management program. Tallahassee forecasts that its DSM programs will reduce winter peak demand by an estimated 58 MW (9.3%) in 2006. Over the next ten years, Tallahassee's DSM programs are projected to contribute nearly 0.8% of the aggregate winter demand savings forecasted by the state's utilities.

FUEL FORECAST

Except for nuclear fuel, Tallahassee provided a price forecast for all fuel types, including high and low price scenarios. Tallahassee'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

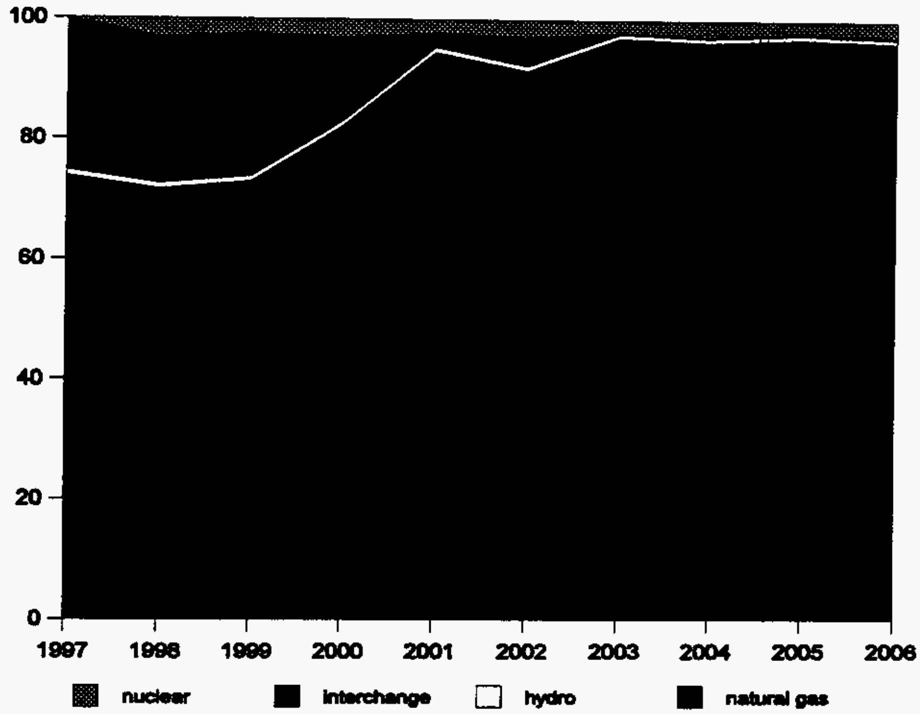


Figure 21: Tallahassee Generation Mix - % by fuel type (1997-2006)

natural gas price forecast prepared for Tallahassee. ICF Resources's most recent price forecast for residual oil, distillate oil, and coal price forecasts were also used. With the exception of natural gas, Tallahassee's 2006 price forecasts for the remaining fuels are significantly above the reporting utilities' average 2006 price forecast.

In its need determination for Purdom Unit 8 (Order No. PSC-97-0659-FOF-EM), Tallahassee 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 Tallahassee's self-build option for Purdom Unit 8 based partially on the projected fuel savings. If Tallahassee 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.

ENVIRONMENTAL COMPLIANCE

Tallahassee 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 Tallahassee'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 Tallahassee's replacement of interchange purchases with new generation from its own units.

Tallahassee 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 Tallahassee's expansion plan.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on Tallahassee's *Ten-Year Site Plan*:

Florida Department of Consumer Affairs (DCA): DCA provided general comments on the proposed addition to the Purdom site. DCA is participating in the state site certification process for Purdom Unit 8.

Florida Department of Environmental Protection (DEP): DEP finds Tallahassee's *Ten-Year Site Plan* to be generally suitable for planning purposes.

Florida Game and Fresh Water Fish Commission (GFC): GFC provided a copy of its 1992 comments which reiterate past comments on the placement of transmission lines crossing Lake Lafayette due to adverse impacts on fish and wildlife.

Wakulla County: The construction of Purdom Unit 8, with the associated retirement and dismantlement of Purdom Units 5 and 6, will represent an overall improvement of the Purdom site. However, the Purdom site has been designated as a Coastal High Hazard Area located on an Outstanding Florida Waterway. Therefore, Wakulla County has determined that adding Purdom Unit 8 is <u>inconsistent</u> with the county's Comprehensive Plan.

SUITABILITY

Based upon the review of Tallahassee's *Ten-Year Site Plan* and the related government and public comments, Tallahassee's plan is suitable for planning purposes.

SEMINOLE ELECTRIC COOPERATIVE

Seminole Electric Cooperative, Inc (SEC) provides full requirements to its eleven distribution system members. SEC currently relies on owned and purchased capacity resources to meet its members' needs. Seminole 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.

SEC's generating resources consist of two 625 MW coal-fired steam turbines in Palatka, and a 15 MW ownership in Florida Power Corporation's (FPC) Crystal River 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).

Seminole will diversify its generation resources with the addition of Hardee Power Station Unit 3 in January, 2002 (451 MW combined cycle unit) and nine combustion turbines (675 MW) by 2006. SEC is currently evaluating the bids resulting from a request for proposals for Hardee Unit 3 and for up to 1000 MW of capacity and energy to replace existing contracts. In addition, SEC's purchase contract of 145 of capacity from TECO's Big Bend 4 unit expires January 1, 2003, and may be replaced at SEC's option with an additional 145 MW CT at the Hardee site.

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.

However, SEC does not use reserve margin as a planning criteria. SEC uses expected unserved energy (EUE) as its sole reliability criterion because SEC relies heavily on other utilities to supply its full requirements and partial requirements capacity needs. When it calculates EUE, 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 regarding who has first call on Hardee Power Station's capacity.

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 judgments. SEC began its analyses with separate, individual load forecasts for each member cooperative; these were combined to yield the final forecast results. Within these analyses, SEC provided detailed

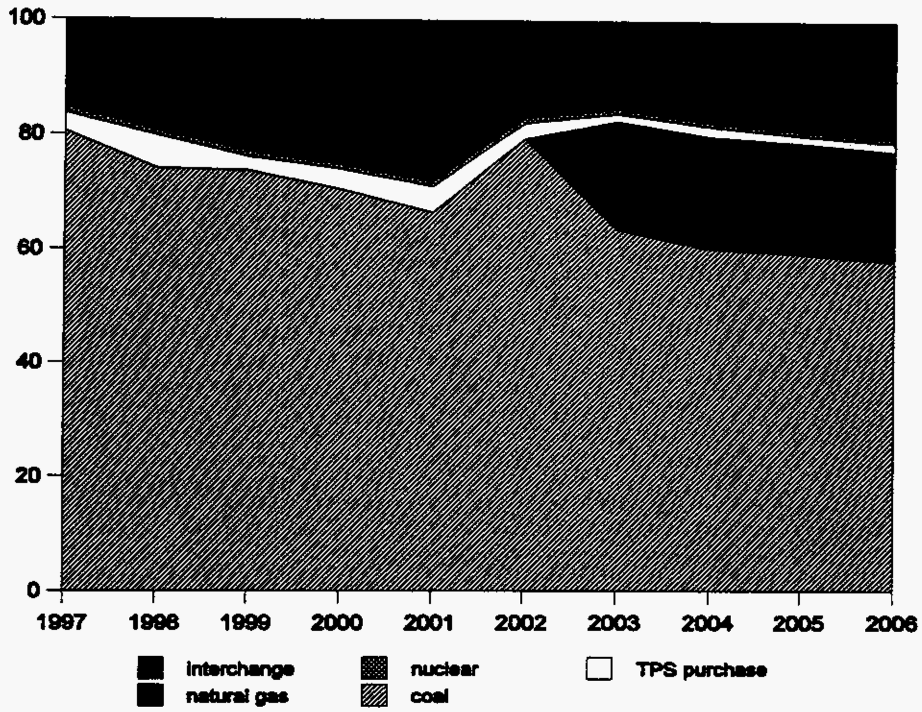


Figure 22: SEC Generation Mix - % by fuel type (1997-2006)

statistical accounts of alternate load forecasts for each customer class based on different economic and weather scenarios.

SEC's absolute percent error in its 1992-1996 retail sales forecasts is 3.59%, the highest among all reporting utilities in the state. SEC's average forecast error for the same period is an over-forecast of 2.39%. SEC's winter peak demand forecast for the next ten years is projected to increase at an AAGR of 3.86%, which is lower than the 5.26% AAGR for the 1987-1996 period. SEC justifies the difference when it addresses 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.

Overall, SEC's load forecast criteria are adequate. The models employed are comprehensive and include data sources that have been properly documented. However, the Commission recommends that SEC redefine some parameters in order to generate more accurate forecasts that may reduce its historical forecast error.

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 (246 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 (7.6%) in 2006. Over the next ten years, SEC's member utilities are projected to contribute approximately 5.2% of the aggregate winter demand savings forecasted by the state's utilities.

FUEL FORECAST

SEC provided a base, low, and high-price forecast for all fuel types except nuclear, to which SEC only provided a base-case forecast. SEC's coal price forecast assumes no significant change in domestic coal production costs or availability of transportation. SEC projects demand for low-sulfur coal to increase faster relative to that for medium- and high-sulfur coals primarily due to the 1990 Clean Air Act Amendments (CAAA). SEC believes that distillate oil will remain the most expensive fuel due to decreased domestic oil production, increased dependence on imported oil, and increased oil demand. Distillate oil prices usually create a price ceiling for the other fuels.

SEC's fuel price forecast shows slight increases for residual oil, natural gas, and coal, and slight decreases for distillate oil and nuclear fuel during the planning horizon. Average annual growth rates for fuel prices are forecasted to range from a high of 2.14% for natural gas to a low of -3.28% for distillate oil. In 2006, SEC expects to pay $21.67 per barrel for residual oil, $30.16 per barrel for distillate oil, $3.81 per MCF for natural gas, $41.52 per ton for coal and $0.61 per MMBtu for nuclear energy. SEC's fuel price forecast is reasonable for planning purposes.

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.

Response to the Commission's supplemental data requests showed that SEC's emission rates are projected to decline. Total emissions are more sensitive to SEC's forecast of energy usage rather than of fuel prices.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

The following agencies provided the Commission with comments on SEC's *Ten-Year Site Plan*:

Florida Department of Community Affairs (DCA): DCA notes that as part of the certification of the Hardee site, it was determined that the proposed use is consistent with local government comprehensive plans.

Florida Department of Environmental Protection (DEP): DEP finds SEC's *Ten-Year Site Plan* to be generally suitable for planning purposes.

North Central Florida Regional Planning Council (NCFRPC): NCFRPC finds that SEC's *Ten-Year Site Plan* is consistent with the goals and policies of the regional plan.

Northeast Florida Regional Planning Council (NEFRPC): SEC's *Ten-Year Site Plan* does not contain renewable energy resources. NEFRPC had no comments on planned facilities, as none are located within the region.

South Florida Water Management District (SFWMD): SFWMD offered no comments, since SEC plans no transmission lines or other facilities within the district. More specific information is needed in *Ten-Year Site Plans* in order to comment on water supply issues.

Southwest Florida Regional Planning Council (SWFRPC): SWFRPC offered no comments, since SEC plans no generation within the region.

Southwest Florida Water Management District (SWFWMD): New withdrawals from the Floridian aquifer within the

SWUCA may be restricted in the future. Utilities should work closely with District staff and consider alternative sources of water when planning new generation within the District.

Tampa Bay Regional Planning Council (TBRPC): TBRPC, Hillsborough County and Manatee County should be notified of any future changes to the Hardee Power Station or associated transmission lines. TBRPC approves SEC's *Ten-Year Site Plan* as consistent with regional policies.

Withlacoochee Regional Planning Council (WRPC): WRPC finds that SEC's *Ten-Year Site Plan* is consistent with regional goals and policies related to energy use, air quality, economic development and efficient movement of goods and services.

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.

V. APPENDIX

STATUS OF NEED DETERMINATIONS AND SITE CERTIFICATIONS

FPC Polk Units #1 and #2
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 is scheduled to be placed into commercial service by August, 1998. Construction of associated transmission improvements started in late 1996 and are due to be completed later this year. FPC plans to sell 440 MW from this facility to SEC for a three-year period from January, 1999 to January, 2002.

SEC 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 2002. This option became desirable because SEC plans to purchase 440 MW of firm capacity on a short-term basis from FPC's Polk County units during this period.

Tallahassee Purdom Unit #8
In May, 1997, the Commission granted Tallahassee's need petition for a 250 MW gas-fired combined cycle unit at the existing St. Marks site in Wakulla County. DEP is currently planning to hold permitting hearings starting later this year, and the Power Plant Siting Board is expected to make a final decision on Tallahassee's proposed unit in 1998. Prior to commencing construction, Tallahassee plans to study the power supply market to determine if purchased power is more cost-effective than Purdom Unit 8. If this study affirms the economics of Purdom Unit 8, the unit will be constructed and enter commercial service in May, 2000.

PLANNED, UNCERTIFIED GENERATING UNITS

Lakeland McIntosh Unit 4
Lakeland plans to build a 326 MW fluidized bed coal unit using funding from the U.S. Department of Energy's Clean Coal Technology Program. The unit will be built in two phases: Phase 1 (157 MW) is expected to be placed into service in January, 2002; Phase 2 (169 MW) is expected to be completed by January, 2005. If Lakeland ultimately plans to build rather than purchase capacity, McIntosh Unit 4 will require certification under the Power Plant Siting Act.

PUBLIC WORKSHOP COMMENTS

The Commission received written comments on Ten-Year Site Plans from many review agencies. Utility-specific comments were addressed previously in this report. At its August 8, 1997 Public Workshop, the Commission received written comments from the *Legal Environmental Assistance Foundation (LEAF)* and from the *Project for an Energy Efficient Florida (PEEF)*.

LEAF and PEEF urged the Commission to find all utility Ten-Year Site Plans to be unsuitable. LEAF/PEEF jointly submitted "Florida's Dirty Secret: A Report Card on Florida's Electric Utilities", a publication which discusses an opinion that electric power generating units adversely impact the environment and health of Floridians. In grading the performance of Florida's electric utilities as unsatisfactory, the joint LEAF/PEEF report draws eight major conclusions: (1) electric generation is a major source of local and regional air pollution; (2) environmental health costs are not considered; and (3) most pollution is from a small number of large utilities; (4) pollution rates vary significantly; (5) competition in the electric industry has major implications; (6) utility conservation programs save little to no energy; (7) utilities make only token use of clean renewable energy; and (8) utility disclosure of air emissions data is useful to consumers.