ORIGINAL

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October 30, 2000

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

VIA FEDERAL EXPRESS

In re: Petition for Determination of Need of Hines Unit 2 Power Plant
Docket No: ~~00164-EI~~ 001064-EI

Dear Ms. Bayo:

Florida Power Corporation ("FPC" or the "Company") is filing herewith an original and fifteen (15) copies of the Notice of Filing Documents Officially Recognized by the Commission.

We request you acknowledge receipt and filing of the above by stamping the additional copy of this letter and returning it to me in the self-addressed, stamped envelope provided.

If you or your Staff have any questions regarding this filing, please contact me at (727) 821-7000.

Very truly yours,

Gary L. Sasso

APP ____
CAF ____
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BEFORE THE PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need of Hines Unit 2 Power Plant.	)	DOCKET NO.: 001064-EI
	)	Submitted for Filing: October 31, 2000

NOTICE OF FILING DOCUMENTS OFFICIALLY RECOGNIZED BY THE COMMISSION

On October 25, 2000, Florida Power Corporation ("FPC") filed and served its Request for Official Recognition (including seven items) in the above styled matter. On October 26, 2000, the Florida Public Service Commission took official recognition of items one through three and seven during the final hearing on FPC's request for a determination of need to build its proposed Hines 2 power plant. FPC now gives notice of filing copies of these items as specifically identified below:

1. Review of Electric Utility 1999 Ten-Year Site Plans, December 1999, Florida Public Service Commission, Division of Electric and Gas; Division of Auditing and Financial Analysis.

2. Hearing Transcript of the August 18, 1999 Agenda Conference in Docket No. 980783-EI, In Re: Petition by Gulf Power Company for waiver of portions of Rule 25-22.082(4)(a), F.A.C., Selection of Generation Capacity.

3. Hearing Transcript Volumes I-VI, In the Matter of Proposed Amendment of Rule 25-22.081, F.A.C.; and Proposed New Rule 25-22.082, F.A.C., Selection of Generating Capacity: Wednesday September 9, 1993; Thursday September 30, 1993; October 1, 1993.

7. Final Order Approving Certification, In Re: Application for Power Plant Certification of Florida Power Corporation Polk County Site, Before the Governor and Cabinet Sitting as the Florida Siting Board, dated January 25, 1994 (separate request also made on Aug. 7, 2000).

Each of these items is publicly available, and such copies are submitted simply for the convenience of the Commissioners and their Staff.

Respectfully submitted,

FLORIDA POWER CORPORATION

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing notice has been furnished via U.S. Mail to all counsel and other parties of record this 30th day of October, 2000.

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REVIEW OF ELECTRIC UTILITY 1999 TEN-YEAR SITE PLANS

VOLUME 1: REVIEW AND ANALYSIS

December, 1999

FLORIDA PUBLIC SERVICE COMMISSION

Division of Electric and Gas
Division of Auditing and Financial Analysis

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INTRODUCTION

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

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

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

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

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

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

PURPOSE -- What is the purpose of this document?

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

INTRODUCTION

PUBLIC INVOLVEMENT

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

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

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

EXECUTIVE SUMMARY

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

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

REQUIREMENT	ACTION
Review the need for electrical power in the area to be served	Reviewed load forecasts, demand-side management (DSM) assumptions, and reliability criteria.
Review possible alternatives to the proposed *Plan*	Reviewed DSM assumptions, fuel forecasts, and generation alternatives modeled to arrive at the projected expansion plan.
Review anticipated environmental impact of proposed power plant sites	Since the Commission does not have expertise in this area, it requested comments from DEP and water management districts regarding environmental impacts and compliance. Comments are summarized in the individual utility sections of this report. Complete comments contained in Volume 2.
Consider views of local and state agencies regarding water and growth management issues	Requested comments from affected agencies. Comments are summarized in the individual utility sections of this report. Complete comments contained in Volume 2.
Determine consistency of *Plan* with the State Comprehensive Plan	Evaluated energy-related aspects of the Comprehensive Plan. Reviewed comments provided by the Department of Community Affairs and from regional and local planning agencies on growth management and Comprehensive Plan issues. These comments are summarized in the individual utility sections of this report. Complete comments contained in Volume 2.
Review *Plan* for information on energy availability and consumption	Reviewed load forecast data and methodologies used to arrive at load and energy forecasts.

EXECUTIVE SUMMARY

FLORIDA RELIABILITY COORDINATING COUNCIL

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

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

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

SUITABILITY AND CRITICAL CONCERNS

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

FRCC'S *1999 RESERVE MARGIN ANALYSIS*

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

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

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

- The FRCC's 15% planning reserve margin criterion can have a substantial adverse impact on operating reserves.

- A seasonal winter and summer peak reserve margin does not account for reliability concerns during off-peak periods of the year.

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

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

AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

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

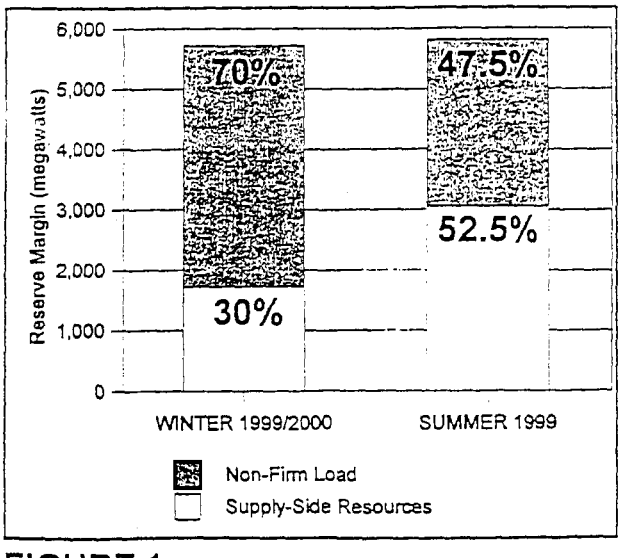


FIGURE 1
RESERVE MARGIN COMPONENTS - 1999

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

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

RESERVE MARGIN INVESTIGATION (DOCKET NO. 981890-EI)

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

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

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

RISKS AFFECTING PLANS

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

COMPETITION

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

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

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

NATURAL GAS AVAILABILITY

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

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

DECLINING COST-EFFECTIVENESS OF DEMAND-SIDE MANAGEMENT PROGRAMS

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

ENVIRONMENTAL COMPLIANCE

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

EXECUTIVE SUMMARY

SUMMARY OF RESOURCE ADDITIONS

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

THE 1999 UTILITY STATEWIDE PLAN

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

RESOURCE TYPE	Winter Capacity (MW)
 COMBINED CYCLE UNITS [1]	6,684
 COMBUSTION TURBINE UNITS	4,342
 CONSERVATION AND DEMAND-SIDE MEASURES [2]	1,554
 COAL UNITS [1]	238
 COGENERATION [3]	-185
FOSSIL AND NUCLEAR STEAM UNITS [1]	-601
TOTAL NET RESOURCE ADDITIONS	12,032

FIRM PEAK DEMAND INCREASE	8,452

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

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

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

FIGURE 2
UTILITY RESOURCE ADDITIONS IN THE NEXT TEN YEARS

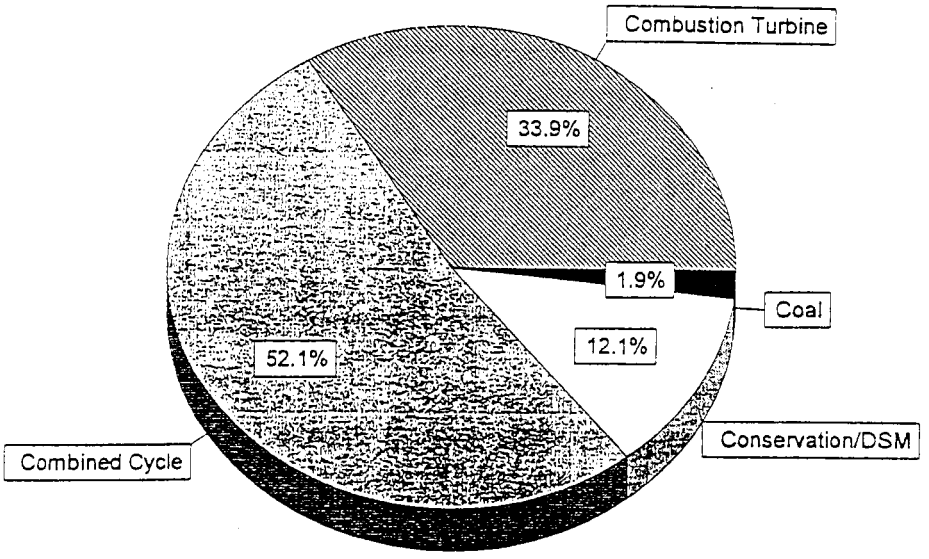


FIGURE 3
UTILITY RESOURCE MIX BY PLANT TYPE -- PRESENT AND FUTURE

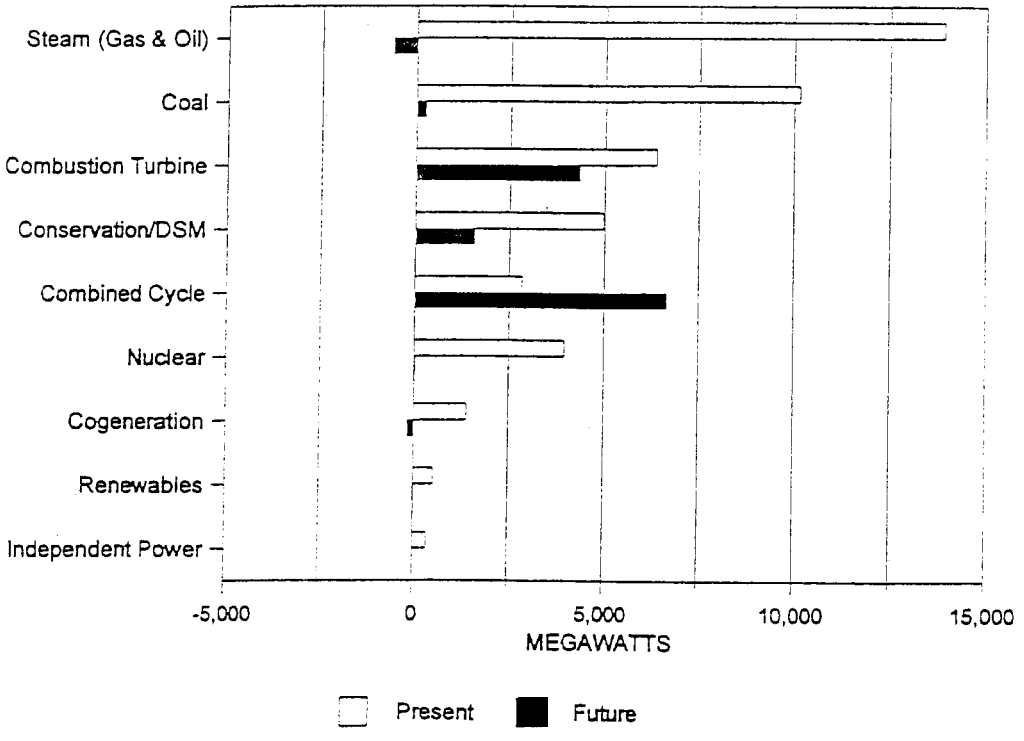
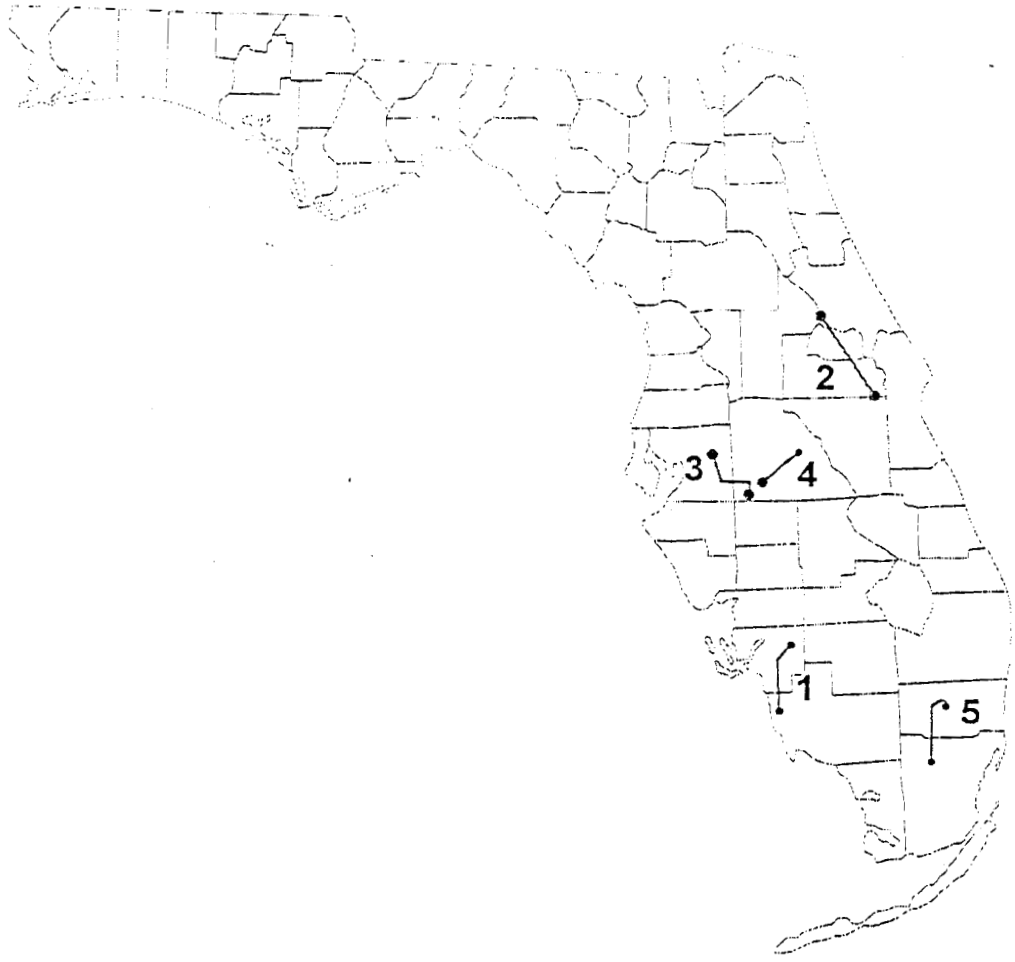


FIGURE 4
PROPOSED MAJOR TRANSMISSION LINES [4]



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

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

INTEGRATED RESOURCE PLANNING

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

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

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

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

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

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

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

Florida Statutes

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

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

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

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

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

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

Rules (Florida Administrative Code)

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

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

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

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

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

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

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

LOAD FORECAST

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

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

EVALUATION OF LOAD FORECASTING METHODOLOGY

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

Collection of Historical Data

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

Derivation of Forecast Model Parameters

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

Assembly of Forecast Assumptions

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

Calculation of Forecast

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

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

EVALUATION OF HISTORICAL FORECAST ACCURACY

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

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

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

TABLE 2
TOTAL RETAIL ENERGY SALES --
HISTORICAL FORECAST ACCURACY

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

Consistency of Forecasts with Historical Trends

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

Summary of Load Forecast Evaluation Process

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

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

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

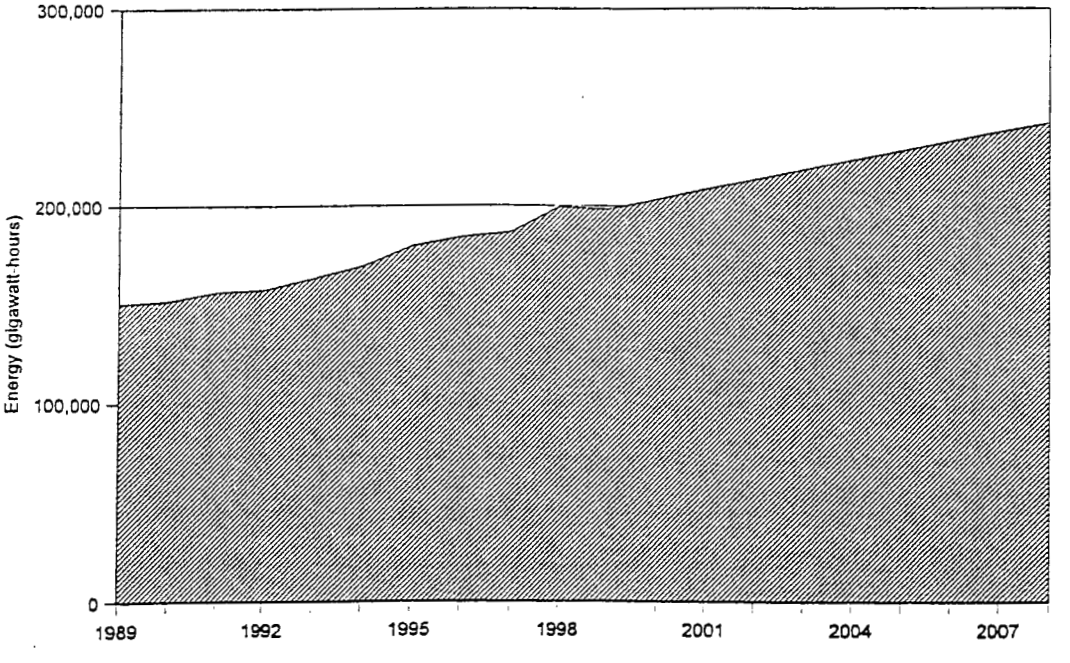


FIGURE 6
SUMMER FIRM PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST

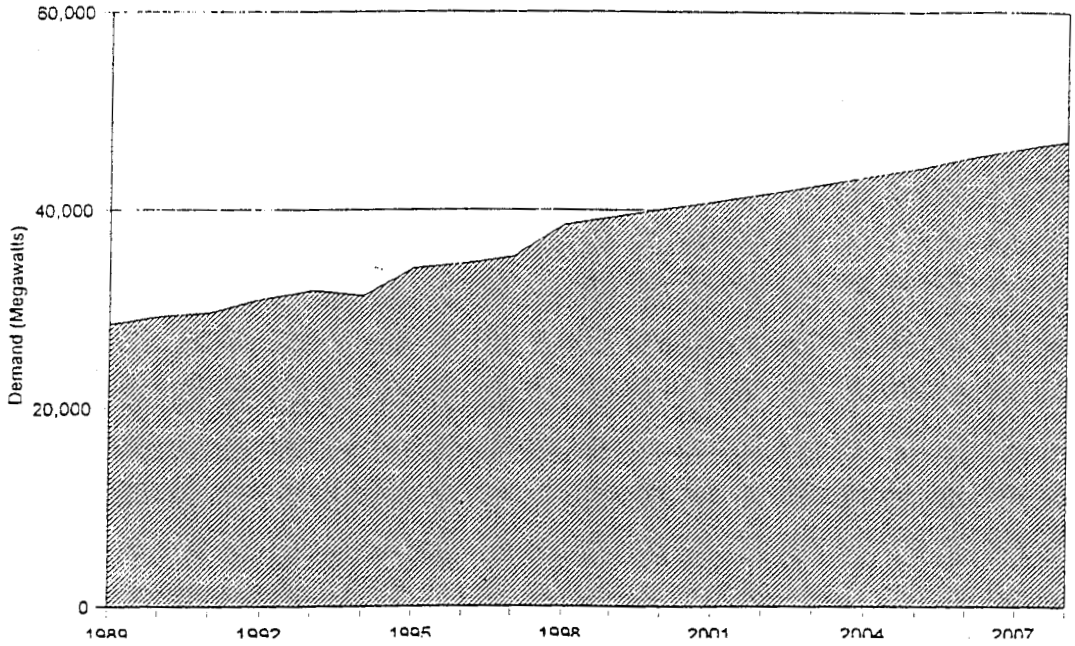
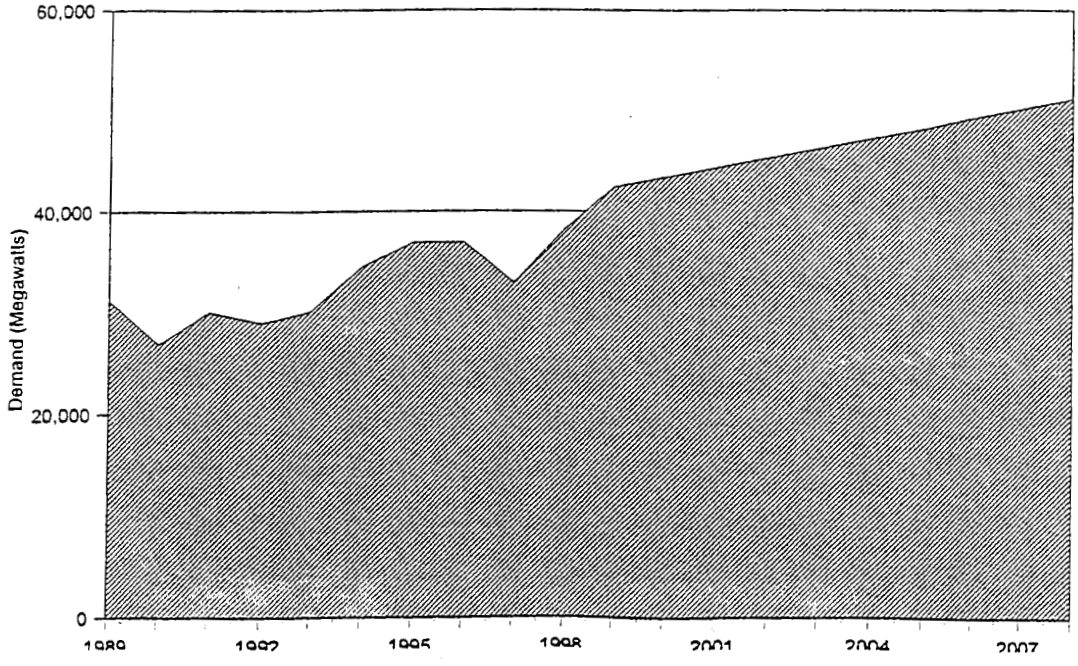


FIGURE 7
WINTER FIRM PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST



DEMAND-SIDE MANAGEMENT

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

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

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

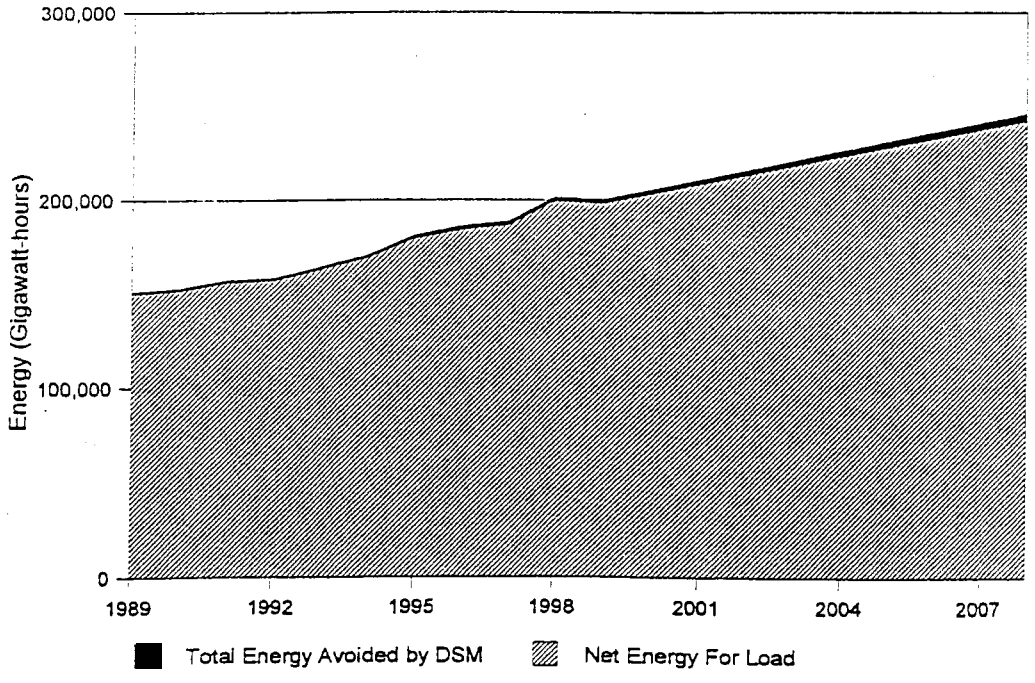


FIGURE 9
ESTIMATED IMPACT OF DSM ON SUMMER PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST

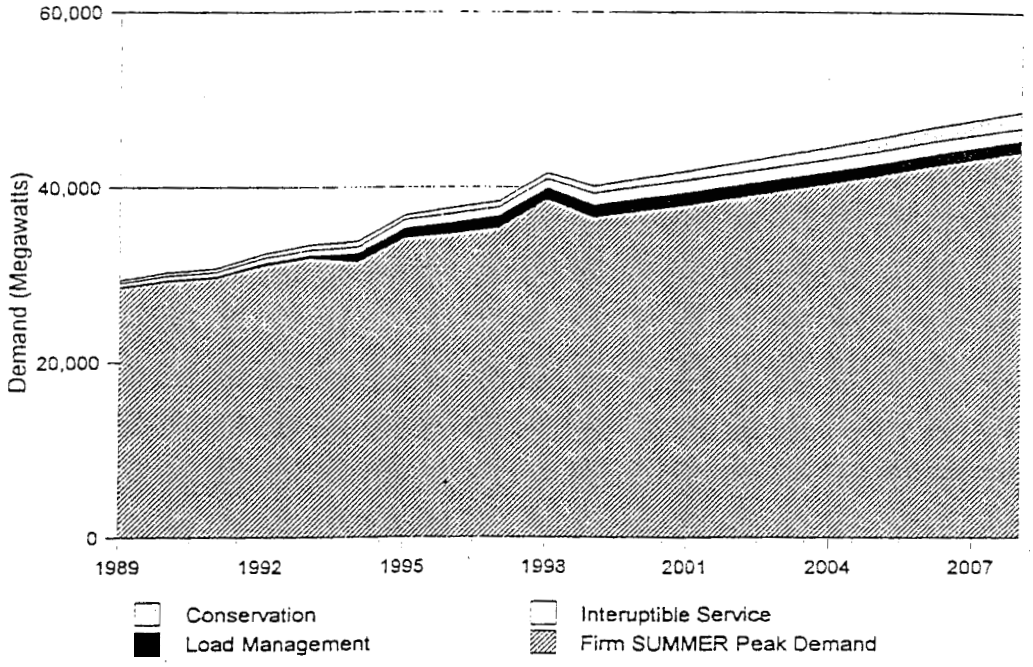
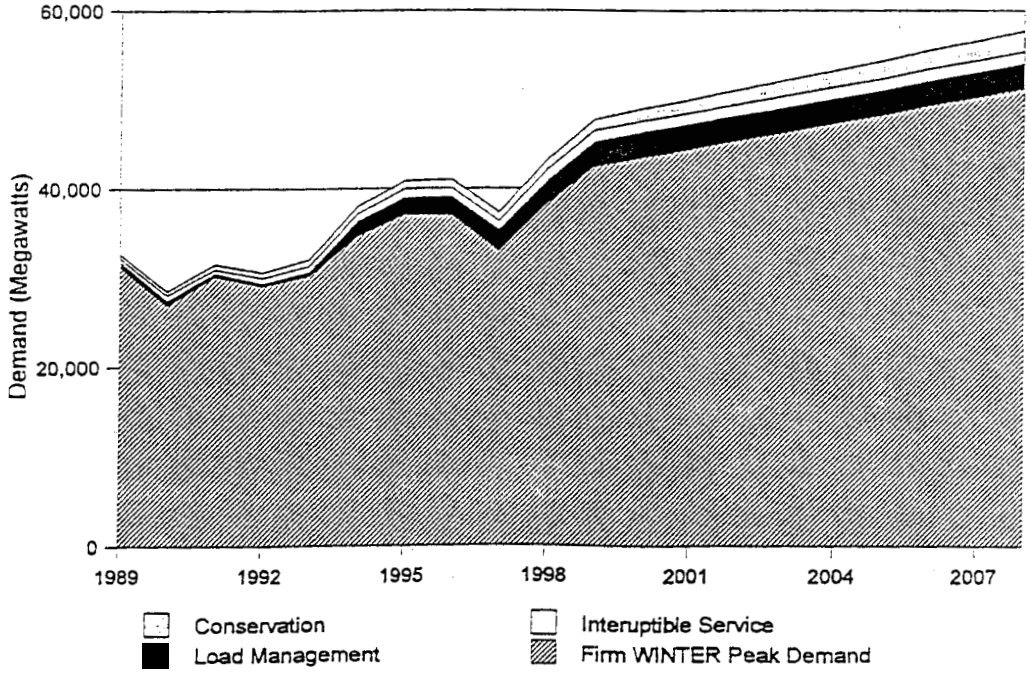


FIGURE 10
ESTIMATED IMPACT OF DSM ON WINTER PEAK DEMAND
STATE OF FLORIDA -- HISTORY & FORECAST



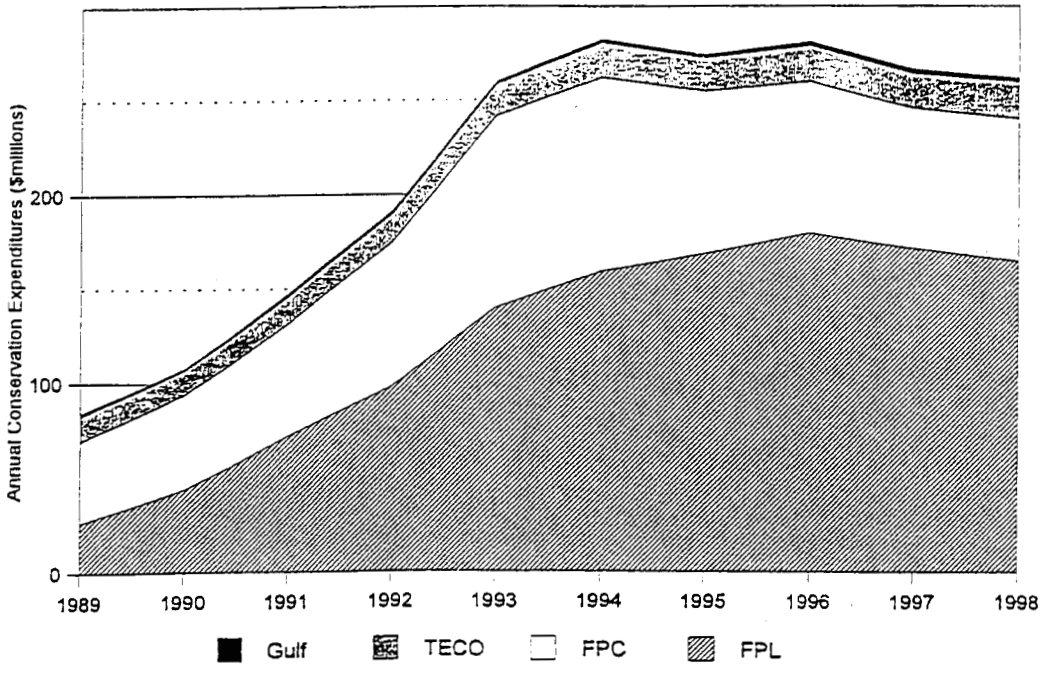
It is not clear whether dispatchable DSM is sustainable over the planning horizon given the current low level of Peninsular Florida's reserve margins. Furthermore, if a utility relies on DSM rather than constructing a generating unit, the utility may also forego opportunity sales. Finally, there may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

ENERGY CONSERVATION COST RECOVERY CLAUSE

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

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

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



REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

CHANGES TO FEECA

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

DEMAND-SIDE MANAGEMENT GOALS

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

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

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

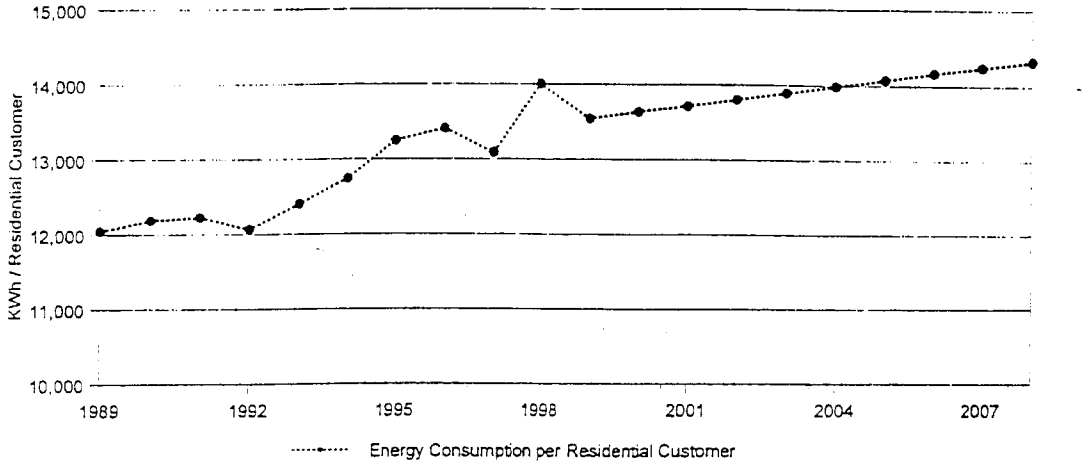
STATE COMPREHENSIVE PLAN

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

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

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

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



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

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

RELIABILITY REQUIREMENTS

RELIABILITY CRITERIA

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

Deterministic Criteria

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

TABLE 3
RELIABILITY CRITERIA FOR REPORTING UTILITIES

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

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

Probabilistic Criteria

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

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

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

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

FIGURE 13
UTILITY FORECASTED RESERVE MARGIN -- STATE OF FLORIDA

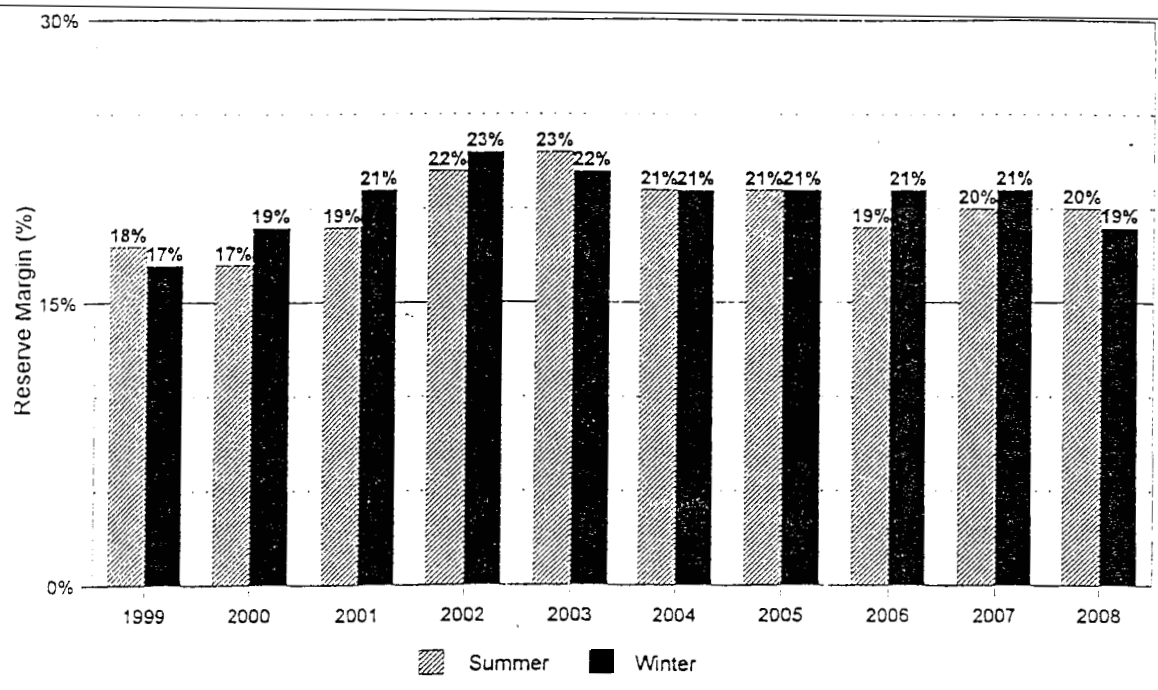
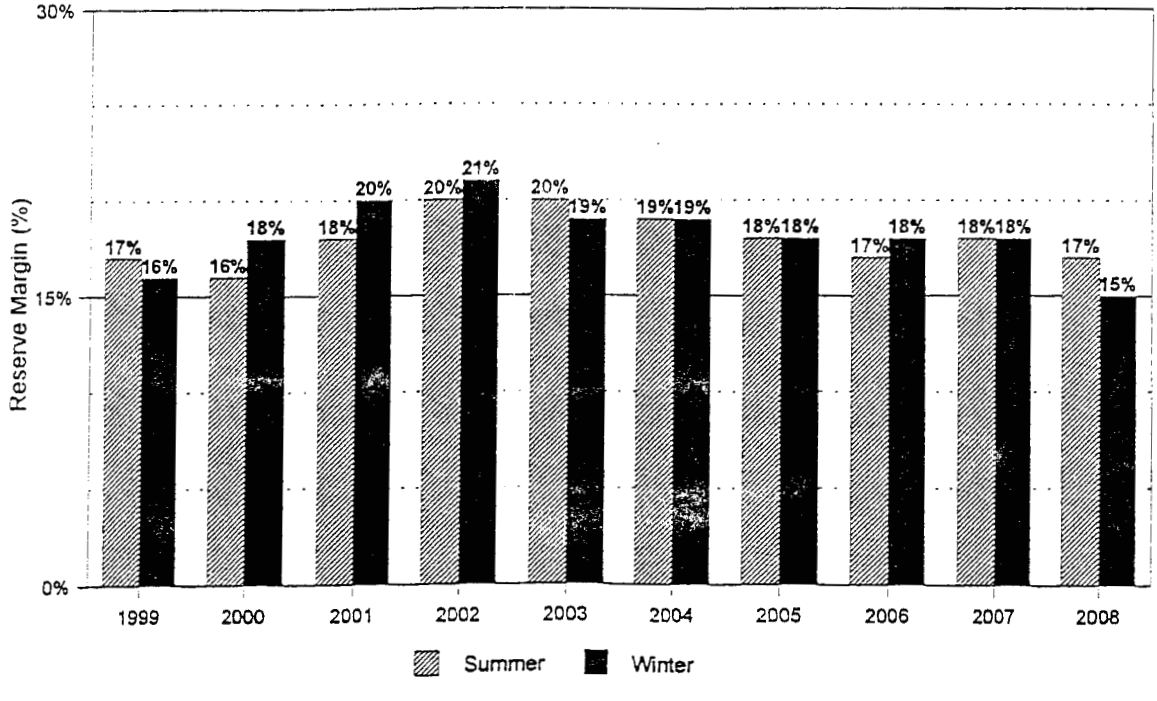


FIGURE 14
UTILITY FORECASTED RESERVE MARGIN -- PENINSULAR FLORIDA



REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

POTENTIAL IMPACT OF MERCHANT PLANTS ON RELIABILITY

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

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

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

TABLE 4
PLANNED MERCHANT PLANT ADDITIONS

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

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

FUEL FORECAST

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

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

(1) Specific knowledge of contractual relationships with fuel vendors is typically combined with reasonable assumptions of future events which the utility cannot control.

(2) Additional forecast sensitivities may be performed by adjusting the assumptions used to test the utility's generation expansion plan under various economic and technical scenarios.

(3) To test their reasonableness, utility-specific fuel price forecasts are compared to several outside sources such as the U.S. Energy Information Administration (EIA), the Gas Research Institute, the American Gas Association, and DRI/McGraw-Hill.

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

COAL

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

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

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

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

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

PETROLEUM

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

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

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

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

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

Residual Oil

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

Distillate Oil

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

Petroleum Coke

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

NATURAL GAS

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

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

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

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

NUCLEAR

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

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

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

RENEWABLES

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

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

GENERATION SELECTION

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

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

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

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

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

GENERATION SELECTION PROCESS

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

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

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

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

TABLE 6
NEXT UTILITY-PLANNED GENERATING UNIT ADDITION
(CERTIFICATION NOT REQUIRED OR NOT YET RECEIVED)

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

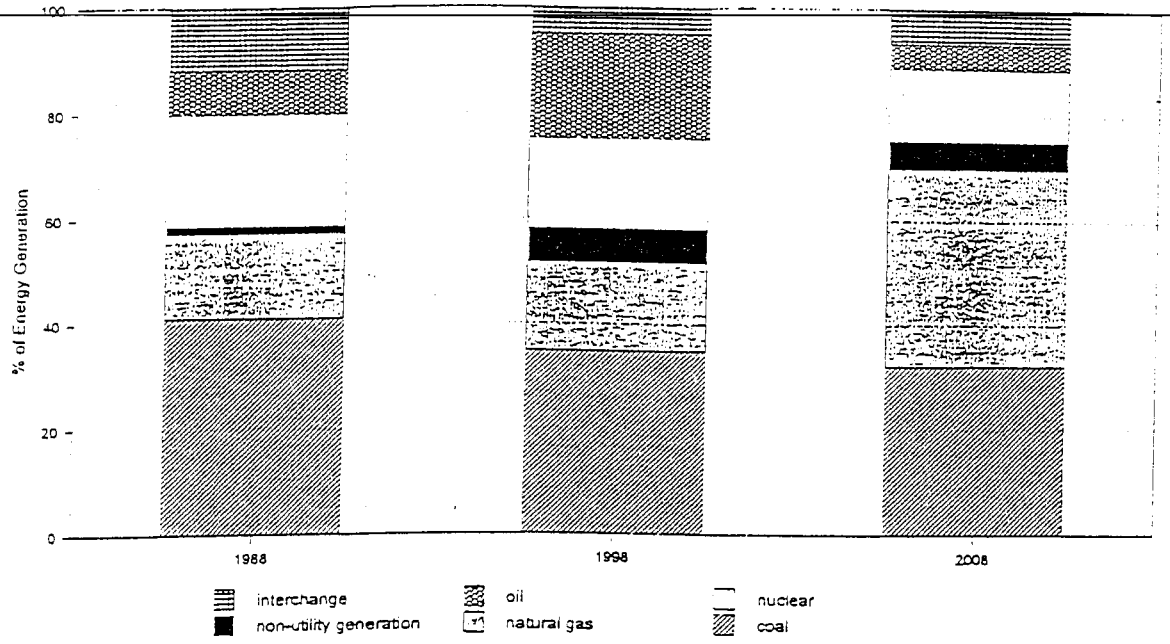
FLORIDA'S GENERATION MIX

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

Natural Gas

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

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



Coal

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

Coal Gasification

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

Hydroelectric

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

Interchange Purchases

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

Purchases from Non-Utility Generators

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

CRITICAL CONCERNS

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

FRCC 1999 RESERVE MARGIN ANALYSIS

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

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

(1) Base case loss of load probability (LOLP) values for 1999, like those forecasted in 1998, are extremely low. These low LOLP values are driven by high forecasted unit availabilities. If unit availabilities degrade to levels seen a decade ago, Peninsular Florida's utilities will likely experience capacity shortages. If utilities reduce maintenance on existing units to minimize costs, or if they hesitate to build new needed generating units, capacity shortages may become a certainty in the near future.

(2) The generally accepted 0.1 days per year LOLP criterion appears to translate to a Peninsular Florida reserve margin of approximately 6% to 8%. The FRCC agrees that a 6% to 8% reserve margin is unrealistically low; therefore, reserve margin is the criterion driving the need for additional capacity in Peninsular Florida. Yet, Florida's utilities have no real-time experience with which to test the adequacy of a 15% reserve margin planning criterion.

(3) A planning reserve margin criterion of 15% can have a substantial adverse impact on operating reserves. A *capacity alert* occurs when Peninsular Florida's operating reserves are small enough such that the loss of the largest unit or major transmission line would cause a capacity shortfall. The Commission has identified five separate occasions since 1998 where Peninsular Florida's operating reserves could have triggered a capacity alert situation had planning reserves been at 15%.

(4) Analysis of winter and summer peak reserve margin does not account for reliability concerns during off-peak periods. Many units are out of service for maintenance during

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

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

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

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

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

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

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

AMOUNT OF RESERVES PROVIDED BY NON-FIRM RESOURCES

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

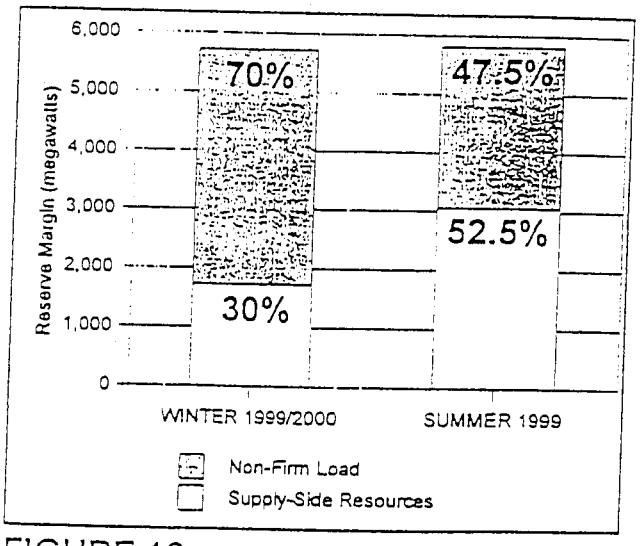


FIGURE 16
RESERVE MARGIN COMPONENTS - 1999

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

REVIEW AND ANALYSIS - STATEWIDE PERSPECTIVE

RESERVE MARGIN INVESTIGATION (DOCKET NO. 981890-EI)

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

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

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

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

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

RISKS AFFECTING PLANS

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

COMPETITION

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

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

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

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

NATURAL GAS AVAILABILITY

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

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

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

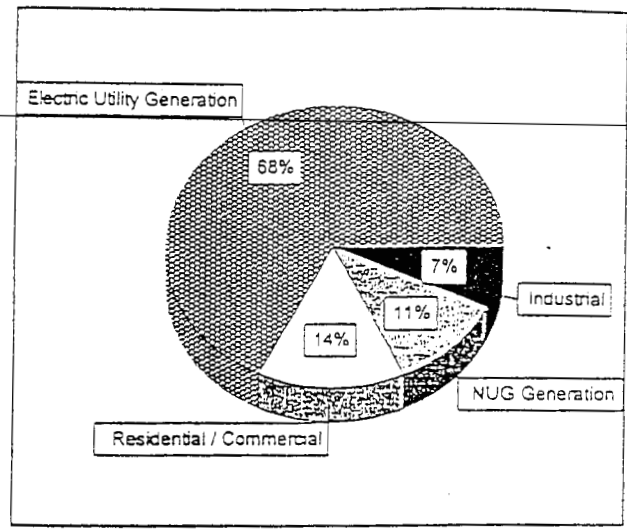


FIGURE 17
NATURAL GAS CONSUMPTION BY END-USER -- 1999

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

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

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

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

- Coastal Corporation plans to construct the 700-mile long Gulfstream Natural Gas pipeline. As proposed, the 1.0 Bcf/day pipeline will extend from near Mobile, Alabama, across the Gulf of Mexico, to near Port Manatee. Once on shore, the pipeline will proceed east to a terminus near the Okeechobee Generating Company's proposed merchant plant. The Gulfstream pipeline has an expected in-service date of June, 2002. Coastal filed an application with the FERC on October 15, 1999.

- Duke Energy's Sawgrass pipeline project has two pipeline segments representing different ownership interests. The first segment will extend from the Dauphin Island Gathering Partnership processing plant near Coden, Alabama to a termination point in Panama City, Florida. The proposed in-service date is 2001. The other pipeline will extend from the Coden plant (through expansion of the Enron-Duke Energy system) into Peninsular Florida. This segment, as proposed, will have a capacity of 0.7 Bcf/day at its November, 2002 in-service date. Duke Energy plans to file an application with the FERC in early 2000.

- The proposed 420-mile long Williams-Transco Buccaneer pipeline is a 1.0 Bcf/day project which will extend from a processing plant in Mobile County, Alabama, across the Gulf of Mexico to the west coast of Florida just north of Tampa, and continue onshore in a easterly direction. The Buccaneer pipeline has an expected in-service date of April, 2002. Williams filed an application with the FERC on October 28, 1999

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

DECLINING COST-EFFECTIVENESS OF DEMAND-SIDE MANAGEMENT PROGRAMS

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

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

ENVIRONMENTAL COMPLIANCE

Table 7 shows the forecasted base-case composite emission rates of Florida's electric utilities. Most utilities forecast declines in their emission rates compared to 1998 estimates. Most of this decline is due to gas-fired repowering projects, while fuel switching and retirement of small oil-fired units account for the rest. Natural gas is clearly the fuel of choice for new generation. Not only have there been improvements in natural gas generation technology, but natural gas-fired generation produces no ash and almost no sulfur dioxide (SO_2) air pollution. Utilities owning coal-fired facilities are contending with air emission restrictions on SO_2, nitrogen oxides (NO_x), volatile organic compounds (VOCs) and particulates.

Ambient air quality in the major metropolitan areas is a public concern. Utilities operating power plants located near or in these highly urbanized areas are likely to experience more scrutiny now than in the past. Retrofit emission controls may be needed to comply with improved air quality standards. The utility is then faced with increased operating costs for existing and proposed units. There is no current legislation at the state or federal level on pollutants such as carbon dioxide (CO_2) and mercury, although there may be some level of future regulation contributes to uncertainty in long-term utility planning..

The use of fossil fuels for electricity generation results in unavoidable emissions. Some emission reduction technologies for one pollutant can increase emissions of another. For example, the limestone used in an SO_2 scrubber releases CO_2 and may increase CO_2 emissions by as much as 3%. Therefore, the combination of complex chemistry, uncertain long term environmental regulations, and each utility's perception of the changes in the national electric utility industry creates uncertainty for environmental compliance planning.
However, the Clean Air Act Amendments of 1990 created the SO_2 allowance (one ton of SO_2 air pollution) and allowance auctions. Each year, EPA is required to hold an auction of SO_2

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

Pollutants	Projected Emissions (Tons per GWh)	
	2000	2007
Sulfur Dioxide (SO_2)	2.8	2.0
Nitrogen Oxides (NO_x)	1.6	1.3
Particulates	0.2	0.1
VOCs	0.02	0.01
Carbon Dioxide (CO_2)	570	601
Mercury	0.00001	0.00001

allowances. EPA's 1999 spot auction resulted in the sale of 152,510 allowances at prices ranging from $41.16 to $230.00 with a clearing price of $200.55. EPA's seven-year advance auction saw the sale of 125,000 allowances first usable in 2006. These allowances were sold a prices ranging from $110.31 to $220.51 with a clearing price of $167.55. None of Florida's electric utilities purchased SO_2 allowances at either auction. However, it should be noted that other auctions, sales, and trading of SO_2 allowances occur.

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

REVIEW AND ANALYSIS - INDIVIDUAL UTILITIES

FLORIDA POWER CORPORATION (FPC)

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

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

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

LOAD FORECAST

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

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

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

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

CONSERVATION

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

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

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

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

ENVIRONMENTAL COMPLIANCE

FPC is not subject to sulfur dioxide (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.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

East Central Florida Regional Planning Council

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

Florida Department of Community Affairs (DCA)
DCA provided general comments on FPC's *Plan* and stated that the Hines facility is consistent with applicable local land use and zoning ordinances..

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

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

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

SUITABILITY

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

FLORIDA POWER & LIGHT COMPANY (FPL)

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

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

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

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

LOAD FORECAST

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

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

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

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

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

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

CONSERVATION

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

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

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

ENVIRONMENTAL COMPLIANCE

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

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

Reduced emissions forecasts are due primarily to unit repowerings planned at Ft. Myers and Sanford, which will be large natural gas consumers. FPL performed two emission sensitivities: *high fuel prices with low demand*, and *low fuel prices with high demand*. These sensitivities show that with low demand and high price forecasts for natural gas and light oil, FPL's system will emit more SO_2, NO_x, particulates and VOCs but less CO_2 compared with the base case. The converse is also true. FPL's analysis demonstrates some of the benefits of lowering demand as well as aggressively pursuing low natural gas prices.

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

East Central Florida Regional Planning Council

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

Florida Department of Community Affairs (DCA)

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

Florida Fish and Wildlife Conservation Commission

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

South Florida Regional Planning Council

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

Southwest Florida Regional Planning Council

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

Southwest Florida Water Management District

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

Tampa Bay Regional Planning Council

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

Volusia County

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

SUITABILITY

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

GULF POWER COMPANY (Gulf)

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

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

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

LOAD FORECAST

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

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

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

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

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

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

CONSERVATION

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

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

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

ENVIRONMENTAL COMPLIANCE

Gulf's compliance strategy is a subset of the overall Southern Company compliance strategy. Gulf's 1999 emissions projections show a general downward trend in most pollutants relative to 1998 projections. This change is consistent with Gulf's plan to add the new Smith combined cycle unit. Estimates of CO_2 emissions, however, substantially increase due to Gulf's expectation of economic dispatching the new natural gas facility at high load factors.

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

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

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

West Florida Regional Planning Council
Gulf's *Plan* is consistent with the Strategic Regional Policy Plan.

SUITABILITY

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

TAMPA ELECTRIC COMPANY (TECO)

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

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

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

LOAD FORECAST

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

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

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

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

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

CONSERVATION

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

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

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

ENVIRONMENTAL COMPLIANCE

TECO is subject to compliance restrictions contained in both Phase I and Phase II of the 1990 Clean Air Act Amendments (CAAA). TECO's SO_2 reduction plan is to use low-sulfur coal at Gannon and add a large scrubber which will serve both Big Bend Units 1 and 2. This is TECO's current plan to achieve the reductions by year end 2000 which has been in their projections since at least 1995. TECO projects a noticeable drop in NOx emissions again this year, but does not explain how this reduction will be accomplished.

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Community Affairs (DCA)

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

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

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

Tampa Bay Regional Planning Council
TECO's *Plan* is consistent with regional policies.

SUITABILITY

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

FLORIDA MUNICIPAL POWER AGENCY (FMPA)

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

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

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

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

LOAD FORECAST

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

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

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

CONSERVATION

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

ENVIRONMENTAL COMPLIANCE

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Community Affairs (DCA)

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

Florida Fish and Wildlife Conservation Commission

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

East Central Florida Regional Planning Council

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

SUITABILITY

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

GAINESVILLE REGIONAL UTILITIES (GRU)

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

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

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

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

LOAD FORECAST

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

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

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

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

CONSERVATION

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

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

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

ENVIRONMENTAL COMPLIANCE

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

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Alachua County Department of Growth Management

No comments are necessary at this time.

Florida Department of Community Affairs (DCA)

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

Florida Fish and Wildlife Conservation Commission

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

North Central Florida Regional Planning Council

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

Suwannee River Water Management District

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

SUITABILITY

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

JACKSONVILLE ELECTRIC AUTHORITY (JEA)

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

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

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

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

LOAD FORECAST

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

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

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

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

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

CONSERVATION

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

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

ENVIRONMENTAL COMPLIANCE

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

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Community Affairs (DCA)

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

Florida Fish and Wildlife Conservation Commission

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

Northeast Florida Regional Planning Council

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

SUITABILITY

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

KISSIMMEE UTILITY AUTHORITY (KUA)

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

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

LOAD FORECAST

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

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

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

CONSERVATION

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

ENVIRONMENTAL COMPLIANCE

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

tonnage reduction basis) by Phase II of the CAAA. KUA is expecting to add new natural gas-fired generation, and the emissions will increase proportionally for some pollutants. If KUA retires old diesel units within the next 2-3 years as their plan suggests, there will decreases in VOC, SO_2, and NOx emissions.

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Community Affairs (DCA)

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

Florida Fish and Wildlife Conservation Commission

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

SUITABILITY

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

CITY OF LAKELAND (LAK)

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

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

LOAD FORECAST

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

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

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

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

CONSERVATION

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

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

ENVIRONMENTAL COMPLIANCE

None of Florida's municipal utilities are subject to restrictions contained in Phase I of the 1990 Clean Air Act Amendments (CAAA). LAK does not appear to be severely impacted (on a tonnage reduction basis) by Phase II of the CAAA. LAK's response to the Commission's supplemental data request reflects the impact of the proposed fluidized bed project, McIntosh Unit 4, coming on line in 2003. LAK anticipates a long-term reduction in both SO_2 and NOx emissions. Other emissions appear to be tracking growth.

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Community Affairs (DCA)
DCA provided general comments on LAK's *Plan*.

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

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

SUITABILITY

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

ORLANDO UTILITIES COMMISSION (OUC)

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

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

LOAD FORECAST

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

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

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

CONSERVATION

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

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

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

ENVIRONMENTAL COMPLIANCE

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Consumer Affairs (DCA)
DCA provided no comments on the OUC *Plan*.

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

East Central Florida Regional Planning Council
OUC plans no new generation that would require certification within the region.

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

SUITABILITY

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

CITY OF TALLAHASSEE (TAL)

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

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

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

LOAD FORECAST

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

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

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

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

CONSERVATION

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

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

ENVIRONMENTAL COMPLIANCE

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

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Apalachee Regional Planning Council

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

Florida Department of Consumer Affairs (DCA)

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

Florida Fish and Wildlife Conservation Commission

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

SUITABILITY

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

SEMINOLE ELECTRIC COOPERATIVE (SEC)

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

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

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

TREATMENT OF HARDEE POWER STATION

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

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

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

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

LOAD FORECAST

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

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

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

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

CONSERVATION

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

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

ENVIRONMENTAL COMPLIANCE

SEC is not subject to SO_2 restrictions contained in Phase I of the CAAA. However, SEC elected to be subject to the CAAA earlier than the Phase II date of January 1, 2000. SEC projects a slow

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Community Affairs (DCA)

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

Florida Fish and Wildlife Conservation Commission

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

East Central Florida Regional Planning Council

SEC plans no new generation within the region.

North Central Florida Regional Planning Council

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

Northeast Florida Regional Planning Council

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

Southwest Florida Regional Planning Council

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

Suwannee River Water Management District

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

Tampa Bay Regional Planning Council

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

Withlacoochee Regional Planning Council

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

SUITABILITY

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

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

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

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

STATE, REGIONAL, AND LOCAL AGENCY COMMENTS

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

Florida Department of Community Affairs (DCA)

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

Florida Fish and Wildlife Conservation Commission

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

East Central Florida Regional Planning Council

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

Volusia County

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

SUITABILITY

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

APPENDIX

STATUS OF NEED DETERMINATIONS / SITE CERTIFICATIONS

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

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

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

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

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

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

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

APPENDIX

PLANNED, UNCERTIFIED GENERATING UNITS

Florida Power Corporation – Hines Units 2 and 3

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

Florida Power & Light Company – Martin Units 5 and 6

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

PUBLIC WORKSHOP COMMENTS

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

(1) The utility plans are inconsistent with the State Comprehensive Plan. In aggregate, the plans emphasize demand-reducing DSM programs such as load management at the expense of energy-reducing programs. Further, according to LEAF, the plans do not include enough renewable resources.

(2) The utility plans overstate the need for new generation. This concern is based on LEAF's first concern that the plans do not contain enough energy-reducing DSM programs. In LEAF's opinion, additional energy-reducing DSM programs, regardless of cost-effectiveness, would reduce the need for additional generation.

(3) The utility plans lack any apparent consideration of the aging fleet of existing plants, their potentially increased maintenance costs, and their considerable current and future environmental costs.

(4) Assumptions that the availability of all existing units is increasing are unsupported. This concerns is based on LEAF's third concern that the utilities plan to rely on an aging fleet of generators as their primary source for electricity.

REVIEW OF ELECTRIC UTILITY 1999 TEN-YEAR SITE PLANS

VOLUME 2: WRITTEN COMMENTS FROM REVIEW AGENCIES AND OTHER INTERESTED PARTIES

December, 1999

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Division of Auditing and Financial Analysis

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DEPARTMENT OF COMMUNITY AFFAIRS

"Helping Floridians create safe, vibrant, sustainable communities"

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Governor

STEVEN M. SEIBERT
Secretary

1 September 1999

Michael S. Haff
Bureau of Conservation, System Planning, and Electric Safety
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Haff:

This office sent to you on 17 August 1999 our review of the 1999 10-year site plans. Upon subsequent re-examination of that document, we found that it contained a number of typographic and other nonsubstantive errors. Having made the necessary corrections in the text, we propose that you substitute the attached, corrected version of the Department's 1999 10-year site plan review for the previously submitted version. The Department's substantive comments and overall evaluations of the 10-year site plans are unchanged.

If you decide to include our review of the 1999 10-year site plans as an attachment or addendum to the Public Service Commission's overall review of the 10-year site plans, we request that you include the cover letter sent with the previous version of our review.

Should you have any questions concerning the corrections, please call Paul Darst at 922-1764.

Sincerely,

James L. Quinn, Chief
Bureau of State Planning

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1999 DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY 10-YEAR SITE PLAN

The Duke Energy New Smyrna Beach Power Company has applied for certification under the Florida Electrical Power Plant Siting Act of Unit 1 at New Smyrna Beach Station. The Department has participated in the certification process. Further comments on the project through the 10-year site plan review process are unnecessary at this point.

1999 FLORIDA MUNICIPAL POWER AGENCY 10-YEAR SITE PLAN: SITE ANALYSIS

CANE ISLAND POWER PARK

The Florida Municipal Power Agency (FMPA) proposes to construct Unit 3, a 244-MW combined-cycle power plant, and Unit 4, a 72-MW combustion turbine, at Kissimmee Utility Authority's (KUA) existing Cane Island Power Park site in Osceola County. Unit 3, a joint project with KUA, was described in last year's site plan. Later FMPA and KUA applied for state certification of the Unit 3 power plant under the Florida Electrical Power Plant Siting Act. The Department discussed Unit 3 in its report to the PSC on the 1998 10-year site plans and has participated in the site certification review of Unit 3. At this time further comments on Unit 3 are unnecessary.

FMPA proposed adding an 80-MW combustion turbine (Unit 4) at Cane Island in 2007 in last year's site plan. This plan is substantially unchanged. Our comments from last year's report to the PSC (reproduced below with some editing changes) are still valid.

It is unclear whether the 72-MW combustion turbine to be added in 2007 would be used as a peaking unit or as a base-load or intermediate unit. If the combustion turbine is to be used as a base-load generating unit, the Department recommends that FMPA include in its plan the conversion of this unit to combined-cycle operation when additional generation is needed in its system. The combined-cycle power plant, which utilizes waste heat from its combustion turbine component to power a steam turbine and generate additional electricity, is typically more thermally efficient than a simple-cycle combustion turbine and emits lesser amounts of air pollutants per unit of energy output. Because of this, the use of combined-cycle technology for base-load generation is considered by the Department to be more consistent with the State Comprehensive Plan than the simple-cycle technology.

The Osceola County Comprehensive Plan designates the land use for the Cane Island site as Rural/Agricultural. Public utilities are allowed in this and all land use categories, provided specified performance standards are met. Adjacent land use designations are Rural/Agricultural to the south, Reedy Creek Improvement District to the west and north, Institutional to the west, and Low Density Residential, allowing up to 5 dwelling units per acre, to the east.

Cane Island is a 100-acre natural upland area within Reedy Creek swamp, in Osceola County. It is located about 10 miles southwest of the city of Kissimmee and about 1.5 miles northwest of Intercession City, a low-density residential community. According to the Osceola County Comprehensive Plan, lands near Intercession City contain very high quality wetlands with minimal encroachments of nuisance species. Comprehensive Plan Conservation Policy 8.1.2.1 states that the county shall identify and protect wetland areas through requirements that include buffering and stormwater detention and retention. The

proximity of this power plant to environmentally significant areas, particularly the Reedy Creek watershed, is of concern to the Department.

STOCK ISLAND

FMPA has added two members to its All-Requirements Project, Fort Pierce Utilities Authority and Key West City Electric. The FMPA expansion plan now includes two small (17.5 MW) oil-burning combustion turbines (No. 2 and No. 3) at the Key West Stock Island generating station. Inasmuch as the proposed in-service date for these units is 1 June 1999, it does not appear that a consistency review by the Department would be meaningful at this date. Furthermore, no information is included in the plan to show the location of the plant, how thermal pollution would be addressed, or how impacts to the manatee and other species would be mitigated. Therefore we cannot determine the consistency of the project with the local comprehensive plan.

1999 FLORIDA POWER CORPORATION 10-YEAR SITE PLAN: SITE ANALYSIS

HINES ENERGY COMPLEX

Florida Power Corporation (FPC) is proposing to expand the generating capacity of its existing Hines Energy Complex in Polk County over the 10-year forecast period. The 8,200-acre power plant site is located northwest of Fort Meade and south of Bartow. The Hines site was certified by the Siting Board in January 1994 for a generating capacity of 470 MW. As part of this proceeding, the construction and operation of the combined-cycle unit (or units), with associated facilities, was determined to be consistent with applicable land use plans and zoning ordinances. According to the 10-year site plan, the 470-MW Unit 1 combined-cycle plant was scheduled to come on-line in April 1999. This would be followed by the installation of the 495-MW Unit 2 combined-cycle plant in November 2004 and the apparently identical 495-MW Unit 3 in November 2006.

FPC expects to eventually locate up to 3,000 MW of capacity on this site. Subsequent installations of generating capacity at this site, except for stand-alone combustion turbines, will require certification by the Siting Board. The Department will review any subsequent applications for modification of the site certification for consistency with the State Comprehensive Plan and with applicable local comprehensive plans.

The Hines site is located in an area designated as PM (Phosphate Mining) on the Future Land Use Map of the Polk County comprehensive plan and is compatible with adjacent land uses nearby. The nearest land uses to the site are designated A/RR (Agriculture/Residential-Rural) and RCC (Rural-Cluster Center). The Hines facility is consistent with applicable local land use and zoning ordinances.

U.S. Highway 98 provides north-south access to the site, and County Road 640 provides the site with east-west access through Polk County.

INTERCESSION CITY

Florida Power Corporation (FPC) proposes to construct three gas turbines on 165 acres at its existing Intercession City site in Osceola County for use as peaking units. The units, with a combined capacity of 249 MW, are expected to be in service in December 2000.

These units were not previously described in the 1998 10-year site plan. The proposed use is consistent with the Osceola County Comprehensive Plan's designation of the site for Institutional land uses. Currently Intercession City has a total generating capacity of 912 MW (winter), spread among 11 power plants which are apparently all combustion turbines used for peaking needs.

TRANSMISSION LINES

FPC proposes to construct six 230-kV electric transmission lines during the 10-year planning horizon, ranging from 1 to 21 miles in length. None of these lines would be required to be certified under the Transmission Line Siting Act.

1999 FLORIDA POWER & LIGHT COMPANY 10-YEAR SITE PLAN: SITE ANALYSIS

FORT MYERS PLANT

Florida Power & Light Company (FPL) lists its existing Fort Myers Plant site as preferred site No. 1 for additional power generation. Construction of the repowering project is scheduled to begin by mid-1999 and to be completed by January 2002.

The Fort Myers Plant comprises 460 acres in Lee County. It is located along the Caloosahatchee River, about 8 miles east of the city of Fort Myers. The plant site is accessible by a four-lane highway (SR 80) and by barge from the Caloosahatchee River.

The existing plant contains two steam-electric generating units of 150 MW and 400 MW capacity and twelve simple-cycle combustion turbines used as peaking units. FPL proposes to add new capacity by repowering the two existing oil-fired steam-electric units with six natural-gas-fired combustion turbines and six heat recovery steam generators. The combined-cycle units thus formed will produce an additional 926 MW (summer rating) beyond what the Fort Myers Plant is currently producing.

The site is in industrial use and surrounded by light commercial, residential, and mangrove wetland. A major portion of the site is designated as Public Facilities on the Future Land Use Map of the Lee County comprehensive plan, with a small area designated as Resource Protection. The site is mostly disturbed, with a scattering of mangroves along the shoreline of the Caloosahatchee River. Listed species associated with the site are the West Indian manatee, the Eastern indigo snake, and the tricolor heron. FPL does not describe any other significant features on the site.

FPL estimates that 150 gallons per minute will be needed by the repowered project for boiler makeup, service water, and inlet fogger makeup. The source of this industrial processing water is expected to be groundwater or municipal reuse water. Recycled water from equipment washing, boiler blowdown, and equipment area runoff could also be used, according to FPL. The Department notes that the use and reuse of water of the lowest acceptable quality for the purposes intended is a policy of the State Comprehensive Plan.

The amount of water needed for cooling the repowered project is not expected to increase significantly beyond the 451,000 gallons per minute taken by the existing plant from the Caloosahatchee River. (The Department notes that in last year's site plan the amount of water currently being used was given as 433,000 gallons per minute. Another change from

the 1998 site plan is that FPL no longer mentions the possibility of using municipal reuse water for cooling.)

FPL states that the heat content of the water used for cooling the repowered project will be dissipated using the existing once-through cooling system and possibly a small cooling tower. Disposal of the cooling water from the repowered project, if the amount or temperature of the used water will vary from the current plant discharge, will need to be carefully planned to avoid adverse impacts on receiving waters and associated flora and fauna. The 10-year site plan states that manatees are attracted to the area where the current plant discharges heated water, but does not provide a discussion of the actions to be taken to minimize or avoid impact to manatees. FPL should coordinate with environmental agencies during the planning for the Fort Myers repowering to ensure that the project does not adversely affect this endangered species. The Department notes that Objective 77.7 of the Coastal and Conservation Element in the Lee County Comprehensive Plan requires the County to minimize impact and mortality of manatees to maintain their existing population.

FPL has received an air construction permit from the Department of Environmental Protection for the proposed repowering project. According to FPL, other permits are pending with the Department of Environmental Protection, Department of Transportation, U.S. Army Corps of Engineers, and Lee County.

For this project FPL has proposed environmental impact mitigation measures such as reuse of plant process water, cessation of heavy oil barge traffic on the Caloosahatchee River, plumbing the plant's sanitation system to the Lee County system to allow closing the on-site septic tanks, and closing the on-site ash basins. These measures are expected to reduce environmental impacts associated with the proposed project. Nevertheless, FPL should coordinate with appropriate environmental agencies in the implementation of such measures to ensure that the project does not adversely affect endangered species on the site and in the vicinity.

Information in the 10-year site plan suggests that FPL does not expect that this project will be required to undergo certification pursuant to the Florida Electrical Power Plant Siting Act. The repowering project requires construction of a natural gas pipeline to the site. FPL has contracted out this fuel supply to Florida Gas Transmission Company, which has initiated the permitting process to install and operate such a facility. If FPL needs to construct a transmission line to carry the additional power of this repowering project, it may be required to undergo certification pursuant to the Transmission Line Siting Act if the line is 230 kV or more in capacity, greater than 15 miles in length, and crosses a county line.

SANFORD PLANT

FPL lists its existing Sanford Plant site as preferred site No. 2 for additional power generation.

The Sanford Plant site is located within the city of DeBary in southwestern Volusia County. The site comprises 1,718 acres (per page 88 of the site plan; page 72 gives the size of the site as 1,889 acres), including a 1,100-acre cooling pond (Konomac Lake, a man-made impoundment) and lands extending south of the cooling pond to the Seminole County line. The site currently contains three steam-electric units (Units 3, 4, and 5) generating 933

MW from heavy oil and natural gas fuels, which are transported, respectively, by barge and by pipeline. Two of the units were brought on-line in the early 1970s and the other has been in service since 1959. Pollutants are controlled through existing mechanical collectors and a limit on the sulfur content of the fuel. The site is accessible by the C&S Railway and U.S. Highway 17/92. Other facilities owned by FPL in the vicinity include a deepwater port on the adjacent St. Johns River and non-operational docking facilities on Lake Monroe. Another utility, Florida Power Corporation, owns a power generation facility to the north of DeBary, which has recently been expanded.

FPL proposes to repower existing Units 3 and 4 with six natural-gas-fired combustion turbines and six heat recovery steam generators. This repowering, which is planned for 2004, would produce 927 additional MW (summer rating) beyond the current capacities (543 MW) of these two units. FPL is currently reexamining this plan and considering repowering existing Units 4 and 5 instead of Units 3 and 4. This plan would gain an additional 240 MW over the repowering of Units 3 and 4.

Either of the repowering options will require additional water for cooling; however, FPL states that the extra water needs will be negligible. FPL expects the repowered natural-gas-burning units to be more efficient and to have substantially lower air emissions than the existing Units 3 and 4.

Supplying natural gas to the repowered units will require the installation of a larger gas pipeline to the site. It will also be necessary for FPL to construct a new substation and two new 230-kV electric transmission lines from the Sanford Plant site to the Poinsett substation, a distance of 60 miles, in order to integrate the Sanford capacity expansion with the FPL grid. There is insufficient information in the current 10-year site plan for the Department to estimate the land use impacts from construction of the gas pipeline expansion and the two electrical transmission lines.

The existing land use at the Sanford site is industrial, with open space and recreational uses surrounding the site to the east and west. Lake Konomac lies to the north of the site and the St. Johns River to the south.

The land use designations shown on the City of DeBary's Future Land Use Map are Industrial/Utility for the Sanford site, surrounded by Agricultural/Residential to the east and west, the manmade Konomac lake to the north, and the St. Johns River to the south. The Industrial/Utility designation allows specifically for major electric power generation and distribution facilities within the City of DeBary. This would include power plants, industrial buildings, open space, cooling ponds, and accessory uses. The Agricultural/Residential designation allows agriculture, agriculture-related businesses, silvicultural activities, and residential at a density of 1 dwelling unit per 5 acres.

Based on the information provided in the 10-year site plan, the Department does not identify any land use concerns with the proposed repowering of the Sanford Plant site.

Information in the 10-year site plan suggests that FPL does not expect that this project will be required to undergo certification pursuant to the Florida Electrical Power Plant Siting Act; however, the 60-mile, 230-kV transmission line needed to carry the additional power to be generated by this project may be required to undergo certification pursuant to the Transmission Line Siting Act.

MARTIN PLANT

FPL's existing Martin Plant site is listed in the 10-year site plan as preferred site No. 3. This is virtually the same project designated as a preferred site in last year's 10-year site plan.

The Martin Plant is located just east of Lake Okeechobee and 7 miles west of Indiantown, in the southwest corner of Martin County. This site was identified by FPL in 1987 as a preferred location for development of coal gasification facilities and ombined-cycle electric generating units. Subsequently, in 1989, FPL filed a site certification application for an ultimate site capacity at the Martin site of up to 1,600 MW of combined-cycle units capable of firing coal gas, natural gas, or fuel oil. The Siting Board approved the first phase (Units 3 and 4) of 832 MW of combined-cycle capacity in 1991. Units 3 and 4 began commercial service in 1994.

Phase II (Units 5 and 6) will require state certification before construction can begin. Unit 5 is projected to begin operation in 2006 and Unit 6 in 2007. Each of these natural-gas-burning units will be rated at 419 MW summer capacity.

Up to 1,300 acres of the site could potentially be used for Units 5 and 6. Associated coal handling, coal storage, and by-product handling and storage facilities will only be constructed during Phase III (coal gasification stage), if needed. The site comprises approximately 11,300 acres.

According to the future land use element of the adopted Martin County comprehensive plan, the site is designated Public Facilities-Major Power Generation Facilities, which is described as follows (Policy M.1.h):

> Currently, the only such designated area is the FPL Martin Plant site and cooling reservoir west of Indiantown. This designation is required for all power generation sites of 10 acres or more in size which contribute electricity to the power grid in Martin County. Such land uses are subject to the same locational and compatibility considerations as required of industrial development.

The Martin Plant site was specifically designated and zoned for the power plant through a planned unit development (PUD) agreement. During state certification, the Siting Board found that the land use designation and zoning were appropriate for the construction and operation of Units 3 and 4. Adjacent land uses consist of mobile homes, residential (density of over 5 units per acre), agriculture (including croplands and pastures), and wetlands.

As a condition of the PUD agreement, FPL has set aside certain portions of its property for upland preserves and wetland mitigation areas. The development agreement addresses the potential environmental impacts of the plant expansion. Detrimental environmental impacts will be either corrected or mitigated to meet the development agreement conditions.

According to FPL's 1997 10-year site plan, construction of Phase III (coal gasification) at the Martin Plant site could result in the loss of 166 acres of "isolated" wetlands. A mitigation program was being completed in advance of actual impacts to wetlands. This is not mentioned in the current 10-year site plan.

Because Martin is an existing site, it has been already impacted by power generating operations (and by years of cattle grazing).

Included on the site is a 6,800-acre cooling pond whose water supply is maintained by withdrawals from the St. Lucie Canal. To avoid impacts to the surficial aquifer, FPL and

the South Florida Water Management District have agreed that the process water shall be obtained initially from the cooling pond with additional process water for the project being obtained as needed solely from the Floridan aquifer through 1,500-foot-deep wells. Aquifer performance tests show that no offsite wells within 5 miles of the site will be impacted by any of the project phases.

Martin County planning staff affirmed that the site remains consistent with the Martin County Comprehensive Growth Management Plan.

CAPE CANAVERAL PLANT

The FPL 10-year site plan lists the existing FPL Cape Canaveral Plant as a potential site for capacity expansion. It does not specify the generating units that might be located there or when they might be installed.

The Cape Canaveral Plant site is located in the Port St. John area of unincorporated Brevard County on the shoreline of the Indian River. The plant site comprises 82 acres, with 40 acres located east of U.S. Highway 1 and 42 acres west of the highway. The eastern 40-acre parcel contains two existing steam power units, each of which has a generating capability of 405 MW (summer). The western 42-acre parcel is vacant. The site has direct access to four-lane U.S. 1, barge access is available on the Indian River, and a rail line is located near the plant. The land on the site is primarily maintained grassy areas and industrial use areas. The adjacent land use is industrial, light commercial, and residential.

The Future Land Use Map in the Brevard County Comprehensive Plan designates the site as Public Facility, which allows electric power generation. The Brevard County Planning Department affirmed that use of the site for power generation is consistent with the Brevard County Comprehensive Plan. The surrounding Future Land Use Map designations are as follows:

Eastern 40-acre parcel—the Indian River, Residential (12 dwelling units per acre), and Recreation to the north; the Indian River, Residential (12 dwelling units per acre), and Mixed Use to the south; the Indian River to the east; and U.S. 1 to the west.

Western 42-acre parcel—Residential (12 dwelling units per acre) and Mixed Use to the north; Residential (12 dwelling units per acre) and Mixed Use (12 dwelling units per acre) to the south; U.S. 1 to the east; Residential (12 dwelling units per acre), Railroad, and Industrial to the west.

Future power plant development on the vacant 42-acre western parcel of the site would raise concerns regarding land use compatibility with surrounding residential use. However, the 10-year site plan does not propose new power generation units on the western parcel during the 1999–2008 period.

PORT EVERGLADES PLANT

The FPL 10-year site plan lists the existing FPL Port Everglades Plant as a potential site for capacity expansion. It does not specify the generating units that might be located there or when they might be installed.

This power plant site is located within Port Everglades in Broward County. It is depicted in the Port Everglades Master Plan with a land use designation of "Florida Power and Light." The land use on the 94-acre site is primarily industrial. Adjacent land uses are

electric power generation (FPL), port facilities, oil storage, commercial, and cruise ship docking and related uses. Therefore, the FPL plan appears to be consistent with the port master plan and compatible with adjacent land uses with regard to the Port Everglades potential site.

The availability of water to serve the proposed plant expansion is a concern to the Department. The 10-year site plan notes that FPL would need up to 130 gallons per minute of industrial processing water for uses such as boiler makeup, fogger usage, and service water. It is not clear from the 10-year site plan, however, whether the 130 gallons per minute would be available from the existing municipal water supply. Currently, the Port has a large user agreement with the City of Fort Lauderdale for potable water. For cooling water, FPL expects to continue the existing withdrawal of 320,000 gallons per minute of seawater in the plant's once-through cooling system.

DESOTO COUNTY SITE

The FPL 10-year site plan no longer lists this 13,468-acre site as a potential site for capacity expansion.

RIVIERA PLANT

The FPL 10-year site plan lists the existing FPL Riviera Plant as a potential site for capacity expansion. It does not specify the generating units that might be located there or when they might be installed. This site was also listed by FPL as a potential power plant site in last year's 10-year site plan.

The Riviera Plant site is located in the coastal portion of Palm Beach County, within the City of Riviera Beach. It is near the Port of Palm Beach, making it conveniently located for barge deliveries of fuel oil. It is also accessible from four-lane U.S. Highway 1 and a rail line. Units 3 and 4, in operation since 1962 and 1963, are oil-burning steam turbines generating 300 MW (summer rating) apiece.

With a total land area of 32.4 acres, Riviera is the smallest power plant site in the FPL system. According to FPL, the land use on site is primarily industrial (power generation). Surrounding land uses are listed as industrial (power generation), port facilities and associated industrial facilities, oil storage, facilities for cruise ships, commercial, and residential.

TRANSMISSION LINES

Table III.E.1 of the 10-year site plan lists 19 proposed transmission lines for the 1999–2008 period. Four of these lines are longer than 15 miles and may require certification under the Transmission Line Siting Act.

1999 GAINESVILLE REGIONAL UTILITIES 10-YEAR SITE PLAN: SITE ANALYSIS

JOHN R. KELLY PLANT (ALACHUA COUNTY)

Gainesville Regional Utilities (GRU) proposes to repower its existing Unit 8 turbine generator at the John R. Kelly Plant with a new simple-cycle combustion turbine and heat recovery steam generator. The facility currently consists of three steam turbines, three gas

turbines, cooling facilities, fuel storage, pumping equipment, and transmission and distribution equipment. The primary fuel for the existing system is natural gas; the alternate fuel is residual fuel oil. The primary fuel for the repowered system will also be natural gas, with distillate fuel oil as the alternate fuel.

The site, located in downtown Gainesville, has been used for power generation since 1912 and is designated Industrial on the City of Gainesville Future Land Use Map. The site is surrounded mostly by highly urbanized areas with little wildlife habitat, with the exception of a large wooded parcel to the southwest of the site. The repowering project will occur within the grounds of the existing facility and will not impact additional lands. Therefore, a Future Land Use Map amendment is not required.

The project is scheduled to begin in November 2000 and to be complete by February 2001. No increases in water consumption are identified. The 10-year site plan states that the existing water consumptive use permit should be sufficient to accommodate the requirements of the site. Cooling tower blowdown, low-volume waste, and stormwater will continue to be discharged to Sweetwater Branch, pursuant to the existing NPDES permit; no new discharges are projected. The new unit will utilize existing fuel oil delivery and storage facilities. Several bulk residual fuel oil tanks will be retired because of reduced usage.

Based on the above information, the project is consistent with the local comprehensive plan and should have no additional impacts to natural resources or public facilities.

1999 GULF POWER COMPANY 10-YEAR SITE PLAN: SITE ANALYSIS

LANSING SMITH POWER PARK

Gulf Power Company (Gulf) is expecting to place additional generating units in service between 2002 and 2007. The first of these units is scheduled to be the 540-MW combined-cycle Smith 3 power plant at Gulf's existing Lansing Smith Power Park in Bay County.

Gulf has applied for certification of Smith 3 under the Florida Electrical Power Plant Siting Act. The Department is participating in the certification review of this project. The following comments are provided for the 10-year site plan review.

The Lansing Smith power plant site is currently designated Industrial on the Future Land Use Map (FLUM) of the Bay County comprehensive plan. It is located in a sparsely populated area of rural Bay County on the north shore of North Bay, approximately 4 miles west of Southport. Surrounding land uses include silviculture to the north and east and agriculture to the west and southwest.

In order to provide space for the installation of the Smith 3 power plant, Gulf Power proposes to expand the existing site by 50 acres to the north on land currently designated Agriculture on the FLUM. Bay County submitted a comprehensive plan amendment in May 1999 to change the FLUM designation on the 50-acre site to Industrial. The amendment is scheduled for adoption in August 1999. Please note that the comprehensive plan amendment states that the total acreage of the plant site is 700 acres, whereas Schedule 9 of the 10-year site plan states that the total acreage of the plant site is 1,340 acres.

Although Schedule 8 of the 10-year site plan provides that fuel transport for Smith Unit 3's natural gas fuel will be by pipeline, the plan does not address the impacts that may result from constructing the pipeline, and states only that "assuming the construction of additional pipeline facilities," there are sufficient natural gas supplies available in the southeastern United States to support Smith Unit 3.

CRIST PLANT

In last year's 10-year site plan Gulf had identified two small (30-MW) combustion turbines, one in 2006 and the other in 2007, at an unnamed location. The 1999 10-year site plan has dropped this plan; Gulf now proposes to repower Units 1–3 at its existing Gulf Crist Power Plant in Escambia County in 2007 by installing an 'F' class combustion turbine and associated heat recovery steam generator. The 10-year site plan does not identify whether the plant will be expanded in terms of additional acreage and, if so, whether a Future Land Use Map amendment is necessary. The plan does not address whether pipeline and electric transmission line installations or upgrades will be necessary. Further, the plan does not address impacts, if any, to public facilities, particularly water usage and discharge. The limited information provided in the 10-year site plan does not allow a determination of the consistency of the repowering project with the County's comprehensive plan.

1999 JACKSONVILLE ELECTRIC AUTHORITY 10-YEAR SITE PLAN: SITE ANALYSIS

NORTHSIDE GENERATING STATION REPOWERING

Jacksonville Electric Authority (JEA) proposes to repower Units 1 and 2 at the existing Northside Generating Station in 2002. Northside Generating Station is located on or near the St. Johns River, just south of JEA's large St. Johns River Power Park. The 754-acre Northside site currently contains three steam turbines and four combustion turbines. Two of the steam turbines, Units 1 and 2, will be repowered using fluidized-bed boilers burning coal and pet coke for fuel.

According to JEA, the 1996 groundwater usage of the Northside facility will be reduced by at least 10 percent as part of the repowering project. JEA also has committed to reduce both the sulfur dioxide and nitrogen oxides emissions by 10 percent from the 1994–95 baseline levels of the Northside steam units.

The Northside Generating Station is located in an industrial area. The site is surrounded by land zoned Heavy Industrial, Light Industrial, and Industrial Business Park to the west and north, the JEA St. Johns River Power Park to the north, the Northside Municipal Landfill to the west, the Blount Island Industrial Port to the south, and the St. Johns River to the east. Thus the repowering, if it does not increase noise, runoff, traffic, and air pollution, should not present any new impacts to surrounding land uses.

Since the output of the turbines will not be increased, JEA maintains that the project will not require certification under the Florida Electrical Power Plant Siting Act.

KENNEDY GENERATING STATION

JEA also is proposing to construct and operate a 149-MW (summer rating) combustion turbine (Kennedy CT 7) at JEA's Kennedy Generating Station by May 2000. This unit

would burn natural gas as its primary fuel with fuel oil as backup. It will apparently be used as a peaking unit, as suggested by its estimated capacity factor of 10 percent.

BRANDY BRANCH SITE

JEA proposes to construct and operate a new power generation facility at the 153-acre Brandy Branch site in western Duval County, 1 mile north of U.S. Highway 90 and 1 mile east of the City of Baldwin. JEA plans to install three 149-MW combustion turbines (Units 1, 2, and 3) at this site. The primary fuel will be natural gas with fuel oil backup. Capacity factors are estimated at 5 percent, suggesting that these units will be used as peaking units, to help meet system peak electrical demands. In-service dates are projected as January 2001 for Units 1 and 2 and December 2001 for Unit 3. Certification under the Florida Electrical Power Plant Siting Act is not required for these units.

The site has been designed to accommodate a fourth generating unit (Brandy Branch No. 4), either another combustion turbine or a combustion turbine conversion to combined-cycle operation. Only sketchy details are provided in the 10-year site plan on this unit. In schedule 8.0 and table 8-2 it is described as having an in-service date of June 2005. Schedule 8.0 gives the estimated summer capacity rating of this unit as 425 MW. Table 8-2, however, states that two of the combustion turbines will be converted to form a combined-cycle plant with a capacity of 558 MW.

The site will not require an additional transmission line capacity until the combined-cycle unit is constructed; apparently the existing transmission line to the Brandy Branch site is adequate.

While reviewing the JEA 10-year site plan the Department also received for review a Department of Environmental Protection Joint Environmental Resource Permit Application from JEA for phase II work at the Brandy Branch Generating Station. In this application, JEA states that it intends to construct a 500-MW simple-cycle combustion turbine at this site. This is apparently a sudden change in JEA's plan for the site; note that the 10-year site plan was submitted in April 1999 and the ERP application was received by the Department of Environmental Protection 2 months later, in June 1999. This large combustion turbine is probably a substitute for the three smaller combustion turbines proposed in the 10-year site plan.

A considerable amount of detail is provided on this project in the application. The primary fuel would be natural gas. The utility will construct a 10- to 15-mile-long natural gas pipeline to bring this fuel to the site.

According to the ERP application, JEA will store 3 million gallons of No. 2 fuel oil onsite as backup fuel. The fuel oil will be stored in 1-million-gallon tanks above ground and placed within a lined, secondary containment berm. Contained waters or oil will be released gradually through a valved system to an oil/water separator for treatment. The separator was designed to contain the oil capacity of the largest source discharging to the separator, which is the generator step-up transformer, estimated at 16,162 gallons. Separator effluent will be routed to an onsite percolation pond for additional treatment prior to groundwater discharge. JEA will prepare a Spill Prevention, Control, and Countermeasures Plan.

The site will require dewatering in three locations: at the oil/water separator, the septic tank, and the wastewater collection sump. Dewatering will be accomplished by a series of wellpoints installed on the perimeter of each excavation, the deepest wellpoint being 13.5

feet. Stormwater from the site will be treated in wet detention ponds and discharged to the wetlands north of the site, consistent with the pre-existing direction of runoff. The applicant proposes to fill 2.2 acres of good quality cypress dome wetlands and to mitigate for it with wetland creation at a 2:1 ratio.

The Future Land Use Map category for the Brandy Branch site is Public Buildings and Facilities. Lands north and west of the site are also designated Public Buildings and Facilities; the lands to the east and south of the plant are designated Agriculture. The Duval/Jacksonville comprehensive plan allows power plants in the Public Buildings and Facilities category; power plants and major utility lines are allowed and specifically accommodated in the Agriculture category. Traffic-generating public facilities (such as libraries) are required to be located on a collector or arterial road. This facility would probably not need to meet this requirement; private-road access to the site will be developed from U.S. 90 within an existing transmission line right-of way. The ERP application indicates that the nearest structures are houses and barns located 2000 feet from the site. The southeast corner of the site abuts an abandoned railroad grade, which has been proposed for use as a recreation facility. Pine forest buffers will be retained on the north and east side of the power block. Based on the information provided in the ERP application, land use compatibility will probably not be an issue in the siting of this project.

The Jacksonville-Duval County 1990-2010 Comprehensive Plan indicates that Jacksonville has had problems with air pollution. Most of these problems resulted from automobile emissions and industrial emissions. The comprehensive plan states that no exceedances for sulfur dioxide have occurred since 1982; however, models project future exceedances. To be classified as achieving attainment for this pollutant, Jacksonville needs to reduce emissions of sulfur dioxide such that the models no longer project exceedance. The location of the Brandy Branch site remote from more intense development will assist in this effort.

The Department does not know whether the 500-MW simple-cycle combustion turbine proposed in JEA's ERP application is intended for peaking operation or to serve base-load. The large size of the unit suggests that it is intended for base-load operation. If this is the case, the Department must reiterate its recommendation from the 1998 report on 10-year site plans, which is that is preferable to use combined-cycle units instead of simple-cycle combustion turbines for other than peaking duty. The reason for this is that the combined-cycle power plant, which utilizes waste heat from its combustion turbine component to power a steam turbine and generate additional electricity, is typically more thermally efficient than the simple-cycle combustion turbine and emits lesser amounts of air pollutants per unit of energy output. Because of this, the use of combined-cycle technology for base-load generation is considered by the Department to be more consistent with the State Comprehensive Plan than the simple-cycle technology.

1999 KISSIMMEE UTILITY AUTHORITY 10-YEAR SITE PLAN: SITE ANALYSIS

CANE ISLAND POWER PARK

Kissimmee Utility Authority (KUA) proposes to construct Unit 3, a 244-MW combined-cycle power plant at KUA's existing Cane Island Power Park site in Osceola County. Unit 3, a joint project with the Florida Municipal Power Agency, was described in last year's site plan. Later KUA and FMPA applied for state certification of the Unit 3 power plant under

the Florida Electrical Power Plant Siting Act. The Department discussed Unit 3 in its report to the PSC on the 1998 10-year site plans and has participated in the site certification review of Unit 3. At this time further comments on Unit 3 are unnecessary.

1999 LAKELAND ELECTRIC & WATER 10-YEAR SITE PLAN: SITE ANALYSIS

MCINTOSH POWER STATION

Lakeland has applied for certification under the Florida Electrical Power Plant Siting Act of the steam cycle conversion of its existing Unit 5 combustion turbine. The Department is participating in the review of this project, obviating the need to comment on it here.

In its current 10-year site plan, Lakeland discusses in some detail a number of generation alternatives in addition to the conversion of Unit 5 to combined-cycle configuration. The preferred alternative, aside from the Unit 5 conversion, is to construct a Unit 4 at the McIntosh plant by January 2004. This would be a 238-MW pressurized circulating fluidized bed unit capable of burning coal or petroleum coke (see below) as fuel. This unit was previously proposed in the 1997 and 1998 10-year site plans.

Unit 4 would be partially funded under the auspices of the U.S. Department of Energy's Clean Coal Technology Program. The DOE grant would apparently require Lakeland to burn coal in the unit for 4 years to meet the Clean Coal demonstration objectives, after which Unit 4 could be switched to burning petroleum coke, which is currently a cheaper fuel than coal. This unit would require certification under the Florida Electrical Power Plant Siting Act. The Lakeland 10-year site plan does not describe any electric transmission lines that would be associated with Unit 4.

McIntosh Power Station currently comprises six power generating units on a 370-acre site located along the northeastern shore of Lake Parker. The McIntosh expansion would be located in an area designated as Industrial on the Future Land Use Map of the City of Lakeland's comprehensive plan. Power generation is an allowable use in the Industrial land use classification. The McIntosh plant is adjacent to lands designated in the Future Land Use Map as Industrial, Recreation and Open Space, Conservation, and Preservation. In addition to these land uses, which act as buffers between the power plant and the populated land uses, the McIntosh plant site is located adjacent to a railroad line and is accessible by East Lake Parker Drive.

1999 SEMINOLE ELECTRIC COOPERATIVE 10-YEAR SITE PLAN: SITE ANALYSIS

HARDEE POWER STATION

Hardee Power Station is an existing Seminole Electric Cooperative (SEC) power plant site located in Polk and Hardee counties, about 9 miles northwest of Wauchula and 16 miles south-southwest of Bartow. The site has access through two-lane County Road 663 and the CSX rail line. Payne Creek flows along the site's western and southern borders.

The site was certified in 1990 under the Florida Electrical Power Plant Siting Act for an ultimate capacity of 660 MW. A 220-MW combined-cycle unit and a 75-MW combustion turbine have been constructed on the site thus far. In 1995 SEC received approval under

the Florida Electrical Power Plant Siting Act for a 440-MW combined-cycle Unit No. 3, which would hike the site's total generating capability to 735 MW by year 2002. SEC plans an ultimate site capacity for Hardee Power Station of 880 MW.

SEC is now requesting a modification of the site certification for Unit 3 to raise its capacity to 488 MW. SEC has no plans to build any additional transmission facilities to carry this additional power.

As part of the state certification of the site, it was determined that the proposed use of the site was consistent with applicable local government comprehensive plans and land development regulations. Mining was the primary land use on the site and surrounding areas.

SEC is also proposing to install twelve 150-MW gas combustion turbines, totaling 1,800 MW of capacity, between 2000 and 2007. No location is given in the 10-year site plan for these units. This capacity is needed to replace expiring purchased power contracts and to maintain SEC's reliability criteria. SEC emphasizes in its site plan that these units are included for planning purposes only and that further studies will optimize the amount, type, and timing of such capacity. The exact type of capacity and source or location will be determined later. Given this situation, the Department is unable to provide any comment on these units other than to repeat its recommendation regarding combustion turbines made earlier in this report, which is that is preferable to use combined-cycle units instead of simple-cycle combustion turbines for other than peaking duty. The reason for this is that the combined-cycle power plant, which utilizes waste heat from its combustion turbine component to power a steam turbine and generate additional electricity, is typically more thermally efficient than the simple-cycle combustion turbine and emits lesser amounts of air pollutants per unit of energy output. Because of this, the use of combined-cycle technology for base-load generation is considered by the Department to be more consistent with the State Comprehensive Plan than the simple-cycle technology.

1999 CITY OF TALLAHASSEE 10-YEAR SITE PLAN: SITE ANALYSIS

PURDOM POWER STATION

The City of Tallahassee 10-year site plan proposes the installation of one new power plant, Purdom Unit 8, during the 10-year planning period. This power plant was certified in 1998 by the Siting Board pursuant to the Florida Electrical Power Plant Siting Act. The Department participated fully in the certification process and has no further comment on this project.

1999 TAMPA ELECTRIC COMPANY 10-YEAR SITE PLAN: SITE ANALYSIS

POLK POWER STATION

Tampa Electric Company (TECO) plans to expand the operating capacity at its Polk Power Station. The 4,347-acre site is located in southwestern Polk County, bordering the Hillsborough County line and 4 miles north of the Hardee County line.

An integrated coal-gasification combined cycle unit of 220-MW capacity (the current 10-year site plan lists the unit at 250 MW) was certified for the Polk Power Station site by the Siting Board in January 1994. This unit was placed in service in September 1996. According to its 1999 10-year site plan, TECO now expects to eventually locate 1,330 MW of capacity at this site, up from 1,150 MW in 1998. Except for stand-alone combustion turbines (such as the three proposed additional units), subsequent installations of generating capacity at this site will require certification by the Siting Board.

Polk Power Station consists primarily of lands recently mined for phosphate. It is located in an area designated as PM (Phosphate Mining) on the Future Land Use Map of Polk County. The nearest non-PM land use to the Polk site is an area immediately north of the western part of the site which is designated as A/RR (Agriculture/Rural Residential). This facility is consistent with applicable local land use and zoning ordinances.

During the planning period TECO proposes to locate six combustion turbines at the Polk site. All six are rated at 155-MW (summer rating) capacity, burning natural gas as primary fuel with distillate oil as backup. Construction is scheduled to begin on Unit 2 in January 1999, with an in-service date of January 2001. Unit 3 has a projected in-service date of January 2003; Unit 4, January 2004; Unit 5, January 2005; Unit 6, January 2007; and Unit 7, January 2008.

The 10-year site plan presents estimated capacity factors of 15.5 to 20.8 percent for these combustion turbines. It appears, therefore that these units will be used to meet system peak loads and intermediate loads. If, however, TECO intends to use them to meet base-load requirements (see note below), the Department would recommend that TECO include heat recovery steam generators with the combustion turbines to form combined-cycle units. The combined-cycle power plant, which utilizes waste heat from its combustion turbine component to power a steam turbine and generate additional electricity, is typically more thermally efficient than a simple-cycle combustion turbine and emits lesser amounts of air pollutants per unit of energy output. Because of this, the use of combined-cycle technology for base-load generation is considered by the Department to be more consistent with the State Comprehensive Plan than simple-cycle technology.

Note: the Department has also received for review an air construction permit application from TECO for two simple-cycle combustion turbines at the Polk Power Station, dated April 1999, the same date as the 10-year site plan. In the permit application TECO proposes to install two 165-MW combustion turbines. The first combustion turbine is scheduled for commercial operation in June 2000 and the second in January 2003. These combustion turbines will operate at annual capacity factors of up to 50 percent on natural gas and 10 percent on fuel oil. The question must be asked, why, in two different documents submitted in April 1999, has TECO changed the proposed capacity rating (165 MW vs. 155 MW), the date of commercial operation (June 2000 vs. January 2001), and the annual capacity factor (50–60 percent vs. 15.5–20.8 percent) of the proposed combustion turbines?

NEW TRANSMISSION LINE

TECO is planning a new 28-mile, 230-kV transmission line in eastern Hillsborough County from the Polk Power Station to the proposed Lithia Switching Station. A location map of this line was not included with the site plan. Based upon the information provided, the transmission line will be placed in an area of the county that is mostly designated

Residential-4 and Residential-6 on the Hillsborough County Future Land Use Map. The transmission lines may also impact areas designated as environmentally sensitive on the Future Land Use Map. In addition, the transmission lines may encroach upon the Fish Hawk Ranch Development of Regional Impact near Boyette Road. The Department is concerned about the potential impacts to the significant wildlife habitat and wetlands designated as environmentally sensitive on the Future Land Use Map and the resources that were to be protected within the Fish Hawk Ranch DRI.

Florida Fish and Wildlife Conservation Commission

ames L. "Jamie" Adams, Jr. Bushnell | Barbara C. Barsh Jacksonville | Patrick E. Geraghty Ft. Myers | Quinton L. Hedgepeth, DDS Miami | H.A. "Herky" Huffman Deltona

Thomas B. Kibler Lakeland | David K. Meehan St. Petersburg | Julie K. Morris Sarasota | Tony Moss Miami | Edwin P. Roberts, DC Pensacola | John D. Rood Jacksonville

LLAN L. EGBERT, Ph.D., Executive Director
ICTOR J. HELLER, Assistant Executive Director

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TDD (850)488-9542

July 20, 1999

Mr. Michael S. Haff
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 31399-0850

Re: 1999 Ten-Year Site Plans for Electric Utilities, Public Service Commission

Dear Mr. Haff:

The Office of Environmental Services of the Florida Fish and Wildlife Conservation Commission has reviewed the 1999 Ten-Year Site Plans for electric utilities in terms of potential impacts to fish and wildlife resources. Our review has determined that at the present time, the plans collectively represent expansions of existing facilities where no significant impacts will occur, or they have not progressed to a stage where sufficient detail is provided in terms of the actual locations of new generating sites. Therefore, although the present plans are suitable as general planning documents, we are unable at this time to accurately predict site specific impacts to listed species and their habitats. We may forward comments to your office in the future when more information becomes available on siting locations.

Thank you for the opportunity to provide input on Florida's electric utility site plans.

Sincerely,

Bradley J. Hartman

Bradley J. Hartman, Director
Office of Environmental Services

BJH/TG
ENV-2-11-4/3
PSC.99



September 9, 1999

Mr. Joe Jenkins, Director
Division of Electric and Gas
Florida Public Service Commission
Tallahassee, FL

By facsimile transmission to: 413-6627

RE: 1999 Ten Year Site Plans

Dear Mr. Jenkins:

LEAF offers the following comments on the 1999 Ten Year Site Plans filed by Florida's utilities. For the following reasons, LEAF recommends that the Commission find the plans are unsuitable:

1. ***Utility plans are inconsistent with the State Comprehensive Plan.***

The Commission is to determine the suitability of Ten Year Site Plans in view of "the extent to which the plan is consistent with the state comprehensive plan." Section 186.802(2)(e), F.S. The Commission should find the plans unsuitable in that:

a. Utility plans are not consistent with the state comprehensive plan's goal that "Florida shall reduce its energy requirements through enhanced conservation and efficiency measures in all end-use sectors" and policy to "...reduce per capita energy consumption" Section 187(12)(a) and (b)1., F.S.

The DSM in the plans before you focuses primarily on shifting usage from periods of peak demand. Though LEAF recognizes the value of reducing peak usage, we believe that utilities should also plan to reduce per capita energy usage as the state comprehensive plan directs.

Focusing more on reducing per capita energy use would also help address reliability concerns. Energy-use-reducing efficiency resources can provide low cost, readily dispatchable, reliability solutions for utilities – as one example: to address unexpectedly high demand during planned off-peak maintenance periods. Efficiency resources also avoid reliability concerns associated with the load management

resources which occur because subscribers can 1) exit the program with little notice, and 2) bypass the control (e.g., installing window air conditioners for use when the central air is cycled off during a heat wave).

More focus on energy use reduction would also conform to the Commission's policy to encourage least-cost DSM when energy savings are high and rate impacts are low.

b. Utility plans are inconsistent with the state comprehensive plan's goal to promote "an increased use of renewable energy resources" and policies to promote "the development and application of solar energy...," and to promote "the use and development of renewable energy resources".

Florida's utilities' plans are inconsistent with these state plan goals and policies because they plan little-to-no solar resources. Failing to plan for a transition to renewables equates to a plan to fail to make a timely transition to renewables. The Commission should take this opportunity to promote and encourage utility investments in solar energy.

2. *Utility plans overstate the need for new generation.*

The Commission is to determine suitability in view of "the need, including the need as determined by the commission, for electrical power in the area to be served." Section 186.802(2)(a), F.S. The plans overstate the need for new supply-side capacity because they forego cost-effective energy-use reducing DSM investments that would reduce or postpone supply-side capacity needs. Instead, planned DSM focuses on shifting use away from peak, leaving untapped the significant potential to reduce per-capita electrical energy use at a cost less than power plants which the Commission has authorized and encouraged (Order No. PSC-94-1313-FOF-EG issued 10/25/94).

3. *Utility plans lack any apparent consideration of the aging fleet of existing plants, their potentially increased maintenance costs and their considerable current and future environmental costs.*

The Commission is to determine suitability after reviewing "possible alternatives to the proposed plan," the "anticipated environmental impact of each proposed electrical powerplant site" and "the plan with respect to the information of the state on energy availability and consumption." Section 186.201(2)(b) and (c), F.S.

As any machine ages, it typically requires more maintenance. Many of the plants built in the 1940's "50s, "60s and even "70s were originally designed for a 25 or 30 year life. Florida has a significant amount of aging capacity, only a small fraction of which is proposed for retirement during the 10 year planning period. These plants will require more maintenance at a time when utilities are cutting costs, including plant and staffing levels. These plants are also among the most inefficient and most polluting in the fleet. They cost ratepayers inordinate amounts of money in being fuel-inefficient and they cost all Floridians in health and environmental damage. Some recognition of the need to retire these plants, or bring them up to current standards, is needed.

4. *Assumptions that the availability of all existing units is increasing are unsupported.*

The Commission is also to determine suitability after reviewing "the plan with respect tothe information of the state on energy availability and consumption." Section 186201(2)(f), F.S. Utility representatives claim that the availability of existing units is increasing. However, as detailed above, Florida is relying on a signficant amount of aging capcity. Utility plans give no apparent consideration to the likely decreased availability of those aging units. Thus, claims that the availability of existing units is increasing are not supported.

LEAF appreciates your consideration of these comments.

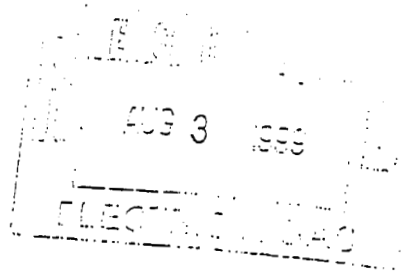
Sincerely,

Deb Swim

Debra Swim
Senior Attorney
Energy Advocacy Project

Apalachee Regional Planning Council

Serving Calhoun, Franklin, Gadsden, Gulf, Jackson, Jefferson, Liberty, Leon, and Wakulla Counties and their municipalities



July 28, 1999

Mr. Michael Haff
Bureau of Conservation, System Planning
and Electric Safety
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Haff:

The Apalachee Regional Planning Council staff has reviewed the Ten Year Site Plan (TYSP) for the City of Tallahassee. The City is currently constructing the addition of a 233 megawatt plant in St. Marks. All issues of regional concern have been addressed. The City has no other power plants planned within or likely to affect resources or facilities of this Region.

If you have any questions concerning this matter, please contact Mike Donovan at 850-488-6211 or 850-674-4571.

Sincerely,

Charles D. Blume
Executive Director

CDB/md

cc: Mr. Paul Darst, DCA

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August 13, 1999

Mr. Michael S. Haff
Bureau of Conservation, System Planning and Electric Safety
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

RECEIVED
AUG 18 1999
ELECTRIC

RE: Ten-Year Site Plan Reviews
Florida Power Corporation
Florida Power & Light
Orlando Utilities Commission
Seminole Electric Cooperative, Inc.
Duke Energy New Smyrna Beach Power Co. Ltd.

Dear Mr. Haff:

The East Central Florida Regional Planning Council (ECFRPC) has reviewed the ten-year site plans for the following electric utilities: the Florida Power Corporation, Florida Power & Light Company, the Orlando Utilities Commission, Florida Power Corporation, and Seminole Electric Cooperative, Inc. The Orlando Utilities Commission, and Seminole Electric Cooperative, Inc. either do not require additional facilities or have facilities located outside the jurisdiction of the ECFRPC. The remaining two – the Florida Municipal Power Agency and Florida Power & Light Company were reviewed with the comments below.

Florida Municipal Power Agency: The agency plans to increase the capacity of the combined cycle unit at Kissimmee's Cane Island Power Park. This plan gives very little information concerning the environmental impact and mitigation measures; instead the section refers to the Kissimmee Utility Authority's 1998 Ten-Year Site Plan. In your initial letter dated May 12, 1998, the Council did not receive the Kissimmee plan. Please send us the copy of the Kissimmee plan so we may complete this review.

Florida Power & Light Company:
An expansion of the existing Sanford to Poinsett transmission facility is proposed in conjunction with the Sanford plant repowering. As this is an existing facility, no regional routing issues are expected. Specific impacts to regional resources or facilities will be addressed during the certification review process.

A repowering of the Sanford plant is proposed. This would involve removing the existing oil and gas fired units with larger natural gas turbines and heat recovery steam generators. According to the Debary Comprehensive Plan, the plant site is

designated as Industrial Utilities and is surrounded by primarily agriculture. This plant presently produces visible air emissions so its repowering with cleaner fueled generators should provide a positive environmental benefit.

It is stated that the current natural gas supply is insufficient to support the new units. No information is presented on what is needed to address this, however if existing gas corridors are expanded, then impacts should be limited. We note the presence of the St. Johns and Wekiva river systems near to the site which will require strict impact avoidance and minimization measures.

Additional cooling water withdrawals from the St. Johns River are projected to be "negligible", but not further defined. Associated impacts with these withdrawals can be addressed during certification/permitting reviews.

The Cape Canaveral Plant in Brevard County is proposed as a possible expansion site. Siting of a new power plant by others in the vicinity of this plant has recently received significant community resistance, however the expansion of an existing facility is seen as preferable by this agency and may receive local support. The Indian River would continue to be used for industrial cooling (550,000 gpm). The Indian River provides habitat for the West Indian manatee, a protected species, with the warm water outfall from this plant providing an attraction for manatees during periods of cooler temperatures. Any increases or decreases in the size of this discharge will need to be considered with this condition in mind.

Florida Power Corporation No transmission additions requiring certification under the Florida Transmission Line Siting Act are proposed.

An addition of 249 MW and 297 MW combustion peaking units is proposed at the current Intercession City Site in Osceola County. This site is located south of the urbanized portions of the Orlando metropolitan area and is buffered from adjacent land uses by undeveloped and conservation lands. It is also served by existing transmission lines, oil and natural gas lines and treated wastewater effluent pipeline from the City of Kissimmee. These factors make the location for facility expansion very desirable from a regional perspective. The site is also located adjacent to the Reedy Creek wetland system. This system provides the only link in Central Florida between the Kissimmee River system and that of the Green Swamp and so represents a significant regional wildlife corridor. Power plant construction and operation could be very compatible with this use, but must be done with adequate consideration given to avoiding impacts to this natural system.

No other activities are proposed within the East Central Florida region.

Orlando Utilities Commission No plant expansions or transmission lines expansions that would require certification review are proposed.

Seminole Electric Cooperative, Inc. No plant expansions or transmission lines expansions that would directly affect interest within the jurisdiction of this organization are proposed.

Duke Energy New Smyrna Beach Power Co. Ltd.

A new generating station at New Smyrna Beach is proposed and has been earlier reviewed by this agency as part of the site certification process. No significant regional issues were identified during that review.

For the purpose of updating your contact records, Mr. Aaron Dowling is no longer associated with this agency. Ms. Sandra Glenn is Executive Director and mailings may be addressed to her at the address that you have on file.

If you have any questions or if the ECFRPC can be of further assistance, please contact us.

Sincerely,

Gregory Golgowski, AICP
Deputy Executive Director

cc: Paul Darst, FL Dept. of Community Affairs

North Central Florida Regional Planning Council

2009 NW 67 PLACE, SUITE A, GAINESVILLE, FLORIDA 32653-1603
(352) 955-2200 SUNCOM 625-2200 FAX (352) 955-2209

August 12, 1999

RECEIVED
AUG 16
ELECTRIC

Michael Haff
Bureau of conservation, System Planning, and Electric Safety
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RE: Regional Review of Seminole Electric Cooperative and Gainesville Regional Utilities Proposed Ten-Year Site Plans:

Dear Mr. Haff:

A staff-level review of the above-referenced items is enclosed in lieu of final action as the Council will not meet until August 26, 1999. An adopted version of the review will be forwarded to you should the Council amend the draft.

Additionally, the Council notified affected local governments and requested their comments on the proposed ten-year site plans. Comments received by the Council from the affected local governments are also enclosed.

Please do not hesitate to contact Steven Dopp of our staff if you have any questions.

Sincerely,

Charles L. Kiester
Director of Regional Programs

Enclosures

xc: Paul Darst, DCA

C:\PUBLIC\CHOUSE\LETTERS\HAFF.899

NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL

August 26, 1999

Clearinghouse Item #155 - Ten-Year Site Plans: Gainesville Regional Utilities and Seminole Electric Cooperative, 1999-2008

INTRODUCTION

In accordance with Chapter 186.801, F.S., all electrical generating companies over a certain size must develop ten-year site plans relating to the siting of new generating facilities and submit these plans to the Florida Public Service Commission and the regional planning council for review. The above-referenced plans cover the 1999-2008 planning period.

BACKGROUND

Based on projected electrical demand for various parts of Florida, the plans identify anticipated new generating facilities needed over the next ten years. Once a need for additional capacity is identified, the ten-year site plans identify possible locations for new power plant sites. More than one site is usually listed as a possible alternative for each proposed electrical generating facility.

Before a plant can be constructed, an application must be filed with the Department of Environmental Protection (DEP) pursuant to the electrical power plant certification (permitting) process established by Chapter 403, F.S. While not as comprehensive as a Development of Regional Impact review, the focus of this process is on environmental impacts, including a special hearing on land use issues. The DEP must involve the Department of Community Affairs as well as the water management districts in the review process. Local governments and regional planning councils can intervene in the certification process.

EVALUATION

Gainesville Regional Utilities

Gainesville Regional Utilities (GRU) plans to add 96 MWs of electrical generating capacity by 2001 by adding an additional natural gas turbine-generator to its John R. Kelly Generating Station located in downtown Gainesville (see attached). It is anticipated that the new turbine-generator will meet all applicable state air emission standards.

Seminole Electric Cooperative

Seminole Electric plans to construct an additional 587 MWs of electrical generating capacity by 2002 in Hardee County. Additionally, the cooperative proposes to build an additional 2,160 MWs of electrical generating capacity in unspecified locations by the year 2007.

No significant adverse impacts to north central Florida are anticipated as a result of the additional electrical generation capacity proposed by Gainesville Regional Utilities. Therefore, GRU's proposed ten-year site plan is consistent with the North Central Florida Strategic Regional Policy Plan. The impacts of the additional electrical generating capacity proposed by Seminole Electric Cooperative cannot be determined for the proposed 2,160 MWs cannot be determined (units 1 through 12 described as "unknown plant name" on Schedule 8, attached) as the location of these units is not identified in the ten-year site plan. It is recommended that the Seminole Electric ten-year site plan identify the locations of its proposed additional electrical generating units.

RECOMMENDATION

It is recommended that these comments be forwarded to the Florida Public Service Commission as regional review.

Steve Dopp

From: Chris Bird [Chris@smtp.co.alachua.fl.us]
Sent: Tuesday, August 10, 1999 10:32 AM
To: GCS@smtp.co.alachua.fl.us
Cc: dopp@ncfrpc.org
Subject: EPD comments on GRU 10 year site plan

Geoff, Michael Drummond indicated that you are coordinating response comments to NCFRPC re the subject GRU plan.

EPD's only comments are related to the proposed continuation of wastewater/stormwater discharges to Sweetwater Branch creek as described on page 58 of the report.

EPD recommends that GRU's proposed continuation of direct discharges to the creek be eliminated. Alternative, more environmentally sensitive methods of treatment and discharge need to be instituted such as discharge to the Main Street treatment plant for the "low-volume waste" and discharge to an onsite or offsite stormwater retention treatment facility for the stormwater.

ALACHUA COUNTY
DEPARTMENT OF GROWTH MANAGEMENT

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Richard E. Wolf
Director
Codes Enforcement

Marilyn Wagener
Director
Visitors & Convention Bureau

Wendy V. Kinser
Principal Planner
Development Services

Ken Zeichner
Principal Planner
Comprehensive Planning

August 11, 1999

Steve Dopp
North Center Florida Regional
Planning Council
2009 NW 67th Place, Suite A
Gainesville, FL 32653

Re: The GRU 10-year Site Plan

Dear Mr. Dopp:

In regards to the GRU 10-year Site Plan-Regional Clearinghouse review, we appreciate the opportunity to comment. The Department of Growth Management has no comments on this item. We understand that Alachua County Department of Environmental Protection has e-mailed comments to you relative to the proposed continuation of wastewater/stormwater discharge to Sweetwater Branch Creek.

Thank you.

Sincerely,

Kurt Larsen

Kurt Larsen, Director
Department of Growth Management

KL/cmb

xc: Richelle Sucara, Interim County Attorney
Chris Bird, Director of Environmental Protection
Ed Culpepper, Director of Public Works
Ken Zeichner, Principal Planner
Geoff Sample, Senior Planner

F:\USERS\CMB\LETTERS\KurtS10NCFRPC-GRU10.wpd

Northeast Florida Regional Planning Council

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MEMORANDUM

To: Northeast Florida Regional Planning Council

Thru: Linda Owens-Myers, Chairman
NEFRPC Comprehensive and Project Planning Committee

From: Jodi Hopkins, Regional Planner

Date: November 1, 1999

Re: Electric Utility Ten-Year Site Plans

On June 16, 1999, the Northeast Florida Regional Planning Council received copies of the Ten-Year Site Plans for Jacksonville Electric Authority and Seminole Electric Cooperative, Inc. These plans were submitted pursuant to Section 186.801, Florida Statutes. Staff has reviewed the proposed plans, and with regard to each of the individual Ten-Year Site Plans offers the following comments.

Jacksonville Electric Authority (JEA)

The Ten-Year Site Plan submitted by JEA includes the repowering of Northside Units 1 and 2, currently in the permitting and detailed design phase, expected to be completed by April 2002. The repowering project will result in a plant wide (steam units only) reduction of particulate emissions, NO_x, SO_2, and ground water use by 10 percent, while providing 265 MW of additional electric supply capacity. This program is at an existing facility and will not result in any new impacts on public facility capacities and is not inconsistent with the City of Jacksonville's Future Land Use Element.

JEA plans to complete construction on a simple cycle combustion turbine generating unit at the existing Kennedy Generating Station in May of 2000. In addition three simple cycle combustion turbine generating units are planned for the Brandy Branch site near Baldwin, FL, with the completion of the first two units in January 2001 and the third unit in December 2001. These programs are at existing JEA owned property and will not result in any new impacts on public facility capacities and are not inconsistent with the City of Jacksonville's Future Land Use Element.

Affirmative Action and Equal Opportunity Employer

Three JEA oil/gas steam units are scheduled for retirement or shutdown. The Kennedy Unit 10 will be shutdown by March 2000 and the Southside Unit 4 and Southside Unit 5 will be retired by October 2001. Upon retirement or shutdown, the units will all be over 35 years of age. This will allow the opportunity to replace the capacity with newer more efficient technology with lower emissions.

Overall, the programs in the Ten-Year Site Plan submitted by JEA are at existing sites and will not result in any new impacts on public facility capacities and are not inconsistent with the City of Jacksonville's Future Land Use Element.

Seminole Electric Cooperative, Inc. (SECI)

The Seminole Electric Cooperative, Inc. (SECI) distribution system members provide electric power to the northeast Florida region are Clay Electric Cooperative, Inc. in Keystone Heights (serving portions of Clay, Duval, Baker, Flagler and Putnam Counties), and Okefenoke Rural Electric Membership Corporation, Inc. in Nahunta, Georgia (serving portions of Baker, Duval and Nassau Counties).

SECI serves its member system load with a combination of owned generation and purchased capacity resources. SECI purchases partial and/or full requirements (PR/FR) power from Florida Power Corporation, the Jacksonville Electric Authority, the City of Gainesville, the Orlando Utilities Commission, and Tampa Electric Company. A contract with FPL for partial requirements purchases was terminated effective January 1, 1999.

SECI is participating in the University of South Florida's Electric Vehicle Solar Recharging project and monitors other solar energy research projects and the advances in fuel cell technology for possible inclusion in Seminole future resource options.

The NEFRPC has no comments regarding SECI's planned facilities since none of the new facilities are located within the northeast Florida region.

Staff Recommendation

Staff recommends that the Comprehensive and Project Planning Committee and the Council accept staff comments and transmit the comments to the Florida Public Service Commission.

South
Florida
Regional
Planning
Council

August 17, 1999

VIA FACSIMILE & U.S. MAIL

Mr. Michael Haff
Division of Electric and Gas
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

RE: Florida Power and Light - Ten Year Power Plant Site Plan 1999-2008.

Dear Mr. Haff:

We have reviewed the above-referenced plan and have the following comments:

- Additional transmission lines to be located in the South Florida region are limited to existing utility easements. They are necessary infrastructure for the economic growth of the region, and are not a subject of concern regarding the goals and policies of the *Strategic Regional Policy Plan for South Florida.*

- With regard to the policies of the utility which impact the resources and economy of the region, Florida Power and Light has balanced conservation measures through its Demand Side Management programs with expansion of energy-generating facilities to simultaneously meet the energy needs of our expanding population while reducing the potential of that need for energy.

- The Ten Year Power Plan Site Plan is generally consistent with the goals and policies of the *Strategic Regional Policy Plan for South Florida*, specifically the following:

Strategic Regional Goal

2.3 Enhance the economic competitiveness of the region and ensure the adequacy of its public facilities and services by eliminating the existing backlog, meeting the need for growth in a timely manner, improving the quality of services provided and pursuing cost-effectiveness and equitability in their production, delivery and financing.

Regional Policies

2.3.22 Encourage the application of resource recovery, recycling, cogeneration, district cooling, water re-use systems, and other appropriate mechanisms where they are cost-effective and environmentally sound, as means of reducing the impacts of new development on existing public facilities and services, and the costs of providing new public facilities and services.

3440 Hollywood Boulevard, Suite 140, Hollywood, Florida 33021
Broward (954) 985-4416, Area Codes 305, 407 and 561 (800) 985-4416
SunCom 473-4416, FAX (954) 985-4417, SunCom FAX 473-4417
e-mail sfadmin@sfrpc.com

2.3.35 Allow flexibility in state, local, and private sector participation in funding public services and facilities.

2.3.36 Encourage the use of user fees which discourage excessive use of infrastructure and services in the region while considering social and economic equity standards.

Thank you for the opportunity to comment. If you require further information, please contact me.

Sincerely,

John E. Hulsey, AICP
Senior Planner

JEH/cp

Southwest Florida Regional Planning Council

4980 Bayline Drive, 4th Floor, N. Ft. Myers, FL 33917-3909 (941) 656-7720

P.O. Box 3455, N. Ft. Myers, FL 33918-3455 SUNCOM 749-7720

FAX 941-656-7724

July 19, 1999

Mr. Michael S. Haff
Bureau of Conservation, System Planning, and Electric Safety
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Haff:

SWFRPC staff has reviewed the Ten-year Power Plant Site Plan--1999-2008 (April, 1999) of Florida Power and Light Company as requested by the Florida Public Service Commission.

Expansion of the Fort Myers Facility

Florida Power and Light Company is adding new generation capacity in Southwest Florida at its generating plant at Fort Myers in Lee County. FPL has proposed expansion and repowering (with natural gas) its two existing steam units at that facility, to be completed by January of 2002.

Two existing oil-fired units will be replaced with six advanced combustion turbines to be fueled by natural gas and six heat recovery steam generators (referred to as "repowering"). The existing twelve combustion turbines at the site will not be part of the project.

In addition, FPL notes that two sections of transmission lines will be added (1.58 miles and 2.57 miles) as a direct association with the repowering project.

Preferred and Potential Sites

FPL has developed a list of sites, both preferred and potential (pages 82+). The number one preferred site is the Fort Myers facility. There are no other preferred sites in Southwest Florida. The discussion of potential sites includes no site in Southwest Florida.

SWFRPC Review

While the Ten Year Power Plant Site Plan for 1999-2008 provides some information about the preferred sites, neither that information nor the information about the potential sites is

adequate for review of a specific project. Additionally, that is not the function of this review as requested by the Public Service Commission.

SWFRPC is aware of the ongoing FPL siting effort as stated in the Ten Year Power Plant Site Plan for 1999-2008. If any of the sites noted above is elevated to the status of an actual project that requires SWFRPC review or if a new site is added to the list of sites for Southwest Florida, SWFRPC will participate as appropriate in review of such site(s).

Sincerely,
Southwest Florida Regional Planning Council

James E. Newton II
Principal Planner

c: Ben Starrett, DCA.

Southwest Florida Regional Planning Council

4980 Bayline Drive, 4th Floor, N. Ft. Myers, FL 33917-3909 (941) 656-7720

P.O. Box 3455, N. Ft. Myers, FL 33918-3455 SUNCOM 749-7720

FAX 941-656-7724

July 19, 1999

Mr. Michael S. Haff
Bureau of Conservation, System Planning, and Electric Safety
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

21

Dear Mr. Haff:

SWFRPC staff has reviewed the 1999 Ten-year Site Plan (April 1999) of Seminole Electric Cooperative, Inc. as requested by the Florida Public Service Commission.

SECI has ten members, with two in Southwest Florida (Glades Electric Cooperative, Inc. in Moore Haven and Lee County Electric Cooperative, Inc. in North Fort Myers). They distribute power purchased from SECI. Neither cooperative generates its own power. None of the generating facilities of SECI is within Southwest Florida.

For Southwest Florida, the nearest generating facility is Hardee Power Station in Hardee and Polk Counties. (The facility is owned by Hardee Power Partners, a subsidiary of SECI.) The site is nine miles northwest of Wauchula, sixteen miles south-southwest of Bartow, in northern Hardee County, on the border with Polk County.

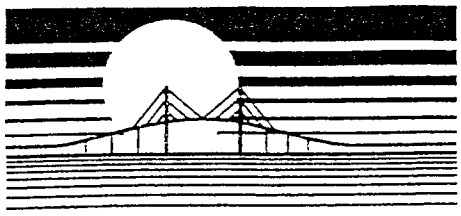
The site is outside the Southwest Florida region. As a result, no comments are offered on the SECI Ten-year Site Plan.

Sincerely,
Southwest Florida Regional Planning Council

James E. Newton II
Principal Planner

c: Ben Starrett, DCA

Printed on Recycled Paper



Tampa Bay Regional Planning Council

RECEIVED
12

Chairman
Barbara Romano

Vice-Chairman
Commissioner Chris Hart

Secretary/Treasurer
Frederick T. Reeves

Executive Director
Manny L. Pumariega

August 9, 1999

Mr. Michael S. Huff
Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Subject: IC&R #227-99, Florida Power Corporation Ten-Year Site Plan Fiscal Year 1999-2008, Pinellas and Pasco Counties

Dear Mr. Huff:

The above-referenced project was considered during the Council's August 9, 1999 meeting and determined to be consistent with the Tampa Bay Regional Planning Council's *Strategic Regional Policy Plan.*

Please contact me if further information regarding this item is desired.

Sincerely,

Kristi Thum, Associate Planner
Intergovernmental Coordination & Review

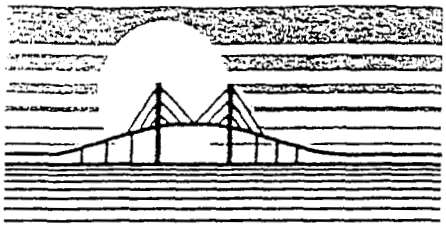
KT/bj

Enclosure

FLORIDA
PUBLIC SERVICE COMMISSION
1999 AUG 12 AM 8:25

9455 Koger Boulevard, Suite 219, St. Petersburg, FL 33702-2491
Phone (727) 577-5151 FAX (727) 570-5118 Sunc om 586-3217
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FLORIDA POWER CORPORATION TEN-YEAR SITE PLAN, PINELLAS AND PASCO COUNTIES, IC&R #227-99.

The Florida Department of Community Affairs has requested review and comment on the Florida Power Corporation (FPC) Ten-Year Site Plan pursuant to Section 186.801, F.S. The Ten-Year Plan is required by Chapter 186, F.S. and 22E-2, F.A.C., and is prepared pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S.

The Ten-Year Site Plan describes the utility's current power generating capacity and demand, forecasts future electrical power demand and estimates future facility needs. In the Tampa Bay region, FPC serves Pinellas and Pasco counties. Generating plants located in the region are the P.L. Bartow, Bayboro and Higgins facilities in Pinellas County and the Anclote site in Pasco County.

Council Comments/Concerns

The FPC has identified a current electrical generating capacity of 9,027 megawatts (MW). This capacity includes utility and non-utility purchased power, peaking facilities, nuclear and fossil steam and combined cycle plants.

FPC customers participating in the company's Energy Management program are managing future growth and costs. Over 500,000 customers participated in the Energy Management program during the year. This excellent participation level provides over 875,000 kilowatts (KW) of peak saving capacity for use during high load periods.

FPC's forecast of capacity and demand is based on serving expected growth in regulated retail load and commitments to existing wholesale customers. As deregulation occurs in the electric industry, customers with choice, such as the wholesale market, are switching to new generation suppliers. This creates an added dimension of uncertainty which a traditional utility is not accustomed to planning for. FPC is not committing long-term generation resources to serve the wholesale market until a viable plan is in place.

FPC's fuel requirements and energy sources reflect a diverse fuel supply system which is not dependent on any one fuel source. FPC expects its fuel diversity to be further enhanced with the addition of future planned combined cycle generation units fueled by natural gas. Natural gas consumption is projected to increase as plants are added to meet future load growth. FPC's coal, nuclear and purchased power requirements are projected to remain relatively stable over the planning horizon.

Recommendation

It is recommended that the Florida Power Corporation's Ten-year site plan be approved.

Committee adopted August 9, 1999.

Barbara Romano, Chair
Tampa Bay Regional Planning Council

This project has been reviewed for consistency with the Council's adopted *Future of the Region: A Strategic Regional Policy Plan for the Tampa Bay Region*. It has been determined to be consistent with appropriate Council policies.

PLEASE NOTE: The Council's comments constitute compliance with Florida's Intergovernmental Coordination and Review process only.

Tampa Bay Regional Planning Council

Chairman
Barbara Romano

Vice-Chairman
Commissioner Chris Hart

Secretary/Treasurer
Frederick T. Reeves

Executive Director
Manny L. Pumariega

August 9, 1999

Mr. Michael S. Huff
Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Subject: IC&R #228-99, Florida Power & Light Ten-Year Site Plan Fiscal Year 1999-2008, Manatee County

Dear Mr. Huff:

The above-referenced project was considered during the Council's August 9, 1999 meeting and determined to be consistent with the Tampa Bay Regional Planning Council's *Strategic Regional Policy Plan.*

Please contact me if further information regarding this item is desired.

Sincerely,

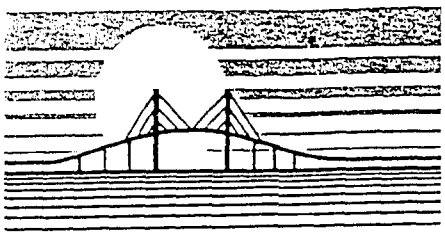
Kristi Thum

Kristi Thum, Associate Planner
Intergovernmental Coordination & Review

KT/bj

Enclosure

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FLORIDA POWER AND LIGHT COMPANY TEN-YEAR SITE PLAN, MANATEE COUNTY, IC&R #228-99.

The Florida Department of Community Affairs has requested review and comment on the Florida Power and Light Company (FPL) Ten-Year Site Plan pursuant to Section 186.801, F.S. The Ten-Year Plan is required by Chapter 186, F.S. and 22E-2, F.A.C., and is prepared pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S.

The Ten-Year Site Plan describes the utility's current power generating capacity and demand, forecasts future electrical power demand and estimates future facility needs. In the Tampa Bay region, FPL serves Manatee County and its only generating plant in the region is located there.

Council Comments/Concerns

The FPL has identified a current electrical generating capacity of 16,416 megawatts (MW) and a projected demand in 2007 of 19,901 MW. The need will be met by demand-side management, buying additional power from traditional sources and cogeneration, repowering existing units, and building new capacity.

Demand-side management (DSM) programs, by 2008, will generate reductions of 3,700 MW. FPL's DSM programs include residential load management, residential energy audits, commercial/industrial efficient lighting and load control, and BuildSmart. FPL submitted proposed DSM goals for 2000 and a decision on those goals is scheduled for the end of the year.

FPL has initiated renewable resources through the concept of "Green Pricing", which is the use of solar photovoltaic (PV) technologies. Research and development projects have been conceived to analyze the feasibility of using PV in potentially large endeavors. FPL has also facilitated renewable energy project using facilities which burn bagasse, waste wood and municipal waste.

Part of FPL's proposed capacity increases are proposed to be met by existing unit upgrades, construction of new facilities at the Martin County Plant, purchases from other utilities and cogeneration. These increases will provide an additional 2,624 MW to the FPL system.

Recommendation

It is recommended that the Florida Power and Light Company's Ten-year site plan be approved

Committee adopted August 9, 1999.

Barbara B. Romano

Barbara Romano, Chair
Tampa Bay Regional Planning Council

This project has been reviewed for consistency with the Council's adopted *Future of the Region: A Strategic Regional Policy Plan for the Tampa Bay Region.* It has been determined to be consistent with appropriate Council policies.

PLEASE NOTE: The Council's comments constitute compliance with Florida's Intergovernmental Coordination and Review process only.

Tampa Bay Regional Planning Council

Chairman
Barbara Romano

Vice-Chairman
Commissioner Chris Hart

Secretary/Treasurer
Frederick T. Reeves

Executive Director
Manny L. Pumariega

August 9, 1999

Mr. Michael S. Huff
Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850.

Subject: IC&R #229-99, Seminole Electric Cooperative Ten-Year Site Plan Fiscal Year 1999-2008, Manatee and Pasco Counties

Dear Mr. Huff:

The above-referenced project was considered during the Council's August 9, 1999 meeting and determined to be consistent with the Tampa Bay Regional Planning Council's *Strategic Regional Policy Plan.*

Please contact me if further information regarding this item is desired.

Sincerely,

Kristi Thum, Associate Planner
Intergovernmental Coordination & Review

KT/bj

Enclosure

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Tampa Bay Regional Planning Council

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SEMINOLE ELECTRIC COOPERATIVE TEN-YEAR SITE PLAN, PASCO, MANATEE AND HILLSBOROUGH COUNTIES, IC&R #229-99.

The Florida Department of Community Affairs has requested review and comment on the Seminole Electric Cooperative (SEC) Ten-Year Site Plan pursuant to Section 186.801, F.S. The Ten-Year Plan is required by Chapter 186, F.S. and 22E-2, F.A.C., and is prepared pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S.

The Plan describes the utility's current power generating capacity and demand, forecasts future electrical power demand and estimates future facility needs. SEC is composed of 11 distribution system members, which includes Withlacoochee River Electrical Cooperative, which serves parts of Pasco County, and Peace River Electrical Cooperative, which serves parts of Manatee County and a small portion of Hillsborough County.

Council Comments/Concerns

The SEC has projected the winter peak demand to increase to 4,230 megawatts (MW) in 2008, representing an annual growth rate of 3.2 percent in the next 10 years. Summer peak demand at an annual rate of 3.2 percent, from a projection of 2,458 MW in 1999 to 3,267 MW in 2008. The remainder of the demand from its member cooperatives is met by contractual purchases from other utilities.

Seminole has contracts with the Jacksonville Electric Authority (JEA) for 53 MW of capacity through 2001, with an option to extent to May 2004. Orlando Utilities Commission is contracted for 75 MW through 2004 and Florida Power Corporation is contracted for 450 MW through to 2001.

SEC, through a contract with TECO Power Services, purchases 145 MW of capacity from the Big Bend No. 4 coal unit and a nominal 295 MW of first call reserve capacity from the Hardee Power Station. Seminole has first priority use of the Big Bend No. 4 capacity for any purpose, subject to an annual energy cap. Seminole has first priority use of the Hardee Power Station as a reserve resource to cover a forced or scheduled outage or reduced capability of Seminole's owned capacity resources.

Seminole's future plans include the installation of a 488 MW gas-fired combined cycle unit call Payne Creek Generating Station (PCGS) to be constructed on the existing Hardee Power Station site. This unit will contribute to meeting SEC's reserve requirements as well as displacing purchased

capacity. An in-service date for PCGS is January 1, 2002. SEC has no plans to build any additional transmission facilities in conjunction with PCGS generating facility.

Construction of the PCGS in Polk and Hardee Counties, although not located in the Tampa Bay region, may impact this region. This facility, in conjunction with proposed or existing facilities of other power companies (Tampa Electric Company and Florida Power Corporation) in the area, may produce unforeseen adverse environmental impacts in the Tampa Bay region. It is recommended that the Tampa Bay Regional Planning Council, Hillsborough County and Manatee County be notified of any future action related to the Payne Creek Generating Station.

Recommendation

It is recommended that Seminole Electric Cooperative's Ten-year site plan be approved.

Further, it is recommended that any additional comments addressing local concerns be considered prior to final action.

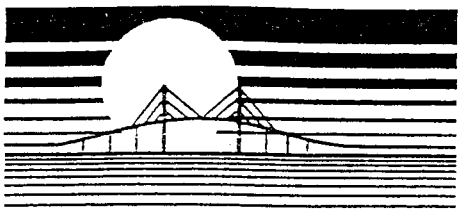
Committee adopted August 9, 1999.

Barbara B. Romano

Barbara Romano, Chair
Tampa Bay Regional Planning Council

This project has been reviewed for consistency with the Council's adopted *Future of the Region: A Strategic Regional Policy Plan for the Tampa Bay Region*. It has been determined to be consistent with appropriate Council policies.

PLEASE NOTE: The Council's comments constitute compliance with Florida's Intergovernmental Coordination and Review process only.



Tampa Bay Regional Planning Council

Chairman
Barbara Romano

Vice-Chairman
Commissioner Chris Hart

Secretary/Treasurer
Frederick T. Reeves

Executive Director
Manny L. Pumariega

August 9, 1999

Mr. Michael S. Huff
Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Subject: IC&R #230-99, Tampa Electric Company Ten-Year Site Plan Fiscal Year 1999-2008, Hillsborough, Manatee and Pinellas Counties

Dear Mr. Huff:

The above-referenced project was considered during the Council's August 9, 1999 meeting and determined to be consistent with the Tampa Bay Regional Planning Council's *Strategic Regional Policy Plan.*

Please contact me if further information regarding this item is desired.

Sincerely,

Kristi Thum

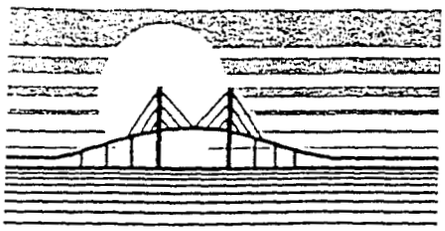
Kristi Thum, Associate Planner
Intergovernmental Coordination & Review

KT/bj

Enclosure

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Tampa Bay Regional Planning Council

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http://www.tbrpc.org

TAMPA ELECTRIC COMPANY TEN-YEAR SITE PLAN, HILLSBOROUGH AND PASCO COUNTIES, AND THE CITY OF OLDSMAR, IC&R #230-99.

The Florida Department of Community Affairs has requested review and comment on the Tampa Electric Company (TECO) Ten-Year Site Plan pursuant to Section 186.801, F.S. The Ten-Year Plan is required by Chapter 186, F.S. and 22E-2, F.A.C., and is prepared pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S.

TECO's Ten-Year Site Plan describes the utility's current power generating capacity and demand, forecasts future electrical power demand and estimates future facility needs. In the Tampa Bay region, TECO serves Hillsborough County, portions of Pasco County and the City of Oldsmar located in Pinellas County. Three of TECO's generating plants are located in the region: Big Bend, Gannon, and Hookers Point.

Council Comments/Concerns

TECO has a current generating capacity of 3,426 megawatts (MW) and projected demand of 4,350 MW in 2008. The need will be met by purchasing additional power from non-utility sources (cogeneration) and/or other utilities, TECO Power Services Corporation, and building new capacity.

Cogeneration, from non-utility sources, is expected to generate 442 megawatts (MW) in 1999. By 2008 the total cogeneration is expected to grow to 459 MW. During 1999, Tampa Electric has entered into transmission wheeling with four of its cogeneration customers, supplying a total of 154 MW of firm contract to two other utilities in the state. By 2008, this total is expected to decrease to 145 MW.

Additional capacity is planned for 2001, based on analysis of system reliability, demand side management goals, projects system demand and energy requirements, purchase power, and the existing Tampa Electric generating system. To meet the existed system demand and energy requirements over the next ten years, combustion turbines are planned for service in 2001, 2003, 2004, 2005, 2007 and 2008 at the Polk Plant facility. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. Hooker Point Station is assuming to be retired in January 2003.

In order to comply with the Clean Air Act Amendments of 1990, Tampa Electric will use low sulfur coal in Big Bend units 1-3, purchase sulphur dioxide allowances and integrate Big Bend Unit 3 flue gases into the scrubber on Big Bend Unit 4. After 2000, Tampa Electric plans to continue to use sulphur dioxide allowances and flue gas scrubbing.

Expansion of the TECO Power Station in Polk County, although not located in the Tampa Bay region, may impact this region. This facility, in conjunction with proposed or existing facilities of other power companies (Florida Power Corporation and Seminole Electric Cooperative) in the area, may produce unforeseen adverse environmental impacts in the Tampa Bay region. It is recommended that the Tampa Bay Regional Planning Council, Hillsborough County and Manatee County be notified of any future action related to the TECO Power Station and related transmission line construction.

Recommendation

It is recommended that Tampa Electric Company's Ten-year site plan be approved.

Further, it is recommended that any additional comments addressing local concerns be considered prior to final action.

Committee adopted August 9, 1999.

Barbara B. Romano

Barbara Romano, Chair
Tampa Bay Regional Planning Council

This project has been reviewed for consistency with the Council's adopted *Future of the Region: A Strategic Regional Policy Plan for the Tampa Bay Region.* It has been determined to be consistent with appropriate Council policies.

PLEASE NOTE: The Council's comments constitute compliance with Florida's Intergovernmental Coordination and Review process only.

WEST FLORIDA REGIONAL PLANNING COUNCIL

Post Office Box 486 • 3435 North 12TH Avenue • Pensacola, Florida 32593-0486
Phone (850) 595-8910 • S/C 695-8910 • (800) 226-8914 • Fax (850) 595-8967
E-mail: postmaster@wfrpc.dst.fl.us • http://www.wfrpc.dst.fl.us

Daniel F. Krumel
Executive Director

Charles D. Covey, III
Chairman

Wilson B. Robertson
Vice-Chairman

RECEIVED
JUL 6 1999

MEMORANDUM

DATE: June 30, 1999

TO: Michael Haff

FROM: Terry A. Joseph - Intergovernmental Review Coordinator

RE: Gulf Power - Ten Year Site Plan - 1999-2008 - RPC#: MJ489-06-2299

The staff of the West Florida Regional Planning Council have reviewed the above referenced proposed project under the Intergovernmental Coordination & Review Process (IC&RP). Based upon review of the information submitted, the Planning Council staff finds the proposal consistent with the Strategic Regional Policy Plan (SRPP), 29A-4, FAC, adopted August 7,1996.

Approval of the above referenced project by the West Florida Regional Planning Council does not obligate funding by local governments.

cc: Paul Darst, Dept of Community Affairs

967

LINDA S. SLOAN, A.I.C.P.
EXECUTIVE DIRECTOR

1241 S.W. 10th Street
OCALA, FLORIDA 34474-2798

Telephone 352/732-1315
Suncom 667-1315
FAX 732-1319
email: wrpc@atlantic.net

WITHLACOOCHEE REGIONAL PLANNING COUNCIL

SERVING LEVY, CITRUS, MARION, SUMTER AND HERNANDO COUNTIES.

OFFICERS

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CHAIRMAN

EUNICE NEVILLE
VICE-CHAIRMAN

WILBUR DEAN
SECRETARY

BY CERTIFIED MAIL

August 16, 1999

AUG 18 ...
ELECTRIC AND GAS

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

SUBJECT: Consistency Review/1999-2008 Ten-Year Site Plan
Seminole Electric Cooperative, Inc. (SEC)

Dear Mr. Haff:

Withlacoochee Regional Planning Council (WRPC) staff reviewed the above-referenced ten-year site plan as it relates to the Withlacoochee region consisting of Marion, Sumter, Levy, Citrus and Hernando counties and found it suitable regarding potential impacts to Regionally Significant Resources.

The main focus of this review is the proposed Payne Creek Generating station which is to be built as an addition to the Hardee Power Station. All proposed development will take place within the existing 1280 acre site which is outside the Withlacoochee Region. No additional transmission facility improvements are proposed in the current review package. However, WRPC is looking forward to reviewing upcoming Ten Year Site Plans that will include the location of the numerous generating facility additions and changes that SEC has planned to provide for future power needs.

Originally, approvals for the Payne Creek Generating Station were received in 1995 and projected to be on line in 1999. However, for economic reasons the plant was not built. In 1998, the Seminole Board of Trustees reactivated the project with an in-service date of 2002. In the time that has elapsed, industry standards for efficiency and emissions have improved significantly. Therefore, the Seminole Electric Cooperative plan is consistent with SRPP goals and policies relating to energy use, air quality, economic development and efficient movement of goods and services within and through the Withlacoochee region.

If you have any questions about this review, please give me a call.

Sincerely,

Bruce Day
Principal Planner

xc: Paul Darst, DCA

Southwest Florida
Water Management District

2379 Broad Street, Brooksville, Florida 34609-6899
(352) 796-7211 or 1-800-423-1476 (FL only)
SUNCOM 628-4150 TDD only 1-800-231-6103 (FL only)
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Bartow Service Office
170 Century Boulevard
Bartow, Florida 33830-7700
(941) 534-1448 or
1-800-492-7862 (FL only)
SUNCOM 572-6200

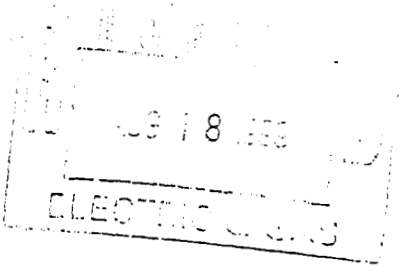
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Venice, Florida 34292-3524
(941) 486-1212 or
1-800-320-3503 (FL only)
SUNCOM 526-6900

Lecanto Service Office
3600 West Sovereign Path
Suite 226
Lecanto, Florida 34461-8070
(352) 527-8131
SUNCOM 667-3271

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Brenda Menendez
Vice Chair, Tampa
Sally Thompson
Secretary, Tampa
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Treasurer, Safety Harbor
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John P. Harllee, IV
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Watson L. Haynes, II
St. Petersburg
John K. Renke, III
New Port Richey
Pamela Stinnette-Taylor
Tampa

E. D. "Sonny" Vergara
Executive Director
Gene A. Heath
Assistant Executive Director
Edward B. Helvenston
General Counsel

August 13, 1999



Mr. Mike Haff
Florida Public Service Commission
Division of Electric and Gas
2540 Shumard Oak Boulevard, Room 200
Tallahassee, Florida 32399-0850

Subject: 1999 Electric Utility 10-Year Site Plans Including Florida Power Corporation, Florida Power and Light (FP&L), Tampa Electric, Lakeland Electric & Water, and Orlando Utilities.

Dear Mr. Haff:

The staff of the Southwest Florida Water Management District (District) has reviewed the Environmental and Land Use Information sections of the above referenced plans. All the proposed power plant expansions addressed in these plans are either on existing sites or have already undergone site certification. As such, we have no water resource concerns that have not already been addressed in the certification process.

If you have any questions or if I can be of further assistance, please contact me in the District's Planning Department at Extension 4417.

Sincerely,

Mark D. Phelps, AICP
Government Planning Coordinator, *Central Region*

MDP

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SUWANNEE RIVER WATER MANAGEMENT DISTRICT

July 8, 1999

JUL 12 19
ELECT

Mr. Michael S. Haff
Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Subject: Gainesville Regional Utilities - Seminole Electric Cooperative's Ten Year Site Plans

Dear Mr. Haff:

This letter is in reference to the Ten Year Site Plans (Plans) prepared by Gainesville Regional Utilities and Seminole Electric Cooperative submitted by the Florida Public Service Commission (Commission) to the Suwannee River Water Management District (District) for review. As outlined in your correspondence dated June 16, 1999, the District has reviewed the Plans for any proposed impacts to natural resources and adjacent land use concerns, land development regulations, and stormwater drainage issues that could occur within District boundaries. The District did not identify any environmental impacts or other related issues during the review of the Plans, proposed to occur within District boundaries, by either of the above-referenced electric utilities.

If you have any further questions, please contact me at 904/362-1001, or toll free at 800/226-1066.

Sincerely,

Jerry A. Scarborough
Executive Director

JAS/wam

970

LYNETTA USHER GRINER
Chairman
Fanning Springs, Florida

M. HOWELL WARING
Vice Chairman
Madison, Florida

SUZANNE COLSON
Secretary/Treasurer
Cedar Key, Florida

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MACEO HOWELL, JR.
Jennings, Florida

JONATHAN WERSHOW
Alachua, Florida

JERRY A. SCARBOROUGH
Executive Director
Live Oak, Florida

DAVID W. FISK
Asst. Executive Director
Gainesville, Florida

County of Volusia

Growth Management and
Environmental Services Center

Growth Management/Planning

123 West Indiana Avenue • DeLand, Florida 32720-4253
Telephone (904) 736-5959

July 16, 1999

21

Mr. Michael Haff
Public Service Commission
Bureau of Conservation, System Planning & Electric Safety
Division of Electric & Gas
Capital Circle Office Center
2540 Shummard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Electric Utility Ten Year Plan/ Volusia County

Dear Mr. Haff:

Thank you for your letter of June 16, 1999, inviting comment on the plans of two power companies within Volusia County, which are subject to agency review requirements. Although both sites are in Volusia County they are within incorporated cities. One site, operated by Florida Power and Light, is located in the City of DeBary and the other site is for a future plant to be operated by Duke Power in the City of New Smyrna Beach.

Specifically your office requested comments on potential conflicts with natural resources and growth management. Polices regarding growth management and natural resource protection for the two sites would be found in the Comprehensive Plans of DeBary and New Smyrna Beach. You may wish to contact those jurisdictions regarding potential impacts.

Power line and natural gas corridors providing service to and from the sites would transverse the unincorporated area of the County and new lines would be subject to review by the County pursuant to the Power Plant Sitting Act.

Although the two sites are in incorporated areas and not subject to Volusia County's Comprehensive Plan we have no objections to the information presented. Also, we are encouraged by the potential positive impact on air quality resulting from the proposed use of natural gas.

G:\ADMIN\WP99\GM\PLA\DYER\HAFF

Printed On Recycled Paper

Please contact me if you have any questions.

Sincerely,

Ben L. Dyer
Planning Director

BLD:ps

c: Ed Rinderle, Director, Growth Management and Environmental Services Center
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
TALLAHASSEE, FLORIDA

IN RE: Petition by Gulf Power Company for waiver of portions of Rule 25-22.082(4)(a), F.A.C., Selection of Generating Capacity.

DOCKET NO. 980783-EI

COPY

BEFORE:	CHAIRMAN JULIA A. JOHNSON COMMISSIONER J. TERRY DEASON COMMISSIONER SUSAN F. CLARK COMMISSIONER JOE GARCIA COMMISSIONER E. LEON JACOBS
PROCEEDING:	AGENDA CONFERENCE
ITEM NUMBER:	8**PAA
DATE:	August 18, 1998
PLACE:	4075 Esplanade Way, Room 148 Tallahassee, Florida

JANE FAUROT, RPR
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APPEARANCES:

Jeffrey Stone, Esquire, representing Gulf Power Company
Joe Cresse, representing TECO
Jon Moyle, Esquire

STAFF RECOMMENDATION

Issue 1: Should the Commission waive the requirements of Rule 25-22.082(4)(a), Florida Administrative Code, as to Gulf Power Company (Gulf)?

Recommendation: No. Application of the rule will not create a substantial hardship for Gulf. Given the increase in wholesale competition, the possibility that bids will converge around the utility's avoided cost if this data is disclosed in the RFP is less likely today than when the RFP rule was implemented. Further, a substantial portion of the data required by subsection 4a of the RFP rule was recently published by Gulf in its 1998 revised Ten-Year Site Plan.

Issue 2: Should this docket be closed?

Recommendation: This docket should be closed if no person whose substantial interests are affected by the proposed action files a protest within the 21-day protest period.

PROCEEDINGS

CHAIRMAN JOHNSON: Item 8.

MR. KEATING: Commissioners, Item 8 concerns Gulf Power Company's petition for a waiver of the requirements of Rule 25-22.082(4)(a), Florida Administrative Code.

Gulf contends that application of the rule will create a substantial hardship on Gulf and its customers. The premise of Gulf's argument is that:

One, if Gulf is required to release its avoided cost information to potential bidders, then the prices offered by those bidders will tend to converge around Gulf's avoided cost.

And, two, that given this convergence of bid prices and given the increase in wholesale competition since the rule was adopted, Gulf's RFP may not result in the lowest cost power alternative.

Staff disagrees with Gulf's argument. We believe that the increased number of potential bidders in today's competitive wholesale market provides more incentive for bidders to present their lowest price. Given the increase in wholesale competition, we believe that the possibility of bids converging around Gulf's avoided cost, if that data is published in its RFP, is less likely today than when the rule was

adopted.

I should also point out that a substantial portion of the information required by the rule is already publicly available through Gulf's 1998 revised Ten-Year Site Plan.

For these reasons, we do not believe that Gulf has demonstrated that it and its customers will suffer a substantial hardship, and it is not clear whether the purpose of the underlying statute will be achieved by the means suggested by Gulf.

I have two final points. First, staff is concerned that granting such a broad waiver would set a precedent that would effectively gut the rule. There are no circumstances in this case that set Gulf apart from any other investor-owed utility that would be required to provide this information under the rule. We believe that if you accept Gulf's arguments and grant this waiver, a precedent will be set that would require persons to look not only to the RFP, but to the waiver in order to determine the state of the law on RFPs.

And, finally, this exact issue was discussed in detail at the hearing regarding the RFP rule some years ago. And the Commission rejected that argument, and we believe should reject it again now.

I believe Ms. Harlow has a few brief comments on the history of the rule and the rationale behind the rule.

COMMISSIONER GARCIA: Before we finish up on the legal aspect, what if we approve this waiver, what effect does that have on -- because this is the first time we're going -- the rule has yet to be used, right?

MR. KEATING: That's what I understand, yes.

COMMISSIONER GARCIA: So if we approve this, does this have an effect on the other companies in the state and how they may view this rule?

MR. KEATING: I think it will. I think there is nothing really that's unique about Gulf's situation here that sets them apart. Basically, I think if you accept their argument, you've accepted the argument that the rule should be repealed.

CHAIRMAN JOHNSON: Any other questions before we hear from the industry group?

COMMISSIONER GARCIA: Well --

CHAIRMAN JOHNSON: Oh, you wanted to add the legal analysis.

MS. HARLOW: Commissioners, I've looked over the transcript from the hearing on this. It was an extensive transcript, a three-day hearing, with

several intervenors. And I wanted to discuss just briefly what we believe the intent of the rule was prior to your discussion.

Prior to adoption of the bidding rule, utilities were not required to negotiate with independent power producers, except in the case of qualifying facilities as required by PURPA.

The bidding rule requires investor-owned utilities to issue an RFP for new capacity which is subject to a need determination. This provides IPPs with a point of entry into the generation selection process. Utilities may then select finalists and negotiate to determine the least cost alternative.

Based on comments made at the hearing, the primary rationale behind the rule was to encourage the selection of least cost generation. Providing IPPs with a point of entry gives utilities an added incentive to sharpen their pencil when making their own proposal.

According to the hearing transcript, the intent of including avoided cost data in the RFP was to provide some basic information for potential bidders and also acts as a sanity check for the Commission itself when utilities file a need determination. It was not the intent of the rule to hold utilities to

the avoided cost data provided in the RFP for cost recovery purposes.

And as a final note, I'd like to mention the staff uses avoided cost data extensively, as well as the Commission, in our analysis of conversation programs. Also, this information is used in standard offer contracts for cogenerators. And as Cochran mentioned earlier, it's published, to a large extent, in the Ten-Year Site Plan, and the Commission uses that information to review those site plans now that data is our primary responsibility.

COMMISSIONER GARCIA: What information that they don't want others to have is it that we don't -- that no one would have? In other words, the company provides all this information in one form or another, except what?

MS. HARLOW: Well --

COMMISSIONER GARCIA: And you listed in the rec, it was like 13 points or something like that, if I'm not mistaken.

MS. HARLOW: Yes, sir.

COMMISSIONER GARCIA: What is required and -- of those 13, which precisely aren't provided?

MS. HARLOW: As required by the rule, a detailed technical description is required. And it says, "At a

minimum, the following information," and 13 points are listed. Now, it's difficult to tell from Gulf's filing which things they objected to. Because their primary argument concerns the avoided cost data, yet there is very much of these -- many of these 13 items here are not concerning cost at all. They're concerning the type of unit, the technical description of the unit that would be placed and where would it be, what's the megawatt size, what's your fuel. These things were not addressed in Gulf's filing.

Staff agrees with LEAF on this point. LEAF said that Gulf did not address the technical description. They only addressed in their argument of what it cost.

If you look down the list of the 13 items, virtually all of these items are included to some degree in the Ten-Year Site Plan, except for Item 6, an estimate of annual revenue requirements. Many of the things that you need to calculate revenue requirements, however, are included in the Ten-Year Site Plan.

No. 10, almost all of No. 10 is in the Ten-Year Site Plan, except minimum load and ramp rates.

No. 12, a discussion of the actions necessary to comply with environmental requirements. That is not extensively discussed in the Ten-Year Site Plan, but

it is discussed to some degree.

And No. 13, a summary of the major assumptions used, that is not required in the Ten-Year Site Plan.

COMMISSIONER GARCIA: Just so that I understand it, so --

MS. HARLOW: I would say that the bulk of the information is in the Ten-Year Site Plan.

COMMISSIONER GARCIA: I'd say more than the bulk. I would say pretty much, except -- you're saying 13 is a summary, and --

MS. HARLOW: Six is revenue requirements. A portion of 10 --

COMMISSIONER GARCIA: But you're saying that that's provided in other places. The formula necessary to calculate it is provided in other places.

MS. HARLOW: Yes, sir.

COMMISSIONER GARCIA: Mr. Bal -- I'm just getting a confirmation from Mr. Ballinger, who couldn't help himself.

And No. 10 is -- No. 10 is only a part of that, correct?

MS. HARLOW: Yes, sir.

COMMISSIONER GARCIA: So, in essence, 6 is pretty much provided for. You're saying only a small part of 10 and then the summary of 13 is. And you're saying

that the summary of 13 could probably be assumed from other things they've filed at this Commission?

MS. HARLOW: I believe so, sir. And, also -- to some extent, at least. And, also, No. 11.

Excuse me, but I neglected to mention that a description of the associated facilities is required, such as transmission lines, is required by the Ten-Year Site Plan. We don't necessarily have a direct estimate of the cost, which is required by the bidding rule. However, in the case of Gulf, they have listed no associated transmission. And so I guess the cost would be zero or close to that.

CHAIRMAN JOHNSON: Any other points you want to add?

MS. HARLOW: I would share Mr. Keating's concern that this is the first time that the rule has been used by any of the investor-owned utilities, and that any action that the Commission makes in this waiver should, as mentioned by LEAF in their comments, be as limited as possible, and that you should also consider the potential effect that it would have on future use of the rule.

CHAIRMAN JOHNSON: Thank you.

MS. HARLOW: Thank you.

CHAIRMAN JOHNSON: Gulf Power.

MR. STONE: Thank you, Commissioners.

Good afternoon. My name is Jeff Stone, with the law firm Beggs & Lane, and I represent Gulf Power Company in this proceeding.

We have come before you with a request for a waiver of the rule. And we have both utilized the provisions within the rule itself that the Commission itself reserved its right to waive the rule upon a proper showing and the provisions of chapter -- of the APA with regard to the standard for waiver.

And I think it's important to remember the purpose of the underlying statute. And that is when it comes time for a need determination proceeding by this Commission, you will be able to determine whether or not the plant is the most cost-effective alternative.

When this rulemaking was undertaken several years ago, FERC 888 had not been issued. There was a fledgling wholesale -- a competitive wholesale market. And the concern was raised in that extensive discussion about whether or not there needed to be a jump-start, if you will, towards encouraging utilities to negotiate with wholesale providers. I think we can all recognize that in the passage of time a lot of things have changed. And whether or not you need this

rule any longer is something that warrants consideration.

We did not come to seek rulemaking, primarily because we don't have time to go through a rulemaking process. We have a need for capacity that we need to be moving on with the request for proposals immediately. And so we sought the waiver request because we wanted to bring to your attention that the circumstances have changed.

We have provided expert testimony in the form of affidavits attached to our petition that document the manner of competitive bidding that is used in other industries as well as in the wholesale market at large -- the wholesale electric power market at large. And this rule requires a deviation from the standard, both in our industry and in other industries. We think that is important for this Commission to acknowledge.

The question is, who is this regulation designed to protect? We submit that --

COMMISSIONER DEASON: Mr. Stone, what is the deviation that this rule requires, and it's a deviation from what?

MR. STONE: In other competitive bidding situations, whether in our industry or in other industries that are not regulated by the Commission,

it is the judgement that potential bidders should make their own independent judgement as to what their price ought to be, and they are not given the kind of detailed financial information that this rule requires.

And I'd like to address at this juncture it is specifically the annual revenue requirements portion of the rule that gives us the greatest concern. And Item No. 13, which talks about the detailed assumptions that lead to that, it is those two provisions in and of themselves that give us the greatest concern. To the extent that we're talking about --

COMMISSIONER GARCIA: Which one of them -- I'm sorry. Again, I'm sorry. I picked up on you as you were finishing. Which two issues give you the most major concern?

I'm sorry, Commissioner Deason, I was just --

MR. STONE: It was indicated that Item No. 6 is not directly in our Ten-Year Site Plan filing, the annual revenue requirements.

COMMISSIONER GARCIA: What part of it is it that you don't want --

MR. STONE: The annual revenue requirements that's required by Item No. 6.

COMMISSIONER GARCIA: Right. But staff states that parts of the form -- elements that are necessary to reach that are already provided. What parts of those elements don't you want to give?

MR. STONE: Commissioner, make no mistake, there is a lot of public information that someone who does the analysis they can get very close to that and make that target. We do not want to provide the road map to that target. We want them, if they are a serious bidder to --

COMMISSIONER GARCIA: Why wouldn't -- and that's a question maybe I'll ask you for a second before Mr. Cresse corrects me on all my incorrect assumptions. But before he gets there, why -- why is that, that you wouldn't want that information out there? Won't that produce a lower bid for you and for the ratepayers? The more information that a bidder has, the better -- the better able he will have to have a price. Once that price is out there, I don't think it's a question of converging around the price, because it costs a lot of money to enter a bid on a project. So if I know what the -- if I and everyone else knows what that price is. And I think that staff used that also as a terminology so people wouldn't miss the boat completely. In other words, we know what we're

shooting for. Yeah, they're going to no where that is, but they know their competitors for bidding that price know what it is, and they're going to be undercutting each other.

MR. STONE: And, Commissioner, that's exactly what I want to try and address. In other industries not regulated by this Commission, when they go out for competitive bid they do not give that kind of detailed financial information and yet they get competitive bids and they go through the process to determine the most cost-effective alternative for whatever project they're taking bids for. And, in fact, not only --

COMMISSIONER GARCIA: But isn't this different? Isn't this industry a little bit different? Because there is all sorts of recovery that's based into this system. There is all sorts of recovery for you, as well as for the ratepayers, on the assumptions made in entering one of these agreements. And on top of that, if I'm not mistaken, this comes before this Commission eventually, anyway. Further, you get to negotiate with whoever wins that bid on very specific details and facts about the bid that was entered. So you get several cracks at them. We get a crack at them. So because there is a general or public policy issue out there, we're sort of, I think, all working toward the

same ends, which is a better price and a more knowledgeable public as well as private in your case.

MR. STONE: Commissioner, if I may, an independent power producer who is not regulated by this Commission, their goal in submitting a bid is to submit the highest possible bid they can submit and win the business, not the lowest. To the extent that we give them a target to shoot at --

COMMISSIONER GARCIA: Let me ask you something.

MR. STONE: -- we will move some of that incentive lower --

COMMISSIONER GARCIA: Can't you beat that bid, though? When they come in with the bid, if you think that that bid is too high and you can do better, can't you do better?

MR. STONE: Yes, Commissioner, but I thought our goal in the whole course of this thing was to ensure that we got the most cost-effective alternative.

COMMISSIONER GARCIA: Well, that's my point, but within reason. And that's one of the -- the rationale that staff used. And I'm trying to remember the words that staff used, but it was so that all bids would be reasonable. Because we don't want -- we don't want people to fail, I mean, in this program. So if we reach -- if we reach a price which is out of whack,

which your experts think is out of whack or you can do better, you can always do better, can't you?

MR. STONE: And we certainly will do our best to make sure that the best deal is achieved for our ratepayers. But the question is does this rule favor ratepayers or favor potential bidders? And we submit that we think in the current framework of the rule it favors potential bidders rather than the ratepayers. And that's all we're seeking, is to try and do the best job for our ratepayers.

COMMISSIONER GARCIA: Let me ask you, under our present system and this rule if we were -- and now looking into the future, the future which some see with great fright of competition, and you were to put out to bid exactly as the rule is, and it was -- and you found that someone came out and bid at a price that was better than some Southern Companies could do, and that bid comes back to this Commissioner, right? If I'm not mistaken. Once you approve that project, that still comes through this Commission one more time before you start off on that project.

MR. STONE: Presumably it would still have to come before this Commission to determine --

COMMISSIONER GARCIA: How would we -- wouldn't we deal with them as we would deal with anyone else in

terms of recovery? In other words, if we were to move to a competitive model, and this was a stranded investment, we'd deal with them the same way we deal with anyone else, wouldn't we? We'd deal with them through you in terms of cost recovery with that contract. If we wanted to move to a competitive scenario, we'd deal with them just like we deal with any other generation unit within your company?

MR. STONE: I don't think that you would look behind their price to see how they came up with their price.

COMMISSIONER GARCIA: No, we'd look at your price. We'd look at the price that they gave you, and then we'd give you recovery of that as a stranded investment, wouldn't we?

MR. BALLINGER: Yes.

COMMISSIONER GARCIA: Good. Thank you.

Mr. Ballinger was the only one shaking his head yes.

We'd look behind that. We wouldn't look behind them, but we'd look at your cost in terms of making you whole in this contract, I guess, because that's what it would be; it would be a contract of some sort for energy, wouldn't it? Am I mistaken, or for building a generation unit. It would be a stranded

investment.

MR. STONE: It could take any form, Commissioner. We're not presupposing that it would be a purchased power contract. But that is certainly one aspect, that it could come through this RFP process.

COMMISSIONER GARCIA: Let me ask one more question, and then -- and then -- when you put this out for bid, is it possible that someone would come in, let's say a Duke Power, and say to you, "With what you need here, I'm going to build a" -- what do they call it -- "a merchant plant to supply the need for your power here as opposed to going through your process. You're going to get all the power you want from us, and there has to be no guarantee to the ratepayers of picking up that cost." Could that be done in this bid scenario?

MR. STONE: There is no restriction that would prohibit that.

COMMISSIONER GARCIA: Okay. All right. Thank you. I'm sorry for interrupting you.

COMMISSIONER DEASON: Well, there certainly would have to be requirements for there to be committed capacity and a first right to that capacity. All that would have to be worked out, I guess, in the contract negotiations.

MR. STONE: I'm sorry, Commissioner, I could not understand everything you just said.

COMMISSIONER DEASON: Obviously, if there is a need for capacity, you've got to have dedicated capacity and the first call on that capacity. So that if there were a merchant plant situation and there was a contract that was finalized in that regard, it would have to be with that understanding. It couldn't be that you just pay whatever our market asking rate is. It would have to be at a stated price for a stated amount of capacity and there to be a guarantee that that capacity would be available.

MR. STONE: Yes, Commissioner. And in terms of the difference between the question that you just asked and the question that Commissioner Garcia asked, there is no prohibition in our RFP process that would prevent consideration of a merchant power plant. But, clearly, the burden would be on us to ensure that we have protected out ratepayers in terms of the contract this is ultimately negotiated.

COMMISSIONER GARCIA: And most probably this Commission would want you to put that burden on, because this is a plant that you need to serve the ratepayers of the state. So, certainly, it would be a requirement that we would want you to include in that.

MR. STONE: Certainly. And our waiver request does not do harm to either of those considerations.

COMMISSIONER GARCIA: No, no. That was for my own edification.

MR. STONE: And I think it's important to remember that our request for waiver does not affect the delivery of information to this Commission when it comes time to review. Our request for waiver only affects the timing of the delivery of information and prevents giving it to the bidders on the front end; just as if they were bidding in any other industry, they would not have that kind of detailed information from the customer, in this case Gulf Power Company, on the front end.

COMMISSIONER CLARK: I want to ask you something about that. What other industries are you comparing it to? Are you comparing it to industries where the person asking for the bid is also a potential supplier of that need?

MR. STONE: Commissioner, I'm comparing it -- and I'm referring particularly to the affidavit that was submitted by Hugh Gower when he was referring to his experience in monitoring other companies that were not regulated in terms of how they go through a competitive bidding process. And in his view, based

on his experience, that it's important for potential bidders to make their own independent judgment. Now, in terms of do I have a specific industry in mind, no, I do not. I was referring to his comments.

COMMISSIONER GARCIA: Because I would assume that in --

COMMISSIONER CLARK: You haven't answered the question.

MR. STONE: Well, I apologize.

COMMISSIONER CLARK: And it's just that do you know if those industries are one where the customer who has put the item out for bid is also potentially a supplier of what he is seeking a bid on?

MR. STONE: I don't have specific knowledge of that, but I don't preclude that from being a possibility, either.

COMMISSIONER CLARK: Okay.

MR. CRESSE: Commissioner, I think you could put General Motors in that category. They have the option of farming out their parts or manufacturing them themselves. And they do it on a routine and regular basis. All major automobile manufacturers do that.

COMMISSIONER GARCIA: But, Mr. Cresse, you would agree that there is a public interest factor that we have and that you have when you're operating in a

regulated system that grants the fact that there has to be a little bit more public information. And when you're looking at a bid, for example, put out by a county government or a state government, those bids are very specific, very detailed. They include all sorts of information that the bidder is made aware of, because we are holding them to a different standard, because they're bidding for sort of -- well, they're bidding for a government agency. In our type of case, the government is involved because we're serving the public interest and you're serving the public interest.

COMMISSIONER DEASON: Well, maybe that's a good scenario. I'm not that familiar with local governments, but, for example, if there were a local government that was either contemplating doing garbage collection themselves or having a contractor do it, if they issued an RFP, would they be required to put in that bid, "And we think we could do it ourselves for X dollars?"

MR. CRESSE: I don't think they're required to put in their bid, nor do I think they put in their bid what they think they can do it themselves for.

COMMISSIONER DEASON: They probably want to keep that a secret so that they can probably get the best

bid from the bidders.

MR. CRESSE: If I was in a municipality --

(Simultaneous conversation).

COMMISSIONER GARCIA: If you will excuse me for a second, Commissioner Cresse.

But, Commissioner, they do tell you what it costs them to do it, and what the previous contractor had to pay for it. And they disclose those facts of what the county either was paying for it themselves or the previous bidder paid. And that contract is part of the public record so that they are able to look at that and glean from that all sorts of costs that probably General Motors never puts out.

COMMISSIONER DEASON: And the same way with the utility. It's public record of what they paid for their last generating unit, what is in rate base, what is the depreciation rate, what is the allowed rate of return, what is the operating and maintenance expense. All of that is public record, but it is past performance, not future.

MR. CRESSE: And the Ten-Year Site Plan is a public record. It contains an awful lot of this same information.

CHAIRMAN JOHNSON: Mr. Stone, were you finished?

COMMISSIONER CLARK: So why not provide it?

MR. STONE: No, ma'am, but --

MR. CRESSE: I'll get to that in just a good minute.

CHAIRMAN JOHNSON: Okay, Mr. Cresse, we're going to let Mr. Stone finish up.

MR. STONE: I will try to be brief. The question was the intent behind the rule. Ms. Harlow outlined it to say to provide certain basic information to the potential bidders. We are doing that. As we indicated in our petition, we are complying fully with the requirement in Paragraph 3, which in large measure, duplicates Paragraph (4)(a), the first three or four items. We have already acknowledged that we intend to give the location, the general size, the type of technology. All that information will be in our RFP package. Quite frankly, it's the nature of the detailed technical and financial information we feel like is best left in the hands of the utility until after the bids are in. And then we will all be able to look at it at the same time and evaluate what is the best, most cost-effective alternative.

In terms of the sanity check, the Commission will have that opportunity when a need determination is brought to it. It doesn't need to have the information given to the bidders on the front end.

We expect to be held accountable to get the best deal for our ratepayers. That's what we're here for, and that's the motivation in our filing this waiver.

And, finally, one last point, the requirement of the statute says that it -- the underlying purpose of the statute has to -- either has been met or will be met. We submit to you that since the passage of the rule, the underlying purpose of the statute has been met by the opening up of the wholesale market. And it will be met by the fact that we have an RFP out there, that we expect to have out there that will make use of that market.

And then finally, you mentioned other utilities -- well, you mentioned other government entities. It's interesting that municipal utilities and cooperatives are not subject to this rule. And they would not have to give out this kind of detailed technical and financial information in their process, although they very likely would go through an RFP process. And we think that that is a distinction that is ~~of~~ merit, too.

When you passed the rule, you specifically reserved yourselves the right to not require any provision of the rule to be implemented if circumstances had changed and a showing was made to

you. We're submitting to you --

COMMISSIONER DEASON: Is there a specific provision within -- is that a specific provision within the rule itself as adopted?

MR. STONE: Yes, Commissioner.

COMMISSIONER DEASON: Can you point that to me? All right. I'm sorry, I don't have the rule.

MR. STONE: It is Paragraph 9. And I can quote it to you in part. It says, "The Commission has reserved itself the right to waive" -- and I'm quoting -- "the rule or any part thereof upon a showing that the waiver would likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers or is otherwise in the public interest."

And we submit to you that at the time you were passing the rule the concern was that there were not enough players on the wholesale side to really give life to the requirement that we negotiate. That has changed. We believe the public interest is met by the current wholesale market, and all we're asking is that you recognize that and give us the opportunity to proceed in the best interest of our ratepayers.

We believe that it is appropriate to grant us a

waiver of the rule, but if you find it more appropriate to give us a partial waiver of the rule and that we be limited to giving out that information that has been submitted as part of our Ten-Year Site Plan information, that would give us the comfort level to be able to proceed with our RFP process. We believe that that is consistent with what the staff has said. It is narrowly drawn. And so to the extent that there is information available in our Ten-Year Site Plan filing as it has been given, we would be happy to provide that as part of our RFP. We don't think it's appropriate, we think you should grant us a total waiver, but to the extent that you would be more comfortable with a partial waiver that allows us to proceed by attaching the Ten-Year Site Plan information itself and no derivations therefrom, then we would be prepared to proceed on that basis.

Thank you. That completes my comments. I would like the opportunity to respond in case there are questions raised.

CHAIRMAN JOHNSON: Sure. Any other questions for Mr. Stone?

Mr. Cresse.

MR. CRESSE: Commissioners, I'm Joe Cresse. I'm here on behalf of Tampa Electric Company.

I want to discuss another issue which you were concerned about when you adopted this rule back in 1993. I think three of the present Commissioners were involved in adopting that rule. You were concerned about the fairness of the issue where one of the parties that may be contracting or may be willing to construct or can construct and operate this plant had to put their bottom-line price out first. And I think it's unfair to require a utility to put its bottom-line price out and let other people bid against it.

The fairness issue you were concerned about. On Page 70 of the transcript, Commissioner Clark says, "What I'm trying to deal with is the notion that they sort of have to put their bid on the table, and the advantage the other parties have to saying, I know all I have to do is just beat that price."

You will get a better price if the potential bidders do not know what the bottom-line price is of the utility. The utility will have to compete for this service in the same manner as the independent power producer with one exception. Their price does not have to be revealed up front. And we think this rule requires that to happen.

COMMISSIONER GARCIA: But, Joe --

MR. CRESSE: You ought not do it.

COMMISSIONER GARCIA: -- in the present system we have, which is -- you said this was passed in '93. Today we have a lot more people out there trying to provide power and trying to build generation plants.

MR. CRESSE: Yes, sir.

COMMISSIONER GARCIA: Don't you think that if we provide that price, what it would cost the utility -- I agree they're going to -- they're going to start with that price as a point, but I doubt Enron wants to be beaten out, or Enron or Duke or the Southern Company by any specific price. When they're out there competitively bidding, they're going to try to undercut each other because the process of bidding is an expensive proposition.

MR. CRESSE: But should the utility be placed at a disadvantage in providing that service to themselves? There is no provision --

COMMISSIONER GARCIA: Well, doesn't the utility have an advantage --

(Simultaneous conversation).

MR. CRESSE: Let me finish, if I might, sir.

COMMISSIONER GARCIA: Okay.

MR. CRESSE: There are some advantages and some great benefits to consumers for the utility generating

plant to be owned and operated by the utility. And I wrote a letter to the Commission in 1993 pointing out some of those advantages. You don't need to place the utility at a disadvantage.

COMMISSIONER GARCIA: Well, why don't you tell me some of those advantages.

MR. CRESSE: All right, sir. At the end of the contract period who owns the land and the air emission standards --

COMMISSIONER GARCIA: I'm sorry.

MR. CRESSE: The price and what --

COMMISSIONER GARCIA: I'm sorry. I didn't hear you, Joe. Start again.

MR. CRESSE: At the end of the contract period who owns the emission standards, the emission allowances? What price will the plant be continued to serve the ratepayers, it will continue to serve at market price, not at average embedded cost, which would be substantially lower after a contract period of 20 years. What happens if fuel prices decline below the estimates used for the bid? That benefit will go to the owner of the power plant. If it's the utility, that benefit will flow to the utility ratepayers. If it's a contractor, that benefit will flow to the contractor.

What happens if the cost of capital changes? And we're at a point now where cost of capital we think is lower than it's ever been. But I have to tell you, it's not lower than it's ever been. Thirty years ago you could borrow money to build a house at five and a half percent. Now, it isn't like it has been. The cost of capital is lower than it has been in the past ten years. But if it goes even lower, who will benefit from it? If the utility owns that plant, the ratepayers will benefit from it. If it goes higher, if the cost of capital goes up, the money that you've borrowed, you're not -- you just go ahead and keep it at the lower rate. So you can't -- that's a one-way street on cost of capital.

The ratepayers cannot benefit on lower cost of capital under a contract. They will benefit on lower cost of capital under a utility owned plant. So it's not just these cost factors that you need to face.

COMMISSIONER GARCIA: But you would probably agree with me that the industry is heading towards competition, so we're probably -- we're probably, to some degree, looking at that future, that we're not going to get that --

MR. CRESSE: I think the industry is heading towards competition in the generation of electricity,

but not in the transport and distribution of electricity, only in the generation. We have had a competitive generation environment in Florida for a good long while. So what's happening in the rest of the country, they may be catching up with us --

COMMISSIONER GARCIA: Right.

MR. CRESSE: -- as opposed to leading us. Because these things, these experiments that are going on haven't all been that smooth.

COMMISSIONER GARCIA: Right. No, I would agree with you there.

MR. CRESSE: The great benefits that were promised in California have yet to materialize.

COMMISSIONER GARCIA: Right.

MR. CRESSE: And I don't know if they have materialized anywhere. I know that they're in this transition process. Always the benefits are oversold.

COMMISSIONER GARCIA: But if you -- aren't we talking about generation here, though, Joe?

MR. CRESSE: Yes, sir, we're talking about generation.

COMMISSIONER GARCIA: I mean, isn't this about generation? And do you think our ratepayers are going to benefit 20 years from now by Gulf owning this, or is it very possible that 20 years from now all

generation is going to be in separate hands or is going to be a competitive issue across-the-board. And if I were a holder of that generation contract, I -- and it probably won't be Gulf, and it probably won't -- or it may be Gulf, but the way we're going to acquire that power is going to be through a competitive bidding process?

MR. CRESSE: If I was the owner of 500 megawatts of power that was combined cycle as is proposed in this particular offer, I would want you to deregulate it entirely. Because I can put it on the market and make a whole lot money --

COMMISSIONER GARCIA: Twenty years from now, right.

MR. CRESSE: -- than I can in a regulated environment. That doesn't mean that the price of electricity is going to be cheaper. It means that I can make more money in a nonregulated environment. And I have to tell you if you're in the business of generating electricity, your primary responsibility is your fiduciary responsibility to your shareholders. You're going to try to maximize their income. You're going to try to maximize the profits as much as you possibly can. And there is nothing wrong with that.

COMMISSIONER GARCIA: Right.

MR. CRESSE: I'm not criticizing that at all. That's just the way it does work, that's the way it should work.

The fairness issue, if you require the utility to put their price up front does not give the utility the opportunity to compete as fair as it would be for an independent power producer. And I think that's the issue. When you require them to put the annual estimate, and the annual revenue requirements and all of the assumptions used in developing that estimate, you're saying, "Put your cards on the table, and we'll shoot at it." And I would much rather think that it would be best for the independent power producers to make their best shot without knowing what the utility's bottom line is.

Ultimately they've got to come back to you. They've got to come back and justify to you. And the burden of the utility is to justify to you the decision they make as a result of this RFP. So you're not getting their last shot at it today.

COMMISSIONER GARCIA: Right.

MR. CRESSE: If there is ever a power plant built in Florida under the present process that doesn't wind up being litigated in front of this Commission, then I'll be the most surprised guy in the country. So it

will be back, and you'll have the opportunity to evaluate what Gulf Power does or what any utility does if you waive this rule.

If you were concerned about the fairness of it when you adopted it, since that time, on Page 3 of the staff recommendation, justification for a variance under 125.42, which was enacted in 1996, includes, "For the purpose requested -- for the purposes of this section, principals of fairness are violated when literal application of a rule affects a particular person in a manner significantly different than the way it affects other similarly situated persons who are subject to the rule."

How would you like to be a contractor and have to put your price up front that everybody else can bid against? I think that's what you're asking the utility to do.

COMMISSIONER CLARK: But, Joe, in this case Gulf is being treated like every other regulated utility. Those are the similarly situated entities to whom this rule applies.

MR. CRESSE: Gulf is not being treated like any other potential bidder for this project.

COMMISSIONER CLARK: I agree with that. But that's not what -- this rule is aimed at the regulated

utility. And to that extent --

MR. CRESSE: No, it's not aimed at regulated utilities. This is a statewide rule.

COMMISSIONER CLARK: Yes. It is the rule that the regulated utilities have to comply with when adding new power, so that it applies to regulated utilities. Those are the similarly situated entities, not the people making the bid.

MR. CRESSE: Well, I read it differently. I thought that the people making bids were similarly situated, those people in the process of trying to acquire capacity were similarly situated.

COMMISSIONER CLARK: I understand your distinction is as to what -- that it puts them at an unfair advantage. But they are not at an unfair advantage. These are the other regulated utilities who have to --

MR. CRESSE: I would agree with that. It puts them at an unfair advantage with the other potential bidders. That's the point I'm trying to make. I'm sorry I wasn't clear.

COMMISSIONER JACOBS: How do you respond to the statements that the essence of this information is already in the public record at the time the RFP is entered? Even if this requirement weren't there.

MR. CRESSE: I would respond to it in the following way: If it's already in the public record, then there is no need to repeat it here. Not all this information is in the public record. And I've pointed out the two areas that are extremely critical.

Actually, Issue 7, which is the discounted cash flow method, is also critical. You have to have the revenue requirements in order to arrive at avoided cost.

So, 6, 7 and 13 are extremely critical in my opinion, that we ought not to have put that on the table up front.

COMMISSIONER GARCIA: Joe, let me ask you something. Doesn't the utility also have an advantage that other competitors don't have? In other words, the utility is sitting there as these bids are made. It clearly has shown all it's cards, but the utility gets a crack at it, too. And it's going to get a crack at it before this Commission if it thinks it can do better. I mean, if you were sitting up here, and I can say that to you because you have sat up here, aren't the ratepayers going to benefit from the fact that the utility is going to get another crack at it and we're going to get another crack at it? And by showing its cards, the utility may be able to draw

some different conclusions by what's out there and still say, "We can do it better and cheaper."

MR. CRESSE: If the utility is not held to these prices --

COMMISSIONER GARCIA: Uh-huh.

MR. CRESSE: -- is what I hear you say, does that provide any benefit? I don't think so, because then the information that you put out may not be the best cost estimate.

COMMISSIONER GARCIA: No, what I'm saying is when this process is over, the utility looks at it. In other words, when our rule goes out there, all the -- you know. And you're right, we're asking the utility to show pretty much all its cards. When it shows its cards, and it gets back a series of bids, and it gets to pick the lowest bid, the utility still has the option, if I'm not mistaken, to beat that price, doesn't it?

MR. CRESSE: Sure, it does. I would assume it would have the option to beat that price. That's a clarification that I think needs to be made.

COMMISSIONER GARCIA: Am I mistaken in that, Joe?

MR. JENKINS: I think that's correct. And by way of perspective on the matter of fairness, we thought it was -- it was not an issue of fairness so much,

because the utility also evaluates the bid. If you want it to be truly fair, we'd have the bidders evaluate the bids.

COMMISSIONER GARCIA: All right.

MR. JENKINS: That's another distinction. It makes no sense, but that's --

COMMISSIONER GARCIA: And, Joe, we're not going to take you there just yet.

MR. CRESSE: I'm not worried about Jenkins having the comment about having the bidders evaluate the bids, and so forth. Let me tell you who is going to ultimately evaluate the bids. You are.

COMMISSIONER GARCIA: But I'm just saying, and changing places, if you were sitting up here, clearly, you've got a -- we've got -- I mean, it is causing competition. It is causing -- it is causing an aggressive look at the numbers. And it's an aggressive look at the numbers by outsiders who want to get into this business, who want to do more of this business.

And that done, when they look at this aggressively, and you look at -- you, as a Commissioner, you've going to be pleased by the fact that Gulf Power comes -- after all this process, we evaluate -- Gulf Power evaluates that bid, and then

they can say, "And I can do it even better." And if the concern was everyone was going to be hovering around that number, I agree with you, Gulf Power is going to want to beat it, or the Southern Company is going to want to beat that because it has certain advantages with it being its own generator.

And the ratepayers have that advantage if we -- and our comfort level would probably be greater when Gulf Power comes in under everyone else. And as a regulator, so be it. I mean, I've got a tremendous benefit because we've forced the price even lower than what Gulf thought it could do. It will have to come even lower than what it thought it could do.

COMMISSIONER DEASON: Well, then what benefit is there of there being any cost information being provided on the front end? To me, it could work just the very opposite. If Gulf doesn't -- if they present cost information that is really not their very best bottom line, and they didn't sharpen their pencil a great deal, they could be luring people to come in with high prices, realizing they're going to undercut them. And they're going to guarantee that they're going to be the ones providing the power.

COMMISSIONER GARCIA: Well, here -- and you can correct me if --

COMMISSIONER DEASON: And if they are required to have their very best bottom-line price and be held to it when they present their RFP, then they are placed at a competitive disadvantage.

MR. JENKINS: I don't think they're held to their RFP price.

COMMISSIONER DEASON: Okay. Then what is the necessity of having any of this cost information provided up front?

MR. JENKINS: Just so we don't get high prices. The idea of revealing that information of Gulf Power or utilities showing their cards, showing a card is that they give some idea to the bidders of what they have to beat. Don't forget, Gulf Power will get to draw a second card; the bidders won't.

CHAIRMAN JOHNSON: What does that mean?

MR. JENKINS: That means that Gulf puts out its number in the RFP, the bidders respond, they know they have to beat that price. And when all of those prices come in through the passage of time, say, in about two or three months, then Gulf Power can come out with still another number. They're not held to that number.

CHAIRMAN JOHNSON: Then tell me again why they put that number -- why we're making them put that

number on the table in the first place.

MR. JENKINS: To prevent, like we saw in Tallahassee, some real high prices coming in. And Tallahassee did not reveal in its bid RFP, its number. When the bids came in, there were -- I would say most of them were higher.

COMMISSIONER GARCIA: Commissioner, what we're doing is saying where the price, more or less, is now so that everyone is aware of where that price is, so that they -- no one is going to come in to bid against Gulf which has said the price is here above them. They're going to have to sneak in.

And on top of that, under that price -- on top of that, we're going to have other competitors who know that Duke is bidding for it, that Louisville is bidding for it, that -- hopefully, someday we'll have other state providers bidding it who have a knowledge of that. And so it just keeps forcing them all to go lower. Likewise, I hope that to some degree this also puts the -- you know, you don't have someone do a crazy bid. Because then the company would come to this Commission and say, you know, "Joe Jenkins Power is saying that they can provide all this at a ridiculous price, and there is no way Joe Jenkins Power can survive." And this Commission will say,

"Well, because we need reliability, because this is for making sure that the ratepayers are served, we may not take a crazy bid. We may not take someone who is low-balling just get into the process and not being serious."

It requires a serious look at the number with serious numbers and then -- then you've got to effect your bottom line. You've got to say, "How much do I want my shareholders --"

COMMISSIONER CLARK: It's not your shareholders.

COMMISSIONER GARCIA: I'm sorry?

COMMISSIONER CLARK: He was trying to talk --

COMMISSIONER JACOBS: It was a left-hand joke. It was a left-hand joke.

COMMISSIONER GARCIA: I'm sorry. It just requires them to keep pressing the bottom line.

And I'm sorry, Madam Chairman, I have a tendency of usurping dead space with my voice.

CHAIRMAN JOHNSON: Really?

(Laughter).

COMMISSIONER JACOBS: Commissioner, I want to get back to the point. I guess, Joe, you raised it, but it kind of ties on to something that was said earlier. This is a sophisticated industry. And it baffles me to think that there will be such -- such a reliance,

blind reliance when the kind of dollars are at stake for these kind of plants, we're not talking about mincemeat here. They're coming in with multiple millions of dollars riding on the line. And it baffles me to think that they're going to sit back and risk winning this contract on the gamesmanship of the company. I can't believe that these companies won't be astute enough and sophisticated enough to understand what the prevailing market statistics are and make a reasonable reliable bid. And if they don't, then the company can come back in on the back end and say, "There's some aberration here. These guys aren't playing by fair rules, and so we now have a legitimate opportunity to direct you, Commission, to a reliable price."

Why doesn't that happen, Joe?

MR. JENKINS: All I can tell you is that in the Tallahassee case where Tallahassee's price was not revealed, per se, we had a number of bidders to come in much, much higher than Tallahassee's ultimate price. The one bidder that may have been close, you had to get down into not so much the price, but the details of what was included along with the price, such as whether the natural gas was a fixed price or whether it had escalators.

And, again, I come back to Gulf Power will get to draw from the deck again after it -- you know, a second time. And as far as fairness goes, if you wanted to be totally fair, at one time we discussed where the Commission would evaluate the bids and not the utility. The bids would be submitted to the Commission, and we would open them and evaluate them.

We wanted to get out of that, so the compromise was for the utility to issue a target for people to shoot at, knowing -- and they're not held to it. And then later on the utility gets to draw from the deck again with a new number and come in and justify it.

It forces the utility to rethink and become more efficient. Let's say initially Gulf proposes $100 a kilowatt. And all the bidders come in at, you know, 95 or 90. And Gulf says, "Aha, if I want the business, I've got to do better than 95 or 90. I've got to go down to 85." And that's what we see in these bidding processes.

COMMISSIONER GARCIA: But conversely, Joe, they can come in and say, "These 90 or 95 aren't in the best interest of Florida, because they are not as reliable. You can't count on them. We're going to have all sorts of problems." And we could still settle on their 100.

MR. JENKINS: And, frankly, if the bids were close, I would prefer that Gulf build it, because it goes in the rate base and not through a cost recovery clause.

COMMISSIONER GARCIA: Which addresses Commissioner Cresse's point.

MR. JENKINS: See, we have an asymmetrical treatment of costs -- or money flows and cost recovery here.

CHAIRMAN JOHNSON: Thank you. Does that answer your question, Commissioner Jacobs?

COMMISSIONER JACOBS: Pretty much.

CHAIRMAN JOHNSON: Commissioner Clark.

COMMISSIONER CLARK: I have a question.

Mr. McGee, you're here to speak on behalf of Gulf Power, is that right? No, Florida Power, sorry.

MR. McGEE: I'm here to speak on behalf of Florida Power in support of Gulf Power.

COMMISSIONER CLARK: All right. Where are the independent power producers? I don't see anyone else here that doesn't like -- is opposed to the rule waiver.

Mr. Moyle, I see you in the audience. Are you here just to listen or do you have a view on it? And, you know, that's up to you as to whether or not you

want to come up here.

(Laughter).

Well, you know, let me just put it this way, it makes me curious as to, you know, it would seem that maybe you all don't need this information. And if you don't need this information, why are we going through this exercise?

I can see that maybe -- what I'm concerned about is maybe the information doesn't have to be publicly disclosed, but maybe I want to see it at the front end, so that I know or I can make an assessment as to whether any gamesmanship is going on. You know, you give us an avoided cost, and then when you get the bids, you see, well, you could beat that. And if that -- if that occurs, then I don't think we'll have a robust wholesale market. Because the independent power producers will probably say, "Why should I come in and make the effort, when they're always going to have the opportunity to beat my bid?" But if you're required to give us the information, then we ask you some hard questions as to why you didn't sharpen your pencil to begin with.

You know, I think there are advantages one way or the other, and I'm curious as to why apparently only LEAF has taken issue with this. Do the independent

power producers really not need this information?

MR. MOYLE: You kind of put me on the spot on this one, but let me tell you my personal view on it, okay? And that is, that you all went through a rulemaking procedure where there was a lot of back and forth, a lot of debate, a number of years ago. I understand my dad was involved in that. And it went back and forth, and you came up with a rule. The rule has never been used.

Now, this is the first time you're going to use the rule. And I don't know that the independent power industry has to come up and say, "Yeah, tell them what you really meant and the rule has to stick today." You know -- I mean, I don't know that we've got to be here saying that. I mean, I'll say it. I think that the rule, that your rulemaking process ought to be adhered to. And the first time somebody comes in and is going to use the rule, you ought not to grant a waiver that really guts the whole rule. I mean, that's my personal view. And I don't know that I've got to be here, you know, saying it, but that's -- you ask me that's what I'd say, you know, on a personal --

COMMISSIONER DEASON: Well, Mr. Moyle, let me ask you about the provision in Section 9, which talks about there being a waiver if it can be shown that it

would likely result in the lower cost supply of electricity, and all the other rule provisions which require there to be a procedure set forth and there to be certain information provided. And that what's at issue here is just the providing of detailed cost information.

MR. MOYLE: I guess with respect to that provision -- I mean, I would feel -- again, this is my personal view. I would feel much more comfortable -- they talk about what every other bidding situation -- you know, we don't have to put our card on the table. But in just about every other bidding situation, you know, if the Department of Management Services goes out for a bid, they get everybody's bid, and then they select one of them. That's not the case here. It's the power company making the selection.

I mean, if you all want to make the determination as to what -- what the best bid is, then let them put their bid in, put it in a Mason jar on the same day that we put it in the Mason jar and give everybody that at the same time and you all can make your selection, would be the way the bidding process normally works. I mean, you know, we're talking about, "Well, we can come back in later on."

And I say the "Mason jar," that was what the

Tallahassee situation was, when you came in and they said, "Well, we want everybody's bid. We'll put ours in a Mason jar." But, you know, these guys are going to get the bids, and they're making the ultimate decision. That doesn't seem very fair to me.

COMMISSIONER GARCIA: I get a feeling, Mr. Moyle, that your client didn't send you here, so you're just giving your personal opinion, so maybe I should just ask someone else.

MR. MOYLE: Well, I guess my point is that when we went through the rulemaking process a number of years ago, we never thought that you would come in and the first time you're enacting the rule that, you know, we've got to stand up and say, "Yeah, let's go back three years ago and make sure you really meant what you said then."

COMMISSIONER CLARK: Mr. Moyle, I appreciate that I put you on the spot, and I understand that it is your personal view.

I do have one of two other questions. I don't -- this was a pretty broad recommendation, and from what I understand from the staff, so was the petition. I guess what I'd like to see from you all is, "Here is the information we think we shouldn't provide, and here is why." Do a matrix. "I don't think I should

provide this information, and this is why. And I don't think I should provide this information."

I disagree with you, Mr. Cresse, with respect to what is already on file. I think there is an advantage in terms of efficiency in getting the bids to put information that is already public information in a form -- in one single spot so there isn't any debate while we read -- we used this, you know, maybe the 1998 version of the Ten-Year Site Plan as opposed to the 1999 version. I think you should be saying these are -- this is the public information we're relying on. But this is the information we don't want to provide and here is why. Have they done that?

MS. HARLOW: No, ma'am, not in my opinion. In fact, today is the first day I've gotten the indication that it was specifically Items 6 and 13 that concerned them. We had a discussion with Mr. Stone and asked him, "Okay, if you got the waiver and filed an RFP" -- we expressed to him that staff cannot understand what information of the 13 items would be included in your RFP. And so we asked him to address that.

MR. STONE: Commissioner, I'm sorry that I did not communicate very well with staff. That's my feeling. And my client should not suffer from that.

I thought I had made it clear that in terms of what we were seeking waiver of, we were seeking waiver of those types of detailed information. And I thought I had said this earlier today, Item 6, annual revenue requirements. And if you'll bear with me a moment, I'll turn back to that.

COMMISSIONER GARCIA: Mr. Stone, maybe you should address exactly why it is that -- I mean, in the broader context, if I might, Commissioner Clark -- why it is you don't want to give that information. Maybe you've got to be more specific. Because in the broader context, I think it's tough for us to rationalize why you don't want to give it.

I mean, I do understand that you are now under competitive pressure. Is it something for the overall system that bothers you that you have to give this information? Does this include the Southern Company information that altogether is going to give competitors an advantage across the nation to beat you somewhere? Is that what worries you? I mean --

MR. STONE: No, sir. I'm here on behalf of the ratepayers of Gulf Power Company. And in our view, putting out the target, the annual revenue requirements allows potential bidders to sit there and target their bid at that number rather than giving us

their best possible proposal. And that's all we're after, is to ensure that they are under the pressure to do their own independent evaluation of what the lowest amount of money they're willing to accept in order to give us what we need in order to serve our customers.

MS. HARLOW: Commissioner Garcia, that assumes that the potential bidders are only competing against the utility. That is not the case. They are competing against each other to get to the negotiating table.

And to go back to -- I almost said Chairman Deason's point earlier about the garbage, the garbage disposal, think of that instance. And say that we were four years ago, and there were three potential bidders. Well, then in a sense they are bidding against the city. But say today, four years later, there are 50 potential bidders. Well, that increases their incentive to bid against each other. So today, more so than at the time of the rulemaking hearing, we have Enron competing against Duke, not just competing against Gulf.

And I would also go back to Joe Jenkins' point --

COMMISSIONER GARCIA: But I add to that. But their bid has to even be sharper than that, because

one more shot Gulf gets at it or the Southern Company. The truth is, no matter how good the bid is -- and I think Mr. Moyle made that point, no matter how good the bid is, Gulf Power is going to look at it one more time. And, clearly, with all the advantages that Joe spoke about. If I can meet your price, I'm going to say good-bye Duke, because it's Gulf, because I know them, because it's part of the system, because we feel comfortable with that. And I think the staff recommendation would probably go with them, correct?

I mean, that's what Joe said. I don't want to -- I don't want to prejudice you because we're going to look at these things. But I think that's where Joe's argument was made.

Let me give you my -- I would probably feel more comfortable -- all things being equal, I'd probably go with Mr. Stone's company, all things being equal. Because for the ratepayer, Joe Cresse stated there are certain advantages in the long run.

MS. HARLOW: Yes, sir, there are. But there is nothing in the rule that requires that the selection be made based on price alone. In fact, the Commission considered that extensively in the hearing. Should we make the determination based on price? Should we make it based on this list of 15 different criteria? And

the Commission decided that that was making a management decision for the utility, and that the Commission was here to review management decisions.

And I'd also, while I have the floor, go back to Subsection 9 of the rule, which Commissioner Deason referred to in which the Commission specifically states in the rule that the Commission may waive the rule. If you read the transcript, the primary thing that was discussed in this case and, in fact, I would say the only thing that was discussed, and it was discussed by Commissioner Deason, was why would we want to put this in here? And he came up with an example, and he used it several times.

What if we were in a situation where we knew ahead of time before an RFP that the utility could build a plant cheaper? And he came up with the example of government funding for a new technology. And when he addressed this, he looked at the rule as a whole. And I think that's very important to look at.

Gulf's primary argument is based on hardship. And their argument says, "You are putting as at hardship by requiring this information in the RFP. Because if we put this in the RFP, it will give bidders the incentive to cluster their bids around our -- what's not really a bid, but our avoided cost

information." That is less likely today than at the time the Commission passed the rule. And the Commission considered this argument at that time.

COMMISSIONER GARCIA: Commissioner Clark, I would echo some of your sentiment about certain things being private. I mean, if this was something that we were asking the company to put out information which affected them in their ability to buy power off the grid because certain people had certain knowledge that a competitor would need, I could understand them wanting to keep that from being public. But that isn't what the company is arguing. It is arguing this specific process before us about competitors, about this specific -- they're not arguing, "Well, Commissioners, if I give you what my power needs are in Florida, I'm going to be giving Duke a tremendous advantage in the future when we're competitively bidding for power, because they know exactly what my need is. They'll be able to price -- they'll be able to sell me things more expensively and they'll be able to beat me on another level."

This isn't information that is going to hurt them, at least that's what Mr. Stone is telling us, that this isn't private information that's going to hurt them competitively as a company elsewhere.

COMMISSIONER CLARK: Can I ask a question? Is the annual revenues requirement, that's essentially cost?

COMMISSION STAFF: Yes.

COMMISSIONER CLARK: Okay. And then what is the other thing they don't want to provide?

MR. STONE: I'm sorry. I have -- when you say is the annual revenue requirements essentially cost, I don't believe that's the case.

MR. BALLINGER: No, you have components in it as far as return, what fuel prices go into it. If I can say --

COMMISSIONER DEASON: Well, I don't understand. Those are costs. It's the cost of fuel, it's the cost of capital. Why isn't -- revenue requirements is really, it is just the tabulation of costs.

MR. BALLINGER: Yes.

COMMISSIONER CLARK: Thank you. Now, what is the other thing you don't want to provide?

MR. STONE: Commissioner, may I --

COMMISSIONER CLARK: No, you can't respond to that. Answer my other question. What is the other thing you want to provide --

MR. STONE: It is particular details in Paragraph 13 that allow you to calculate annual revenue

requirements from the cost of the facility.

COMMISSIONER CLARK: And what are those?

MR. STONE: Rate of return, depreciation rates, those things that may change over time but that we would be giving out our forecast of that.

COMMISSIONER CLARK: All right. Let me ask this question, are those costs -- is that information we use in determining avoided costs for other purposes, such as conservation and those sorts of things?

MR. BALLINGER: Yes. If I can, this is kind of as Yogi Bera would say, deja vu all over again. We had these same arguments when the rule was developed about the type of process to do. What staff wanted to do was try to strike a balance. As the utility has the obligation to serve, we wanted them to hold the cards for the ratepayers of Florida. They have the right to reject all bids even if they are less than theirs for various reasons.

As Mr. Cresse pointed out, there are some benefits of a utility owning a generating unit today in a regulated environment. If we go to competition things may change, if we totally deregulate generation. But the rule as it stands envisions a regulated environment.

The cost information that is out there that is

required is basically what we would require in a need determination. To look is it the most cost-effective alternative. We are forcing the utilities, if you will, to put their best foot forward so the bidders know -- the Duke and Enrons of the world know what it takes to build a combined cycle unit.

COMMISSIONER CLARK: Okay. Let me ask Mr. Stone one thing. How would you feel about not putting that information out initially, but you have to submit a bid with all that information at the same time and that is the bid that you are going to evaluate everybody else's bid by, and you are going to have to say why despite the fact that you are not the lowest bidder you think you are still the best. Would that be satisfactory?

MR. STONE: Well, I think Mr. Ballinger has already covered that, and he said that would put -- take out our role as management to be able to do the best interest of our ratepayers. I think we need to have the opportunity to evaluate those bids on nonprice attributes and make those determinations. And we can't tell you what that is going to be until we have been able to evaluate each bid.

COMMISSIONER CLARK: What I have said to you is you have to decide what is the best Gulf Power can do

to meet that requirement, and you have to submit that at the same time as other bidders. Let me finish. And then you can -- if you have a bid for $100, one for 95, and you are at 105, you nonetheless can come in and say we still think we are the best because of these reasons, and then you come justify it to us.

But the point at which -- you only get the same shot they do to do your best deal. What would be wrong with that?

MR. STONE: I think there are some practical limitations on that. We have to undertake this RFP process, we are still in the process of getting the detailed site-specific type of information that would be used in a need determination proceeding. We don't have all of that information available to us today, yet we need to go out with the RFP.

Quite frankly, I've got some system planners telling me I needed to have issued this RFP last month in order to meet the time lines to be able to come before you with a need determination proceeding in order to be able to meet the on-line requirement in 2002 in a timely fashion. If we were to wait until we had the kind of detailed information that you are talking about, we would have to put in at the same time. I'm not sure how we can assure ourselves that

we are going to be able to meet that 2002 need because, quite frankly, we are having to push things further out before we can even issue the RFP.

The RFP is a process by which we gain additional information about what the market is out there. We are not prejudging that we are going to build this capacity. We know what we have out there for planning purposes right now. We want to know if somebody else can do a better deal for our ratepayers, and if so, we want to snap that up. The only reason we were here before you with this waiver --

COMMISSIONER CLARK: If you haven't done all of that how are you going to be able to evaluate the bids? How long do you -- maybe I'm not understanding. How long after you put something out do you require them to bid?

MR. STONE: They are going down parallel paths, Commissioner. We are trying to get the information from the potential bidders at the same time we are doing our site-specific development of information. And at the same time when we get to the point that all the bids are in, the process is closed, then we start evaluating. We hope to have better information than we have available today.

COMMISSIONER CLARK: But you can't do that at the

same time they are required to -- in other words, all the information -- they have the same problems to some extent. They are making estimates, but on a date certain they have to decide to go with their estimates. Why shouldn't you be required to do that?

MR. STONE: They don't have the obligation to serve that we do. They don't have the need to have capacity on-line in 2002. If they don't succeed in our project, they succeed someplace else, so be it. Our problem is we have to not only --

COMMISSIONER GARCIA: Wait a minute. Can't that be part of what they bid for?

MR. STONE: It's a timing issue, Commissioner. It's a question of if we were to be in the position to give that kind of detailed information, precise information, site-specific information, before we even issued the RFP, then we either have to start that process earlier or we have to find other means to meet the need that we have already identified in 2002.

Quite frankly, we filed a ten-year site plan proposal in April that did not include this project. We continued our evaluation, and this project came to the forefront. We amended our ten-year site plan information in June in order to give you the best information we had available. We are still in the

process of developing even better information. But the time frame is such that we need to go out for the RFP now in order to meet that 2002 need. Given the fact that in order to meet that 2002 need we very likely are going to have to come before this body with a need determination petition which will have the best information available to it at the time we file that petition, not necessarily the best information available to us today.

We have taken a great deal of time today. Quite frankly, our petition was to recognize the fact that when you passed this rule there was a great deal of discussion on this. There was a divergence of opinion, and the Commission made a decision in order to take advantage or that relied on the environment as it existed when the rule was passed.

A lot of time has passed. The rule has not been used. I suspect that Mr. Moyle's comments would be such that no one expected there not to be an RFP issued under this rule for four years. But that has, in fact, been the case, and the reason that has been the case is changes in the marketplace, the uncertainty in the marketplace. No one has been building capacity.

We now find ourselves in a position to need to

build capacity, we are getting ready to come before you in a need determination proceeding, and we want to be able to do the best thing for our ratepayers. We believe that either granting us the waiver we have asked for or granting us a partial waiver that will allow us to give the ten-year site plan information that we put out in June as part of the RFP meets the best interests of our ratepayers, and that's what we came before you asking for.

CHAIRMAN JOHNSON: Thank you, Mr. Stone. Mr. Cresse, could you answer the question that Commissioner Clark had posed about why you shouldn't be required to put all the bids on the table at the same time?

MR. CRESSE: Would you repeat that question, please.

CHAIRMAN JOHNSON: Why the utilities shouldn't be also required to put their bid on the table at the same time?

MR. CRESSE: My opinion is it's not in the best interest of the consumers.

CHAIRMAN JOHNSON: And why not?

MR. CRESSE: The reason it's not in the best interest of the consumers is if you request bids people are going to bid against one another. The

utility then is going to analyze that bid and they have the opportunity, as you said earlier, to determine whether or not they can beat those bids that came in. They have that opportunity. I think that opportunity should be preserved because that is what will wind up getting you the lowest price.

The utilities have the desire to own and operate their own plants. There is benefits to the consumers for them owning and operating their own plants as opposed to purchasing from independent power producers. So if the price is the same or close to the same, I think that the utility has to come to you and justify the decision they make. And that justification may include owning that plant as opposed to operating it. So they shouldn't have to put their bid in with everybody elses.

Nobody does it. How would a contractor that was going to build his own house, why would he have to put his price up front? Why couldn't he negotiate it?

COMMISSIONER CLARK: Well, Mr. Cresse, let me ask it a different way. As I understand your main objection is why should they have to put their bid on the table to begin with?

MR. CRESSE: Right.

COMMISSIONER CLARK: It's not fair.

MR. CRESSE: Right.

COMMISSIONER CLARK: Well, by advocating what you are, that they should not have to put the bid in at the same time, well, then they are the ones who are getting the opportunity to see everybody else's bid and then put theirs on the table.

MR. CRESSE: That's correct.

(Simultaneous conversation).

COMMISSIONER CLARK: And that is fair why? And that is --

MR. CRESSE: That is in the public interest.

COMMISSIONER CLARK: And why is that in the public interest?

MR. CRESSE: Because it will result in a lower price than you would get otherwise if they were required to put their price on the table and bid simultaneously with everybody else. The opportunity to negotiate with multiple bidders is foregone under what you just described.

COMMISSIONER CLARK: What does that do to a potential competitive bidder? Why would he ever put in a bid if the utility is always going to be able to beat it? Why would he go to that expense?

MR. CRESSE: I don't know why -- he would do it because he thinks he could make some money in the

process.

COMMISSIONER JACOBS: I agree with that theory of the extra measure of reliance on what the company, the utility will provide. But that takes me back to the rule, because that means on the first shot the utility is going to have done a fairly decent job of sharpening its pencils, but I understand it's because there is going to be some gamesmanship.

But whatever gamesmanship gets played, for those very reasons I would expect when they come with that second shot at the apple that the extra card that Joe keeps speaking of they are going to be right on. And whoever they can't beat when they come with that second one, well, there are going to be some pretty legitimate reasons why they can't. At that point in my mind the gamesmanship is gone because they are very serious at that point.

MR. CRESSE: I think that's correct.

CHAIRMAN JOHNSON: Any other questions, Commissioners? Mr. Vandiver, did you -- to this item?

MR. VANDIVER: I was going to discuss a procedural matter with Mr. Elias.

CHAIRMAN JOHNSON: Okay.

COMMISSIONER GARCIA: Well, I guess I will move staff, unless our lawyers have another issue. But I

will say this to the company, if there is something that you don't want anyone to know because it is going to affect your competitiveness, even outside of Florida markets, if there is something that affects you that you say, "Well, Commissioner, by providing this information Gulf Power is not going to be able to be competitive, we are giving our competitors an advantage --" in this case I think we are giving your competitors an advantage to beat your price and that's good. And that being the case, I think staff is absolutely right in its rationale, and I support staff, and I will move staff.

COMMISSIONER CLARK: Let me ask one more thing, Mr. Stone. Why can't -- why won't we ultimately serve the ratepayers doing this, because once you get the bid you can always say we can do it for less and here is why?

MR. STONE: Commissioner, again, when we submitted our waiver request, we had talked with experts in the area and they said to us it is generally better, you get better bids, you get more competitive bids if each bidder is required to do its own independent analysis. That there is the risk of price convergence if we give that kind of target out there.

Having been advised of that potential risk, we thought it was in the interest of our ratepayers to file this waiver request. And that's all we were seeking.

COMMISSIONER CLARK: Well, let me ask you from the standpoint of your analysis of it, why, if you have to put this information out there and then you get bids, and you still have the opportunity to come in lower, it seems to me that the ratepayers are then served.

MR. STONE: But if the bids that come in are lower because of that extra degree of uncertainty, if you will, that they don't have a target to hit, then we are forced even lower still.

COMMISSIONER CLARK: Good news, right, for the ratepayer?

MR. STONE: But that's all we were asking for with the waiver request, is to not put that number out there other than what is already in the public record. And, again, a partial waiver of the rule gets us where we are trying to get in the fact that the ten-year site plan information could be all that is required.

COMMISSIONER CLARK: Mr. Cresse, can you answer that? If the fact of the matter is that the utility always has the opportunity to beat it, then ultimately

the ratepayers are served by this rule.

MR. CRESSE: I think what you just described modifies my fairness argument. I don't think it changes the basic argument of how it would effect bidders that Mr. Stone said, but I'm somewhat satisfied that the fairness issue has been somewhat modified by a clear understanding that I did not have that we get a second shot, a second bite at the apple.

COMMISSIONER CLARK: Is that true, they do, in fact, get a second shot?

COMMISSIONER GARCIA: Yes.

MR. BALLINGER: Yes, ma'am. That was the whole intent. Since the utility does have the obligation to serve, they would be the ultimate surveyor, if you will, of the bids. They could even have a higher priced bid and come in and convince you that their's is the best deal for other reasons.

COMMISSIONER CLARK: Or they could come in with a lower price.

MR. BALLINGER: Or they could come in with lower.

COMMISSIONER CLARK: Well, then, I think we have solved our problem.

COMMISSIONER JACOBS: Let me ask this, just because I'm interested, to staff, really. What does having -- what does the bidders who are going to come

after this project, what does Item No. 6 give them in preparation of the bid?

MR. BALLINGER: You're saying what does Item No. 6 give the bidders?

COMMISSIONER JACOBS: Yeah. Actually, my real interest is what detriment is there to them if they don't have it up front?

COMMISSIONER GARCIA: What detriment is it, you mean, to the bidders? What detriment does a bidder have by not having that information, correct?

COMMISSIONER JACOBS: Up front, yes.

MR. BALLINGER: Quite frankly, these same arguments, again, like I said, were done at the rule hearing, and from a truly competitive nature, you're right, you get better bids if nobody sees each others price, you seal them all, throw them in a Mason jar and you pick the lowest one that way. We don't live in that world.

COMMISSIONER GARCIA: Wait. Mr. Ballinger, though, don't you agree that this is even better than that process, because --

MR. BALLINGER: I was getting there. I was getting there.

COMMISSIONER GARCIA: Okay. All right.

MR. BALLINGER: Since we are in a regulated

environment, I think this is a better process, because we force the utility to put its best foot forward. I can't tell you the number of phone calls I had prior to this rule from IPPs and even QFs saying that on one day avoided cost was $100, the next day it was 50, the next day it was 75. It was bouncing all over the place.

They would get different people of who they were negotiating with. One week it would be these two people, the next week it would be these two people. We are trying to force the utility to be fair and up front with its negotiating practices.

This rule was envisioned to get the IPPs now into the market, which were a new entrant. The way to do this was to make the utility put forth the information that it knew at that time, the best information it had available, much like it would do in a need determination proceeding, so we, as the ultimate judge, can decide whether it is the most cost-effective alternative. These are the types of thing we look at in evaluating that. A bidder such as Duke or Enron knows how much it takes to build a combined cycle unit.

COMMISSIONER DEASON: So you're saying they don't need the information, but we do.

MR. BALLINGER: From a true sense, no, I think we do in order to keep the utility in check. We use this information --

COMMISSIONER DEASON: Well, we need it, but the sophisticated bidders, they know what they can build a plant for, they don't need Gulf's cost information, they know what they can build it for, and if they want to be competitive with other bidders and Gulf, they are going to submit their best bid right of front.

MR. BALLINGER: Right. Because ultimately we are going to evaluate the bid versus the utility, we are going to look at these things to see which is the most cost-effective.

COMMISSIONER GARCIA: This is a backstop for us, though.

MR. BALLINGER: Exactly. If there was a bidder out there who needed this information to submit a bid, I don't think I would want them selling in Florida. They are not sophisticated enough. The people out there know what it costs and what a utility can probably build it for.

This is for us to keep a check on the utility not only in generation, but in conservation, as well. We use this stuff day in and day out.

COMMISSIONER DEASON: Well, now, how have we been

getting that information for the last four years, since there has not been an activation of this rule requirement?

MR. BALLINGER: We get it in individual dockets when we look at cogeneration contract approvals. We ask for these runs. We ask for comparison of revenue requirements. Whenever we have a need determination, which we haven't had, either, we look at this as far as revenue requirements from different alternatives.

In conservation, we look at the avoided unit, we look at the revenue requirements and other expenses in evaluating a conservation program. So we do it on a case-by-case because avoided cost changes from month-to-month, basically.

COMMISSIONER CLARK: You know, I would agree with the idea that sophisticated bidders probably don't need that information, but I would indicate it probably does give some necessary information, such as -- and I would assume Gulf Power would take the same advantage of the bids they put in. That they may say we have negotiated this kind of deal for fuel, and it may be that Gulf has done it one way, when they see Enron's bid or Duke's bid, they say, aha, we could do it the same way and we can get it at a lesser price.

So that some of that detail I think is going to

be helpful to even the sophisticated bidder. But I will admit that it gives the person who has the last opportunity the ultimate advantage. And in this case, if I understand it, it's the utility.

MR. BALLINGER: And I think they should. As long as we have a regulated environment in generation and as long as they have the obligation to serve I think they should have that second advantage.

COMMISSIONER JACOBS: Let me try this and see what happens. I would like to move staff with the exception, so I would amend the original motion, to Item 6, which would require that that information be filed with the Commission, but not be put in the RFP up front.

CHAIRMAN JOHNSON: So you're offering a friendly amendment to the motion?

COMMISSIONER JACOBS: I don't know if it's a friendly amendment or not. I will leave that to interpretation.

CHAIRMAN JOHNSON: Well, there is an outstanding -- let me entertain, then, the outstanding motion. There is a motion to approve staff --

COMMISSIONER GARCIA: I'm not going to accept that.

COMMISSIONER JACOBS: I didn't think it would a

friendly amendment.

COMMISSIONER GARCIA: I think -- and let me just state it, since I made the motion. I think that staff is right here. I think that, you know, if there is anything that has weakened my feeling for staff was Mr. Ballinger's argument towards the end, because I do think you are right, Mr. Ballinger, this is not essential for the sophisticated customer, but it allows a ballpark entry, and we want people to be interested.

I think Mr. Cresse's point was well taken, but I think Mr. Cresse also admits that the fact is that this provides for a more competitive bid on down the line because the incumbent is going to get a chance to look at it. And I do think that it provides us a safeguard.

That being said, this Commission looked at it, I did not have the benefit of being on this Commission, but we had the benefit of three of the sitting Commissioners, and I feel comfortable that this rule is in the best interest of the ratepayers, of this Commission, and of this state.

CHAIRMAN JOHNSON: Okay. There is a motion.

COMMISSIONER CLARK: I would second it, and I would point out that because I don't think the

argument that bidders will converge around the price put out has been borne out by the discussion. I think what has been -- and that is the basis on which the waiver was asked for, that it will be adversely affecting the ratepayers.

And I think the discussion has indicated two things; that is, first of all, that there are multiple bidders. There will be bidders besides Gulf Power, and while they may know the preliminary bid in effect of Gulf Power, they will not know it of the other potential bidders, so it will give them the incentive to come up with the right bid.

Secondly, the last evaluation will be Gulf Power's, and they will have an opportunity to put in yet another bid showing that they can meet the price. And in the end that will result, in my view, at least under the scenario we have been presented, with the least cost to the customers. So a need for the waiver which was to benefit the ratepayers has not been demonstrated.

CHAIRMAN JOHNSON: There is a motion and a second. Any further discussion?

COMMISSIONER DEASON: Well, let me just say that I agree with a lot of the discussion that has been had here today, and I disagree with some. I think what we

need to do is put ourselves in the place of what was contemplated when this rule was first adopted. And what we wanted to do was to create a competitive environment, to try to stimulate that, to have bidders who would provide bids that fully responded to what was needed in the time frames in which it was needed in, and that they would present their best method of providing that need and their best price for doing that. And we felt that the ratepayers would benefit from doing that.

We also agreed that it would be best -- that it was not our place to be the substitute of management and to evaluate those bids ourselves, and as long as there was rate base regulation that we could hold the regulated utility accountable for their decisions, and ultimately whatever their decision was as a result of the bidding process it had to come to the Commission for final approval.

But I would submit that some things have changed since that time, and that we do know there is a more competitive market out there than what there was when this rule was first adopted. I'm having difficulty with the concept that this information -- it seems to me that we need to have the utility provide all essential information so that there will be the

maximum amount of bidders who will respond, fully respond with an acceptable alternative, and that they will present their most competitive price for doing so. But we don't need any more information than that.

I question whether the detailed cost information as envisioned within Item 6 is necessary for there to be that type of response. I think that the sophisticated bidders who we want to come and participate in this bidding process, they fully know generally what the essential starting point is, and this information is not needed for that. I think that there is some danger that if we put this information out that there could be a tendency for that to be the starting point and that perhaps that the bidders would not sharpen their pencil quite as much as they could otherwise. Perhaps not. I think that's kind of a philosophical debate as to whether that would happen or not.

What we want to do is to have the bidders come in, as many as possible. I don't think this information is necessary to do that, and for that reason, I would tend to agree that the provision within Paragraph 9, which says the rule or any part of the rule could be waived on a showing, I think that that showing has been made, so I would disagree with

the motion.

CHAIRMAN JOHNSON: Any further discussion? I see the arguments on both sides of this particular issue, but -- and I tell you at first in reading the initial petition I was more inclined to rule with Gulf Power given that the markets have changed and we are seeing more competition in this particular area. But as we have had the dialogue, and to the extent that staff is sure, and Mr. Elias and Mr. Jenkins have also agreed that this process lends itself to allowing the IOU to put in yet a second bid.

So when Gulf Power made their argument as to what putting this bid out there would do and the fact that that would start the bidding process higher, and that the independents would come in right under Gulf, to the extent that that is true, that is ameliorated by the fact that Gulf can then come back in. And in my mind if we do have a lot of providers in the market and we are dealing with a competitive market, I'm hopeful that that would not happen, that is that the bids all come up right under Gulf's.

But we have a check in place, because if it does you get another opportunity. That I was not clear, and when Mr. Jenkins said that I thought, well, okay. But it has been repeated several times in such a way

that I find some comfort in knowing that we are probably going to get to the lowest price because, Gulf, you have to provide us with all this delineated information, you're going to put it out there on the table as to cost, the companies are going to come in, and yet you get to come in one more time. And to my satisfaction I think that that will lead to the lowest price for the ratepayers. So for that reason I will support the motion and second. Any further discussion?

COMMISSIONER JACOBS: Well, I think I'm pretty much -- first of all, I withdraw my other motion if that wasn't clear. My sentiments are pretty much in line with Commissioner Deason's. I really doubt that the sophisticated bidders will need that information. I do think it may have a tendency to taint the early rounds. But I'm comforted, because I think by the time the utility comes back in most of that gamesmanship is gone. But I do think that it may have a tendency to obscure some of the early bidding process.

CHAIRMAN JOHNSON: There is a motion and a second. Any further discussion? Seeing none, all those in favor signify by saying aye.

COMMISSIONER CLARK: Aye.

COMMISSIONER GARCIA: Aye.

COMMISSIONER JACOBS: Aye.

CHAIRMAN JOHNSON: Aye. Opposed?

COMMISSIONER DEASON: Nay.

COMMISSIONER JACOBS: I said aye.

CHAIRMAN JOHNSON: The motion is approved on a 4-to-1 vote.

COMMISSIONER GARCIA: Madam Chairman, I just want to state to the company that if there is something in here, and I think there is no reluctance on the part of the full Commission, if there is something that you are providing that gives a competitor an unfair advantage to your company and its standing in the competitive market as a whole, you should point that ought to staff and I think they are going to be understanding as we would be. I just don't think you made those arguments here today.

MR. STONE: (Inaudible, microphone not on).

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CERTIFICATE OF REPORTER

STATE OF FLORIDA)

COUNTY OF LEON)

I, JANE FAUROT, RPR, do hereby certify that the foregoing proceeding was transcribed from cassette tape, and the foregoing pages number 1 through 83 are a true and correct record of the proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 24th day of August, 1998.

JANE FAUROT, RPR
P. O. Box 10751
Tallahassee, Florida 32302

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	
Proposed Amendment of Rule 25-22.081, F.A.C., Contents of Petition; and Proposed New Rule 25-22.082, F.A.C., Selection of Generating Capacity.	DOCKET NO. 921288-EU

FIRST DAY - MORNING SESSION

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN J. TERRY DEASON COMMISSIONER SUSAN F. CLARK COMMISSIONER LUIS J. LAUREDO COMMISSIONER JULIA L. JOHNSON
DATE:	Wednesday, September 29, 1993
TIME:	Commenced at 9:50 a.m.
LOCATION:	FPSC Hearing Room 106 Fletcher Building 101 East Gaines Street Tallahassee, Florida 32301
REPORTED BY:	JOY KELLY, CSR, RPR Bureau Chief SYDNEY C. SILVA, CSR, RPR PAMELA A. CANELL Official Commission Reporters

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KENNETH A. HOFFMAN, Messer, Vickers, Caparello, Madsen, Lewis, Goldman and Metz, Post Office Box 1876, Tallahassee, Florida 32302, Telephone No. (904) 222-0920, appearing on behalf of the City of Tallahassee.

MARSHA RULE, FPSC Division of Legal Service, 101 East Gaines Street, appearing on behalf of the Commission Staff.

ALSO PRESENT:

CRAIG HEWITT: FPSC Research & Regulatory Review.

I N D E X

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P R O C E E D I N G S

(Hearing convened at 9:50 a.m.)

CHAIRMAN DEASON: Call this hearing to order, please. We'll begin by having the notice read.

MS. RULE: This is a rulemaking hearing in Docket No. 921288-EU. The whole notice consists of all the rules and I prefer not to read them right now.

CHAIRMAN DEASON: Very well. Take appearances, please.

MR. MAY: Mr. Chairman, my name is Bruce May. I'm with the law firm of Holland and Knight here in Tallahassee, appearing on behalf of Enron Power Corp. My address is P. O. Drawer 1810, Tallahassee, Florida 32302. Mr. Bob Reilley, the Director of Regulatory Affairs with Enron, will be making an appearance and has prepared a brief summary of his comments he filed on September 10, and is prepared to give those at the appropriate time.

CHAIRMAN DEASON: Very well, thank you.

MR. CHILDS: Commissioners, my name is Matthew Childs of the firm of Steel, Hector and Davis, and I'm appearing on behalf of Florida Power and Light Company.

MR. BRYANT: I'm Frederick M. Bryant, and also with me today is Bill Willingham, law firm of,

Moore, Williams, Bryant, Peebles and Gautier, P.O. Box 1169, Tallahassee. We're here today on behalf of Florida Municipal Electric Association and the Florida Municipal power Agency. And depending upon the structure of this proceeding, we may have some of our cities present some testimony.

MR. WILLIS: I'm Lee L. Willis, together with James D. Beasley, P.O. Box 391, Tallahassee, Florida 32302, together with Joseph B. Cresse, P.O. Box 1876, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

MR. NEISER: Mr. Chairman, my name is Richard W. Neiser, Post Office Box 14042, St. Petersburg, Florida, appearing on behalf of Florida Power Corporation. And we have five witnesses who would like to make comments to the Commission today on direct and then three on rebuttal.

MR. WILLIS: Mr. Chairman, I do want to add that we have three witnesses, Tampa Electric has three witnesses: John Rowe, Don Mestas and Sam Hadaway, who would like to present comments and summaries of their compiled testimony.

CHAIRMAN DEASON: Very well.

MR. GADDY: Mr. Chairman, Commissioners, my name is Rodney Gaddy. I'm an attorney with Florida

Power Corporation.

MS. SWIM: Deborah Swim on behalf of the Legal Environmental Assistance Foundation, 1115 North Gadsden Street, Tallahassee 32303. I will be making some brief remarks on behalf of LEAF.

MS. KAUFMAN: Commissioners, good morning. Vicki Gordon Kaufman of the law firm McWhirter, Grandoff and Reeves, 315 South Calhoun Street, Suite 716, Tallahassee 32301. I'm appearing on behalf of the Florida Competitive Energy Producers Association. We have six witnesses who will be making comments before the Commission this morning.

MS. BROWNLESS: Thank you. Suzanne Brownless, Suzanne Brownless, P.A., 2546 Blairstone Pines Drive, Tallahassee, Florida 32301, appearing on behalf CEPA as well as Destec Energy and Air Products and Chemicals.

MR. MOYLE: My name is John Moyle. I'm an attorney with the firm of Moyle, Flanigan, Katz, Fitzgerald and Sheehan with offices in West Palm Beach and Tallahassee. I'm making an appearance today representing the Florida Competitive Energy Producers Association and J. McKowski and Associates, Inc.

MR. McGLOTHLIN: My name is Joe McGlothlin of McWhirter, Grandoff and Reeves, 315 South Calhoun

Street, Tallahassee. I'm appearing here for Falcon Seaboard Power Corporation. Falcon Seaboard is a member of the Seaboard organization participating in that capacity.

MR. WATSON: I'm Ansley Watson, Jr., of the law firm of McFarlane, Ferguson, P. O. Box 1531, Tampa, Florida 33601, appearing today on behalf of the Florida Competitive Energy Producers Association and Ensearch Development Corporation.

MR. ERWIN: Yes, my name is David B. Erwin of the firm of Young, Van Assenderp, Varnado & Benton, 225 South Adams Street, Tallahassee. Also appearing with me is Roy Young of the same firm, and we're here on behalf of Kissimmee Utility Authority and Orlando Utilities Commission. There's one witness for Kissimmee Utility Authority that we would like to put on and then Orlando Utilities Commission has filed some comments but has no witnesses.

MR. McKENZIE: Norrie McKenzie, I'm with Peninsula Pipeline Company, a subsidiary of SONAT, Inc. My address is Four Greenway Plaza, Houston, Texas 77046.

MR. MELSON: Richard Melson of the law firm Hopping Boyd Green and Sams, Tallahassee, representing Seminole Electric Co-op. We will have one witness on

behalf of Seminole.

MR. STONE: Jeffrey A. Stone of the law firm Beggs and Lane, Pensacola, Florida, representing Gulf Power Company.

MR. WRIGHT: Robert Scheffel Wright, law firm of Fine, Jacobson, Schwartz, Nash and Block, 215 South Monroe Street, Suite 804, Tallahassee, 32301-1859, appearing on behalf of ARK Energy. ARK prefiled comments in this proceeding. The specific author of the comments, Mr. Siderewicz, is unable to be here today. And so at the appropriate time, I will be making a brief presentation on behalf of ARK. Thank you.

MR. DONELAN: Richard T. Donelan, Assistant general Counsel, Florida Department of Environmental Protection, 2600 Blairstone Road, Tallahassee 32399.

MR. HOFFMAN: Mr. Chairman, my name is Kenneth A. Hoffman of the Messer, Vickers firm, P.O. Box 1876, Tallahassee, Florida 32302. I'm appearing on behalf of the City of Tallahassee. The City of Tallahassee has filed comments in this proceeding. Those comments will be summarized by Mr. Gary S. Brinkworth, who is the Superintendent of System Planning for the City's Electric Department. His address is 300 South Adams Street, City Hall,

Tallahassee, Florida. Thank you.

MS. RULE: Marsha Rule, 101 East Gaines Street, appearing on behalf of the Commission Staff.

MR. HEWITT: I'm Craig Hewitt, Commission Staff, Research.

CHAIRMAN DEASON: Any other appearances?

COMMISSIONER LAUREDO: This must be really important, Mr. Chairman. An awful lot of people are here; an awful lot of important people here.

CHAIRMAN DEASON: More than one page of appearances. That may be a record. Ms. Rule?

MS. RULE: Before we get into some procedural matters, I would like to point out that Staff can't see past this (indicating) and the members of the public and the Staff presentations will be made before whoever this is. So I would ask that they at least put the screen down before and after the presentation, please, if anybody will admit to it being theirs.

COMMISSIONER LAUREDO: Why don't we just take it down?

MS. RULE: Well, I think somebody tried to but couldn't figure out the button you have to push to get it down.

CHAIRMAN DEASON: Would someone just pick it up and move it over out of the way for the present.

time. That may be the easiest.

MS. RULE: Would you like me to cover some of the procedural matters?

CHAIRMAN DEASON: Yes, please.

MS. RULE: I've distributed to you the appearance list, and that includes the people who have signed up. Some of them may be presenting testimony, some of them may not be. But, in any event, you may wish to call participants from this list. If anybody is not on the list and has neglected to sign up, there is still a few more pages left there, you can sign up.

Everybody should have received a rulemaking hearing information sheet. There are extra copies on the table by the door. It lists the general order of presentation beginning with Commission Staff and then following down the list. There's been one request to be taken, not exactly out of order, but Florida Competitive Energy Producers Association has asked to go first within the nonutility generator category.

Hearing transcripts will be available for parties on October 15th, 1993, and their posthearing comments will be due on October 29th, 1993.

When people come to make their presentation, there is no need to move into the record any comments or exhibits or testimony that has been prefiled unless

it is not contained in the exhibit books. There are three exhibit books available for you to review. There's one on each side of the room and one in the middle. Please, at some point in time, check to make sure that your comments are in there.

During presentations we'll be handling original and responsive comments at the same time. So you need to make all your comments, including those on Section 712 of National Energy Act, at one time. My understanding is that there is no formal limitation on time for the presentationS, but that the Chairman reserves the right to limit presentation time if it appears that we need to do so. There are three days scheduled for this hearing. Parties will be available for cross examination or questioning for clarification purposes. And, again, the Chairman reserveS the right to limit the time for questioning if it becomes necessary.

CHAIRMAN DEASON: Okay. Let me just add one word of caution. We're here to get as much information as we can; that's the purpose for this hearing. And so we certainly are going to not only allow, but encourage there to be clarifying questions of peoples' positions. But to the extent that we're getting into cross examination for impeachment purposes, I think that's

probably a little bit outside the purpose of the hearing that we're here for today, so please keep that in mind. Please keep your questions along the lines of trying to get relevant information clarified for the benefit of all here today. I think that's the purpose of this hearing. Am I correct in that, Ms. Rule?

MS. RULE: Yes, sir.

Staff would also like to move into the record the Composite Exhibit No. 1 and No. 2. The ones that are available for people to examine. They include the FAW notice and the proposed rules. The materials that the Commission has provided to the Joint Administrative Procedures Committee, the Notice of Rulemaking, and timely comments that have been filed.

CHAIRMAN DEASON: That consists of Composite Exhibits Nos. 1 and 2.

MS. RULE: Yes, sir.

CHAIRMAN DEASON: Very well.

(Composite Exhibit Nos. 1 and 2 identified and entered into the record.)

MS. RULE: I would also like to clarify a matter I've had several questions on. The Commission's formally proposed rules are those that were published in the Florida Administrative Weekly. Thereafter, Staff circulated an alternate draft and those are

included Mr. Ballinger's comments. Mr. Ballinger intends to discuss those in his comments today, but I would like to point out to the parties that those are not the Commission's formally proposed rules. The rules that have been proposed by the Commission are different than the ones contained in Staff's comments.

CHAIRMAN DEASON: Are we ready to proceed with Mr. Ballinger?

MS. RULE: Yes, sir.

MR. NEISER: Mr. Chairman, I have one preliminary item that I would like to at least discuss with you preliminarily. Of our witnesses, we have one out-of-state witness that has a conflict for tomorrow. He is available today and Friday, but looking at the order of things, it is appearing to me that the normal flow of things might have him be on tomorrow. What I would like to do is reserve the opportunity as the day proceeds here a little bit to discuss with you how we might possibly take him out of order to accommodate the difficulty of tomorrow.

CHAIRMAN DEASON: I appreciate your bringing that to our attention and as things progress today, please let us know how things stand in your mind and if need be, I'm sure we probably can make an accommodation.

MR. NEISER: Thank you.

MS. RULE: One more item. I notice a lot of people here who do not regularly speak before the Commission. Please, for the court reporters, identify yourself every time you say something, particularly if we get into cross examination or questioning later on. It's very helpful for you when you read the record to be able to know who's asking the questions.

CHAIRMAN DEASON: With this many participants, I'm sure the court reporters would appreciate that.

Mr. Ballinger? First of all, let me ask the parties, are there any preliminary matters which need to be addressed by any of the parties before we proceed in the presentations? Very well. Mr. Ballinger?

TOM BALLINGER

appeared before the Commission and testified as follows:

MR. BALLINGER: Thank you, Commissioners.

Before I start, I'd like to make one typographical correction to my comments, if anybody has it.

On Page 12, Line 8, it was pointed out to me, that should read "Attachment 1" instead of "Attachment 2." With that, I'd like to go ahead and summarize my comments, if I can.

My comments are divided into three basic

sections. The original Commission-proposed rule on capacity selection, an alternative to that proposed rule, and proposed rule language to comply with Section 712 of the National Energy Policy Act of 1992.

The rule language originally proposed by the Commission at the August 3rd, 1993, agenda would provide a clear port of entry and closure, which are key problems associated with the Cypress case. And I'll use that word kind of generically.

This proposed rule was very flexible and does not provide clear guidance to the affected utilities. Prospective nonutility generators claim this may result in the fox guarding the henhouse. This rule is shown in Attachment 2 of my comments.

Since the August 3rd agenda conference, Staff has put together an alternative to the formally proposed rule, which is contained in Attachment 1. This alternative language contains provisions that would require all utilities to issue RFPs, or Request for Proposals, prior to filing a determination of need. It would require advance notice of the intent to issue an RFP in a statewide and national circulation forum.

For the purposes of winnowing a large number of responses to a few finalist, each RFP package would include the type and timing and costs of the utility's

avoided unit, a schedule of critical dates for reviewing and selecting finalists for subsequent negotiations, and a preidentification of the weighing and scoring and evaluation criteria in order to select those finalists.

The RFP or the Commission's rule would require that preference be given to high efficiency cogenerators, municipal solid waste facilities, and facilities using renewable fuels, such as solar and biomass.

The rules would require utilities to negotiate for the best contract with RFP finalists. It wouldn't be a strict scoring procedure. It would allow nonwinning bidders to challenge the selection process at the need determination proceeding. This intervention would allow for parties -- no intervention would be allowed for parties who did not participate in the RFP process.

The rules also provide flexibility to the utilities by allowing for a case-by-case waiver from issuing an RFP based on the demonstration by a utility that a waiver would be in the best interest of the general body of ratepayers.

This alternative language would require utilities to openly solicit proposals, from which the most viable ones would be selected for subsequent,

contract negotiations. This process should result in the best project at the best price for the utility's ratepayers. Basically this is the same process that has been successfully used several times in Florida.

Some issues common to any bidding proposal are bifurcation, RFP preapproval, clear point of entry and closure. These are terms you'll hear a lot about over the next few days.

Both the originally proposed and Staff's ultimate rules allow for a clear point of entry and closure by requiring advance notice and for established dates for the completion of the selection process.

These seem to be areas in which the parties generally agree of having the advance notice and some critical dates assigned.

The issue of bifurcation is a different matter. This issue really boils down to who will benefit in a bifurcated proceeding. In my mind, the ratepayers assuming more risk with no additional benefits. The same is true for a preapproval of either a need in megawatts or a bid package. This also places the Commission in a decision-making position during a typical fluid planning process.

From reading comments filed by others, I have noticed a few areas of the alternative rule that may

require clarification. The requirement to issue an RFP would not preclude a utility from ultimately building a power plant itself. The utility would to be required to provide justification for this decision at the need determination proceeding, where all providers who responded to the RFP could argue their case as well. Turn-key and other utility proposals could also be included as part of the RFP. Also, any bidding rule should apply to municipalities as well as IOUs, as long as the Commission has jurisdiction over the need aspect of power plant certification.

Section 712 of the National Energy Policy Act requires that the Commission make a general review of four issues. At the April 20, 1993, agenda conference, the Commission directed Staff to address these issues during the bidding rule proceedings. Staff has included language that basically reviews these areas on a case-by-case basis. The municipalities have raised the issue that these requirements should only apply to IOUs, since Section 712 refers to utilities which the Commission has ratemaking authority over.

Staff views the requirements of 712 as viability issues, and as such these should be addressed by municipalities as well. As certain provisions are not applicable, then that can be stated as part of their

petition for need. And this concludes my summary.

CHAIRMAN DEASON: Thank you. Questions?

CROSS EXAMINATION

BY MR. CHILDS:

Q I'd like to ask you, in terms of the scope of the application --

CHAIRMAN DEASON: Mr. Childs, would you identify yourself?

MR. CHILDS: Matthew Childs, representing Florida Power and Light.

Q (By Mr. Childs) In terms of the scope of the rule proposal in your testimony, have you given any thought to whether the Commission should or will exert jurisdiction over the contracts that result from the RFP process? And by "exert jurisdiction," what I mean is, we're talking about 30-year contracts potentially or longer, that may or may not have disputes as you go through time, and my question is whether the Commission would be a part of the process of overseeing those contracts?

A Well, part of that sounds like a legal question of whether we can interpret changes to terms and conditions as you go through time. The other part I think we would retain our jurisdiction over the cost recovery of those contracts.

Q I'm thinking about really contract administration; that is not cost recovery, I think that certainly is a subject for concern, but as to the contract administration as to whether the contract has been performed or not performed.

A That may be a legal question, Mr. Childs.

COMMISSIONER CLARK: Can I ask you a question, Mr. Childs?

MR. CHILDS: Sure.

COMMISSIONER CLARK: What is it your view, that the Commission should or should not?

MR. CHILDS: My view is that the Commission should, and that --

COMMISSIONER CLARK: Should?

MR. CHILDS: Should, at least consider the extent to which -- and I guess I have a preliminary view that maybe it should, in many aspects, have jurisdiction. Because I assume that the Commission may hold the utility to administration of the contract. And I guess I also assume that there are going to be circumstances where, for example, there is a dispute as to whether capacity or energy should or should not have been produced at a particular point in time. And I think it may be very difficult to have the contracts administered by the various courts in the state --

COMMISSIONER CLARK: Okay.

MR. CHILDS: -- as we go forward. I'm primarily concerned about multiple jurisdictions looking at contracts from time to time, and it seems to me you have a question of who's regulating that relationship.

COMMISSIONER CLARK: Okay.

CHAIRMAN DEASON: Mr. Childs, let me ask you, do you feel that we have the authority to craft a rule which gives us that authority? Is that part of our natural jurisdiction, or would we be in violation of unlawfully expanding our jurisdiction?

MR. CHILDS: I don't know the answer to that. And I have thought about it, I guess is one of the reactions I had is that if there was a concern there and -- is that potentially any problem as to the scope of your jurisdiction might be addressed by the contract itself. Simply providing a method for dispute resolution. I think you already have that as it relates to dealings with QFs. There is some mention in the rule of that authority.

Q (By Mr. Childs) Is it your view that -- I can't see you but I'm here -- is it your view that if we use an RFP process in the future that the utility would have the discretion of whether it wanted to even

propose to provide capacity at all?

In other words, rely totally on the responses that it got to an RFP and simply say, "For this one we don't care to participate."

A I think that would be an option. I don't know why that would.

Q Okay. You don't know why it would?

A I don't know why a utility would not want to participate and build its own units.

Q Okay. Related to that, do you have any view of whether if the utility does participate in an RFP process, whether the utility should be held to any different performance requirements than an independent power producer might be held to under its negotiated contract?

A Is your question basically assuming the utility entered into a contract with itself, let's say, with performance criteria and these types of things?

Q Sure.

A With that would come along the utility being held to its price through time.

Q Yes.

A Okay. Well, the problem -- and that's one reason Staff -- I'm going to expound a little bit on this -- one reason Staff did not go with the proposal to have sealed bids where a utility would participate

in a sealed bid and have a third-party evaluator, you run into problems with that. How do you select the third-party evaluator? How do you develop a strict scoring mechanism without any subjectivity to select a winner, or do you put the Commission in the role of making that decision? And that's not Staff's intent.

So I think, assuming the utility being held to the same requirements, makes that other assumption that you're going to have a sealed process in a nondisclosed bid.

Q Okay. All right. But if you did have hypothetically a sealed process and maybe even independent review, really what I'm trying to get to is, for instance, if the utility was selected and approved by the Commission as the best project at the best price, and then there was a default and the plant wasn't constructed. Would the utility be able to avoid any further obligation to meet that load simply by paying the penalty that everybody else would pay if they had bid on the project?

A No.

Q Okay.

A The utility still has the obligation to serve.

Q I want to address, if I can, a little bit on the issue of closure, which I think is considered to be

a very important point. And I think your attachment -- and I forget the number because I got confused with the numbering, but the attachment at Page 32, Subsection 5, I think that's intended to address closure; is that correct?

A Yes. This is part of the originally Commission proposed rule.

Q And this is also I think in the draft that you're suggesting might be an improvement, isn't it?

A Yes. I don't know if the language is exactly the same, but it's -- let's see -- if you turn to Page 26.

Q Okay.

A I'm sorry, that's not the right page. 27.

Q 27.

A Subsection 7.

Q Okay. Well, I think as you've written it it's Subsection 7. The difference might be initially that you have to submit a response in order to be able to participate in the need proceeding, and under the original draft you had to just participate in the RFP process.

A Well, the original proposed rule didn't specify an RFP, it just had selection process, so we had to use participate because we weren't sure what the process would be.

Q And I guess that's my question. Would you agree that the word "participate" may be a little vague

and may permit those that only had minimal contact with the process to, in fact, be authorized to participate in the need case?

A I don't think so. In my interpretation of that, if somebody just made a phone call and inquired about it, I don't think that's participating in the process.

I think if the original proposed rule -- if somebody only did that cursory review, in my mind they didn't participate. But if they tried to negotiate whatever the process was and made a good-faith attempt to actually be involved in it, then they participated. It is a gray area, but this whole rule, as I said earlier, was very flexible. It was very open ended.

Q But in terms of closure, which I thought was a very important objective. Would you agree that in terms of attempting to administer it, that it might be beneficial to know in advance what the scope of the possible interpretation of the word "participate" was?

A Probably. The purpose of closure was to not have somebody who did not participate at all, or was not involved at all, come in at the eleventh hour and make another proposal.

Q In your testimony you are addressing, I think, your alternate rule language and state that this should result in the best project at the best price for

the utility ratepayers. In your view is that the goal of the rules, that is to get the best project at the best price for the ratepayers?

A Yes.

Q And is that goal also to provide sort of the bill of rights for IPPs to participate in supplying power, or is the focus on the impact on the customers?

A I think it's the impact on the customers. I don't think it gives -- our rule is intended to give IPPs the sole right to build capacity.

Q Okay. In discussion of the alternate rule that you have, you have provisions that call for some detailed information by the utility relating to the type of unit that it would build and all of the cost parameters and all of the operating parameters, et cetera, before it issues an RFP, and that that information would be part of the RFP and be publicly available. And in reading your testimony I think you explain that you think that's important, that that information be available because of the conservation review by this Commission.

Just as a question: Do you think that by making the information available, the utility making the information available in advance in that detail, that, in fact, the utility is either, one, taking

itself out of the game of the RFP process, or two, perhaps suggesting to bidders the area of a successful bid price?

A I don't think it's either.

Q Okay.

A The intent of that is, again, focusing on keeping the lowest rates to the ratepayers. On the other hand, we're recognizing the utility's obligation to serve and that's why we did not recommend a sealed bid proposal where a utility keeps its price close to its chest.

I think it's important to put that out there for the conservation aspect so the utility -- I mean, it has to gauge conservation with both timing and type of a unit. I think it's also important to put it out there as a threshold for screening out people; If they know they can't beat that price, they won't submit a bid.

Q Okay.

A It also recognizes -- by putting the price out there, I don't think it precludes the utility at all; because Staff is recognizing the obligation to serve and there may be selection of units for other than dollar figures. There are other criteria that you look at, and we are keeping that burden on the utility.

Q On the issue of having information available for conservation, that you need that data on the avoided unit. Do you see the potential for a conflict there that if you are going to use the utility avoided cost data for application of conservation, but if at the same time have made the judgment that the RFP process will produce an even lower price, that you're using an inconsistent basis for evaluation? In other words, you're using a price that you have already concluded is probably too high?

A You're saying that a bid --

Q Yeah.

A -- a strict bid would develop your avoided cost. And if you did conservation on the utility's best estimate, which turned out to be too high, are you misrepresenting conservation?

Q Actually, I'm not saying that, you know, that you would necessarily. I'm just trying to find out if your view is that you have to have the utility avoided cost data for conservation and then rely upon it for conservation programs, but at the same time you assume that the competitive bid will be lower, doesn't that represent somewhat of a conflict? (Pause)

Let me ask the question differently. Have you thought about in terms of conservation, if you're

going to use avoided cost data making the conscious decision that it is proxy information, that it is for that purpose, that it may not be refined to the nth degree and it may not be something that you need to pursue all that much?

A No, I still think it's important to have that price as refined as possible.

Q Okay.

A True, you may get a bid that is lower, but I still believe that information needs to be developed as close as possible for conservation. The problem I get is I don't think there is a contradiction because, typically, conservation won't defer the entire need of that unit. It defers a small piece of that unit and it's an iterative process where, true, you may go through a bid and get a lower price. Well, then that may be the gauge for which you do additional conservation. So it's a chicken-and-egg kind of thing. But I still think that the utility's guesstimate of what their avoided cost is needs to be as refined as possible.

Q Should the utility expect that respondents to an RFP are going to not only rely upon the information to decide whether they're in the ball game but, for example, rely on the information as it relates to the

fuel price forecast as an expectation of what they're going to be paid for fuel?

A They can do that, but they assume the risks that go along with that.

MR. CHILDS: Okay. I thank you very much.

MR. BALLINGER: Thank you.

CHAIRMAN DEASON: Mr. Bryant?

CROSS EXAMINATION

BY MR. BRYANT:

Q Mr. Ballinger, I'm Fred Bryant, and I represent the Florida Municipal Electric Association, which is a trade association for Florida's 32 municipal electric utilities, and I also represent Florida Municipal Power Agency, which is a nonprofit agency owned by the municipal utilities for the purposes of building generation and transmission projects. And that's the basis for which I'll be asking you some questions. We have submitted comments and we have sent those comments to you and I assume you have read those comments, sir.

Would you explain to me, sir, the -- what I call the "712," Section 712 part of your proposed rules, which I assume is the genesis of which is from the newly passed National Energy Act. Is that correct?

A Yes.

Q Would you explain to me your understanding of what that proposal or that Act requires?

A It basically requires the Commission to do a general evaluation of four criteria to consider. It didn't state how the Commission had to do it or there were some certain deadlines and time lines of when it had to be done and that's up in the air. We're not sure if that meant you only had to decide to decide or actually make a decision by those deadlines.

Basically, they were areas that have been controversy about the nation dealing with cost of capital, reliability of purchased power, its affect on the utiilties' fuel supply adequacies, and should there be a preapproval process for contracts.

We've tried to do this as a proposed agency action order at one time to basically state, "Let's do this on a case-by-case basis." These are issues Staff has looked at every time in a need determination proceeding or a contract approval. They may not be specific issues in a proceeding but they are looked at, they're viability issues. So they're nothing new to the Commission.

What we proposed was to go forward with an order that said, "We will continue to do that on case-by-case basis." The Commission decided that since

it was encompassing all utilities that it would be best placed in rule language. So basically what we did is incorporated in rule language that says, "We will do it on a case-by-case basis. When you file a need determination, come forward and explain to us these four areas, give us a discussion whether they apply or not and, if so, why."

Q Would you agree, sir, or is it your understanding that this Section 712 provision of the National Energy Act does not apply to the municipal electric utilities or the rural electric cooperatives?

A Is that because of the ratemaking authority reference in the 712 issue?

Q Yes, sir. And I'm not asking you a legal question to be unfair; I'm asking your understanding of whether or not 712 does or does not apply to the municipal utilities in the --

A That may or may not be. I think some of them may apply. I think if you end up entering into a contract with a nonutility generator, let's say, and he comes in for a need determination proceeding, I think it's this Commission's duty to look at, in the course of certifying the need for that power plant, whether it's a viable plant virtue its fuel supply. Do they have adequate assurances for fuel supply?

So I think as long as we have jurisdiction over a need determination proceeding, I think it does apply to municipalities.

Q And I realize it's unfair for us to debate legalities, because obviously you're here not as a lawyer. But would you accept my statement, subject to check with your legal department, that Section 712 does not apply to the municipal utilities or the rural electric cooperatives because the Commission does not have ratemaking jurisdiction over the municipals or the cooperatives and that language is consistent with the passage of the National Energy Act in 19 -- help me?

A '92.

Q No, before that, the act before that.

A Before my time.

Q The PURPA Act.

A I'm going to let our attorney answer that one.

Q I understand. I wasn't asking you for a legal question.

A Well, I think she can answer it in this type of proceeding.

Q Let me ask you, then, assuming it does apply, how would you interpret the language that you have put in your draft rule that, "If the generation addition is

a result of a purchased power agreement between the utility and a nonutility generator, the petition shall include the discussion of the potential for increase or decreases in the utility's cost of capital"? Now, let's take that first.

I assume you're talking about the situation where a NUG or an IPP or some nonutility comes before this Commission for a need determination of a power plant that it is seeking to build. Is that a correct presumption?

A Yes.

Q Now, I assume then the second correct presumption would be that that NUG or IPP's contract is with a municipal electric utility?

A Right, or else they couldn't be an applicant under the Act.

Q Excuse me?

A That's correct. They need to have a contract or else they could not be an applicant under the Act, the Power Plant Site Act.

Q Who could not be an applicant?

A The NUG. That's another controversial issue, too.

Q Yes, I understand. And in that scenario, then, you would require that the IPP and the municipal

utility to participate in your need determination?

A Yes.

Q And in that proceeding you would require the municipal utility to have a discussion of the municipal utility's -- the potential for the increase or decrease in the municipal utility's cost of capital?

A Yes.

Q What is your understanding of a municipal utility's cost of capital?

A I'm not a finance expert.

Q Well, sir, you wrote the rule.

A Well, a conglomeration of Staff wrote the rule.

Q What is the Commission Staff's interpretation of a municipal utility's cost of capital?

A It's basically their debt and equity structure.

Q Debt and equity structure. Is it your understanding that municipal utilities finance their utility functions through debt and equity?

A No, it's primarily debt.

Q Primarily debt? What kind of debt?

A Tax-free.

Q Tax-free revenue bonds, is that correct, sir?

A Yes.

Q Do you know how tax-free revenue bonds, what their source of payment is, sir?

A No.

Q Would you accept as being true and correct that the municipal utility's debt structure are tax-free revenue bonds, the source of payment of which are revenues from the sale of electricity?

A I guess the only inclusion of this rule, rather than trying to pinpoint certain circumstances where they would or would not apply, is to include it in every petition for a determination of need. If the municipality does not believe it applies, they can state so in their determination of need.

Q You would place the burden on my clients, a financial burden, a legal burden, to respond to a portion of the rule that is not applicable, sir?

A I don't think it would take much effort to respond that it's not applicable.

Q What about the provision in the proposed rule that says, "the effect of the seller's financing arrangements on the utility's system reliability?" Now, who do you mean by "seller"?

A That would be the nonutility generator.

Q And what do you mean by "seller's financing arrangements"?

A That's typically referred to, since a typical nonutility generator is heavily debt financed, does that have an impact on the reliability of that project and then onward to the utility's system?

Q What do you mean by "utility's system reliability"?

A Is that capacity going to be there?

Q What do you mean by the provision, "any competitive advantage" the financing arrangements may give the seller"?

A Mr. Bryant, this language is directly out of the 712 Act --

Q That's my point, sir. The reason it's exactly out of the 712 Act is because Congress realized and so stated that 712 is not applicable to municipal utilities, because municipal utilities simply don't fit within this guideline. And my quarrel with this, sir, is, if we don't fit and if there's some legitimate reasons for having this type of information presented to the Commission, then you need to design a rule so that it fits.

A Well, I can't speak to Congress's intent to leave municipalities out, as you state. It is my belief that as long as we have jurisdiction over the siting of power plants that this information should be

in there.

Q Yes, sir --

A If it's not applicable at that time, it's not applicable.

Q Don't get me wrong, I'm not quarreling with your interpretation of the Act or whether or not you believe the Act does or does not apply, because that's unfair. But what I do quarrel with is statements that say, "Well, if you're different, come in and demonstrate where you're different."

If we're different, then the rule should be different, so we don't have this same kind of argument. And I'm purposely making an argument so you can see at some point in time we might have this same type of argument, which I think is wasteful.

What do you mean by give the seller -- advantages of financing arrangements may give the seller and the fuel supply adequacy of the seller. Any competitive advantage of financing arrangements may give the seller and the fuel supply adequacy of the seller, how do you envision that applicable to municipal utilities?

A It's basically the financing arrangements of the NUG that they differ from the purchasing utility; and if so, do they give it a competitive advantage?

Q Competitive advantage over whom, sir?

A Over the utility.

Q Over which utility?

A The purchasing utility.

Q Would you explain to me how a NUG could have a competitive advantage over a municipal utility?

A I don't know. That's the whole problem, Mr. Bryant, is this area is tainted with several "what ifs" and rating agencies have said they can't pinpoint it. It's Staff's belief that we need to look at this on a case-by-case basis. There's certain circumstances that may change things one way or the other. We're just trying to keep this rule as open-ended as possible.

Q All right. (Pause) Well, let me move on, sir. I'm troubled by your lack of understanding of how this would apply to municipal utilities --

A Well, and the other -- let me clarify, too. The other portion is if we make a determination that municipalities are exempt because of their financing arrangements, that's, in my mind, almost making the decision that financing arrangements do have an impact. And Staff is not willing at this time to make that decision. That's the trouble I'm in is it's a very new and evolving era; and while you're points may be right, they are almost de facto making a decision that there

is an impact there.

Q And I would submit to you, Mr. Ballinger, that before Staff makes such a determination, they ought to understand first what the particular facts are that are applicable to the municipal utilities, so you can draft a rule that would be applicable.

MS. RULE: Chairman Deason, at this point, I would like to put an objection into the record. We're not here to attack Mr. Ballinger nor particularly to explore the depth of his particular understanding of any provision. What we're trying to do is gain a policy understanding of what is before the Commission at this time.

Mr. Ballinger may not be an expert of cost of capital. He may not be the one who drafted a particular provision. Mr. Bryant's trouble with his lack of understanding, I think, is out of line at this point. And I would ask that we direct questions to the witness that explore the policy implications of these rules.

Mr. Bryant has a fine point, that it may not be a wise policy decision to require municipal utilities to comply with some of these provisions. I believe he should make that point in another fashion.

CHAIRMAN DEASON: I think you've made a good

point. I think Mr. Bryant has already indicated that he's going on to a new area.

MR. BRYANT: Yes.

Q (By Mr. Bryant) My next question in this series, do you understand that municipal utilities have no, for lack of a better term, institutional need to build power plants or no profit motive or stockholder need to build power plants?

A I can generally agree with that.

Q And that our stockholders are our customers?

A Yes.

Q And that's why we don't pay dividends. And would you agree that we don't have rate base as such?

A Yes, you don't have stockholders and rate -- you don't have two separate forms.

Q Sure. So there are differences between the investor-owned utilities and the municipal utilities in those areas?

A That's probably the reason we don't set your rates.

Q Either that, or you don't want to have to put up with people like me.

Let me ask you, then, would you agree that the bidding process and the need for bidding might be driven in part because of the perceived -- and I want

to underscore "perceived" -- bias of an investor-owned utility to build its own power plants?

And I'm not criticizing investor-owned utilities, that's the reason I used "perceived."

A No, I don't think so. I think the requirement for bidding in the industry as a whole is changing. There's more providers of capacity. Technology has changed. Congress has realized that created a whole other type of generator, an EWG. I think bidding is required and that is why Staff's proposal is more of a means to see what's out there; to beat the bushes, not to get into the details of scoring and who should be best; still leaving that to the utility but just making sure that the utility is doing its job to get the best project for its ratepayers.

Q But certainly you would agree that there are financial incentives for an investor and utility to increase its rate base by building a power plant?

A Yes.

Q And you would agree that municipal utilities do not have those financial incentives?

A I don't know. It's a hard thing to say. I guess since you're saying is that all they have is ratepayers, they don't have stockholders, they have some sort of a natural incentive to keep their rates

low.

Q Have you ever appeared before a city commission trying to sell to a city commission the proposal of building a power plant?

A No. I don't think that would be a very fun job.

Q Would you accept my statement, sir, that I have that, and it's not a very pleasant job?

COMMISSIONER CLARK: Mr. Bryant, can't we get this directly from you rather than asking it through Mr. Ballinger? I'm sure you filed comments in here and we can get it that way.

MR. BRYANT: I think it's important, Commissioner, that we have --

COMMISSIONER CLARK: I do, too, but I don't see this as reason for going through Mr. Ballinger to make a point. You can make the point directly. This is just a rulemaking hearing.

MR. BRYANT: I understand, Commissioner. I'm going to move on, but I think the point is to make sure that the Staff, who is proposing the rule, is clear in their understanding of the differences between the investor utilities and municipals and cooperatives, because there are portions of the rule that we have suggested that need to be corrected.

COMMISSIONER CLARK: Well, I think that needs to be made clear to the Commission.

MR. BRYANT: And we will and have filed comments on that, Commissioner. But, remember, his opening statement was that the rule as written should apply to the municipals and cooperatives.

COMMISSIONER CLARK: And this is your opportunity to tell us why it should be.

MR. BRYANT: Yes, ma'am.

COMMISSIONER LAUREDO: If I may, can I ask you a question?

MR. BRYANT: Yes, sir.

COMMISSIONER LAUREDO: The same questions you asked the witnesses, there are circumstances where municipalities by generating and expanding their revenues from electricity, can subsidize tax, the tax base of the community. Would that be an incentive, as you were trying to question him, to build more plant, produce more energy?

MR. BRYANT: No, sir. The incentive is not to build more power plants. The incentive is to sell more electricity.

COMMISSIONER LAUREDO: And, of course, if there was a necessity to build more plants to produce -- to sell more electricity, that logic would be that

that would be an incentive if there was a benefit. That is not the same as it would be the benefit to the stockholder, but it would be a political benefit to, in essence, subsidize the legitimate cost of government.

MR. BRYANT: Certainly the incentive is not building the plant, it's to sell the electricity, Commissioner. And, quite frankly, I think the incentive would be finding the cheapest way of selling the more electricity. If it cost us twice as much to sell that electricity by building our own power plant than buying from someone else, we have the risk of having twice the amount or less profits. The cheaper we can sell -- our motive is on the selling side because that is where we get our profits, not on the building side.

Q (By Mr. Bryant) Sir, in several portions of your rule we have submitted comments that suggest changes if the RFP process is to be applicable to the municipal utilities. For example, you have criteria for the consideration of AFUDC, which I understand would be allowance for funds used during construction, and several other provisions that appear to be directly applicable only to the investor utilities. Have you reviewed our comments on what I've called the "technical changes"?

A Yes.

Q And do you have any quarrel with the technical changes to make sure that the rule where it's applicable to municipal utilities does not have provisions applicable such as AFUDC?

A It's possible and I don't know which would be more efficient to try to write into the rule, all these except A, B, C and this; or you all just ask for a waiver of these certain provisions before you do it, which should be a simple notation.

I mean, they may or may not have merit. I haven't made that decision yet, but I have considered them. Some of them do seem to be reasonable. I just don't know the best way to go about doing it; whether to modify the rule or to do it through a waiver provision.

Q Sure. Would you quarrel with a provision in the rule that requires municipals to go through an RFP process and maybe with some very basic generic requirements, and then at the need proceeding the municipal utility would have to demonstrate and justify that RFP process?

A That's possible. That's one possible solution.

Q For example, I suppose that an RFP process

could be very different when you're looking at building a combined cycle unit that would be 76 megawatts or 80 megawatts, I guess, of steam as opposed to a 400- or 500-megawatt power plant?

A They may or may not be. I mean, I can't tell. I guess I really don't understand your question. Are you saying just because of the size of one, one may be more detailed than another?

Q Yes, sir. Intuitively one might presume that.

A I don't think so. I think the only thing in size would be the investment by the nonutility generator whether he wants to bid or not. Because, obviously, a larger plant has got more dollars tied up into it. A smaller one, he may not think it's worth his while to go through a bidding process. But as far as the detail of what should be in the RFP, I can't think of anything that would discern the two.

Q What about a situation where, in your proposed rule, you have given preference to solid waste burners? What if you had a community that by city commission vote said that they did not want to have any power supply coming from a solid waste producing facility?

A That is a waiver provision.

Q So you would envision that a petitioning utility could say, "The city council on such and such a date voted not to participate in solid waste burning facilities"?

A I think that's one way to handle it, yes. The rule, basically, leaves the utility in control or at least managing its resources.

Q So you would allow outs for actions such that the city council has taken such action?

A I can't say whether that action itself would constitute a waiver. I think it's a reason to ask for a waiver and what the Commission's decided -- I can't tell you whether I think that's valid or not at this point.

Q Sure. That's a fair statement.

Do you see any difference in the RFP process in the criteria in the scoring based upon size alone, for example? I suppose that an RFP for 500 megawatts would be much more reasonable to screen responses of thousands of megawatts than it would be an RFP proposal for 100 megawatts.

A I guess I'm not sure I follow your question.

Q Well, I'm troubled a little bit by the process. And I didn't suggest a fix in our comments, and I don't think I have a fix -- the criteria that's

proposed for evaluation may be more onerous on the smaller plant than it is on the larger plant. And I'm just asking if you all have thought about that. I don't know -- I don't have any solutions.

A Are you going through the cost and preparing the RFP?

Q Yes, sir. The whole technical details.

A Well, that's why we're trying to make it only if the plant is going to come under the Power Plant Site Act, which is 75 megawatts or greater. That's a good size facility. I don't really have a good feel for what percentage of the facility cost is tied up in an RFP. I mean, I don't know if the facility costs a million dollars; if the RFP is going to cost 100,000.

It's my intuition that a plant of that size. It has to go through the Power Plant Site Act already with all that permitting and expenses in there. I don't believe that the development of an RFP would be that much of an incremental cost. I haven't seen any numbers to dissuade me otherwise. And that's the threshold. That's why we're not requiring an RFP for every capacity addition out there.

Q Would you envision the ability if those difficulties did present themselves with those burdensome costs that some type of waiver provision

also be applicable in that situation?

A You can ask for it. I can't tell you whether it would be or not.

Q Sure, I understand.

A Sure.

MR. BRYANT: No further questions.

CROSS EXAMINATION

BY MR. WILLIS:

Q Mr. Ballinger, I'm Lee Willis representing Tampa Electric Company.

Mr. Ballinger, if an applicant wishes to build a power plant, an electric utility wishes to build a power plant of over 75 megawatts, it has to come to this Commission for a determination of need; isn't that right?

A Yes.

Q And in the context of such a proceeding the issues that the Commission considers is system reliability and integrity and whether or not the proposed plant is the most cost-effective alternative; isn't that right?

A Yes.

Q And so that's what the purpose of this rule is in trying to put it in the context of why we're here is to determine a method by which the Commission could

determine what is the most cost-effective alternative?

A I think the whole purpose of having any kind of a formalized selection process is to avoid surprises at the end of the need determination proceeding that you don't have someone come in at the eleventh hour with a better proposal. It may be valid or not. We're trying to add order to this process. There's a lot of participants out there now. We're trying to accommodate both sides; but, yes, that is the intent of any formalization of this process is to try to answer as much questions up front as we can.

Q And that process is the same for all electric utilities including investor-owned utilities, REAs, municipalities; isn't that right?

A As far as the Power Plant Site Act?

Q Yes.

A Yes, it does not discriminate between utilities.

Q You state in your comments that what you're proposing is, basically, the same process which has been successfully used several times; isn't that right?

A Yes.

Q And one of those times, and I believe the first time, was the Seminole proceeding that resulted in the Hardee power station; isn't that right?

A Yes.

Q Now, that particular proceeding, which you view as successful, involved a procedure where a short list was determined with subsequent regulations; isn't that right?

A Yes.

Q Okay. And I believe that you have stated that the RFP process with subsequent negotiations has worked and will continue to work in the future; isn't that right?

A That's my belief. And it seems to have some support of both utility and nonutility generators. Its seems like a happy middle ground, but I believe it will work.

Q There have been several procedures which have used bidding and have resulted in what you believe to be a fair selection process; isn't that right?

A Yes. I think on Page 7, I go through some of the bidding procedures that have gone on in Florida; the Seminole bid, the FPL bid that resulted in Scherer. Seminole has recently gone through another bid. They will be coming in for a need determination. The Orlando Utilities Commission, these types of thing.

Q The point is that each one of those procedures weren't exactly the same, were they?

A No, they were developed by the utility. The bid process was developed by the utility, it was scored by the utility and then the ultimate winner was brought before the Commission in a need determination proceeding. And I must say that most of those, if not all of them, the need determination proceeding was fairly straightforward. I don't want to say noncontroversial, but it was fairly clear and orderly.

Q Well, you would agree with me that while it's important for the Commission to move forward with a definite measured step that it is important to retain some elements of flexibility so that this process can evolve; isn't that right?

A I don't know about the process evolving. I think the Commission has a good feel for where the industry has progressed. I think, also, we are, with this alternative language, recognizing that the utility still has the obligation to serve and, as such, should maintain some flexibility.

However, on the other hand, we have a large number of nonutility generators out there. Competition is coming in the generation market. It's here. We are trying to put some order to it. So from an administrative agency, we can deal with it. So I don't know that it's going to evolve further until we have

total deregulation of the generation market.

Q Well, what I meant by that is that it's important for you not to have such rigid procedures that one company would be forced to follow a specific cookbook procedure which, if it's not followed to the exact letter, it gives rights to other persons that participated in it and endless litigation over these details?

A I agree. I don't think you can draft a rule that would have every "i" dotted and "t" crossed that would contemplate every example. I think from the ratepayer's perspective, it is best to have negotiation to fine-tune a project to specific needs, changing circumstances. You have changes in the environmental regulations going on, in the economic regulations going on. You having siting concerns, transmission restraints. To try for the Commission, at this juncture to develop a rule that would be specific and concrete, it would be obsolete the day it was printed, in my opinion. I think it's unwise of the Commission to get into that role, also, of managing the utility, of telling them now what to do in the future.

Q Now, on the 712 standards I believe you said that you felt it would be appropriate to consider those on a case-by-case basis; is that right?

A Yes.

Q And isn't one of reasons for that is that this Commission can consider specific evidence based on the particular facts and circumstances of a utility in a 120.57 hearing where there is much more discussion of that and where facts are found?

A Yes.

Q Okay. I want to ask you a question on your draft, and it's probably a pretty minor point. But on your requirement to provide timely notification, one of the things that concerned me about the way -- your language is requiring publication of a notice in major newspapers, periodicals and trade publications and knowing that we're going to probably litigate every letter and word of this rule at some point, wouldn't it be better to make a more specific requirement in there that it would be required in the Florida Administrative Weekly, for example, so that we wouldn't have the uncertainty of where this notice would be published?

A We argued about this, too. It's possible to make it say, "Publish an ad in the Wall Street Journal," let's say or something of that nature. At the time this was drafted we went round and round on this, and we decided this was good enough to get the idea out there, that we're looking for statewide and

national circulation, so you cover a broad area. If that can be done with better wordsmithing, you know, we're open to that.

Q That's something that you're going to consider?

A Yes, I think the goal is to -- I guess to be keyed in on the words "ensure statewide and national circulation." If someone can come up with the specific language that accomplishes that goal, I think Staff is acceptable to that. That was our primary concern is that we -- that the notice covers a wide spectrum.

MR. WILLIS: Thank you very much.

CROSS EXAMINATION

BY MR. NEISER:

Q Mr. Ballinger, I'm Dick Neiser with Florida Power.

As we have laid your alternate rule side by side to the Commission's proposed rule, I think what we see is a major distinction; is that in the Commission's proposed rule there is no requirement of the utility to disclose its cost or avoided cost information in advance of the bidding. But in your rule there would be.

So my question really is if you see that as a major distinction and if your objective is to look for

the best deal for the ratepayers in this bidding process, why do you really see your method as producing the lowest possible cost for the ratepayer rather than for the truly confidential bidding approach that the utility does not disclose its data.

A Okay. Again for my reasons, if you go to a truly confidential bid procedure where the utility's price is not disclosed, then that raises the issue of who is going to evaluate those bids?

We've had proposals from TECO that they want to do that but they'd be the evaluator of the bids. We have had other proposals that if we do a sealed bid a third party or the Commission does the evaluation.

Staff believes it would be unwise to do that for those two reasons. One, to have the utility evaluate the bids shifts the playing field in my mind. Why should they submit a sealed bid and then be the ultimate judge? That seems to run contradictory there. To have the Commission or a third-party evaluator places one, the Commission, in management's shoes, selecting them. Two, how do you handle a third party; who hires them and who have they represented in the past? You're going to get into squabbles about that every time: which consulting firm, who they worked for last, those types of thing?

The third thing is, in my mind, the most important is to do a process like that, while it sounds good and it sounds competitive and everybody is on an even field, the administrative nightmares of coming up with a scoring procedure to make it clear who the winner would be is incredible.

I think Staff is thinking that and allowing, in lieu of the utility having to submit a sealed bid, giving them the flexibility to negotiate with people and ultimately reject all bids if they feel their project is the best project for the ratepayers. And they have the burden to come in justify to the Commission that their project is the best.

I think if we go the other route, those other requirements are going to be insurmountable.

COMMISSIONER CLARK: Let me ask a question about that, because it seems to me your focusing on a concern that somebody who is submitting a bid is likewise going to be able to evaluate it? I mean that's your concern?

MR. BALLINGER: That's one. There's been a couple of proposals of how to handle a sealed bid approach where the utility and nonutility generator's price are unknown to all others. One is have a utility evaluate them after they are collected. Another is to

have the Commission or a third party, independent party, evaluate them.

I don't agree with the utility evaluating them.

COMMISSIONER CLARK: Why?

MR. BALLINGER: Intuitively it sounds contradictory. Why should a utility, one, they seal a bid, but two, then they evaluate everybody. And also, with that, I have not seen utilities saying, "We are also willing to live with that bid price forever and forever," and that is another key factor that has not been mentioned.

COMMISSIONER CLARK: What bid price, their bid price?

MR. BALLINGER: What they submitted. If they are willing to put it in, are they going to live with that forever?

COMMISSIONER CLARK: Well, presumably, they would have to live with their prices they are going to have to disclose also.

MR. BALLINGER: Not necessarily. Think of it now. If a utility typically builds a plant. Let's say we had no nonutility generators and a utility came in here for a need determination, showed you its plant and a proposed price and we blessed it and it went on its

way and got built. It comes time to put it in rate base and they have had cost overruns. All right. Now, they may get those put in or they may be subject to disallowances. It is a risk. They do have an opportunity to allow those costs in.

In addition to that as time goes on, they make capital additions to plants, which increase the rate base. And they come under Commission review and all but they have that opportunity to do that. We've looked, as part of the EIS, requested information about the current plant balances as opposed to when they first went in service. And I'd venture to say 99% of the plants are worth at least the same, if not more, than they were when they originally went in service.

COMMISSIONER CLARK: I think what you're describing is connected to having the utility buy it and its ability to come in and get cost recovery for everything they do. Whereas, if they do a contract, it's only the contract price that we'll be looking at.

See I'm not -- I guess what I'm not understanding is you're saying that that's connected with having the utility -- you can cure that by having the utility disclose the price ahead of time. I don't see how those two are connected.

MR. BALLINGER: I'm not sure I understand the

question entirely.

I'm not carrying the utility evaluating sealed bids by having them disclose their price.

COMMISSIONER CLARK: No. Now, what you're saying, if I understood you correctly, is you feel that they should disclose their bid ahead of time. And one of the reasons that needs to be done is because if they are the ones who build the plant, they have the ability to, in effect, increase that price to get it coming to us directly for recovery where you don't have that with respect to power you've contracted for.

MR. BALLINGER: Now, I think I understand the question. That's not the reason I would disclose their price because they have that opportunity.

I'm saying that I would prefer a system where a utility has the flexibility to negotiate with people; it may ultimately result in them still building it, not only from the fact of they have the opportunity and maybe the obligation to add capital to a plant to keep it going, but also if we go the other route with a sealed bid and hold them to their price, the administration of that is a nightmare. I don't think we will get anywhere doing that.

There's been -- one, I don't know that the utilities are willing to live with that bid forever.

COMMISSIONER CLARK: Their bid.

MR. BALLINGER: Their bid.

COMMISSIONER CLARK: But they would be willing to make people who they contracted for the power to live with their bid?

MR. BALLINGER: Well, my belief is I think that still remains to be seen.

I know nonutility generators have said, "We've signed a 30-year contract, we're bound by it." You know, somehow I don't think that's going to happen, that that contract will remain the way it is for 30 years. I think at some point there may be renegotiations of that contract. It's a fact of life. We have the same thing with long-term coal contracts. You find out they're not cost effective, the utility goes in and tries to reopen them or renegotiate. Things change.

COMMISSIONER CLARK: The utility would still have the burden of when they determine that perhaps the existing contract is no longer in the best interest of the ratepayer, to request a renegotiation. And if they don't renegotiate, suggest to the Commission that they be allowed to breach their contract or something in order to get a lower price.

MR. BALLINGER: Oh, yeah. That goes under

the general obligation to serve and to manage their resources.

COMMISSIONER CLARK: How about the person who submitted the bid, and by submitting the bid and signing the contract they agreed to deliver power at a certain price. What ability do they have to come in and, in effect, increase that price?

MR. BALLINGER: They can try, and it hinges on the obligation to serve.

I know people have argued that they have a contractual commitment. There's a lot of money tied up. They take it very seriously. But in my mind it is just that, a financial investment. In any financial investment there has to be a point in time where you reach a threshold and you cut your loses and you may walk away if you're losing too much money, or someone else will come in.

I agree, that it is taken very seriously. I just find it hard to accept the fact that the contract will remain 30 years unchanged. It may happen. We haven't had that long of an experience. I think the longest nonutility contract has been in existence since, you know, maybe 10, 15 years at most.

COMMISSIONER CLARK: Are you suggesting that nonutility generators have the same ability later on to

come to the utility, through the utility to the Commission, and request, in effect, an increase in the contract price because they've had to do something to their generating unit, and it ought to be passed on in much the same way the utilities might do it now when they add something to their plant and they get recovery?

MR. BALLINGER: I think they can try to negotiate with the utility on that, yes. And the utility's responsibility to its ratepayers, if they felt it was inappropriate, they would take that into consideration in the negotiations and perhaps offer to buy out the unit. It's a --

COMMISSIONER CLARK: All right. Now, tie that all back for me into the bidding process and why that translates into the utilities should have to put their bid out first, or we should use a third party or the Commission if we're going to allow them all to submit their bids, sealed bid arrangement.

MR. BALLINGER: Okay. I don't --

COMMISSIONER CLARK: You don't think they are connected?

MR. BALLINGER: I don't think so. I think --

COMMISSIONER CLARK: Neither do I. I thought you were trying to make that argument that it is.

MR. BALLINGER: We selected one alternative in lieu of another, you know. Remember, Staff's proposal is we're using bidding as a general term but it's really to screen out people from a viability standpoint, and then negotiate with three, four, five, whatever, to get a good price, work on the price deal and other fine tuning things, this and that.

It's basically a mechanism that mimics what the utility should be doing already, out there beating the bushes to see what other alternatives are out there and negotiating. It tries to put some structure to that with some time lines and notification so that we have an orderly process from an administrative standpoint.

COMMISSIONER CLARK: Is it your view that the utility should not be able to submit a sealed bid along with everybody else and then evaluate it because they will have an advantage to being the evaluator?

MR. BALLINGER: I think that's something that will be argued every time. If there is any subjectivity at all in the evaluation, why should someone who also submitted the bid be the evaluator? That's --

COMMISSIONER CLARK: Well, what you're saying is there may be a wrong for which there needs to be a

remedy. They may not be fair in their evaluation of all the projects, and they may be partial to their own.

Isn't the remedy then, when they evaluate all of the bids including theirs and they say, "You know, we're the best one for this," they still have to come to us and say, "They are the best ones." And they are going to have to prove to us their evaluation was fair.

MR. BALLINGER: Well, why, then, do they have to go through the sealed bid if they're going to do that? And under our proposal they have that same opportunity to reject all other bidders and say, "Our product is the best," and prove it to us.

COMMISSIONER CLARK: What I'm trying to deal with is the notion that they sort of have to put their bid on the table and the advantage other parties have to saying, "I know all I have to do is just beat that price."

MR. BALLINGER: That's not the intent. I know that's been put out that if the utility discloses its price, everybody is going to kind of congregate around that price. That may be all well and true but the intent of the screening is to screen viability in real projects, and if they are close to that price, fine. That makes the utility also sharpen its pencil for disclosing its price, not only for generation but

as I said earlier for conservation. That we don't want an off-the-cuff avoided cost for conservation and then let's sharpen our pencils when we go to actually build it.

I think the Commission wants to have both of those numbers relatively the same. And I don't know how we can do generation and capacity selection in secret and still evaluate conservation when we need that price in the open.

COMMISSIONER CLARK: Well, okay. I see your point about conservation, but I don't necessarily see the point that we have to -- even given that they've set it out, it's not really going to be the true avoided price if, in fact, they select somebody else that is less. I mean, it's never really going to be -- I think as Mr. Childs says it really is just a proxy.

MR. BALLINGER: It may or may not be. It may be the actual price, but I think to say that what we do for conservation is something, and then if we're going to submit a secret bid, we're really going to fine-tune it.

COMMISSIONER CLARK: There's danger in doing that, too.

MR. BALLINGER: I think that's a disservice.

COMMISSIONER CLARK: I mean, on the one hand

suggesting that this is a good price for conservation and lo and behold they come in with a very much better price, then you begin to question the validity and the integrity behind the first one.

MR. BALLINGER: All else being equal, if the utility puts out its best price and is open to everybody, and people can beat it, then the utility should be buying from those other people. I mean, there's -- and I think they also owe it to the ratepayers as far as conservation goes to have that price as sharp as they can. However, by putting it on the table and disclosing it to others, they are retaining the flexibility of controlling and selecting that. It may not -- from a strictly dollar standpoint it may be a little higher than another project, but there may be other factors to consider which make it the best project for the ratepayers. And that's the flexibility I think Staff wants to maintain with the utility.

COMMISSIONER LAUREDO: Mr. Chairman, I just wonder, in light of the problem Commissioner Clark had, whether we can take a five-minute break to check the bugs in our microphones.

COMMISSIONER CLARK: I have to say the thought occurred to me that that's what it was.

CHAIRMAN DEASON: Mr. Neiser, Commissioner Clark has used all your time. I'm sorry. (Laughter)

MR. NEISER: I've enjoyed it; it's been fun.

CHAIRMAN DEASON: We are going to take a ten-minute break at this time. When we come back, you can resume your questioning.

MR. NEISER: Thank you.

(Brief recess.)

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CHAIRMAN DEASON: If we could all take our places, please, we'll try to begin. (Pause)

Mr. Neiser, I believe you were inquiring.

MR. NEISER: Thank you, Mr. Chairman.

Q (By Mr. Neiser) Mr. Ballinger, going back to my first question, which was basically, "Do you believe that the method that you have proposed in your rule will produce the lowest cost estimate for a new power plant rather than the method proposed by the formal method of the Commission?" And I think what I heard you answer was that it is because of the administrative nightmare that would result by doing it through competitive biddings totally, in the blind, that you had reservations about doing it that way, rather than being assured that that would produce the lowest price.

And I didn't say that very well, but do you

understand --

A I think that's one reason I want to maintain the flexibility with the utility, rather than have a sealed bid scored totally and you go through and count up the numbers and that's the winner. That's one reason for the proposal as it is.

Q Would you be satisfied with the Commission's primary rule if that administrative nightmare could be solved, such as possibly by the employment of an independent consultant to look over the shoulder of the utility's evaluation before it comes to the open forum for proof? Much like an independent auditor would look at the financial accounts of a company to certify, "Yep, this is what they've done for a year."

A Are you saying that the original proposal, which didn't specify a process or a sealed bid process, but if the utility chose to do a sealed bid process that it would also have a third party evaluator along for the ride, basically?

Q I'm saying if that is a possibility of how to solve the bid evaluation concern that you have.

I think what I keep hearing you say is you are very much concerned about the utility evaluating the bids if it is a bidder. And if that could be solved, would you think that the best price could be

obtained through confidential bidding rather than the utility showing its hand in advance of the bidding procedure?

A I don't know. Because twofold: one, if you did that and you had an independent consultant, I think you're going to have squabbles over who that consultant should be and how truly independent are they? I think that's a given.

The other is, how do you get a scoring procedure so precise that there's no controversy? That's the problems I think -- I don't know how they can be surmounted.

Q Okay. But, Mr. Ballinger, what I'm trying to see what is in your mind is whether it is the administrative concerns as to why you are recommending your procedure and your rule or is it your belief that your rule will produce the lowest priced generation?

A I think it's both. I think not only administrative, but I think price-wise, I think it's best to leave the decision, the ultimate decision, in the hands of the people who have the obligation to serve, the utility, that will result in the best project for the ratepayers.

I'm a firm believer that any time you try to tie too many hands with administration, you're not

going to get the best price. It's going to be obsolete.

So it is for both reasons. It's administrative difficulty and I don't believe it will yield the best price because are you not going to be able to pinpoint every circumstance to put a scoring on. I think individual negotiations work out the best project not only for ratepayers but for the utility and nonutility generator as well.

Q But you admit there are a lot of unknowns as this moment as to how that would all work out in terms of the evaluation of bids and so on?

A Yes.

Q Are you familiar with any other type of competitive bidding arrangement where one of the parties who is interested in doing the business shows its position in advance of others being asked to submit confidential bids? And has it worked? Have you ever seen it actually happen?

A I guess you've got to understand, too, this is a little different in that we're not holding the utility to that price if it shows its hand. Okay? And that may be a distinction. I agree with you if you're competitive --

(Simultaneous conversation)

Q I'm hearing that but I did not know that.

A Okay. I thought that was clear, that the utility still has the option to reject all bids. It also has the ability, if you will, to come back before the Commission when the plant actually goes in service, if there were cost overruns, and justify those costs and what costs goes into rate base. It also has the ability to add capital to that plant through time, if necessary.

Q But you're not aware of anywhere where this experiment has taken place and actually watched it work? You're saying there's something different here, But are you aware of any situation where one party to a competitive bid arrangement shows its hand?

A Well, you know, in the Seminole bid that went through, that was a bifurcated proceeding that came to the Commission. And they filed for their need determination and the Commission had all the information on the Seminole build option, okay? They were in the middle of the RFP; they were in the middle of negotiations on what wasn't completed. But the Commission made the evaluation based with Seminole's price known, and that process still went forward and they got a better price. So I guess that's one instance where it's known.

But I think if everything else is equal, if we are requiring somebody to be held by their price, I don't think it would be fair for them to disclose their price.

Q Let's talk about what the price would be that the utility would disclose.

As I hear your proposal, it would be if the utility were to be the successful bidder, it would be business as usual for the utility in that the generation would be rate-based and the future would be taken care of in terms of demonstrated need to the Commission, so that the price perhaps submitted by the utility would be that which is a known need for today without taking into account what may take place for the next 30 years.

A Yes.

Q Is that correct?

A Yes.

Q Then how would that square with what those who would bid against that, who perhaps would have to take care of the 30 years of the contract without knowing what the future may hold --

A Well, I think --

Q -- how would they bid against that number?

A They bid against it, and I think your own

witnesses realize that maybe in contract terms there need to be reopeners or other clauses like that to take care of these concerns, to put them on an equal footing with the utility who can make additions or changes; and realize that the dynamics of a power plant, that we can't predict the future for 30 years.

Q So you're suggesting then that the other bids would not necessarily be bids that would take care of the needs of that generating plant for 30 years?

A Let me see if I understand. That they'd be bound and forever, ever more the same terms and conditions for 30 years? Or are they strictly tied --

Q That is my understanding of how some of these things work, is that NUG makes a bid and says, "Here's what I'll run this power plant for 30 years, and this is what you can expect to have to pay me for that."

A Right.

Q Okay. And so their price would obviously have to be a big enough sum of money to do that, to take care of some contingencies for the future.

A Sure.

Q But if the utility discloses a number in advance that does not have to do that because it's business as usual, why wouldn't the utility's number always be the less?

A I don't know. That's an interesting question. But I think people realize that it may not be a 30-year contract with contingencies built in, let's say there may be room for reopeners. There is also different financing arrangements that may improve their benefit.

In my mind it comes down to a nonutility generator is making a financial investment, period. A utility is making an investment that is also an obligation, a "required to serve," and must maintain it and respond to changes. A financial investment, it gets to a point you're going to have a threshold where they may walk away; the utility may have to assume that contract.

However, if you have a big project, say a 300-megawatt nonutility generator out there selling power, if he comes to the utility and says, you know, "I need more money, things have changed, I got to do this," he's got a good bit of leverage. Because if he goes off the system, the utility is losing 300 megawatts of capacity that it relied on to keep the lights on.

So, I think we'll see this evolve through time. I don't think we can look at it clear black and white that it is what it is today.

MR. NEISER: That's all the questions I have, Mr. Chairman.

CHAIRMAN DEASON: Let me make an announcement as far as lunch plans are concerned. We are going to take a lunch break today, it's going to be approximately from 12:30 to 1:30, just for your own planning purposes.

Ms. Swim?

CROSS EXAMINATION

BY MS. SWIM:

Q Mr. Ballinger, I'm Debra Swim with the Legal Environmental Assistance Foundation. I just have a few questions to try and understand where you're coming from.

In the rule, the alternative rule proposal, there is a statement that there will be a preference, there has to be a showing by the utility that they've given a preference to renewables and to garbage incinerators. Can you explain how, you know, how to tell whether or not there's been a preference? Are we talking about, you know, how would you tell whether there has been a preference?

A There's also a third entity in there of high efficiency cogenerators.

Q That's right.

A Our intent of this, it has been misconstrued by some that we want a preference in the form of price. That is not our intent. We don't think they should be paid above avoided cost, they should be able to negotiate with everyone else.

The preference should be just in getting them to the bidding table or making their responses less burdensome, some fashion to get them to the negotiating table maybe ahead of someone else or a little easier than someone else. (Pause) It could be through a scoring; you know, if their screening criterias are strict, you have to meet a minimum score; they may give a renewable an additional ten points or something of that nature. It's just to screen them to the finalists from which to negotiate.

Q But the ultimate competition would still be in terms of price?

A Yes.

Q All right. And moving on to another topic: I assume that you agree that the need for energy services can be met either through generation of power or increasing efficiency of end use of electricity, such as, you know, installing highly efficient lighting or insulation in homes or increasing the efficiency of heating ventilation and air-conditioning services. Is

that accurate?

A They're both a resource, they serve different purposes. Some are similar, some are different.

Q But both of them can meet the need for energy services?

A Yes and no. You can't add enough insulation, maybe, let's say to avoid 400 megawatts of power plant. There's a --

Q I'm not talking numbers here, I'm just asking, do you agree that both of these are ways to meet a need?

A Yes.

Q I'm not stating specifically how much.

A Yes, yes. They both can be used and they need to be used together.

Q In the rule that, the alternative rule that you're proposing, it specifically says that the utility, when they are making their selection, that they have to select a provider of generating capacity. Can you explain what your thinking is in not allowing the utility to also select a provider of efficiency capacity?

A Sure. Currently, the way the planning process is done now, is the effects of conservation, I'll use DSM as a catchall, both load management and

high-efficiency insulation and these type of things; I'll just use that as a catchall phrase. The impacts of DSM are included in the load and energy forecast.

Q Of utility-financed DSMs?

A Yes. And those are programs that are determined to be cost-effective for the utility. To then require additional bidding with DSM, you run into two problems: One is, if they haven't passed the cost-effectiveness to begin with in the first place, that's a problem. And the second is timing; that once you have already included conservation and you show a need for power, it is very difficult for insulation to pick up 400 megawatts of need. It's just a saturation thing. You're doing it in small increments as opposed to one big power plant that can be added in a chunk.

Q So the timing of when a utility's investments and efficiencies are evaluated is important in that regard?

A Yes. And I think the current planning process gives a preference to conservation in that it's included up front in the demand and energy forecast. Now, we can argue all day about which is cost-effective: does it pass RIM or does it pass TRC? The bottom line is, as long as it's included in the demand and energy forecast, it's getting a preference

over generation.

Q Well, I think, you know -- I'll try and put this in the form of a question.

It does make a difference, as you've said, whether or not a utility's investment in efficiency is measured by the RIM test or the TRC test of cost-effectiveness. It will make a difference, you know, how much of a utility investment in efficiency there is. Is that right?

A Uh-huh.

Q And the test that you put in this rule of the selection of a generating alternative is to select the least cost way to provide the service that, the megawatts, or we might call them "negawatts," that are said to be necessary.

Now, if there's a decision by the Commission to not require utilities to invest in demand-side measures that cost less than the avoided unit because of a concern about rate impacts, then there will be a remaining pool of efficiency measures that under the total resource cost costs -- total resource cost test costs less than the avoided unit?

A But I think the Commission, by doing that, has made that policy statement that they want to look at rates. It's out front. And yes, they are screening

them out, I agree. If you say that you're going to use RIM as a screening for cost-effectiveness, then, yes, there will be a pool of measures out there that may cost less on a revenue requirement basis but their impact on rates and the subsidization of nonparticipants is too great.

Q So, then, the selection of the generating capacity alternatives is based on a least-cost basis but -- under those circumstances if the RIM test is used, but then the demand-side selection would not be a least-cost basis?

A I think it is, and you're able to do it from a policy standpoint of how you're going to evaluate DSM. And, like I said before, it's given a preference in that it's included in the load and energy forecast. So it's taken into account before you even consider generation.

MS. SWIM: Right. Okay, thank you.

MS. BROWNLESS: Hey, Mr. Ballinger.

MR. BALLINGER: Good morning.

MS. BROWNLESS: I just have a few questions so that I can be sure --

CHAIRMAN DEASON: Ms. Brownless, would you identify yourself?

MS. BROWNLESS: Yes, sir. This is Suzanne

Brownless, and I'm here on behalf of CEPA and Air Products and Chemicals and Destec Energy.

CROSS EXAMINATION

BY MS. BROWNLESS:

Q I just have a few questions that go to the mechanism of your rules so I make sure I understand the steps that would be involved.

As I understand the process that you proposed in the alternate rule, what you would do is have the utility prepare and issue an RFP, evaluate that RFP, use the RFP as a screening process to develop a short list of bidders, negotiate with those bidders and either select one or not as they deemed appropriate. Is that right?

A Yes, that's a good summary of it.

Q Okay. In this scenario, is the utility really the default builder? In other words, the utility goes through the whole process and if he doesn't believe a bid is responsive enough or low cost enough, then he, in fact, is the builder of last resort?

A Yes.

Q Okay. And when --

A They have -- I'm sorry.

Q Sure.

A But that, along with that obligation to serve and the monopolistic right, has to come before the Commission and justify that decision.

Q Okay, that's my next question, I guess, is a timing question.

When does the utility let folks know that he intends to build this capacity himself? (Pause) Is the opportunity -- is that knowledge only made known when he comes in for the need determination on his plant he wishes to construct?

A I would presume that they would let all the finalists know that they couldn't reach agreement and they were going to build it themselves before actually filing. But I guess it's possible they could be negotiating along while preparing a filing on the side and file it. I don't know how well that would go over, but, I mean, I can't give you an exact time frame of when they would notify them and then they would file their need determination.

Q But presumably they could be negotiating at the same time as preparing their own need determination filings. I mean, that would be an option under your rule.

I guess what I'm trying to get at here is there is no clear procedure in your rule to let not

only the short list of folks but people who may have participated in the process that didn't make the short list know that the utility intends to construct prior to the date that they come in for their need certification hearing.

A Oh, I agree. And again, we go back to the purpose of this is keeping those types of decisions, timing decisions and coordination with the ones responsible for maintaining the grid, the utility. And if they get stuck behind the eight ball, they're going to be the ones that have to bear the burden.

So I think, to tie in, it goes back again to the more you identify and make it bureaucratized, you're in the planning mode, you're in the negotiating mode. Things are changing, different things are happening, and they need to be able to respond. The more we put into a rule that ties people's hands either with time lines or preapproval things, we're doing a disservice to the ratepayers and we're also placing the Commission into a decision-making mode as opposed to the utility.

Q So the process as you've proposed is one in which the Commission's role is a totally after-the-fact review role, very similar to what they do now in need determination cases.

A Yes, it's regulation.

Q Well, it's that type of regulation, right? You've indicated in responses to some questions from Commissioner Clark that you believed if a sealed bid procedure was used, it would be unfair to have the utility submit a sealed bid and then evaluate those bids; is that correct?

A Not only unfair, I think it would be litigated every time.

Q Well, aside from the litigation, your statement is that you believed it would be unfair?

A Personally, I wouldn't think it would be fair. If I was a bidder, I would litigate it.

Q I guess I'm having trouble seeing why it is unfair for the utilities to submit a sealed bid and then evaluate those bids. But fair for the utility to write the RFPs, issue them, evaluate them, select a sort list of bidders with no waiting criteria put out ahead of time and ultimately still reserve the ability to build -- to reject everybody. Why is that fair whereas if they submitted a sealed bid it wouldn't be fair for them to evaluate the bid?

A Because the premise under for a sealed bid to work, you need to have every weighting criteria decided up front where there is very little, if any,

subjectivity in the evaluation process. And that I don't think can be accomplished.

Q So your problem with the sealed bid is because you believe that the use of a sealed bid necessitates revelation of the scoring mechanism ahead of time? Do you believe that premise necessarily follows? I mean, couldn't you have a bidding process where the criteria were kept by the third-party evaluator, for example, and litigated on the back end in your need determination? Those don't go together, do they, necessarily?

A The purpose for doing a sealed bid is to hold everybody's price at bay. And then put everybody, quote unquote, "on a level playing field," and then you come to the evaluation. In order for that to work, the evaluation needs to be done away with up front. There can be very little subjectivity by anyone, by either a third party or the utility or the Commission. Otherwise, you might as well just disclose your price and leave the subjectivity. That is a tradeoff you're getting.

If you can come up with an evaluation criteria that covers everything, No. 1, I don't believe it would be useful after the day it was written because things would change. Let's say, for example, that

could be done, then maybe a sealed bid is the way to go to where all you have to do is open it up, score numbers on a sheet and you would have a winner. It would be pure and simple. I don't think you can do that.

Q I guess --

A So in lieu of that, I'm saying the utility does not need to because there are subjective reasons to pick a power plant. There needs to be subjectivity in deciding which plant to build and where and what time and these kind of things that need to work out between a utility and a nonutility generator.

To allow that flexibility, I don't think it would be right to have a sealed bid and hold somebody to it. I think they need to put out their bid as a first cut. Say, "Here's what we think we can build it for, what do you all think?" Now, sure, people are going to congregate around that price. It may be artificially high from what their true cost is. The bottom line, if the utility puts it out there, people are going to bid. They've got to justify to us why they can build it cheaper.

Q Let me tell you what my confusion is. My confusion is the premise that a sealed bid requires prior explication of the scoring criteria, which is not

to be confused with the fact -- I want to make it perfectly clear that CEPA believes that the scoring criteria should be revealed on the front end and that's a necessary requirement. But I don't guess I get the connection between having delineated criteria and allowing the utility to participate in the process by a sealed bid where they're held to that bid on the back end, but I want to leave that for a minute and ask this question: What about utility affiliate bidding? Your rule doesn't mention that at all. Would utility affiliates be able to compete with everybody else or would they be considered a default builder like the utility?

A No, I think they're in competition with everyone else.

Q How would you handle standard offer contracts?

A In my comments I mentioned we may need to look at our present QF rules, as I recall them; the standard offer contract rules, this kind of thing. I made some suggestions that if we go to a bidding procedure, we may want to limit standard offers to projects that are 100 kilowatts and less pursuant to PURPA. That's one way to handle them.

Q Under your definition, would all new capacity

additions be bid?

A I'm sorry?

Q Under your rule, would all new capacity additions be bid, is that the purpose?

A No, only the ones that would be required to go to the Power Plant Site Act. In other words, if a utility wanted to build a CT or needed a CT for its own unit, it would not have to bid that out.

Q How would repowerings be handled?

A Excuse me?

Q Repowerings?

A If it wouldn't require going through the Site Act, it would be the same thing. And that's not to say that on a repowering they wouldn't bid out to individual vendors for the project, which they may or may not do.

But our rules are tied to the need determination proceeding to where the Commission has to make a determination that, yes, this plant is needed and it looks like the least-cost alternative. That is the only reason we're requiring bidding only in those instances.

Q Would your rule allow the simultaneous negotiation of contracts with independents or other utilities for less than 75 megawatts of power --

negotiation of purchased power contracts?

A You get into that with the QF rules. There is a conflict with this that our QF rules require utilities to negotiate with QFs in good faith who are greater than 75 megawatts. And it says that less than 75 megawatts you can get a standard offer. Whether or not they could negotiate with people less than that, probably off the top of my head that probably would because that project, if it ever came to fruition, would not go through the Power Plant Site Act.

Although, I think that the nonutility generator needs to keep in the back of their mind that if they choose to go through the Power Plant Site Act, that their project would be as a result of a bidding, you would run into a conflict then.

Q So under what you've proposed here as your alternate rule, you would really have three schemes of purchasing power. One would be this 100 kilowatt standard offer contract, one would be negotiations for projects less than 75 megawatts and one would be a bidding type of procedure for projects over 75 megawatts? Those would all be coexisting?

A It's possible. I don't know what you would really find in the negotiated less-than-75-megawatt market. I don't know how much would be there, and it

may be that we maintain our standard offers for 75 megawatts and below for that reason. I'm not sure, so there may only be the two. There may only be a standard offer and there may be then the bidding.

Q Okay. But it either has to be one or either -- all three have to exist simultaneously or you have to keep the standard offer as it is now, and for everybody over 75 megawatts use some type of bidding procedure? That seems to be the two theoretical options that are out there?

A There may be more. I think you can also throw in that you just make standard offers embedded costs and go with that if it's less than 75 if that they don't have to go through the Site Act; that's another alternative. But I think you're going to have at a minimum two tracks.

We're required by PURPA, or utilities are required by PURPA, to offer standard offers to QFs at least 100 kilowatts and less. I mean, that's a minimum. There are not many out there under that range, but that's the bare bones minimum of the federal law. Where you go then above that, I don't know.

I think our intent is we've seen a move in the industry towards larger units. I think the history I gave in my comments shows that the Commission started

off with a statewide standard offer to kind of jump start the industry for these small people less than 75 megawatts. We saw some small ones, you know, 30, 40, 80 megawatts here and there and standard offers were way to offer a no-hassle and a fall back position, give them some leverage to the smaller people. We started to see more and more larger developers. 100, 200, 300, 400-megawatt projects, which is going along with the industry in the nation that there is more competition for power. I think the smaller niche market may have served its purpose, it may not be there.

So I think Staff's intent is to try to bid everything. Okay. But only if the utility's plant would have been coming in for a need determination. So I guess it's possible that just hypothetically a utility had a need and it went out for a bid and they got nothing but 74-megawatt projects to fill that need, several of them, and none of those would go through the Power Plant Site Act, but they found them through bidding.

Now, if they were trying to negotiate, they would still have to do a bidding procedure to prove up their own plant that was a 400-megawatt plant. So they're going to be conducting this thing. They may be doing it simultaneously, I'm not quite sure.

But I still think that Staff's intent is to get -- we've seen the evolution of the market, of the industry to larger units and more competition. I think bidding is going to capture the vast majority of projects out there.

Q Okay. But if you use standard offers, whether you limit them to 100 kV or whether you expand that to the existing 75 megawatts, you're going to have to have some type of set aside for that capacity, aren't you, in order to make it work in the overall scheme -- an overall planning scheme?

A Another way to treat it is if you made it 100 kilowatts, you may just make it embedded cost and that's it. You don't have to worry then about the interaction between the bid price and an administrative avoided cost.

Q I guess that is my next question. How do you intend to determine avoided cost under your alternate rule? Would it be the bid price?

A It could be if the rules, the QF rules, remained unchanged. It could be argued that that could be the bid price. I mean, that could be the avoided cost then is what the ultimate winning bid was.

Q And so then we would only have -- if we had avoided cost set by bid, then avoided cost would only

be set when the utility chose to come in for a need determination; is that right?

A Uh-huh. That's a problem. I think the intent of this is we need to recognize that there may be some additional changes to our QF rules, but those we can't decide until we decide what kind of a bidding mechanism we have. You can talk about them at the same time, but we needed to figure out what we're doing on bidding first and then take that over to how it would impact our QF rules and decide what to do with them.

Q Well, we're just trying to explore --

A And we didn't want to really muddy the waters with both of these rules at the same time.

Q Would the Public Service Commission have any role at all in the negotiations with folks on the short list, or would that be done solely by the utility at their discretion?

A As far as an arbitrator?

Q Participant.

A Participant? No, we would not.

Q To your knowledge has the Public Service Commission ever approved a cogeneration contract with reopeners; with reopener renegotiation provisions in there?

A I do know that we've approved contracts and

shortly thereafter we've modified them on the agreements of both. So that's really a reopener. I mean, it may not have a specific reopener but the parties got together and worked out language that was amenable to both and brought it before us.

Q But to your knowledge have you ever approved any contracts that had reopener language like you're suggesting may be appropriate in them?

A I can't say for sure. I don't believe so. I don't believe I've ever seen one that says, "If such and such happens, we may reopen it." You can say there is a form of reopener in the fact that there's under some of the force majeure clauses the cogenerator will do its best results and the utility will work with them to get it, so that's a form of reopener if there's a problem. So there's those kind of things, but it's never specifically said, "After ten years, we'll relook at this contract."

Q Or if X, Y, Z happens -- for example, environmental compliance costs or whatever, we will reopen this contract.

A No. The only reopener I have ever seen has been the reg out clause where utilities have put in if the Commission disallows costs, this contract is null and void.

Q Okay. Under your scheme when you got to the need determination hearing at the end, either on the winning bidder or on the utility's own project, would the criteria for the selection of the winning bidder be revealed at that time to all participants in the process, and not only to the Staff of the Public Service Commission, but to everybody?

A Yes. I think the utility has -- at that time they have the burden to, basically, walk the Commission through their process to show that they did timely notification, just like they do now under need of determination. That's one of the exhibits is the notification in the papers or whatever like that. They would have to provide that, they would have to provide the RFP -- the RFP package would be provided up front for Commission review before it is submitted to the parties, not for Commission approval. It has to be very clear. That is mainly for, if the Commission sees something that is way out of line, we can, on our own motion, bring a utility in and question them.

Q I'm going to come back to that.

A I'm sure you will.

At the need determination proceeding, the utility then would have to go through its evaluation criteria and how it's screen out based on probably the

subjective matters nonutility generator A, B, C, how it arrived at a short list. Okay. And if none were the ultimate winner, explain why.

Q Is that the process that you believe to be in place at this time?

A I think so, yes.

Q Are you familiar with the Cypress proceeding? Did you participate in that?

A I listened upstairs. I didn't come in the room.

Q Do you remember whether Florida Power and Light in that proceeding shared its scoring and weighting criteria with all the participants in the process?

A Well, in that one, my understanding is that wasn't a, quote unquote, "bid process." It was an extension of negotiations from a bid process, so there really wasn't any strict scoring criteria that I'm aware of that was applicable to all. There wasn't a pool of providers, is my understanding.

Q Well, the final criteria that Florida Power and Light used to select the Cypress Energy case from the short list of bidders that it developed from its RFP, was that criteria ever publically revealed to all the participants in that process?

A I don't know. I don't know.

Q Well, would you accept, subject to check, that was revealed to the Staff of the Public Service Commission but not to the other participants?

A Sure.

Q I want to go back to your point about filing the RFP for informational purposes. And I'm looking on Page 12 of your testimony, Lines 6 through 12.

I think you just told us that this RFP would be filed and that the Commission could question it if it wished to. You have also indicated here that any affected party could also file a petition to question this RFP; is that correct?

A Yes.

Q What is the difference between having the utility file an RFP, which the Commission and any affected party can question, and the process that CEPA has proposed that the RFP associated with the model contract be filed with the Commission and the subject of a hearing, if any affected party wishes to have one. What's the distinction here?

A There is a couple. One is it's not an administrative requirement every time for approval, okay, which I think CEPA has acknowledged that if nobody contests, the Commission can issue an order in

20 days approving the RFP. I don't think that will ever happen. That's my own personal opinion on that.

The other thing is by filing it and not requiring a Commission action on it, if somebody questions that RFP, it's a burden of proof issue. If they want to question the RFP, they need to come in with a prima facia case showing specific parts of that RFP that are unfair.

And I think that needs to be taken very strongly. That is their burden of proof. If they want to come in and request a hearing, it's much like a complaint against the utility. They have the burden of proof of showing that they are going to be harmed by this.

Q Let me ask you just a practical question here: Then I assume your rule would not give an affected party the right to question this hearing, or does it? Is this what you consider to be the clear point of entry for interested people to question the nature of this RFP, and the underlying need that supports it?

A Yes, they can question it. They may not be granted a hearing on it. They can raise it as an issue and then go ahead and participate through with basically an objection noted, if you will; that may be

one course.

Its main thing is to not tie up administrative, put the Commission in the decision mode up front. It is to give people, a party, as they can now at any time, to file a complaint with the Commission about actions by a utility. Just when we did not have bidding rules and utility submitted bids or solicited RFPs, a party could have complained to the Commission and said, "Wait a minute, this isn't fair. These guys are doing -- they all want nuclear plants," or something like this. Now that's crazy.

And that's all we're trying to say, is to keep that part of it status quo. We don't want to lock the Commission in via a rule in always approving a RFP. If there's a legitimate discrepancy or complaint, we want to hear it.

Q But if someone follows up on your example and says, "Hey, this is only for nuclear plants and we believe that to be inherently unfair," is it your testimony that that would, in fact, be a prima facie case to have a hearing on that RFP?

A Sure, or something. We only want plants that will be built on the moon. You know, something of that nature, yes, that would be a prima facie case. If it can be shown that this bidding thing is so lopsided,

one way or another, that may give a party reasons to have a hearing. And then, yes, we will deal with it.

Q But the bottom line here is that if the RFP is filed and parties are allowed to question it, the chances that it will be questioned are fairly great, are they not?

A They will be questioned, but I don't know that it will be that many valid reasons. You'll have people coming --

Q But you'll have to have some administrative process to determine that; will you not?

A Sure. It would be a motion and you would go through it.

I agree, there's no easy way around it. Any time you do this, which you can do at any time now even if we didn't have them file it. If we just had the utility issue a RFP, and we never saw it, of a need determination proceeding, a party could mail it to the Commission and say, "This is crazy. Look what they are doing." And we would have to act accordingly. All we're doing now is having it so the Commission is aware of what's going on. If we decide on our own motion to do something, the parties have their same exact rights. I don't think it's wise to tie the Commission's hands by requiring it every single time that they go through it.

Q Even though there would be no protest filed under -- if there is no protest filed under the CEPA's rule, it would administratively go on?

A But under CEPA's rule, you have put the Commission in the burden of approving that, and blessing it via an agency action, via an order, one only within 20 days, which I've never seen an order get out of here within 20 days of a filing. But you put the Commission on the burden of making that decision up front during a planning phase. The whole goal of this is to keep the utility in control ultimately because they're the ultimate ones responsible for it.

Q But you must admit that under what you've written on Page 12 of your testimony, practically speaking, the Commission may be in that posture anyway?

A Yes. If somebody has a valid complaint, we may be litigating the RFP package. I totally agree with you.

Q Okay. And if you were litigating the RFP package wouldn't you necessarily also be litigating the megawatt need associated with it?

A Possibly.

Q That would certainly be an issue that might come up as a corollary issue?

A I've got to point out it can be done now at

anytime.

Q Uh-huh. I'm --

A I think though what -- I want to make clear, I think if the Commission adopts a rule such as this, as this alternate, that they are sending the signal that they don't want to have gratuitous litigation, or it may be out there and asked all the time, but I think they are making that signal, "you better have a very good case before you come in."

Q Well, let me ask you this practical question: If the utility holds all the information on the RFP and issued the RFP and the only thing that's revealed is the RFP documents itself, an affected party comes in, wouldn't he have to do some discovery on that RFP in order to maintain his burden of proof unless his burden is satisfied by a prima facie showing on the documents themselves. I mean, isn't that the nuts and bolts of how litigation works?

A I think so. I don't think you'd have to do discovery, though.

Q So you would --

A I think what it has to do is a motion has to present some facts or allegations before the Commission that show that you would be harmed because of this.

Q But it has to be limited to what you have

before you, so you're suggesting that it would be limited only to the documents?

A Sure.

Q Okay.

A Sure.

Q And you wouldn't allow people to do discovery?

A If a utility said, "We want plants only built on the moon, that's our RFP. That's the only people who can apply." Well, obviously somebody would jump in and say that's crazy and all this and we would act accordingly. I think you would have to deal with it on a case-by-case basis.

Q Okay. I want to clear something up. If the utility publishes its avoided cost, as you've indicated they should in their rule, would they subsequently be bound by that avoided cost if they reject all bids?

A No. Well, they would to the extent they have to justify anything different than that.

Q But that justification is going to take place in some subsequent rate proceeding; is that correct?

A Yes.

Q Okay. I want to go back to some discussion about your conservation argument, because I had a different view of it than what Mr. Childs' had previously discussed with you.

Is this argument that -- can I summarize it by saying, "One aspect of your concern about conservation is that if avoided cost is developed using a bidding procedure, unless you are doing conservation program approval at the same time you're developing avoided cost, there's going to be a mismatch there, or use of one number to evaluate conservation programs and another number to evaluate bids?"

A I'm not sure. My main concern with conservation went to a bifurcation approach. That you wouldn't want to -- some people have talked about bifurcation as far as approving the megawatt need, okay, and my comments were more towards you can't do that without a price tag attached to it because what are you going to do about conservation, because they need both.

Q Okay. Let me stop there. And that's because the rate impact test, the total resource recovery test, and the other tests used to measure the cost effectiveness of conservation programs measure a value of deferral, and that's pegged to avoided cost; is that right?

A Yes.

Q Okay. So your concern then is that you would be using one set of information to evaluate conservation

programs which are modeled in the generation expansion plan, which produces megawatt need?

A Yes.

Q So it's a mismatch between figures used to develop the megawatt need and the ultimate avoided cost figure is produced by the bidding program.

A It could be. And it's an iterative process.

Q Okay. Well, how does that differ from what we have now? In other words, don't utilities use their most current evaluation of avoided cost now to evaluate conservation programs, which are then modeled in generation expansion plans which are then used to identify need?

A Yes. And the only thing I was saying is -- again, my comments went more to the bifurcation of only approving a megawatt need. You shouldn't do that because that would squelch conservation. You need to have -- if you're going to preapprove anything, which I don't agree with anyway, but if you're going to preapprove it you need not only the type, but the timing and the amount. You need the whole picture. Because it relates back to conservation.

And I think Mr. Childs' argument was what if the utility did its price for conservation, but then when it came to bidding it had to do a sealed bid, it

would really sharpen its pencil and get that price down to bare bones. Those two would may be different. I don't think that's right for the ratepayers of Florida. I think those two should be the same.

Q Well, let me ask you this question: If --

A And that's why I say you should publish it. You've got to publish it for conservation, you might as well publish it for bidding.

Q If the utility were subsequently to sharpen its pencil and come out with a lower bid, wouldn't that be the avoided cost for the next round of evaluating conservation programs? And don't you periodically evaluate conservation programs anyway? So wouldn't this be a self-correcting mechanism over time?

A It could be. But again, you're tying it only to price. The decision to pick a unit is not only price driven. There are several strategic concerns. So price-wise you're right, it may change. And it is an iterative process, I agree.

Q And that's exactly what's going on now, is it not, the utility reevaluates its avoided units and uses those to --

A Yes.

Q -- evaluate conservation programs. And those avoided units are changing and so the evaluation of

conservation programs is reiterative now?

A Yes. And it may not change. My only concern is where you do not approve just a megawatt need beforehand and then go on and find the generation. One, I don't think you can do that because you can't -- generation planning, you don't identify megawatts. Megawatts are tied with the unit based on LOLP calculations. A 500- megawatt coal plant may have the same impact on reliability as two 200-megawatt combined cycles. And so on and so forth. There's not a direct linkage between megawatt and LOLP, which is primarily the driving force in reliability.

Q Okay. But could your problem be solved by a bid that was specific as to plant-type, location, fuel?

A Yes. I think the utility should disclose it because they need to disclose that information for conservation, okay. If they're not going to disclose it, then we're unaware of how to evaluate conservation. If they disclose it in conservation but then allowed to do a sealed bid over here, which may be lower, one, you've biased against conservation, or maybe -- actually you bias for conservation.

Q You bias for conservation.

A You've got a higher price, but the information that you developed and disclosed over here

may give some competitive edge to somebody going to submit a bid over here. You know, I don't know. I think we need to maybe treat them both the same way.

CHAIRMAN DEASON: Excuse me for just a moment. Ms. Brownless, how much more do you have?

MS. BROWNLESS: Just one more.

Q (By Ms. Brownless) But that information is all public record right now, right?

A On the conservation side?

Q Yes.

A Yes.

Q So that's no change in the status quote?

CHAIRMAN DEASON: Ms. Brownless, that was your one question. You said one question. In all seriousness, I've given you a great deal of latitude with the amount of questions you've asked this witness because I hopefully am correct in assuming that you're representing an entire group of interested persons.

MS. BROWNLESS: That's correct.

CHAIRMAN DEASON: But, nevertheless, you have been questioning for some time now.

We are going to break for lunch. I would request that if you have any more questions, I'll give you an opportunity to wrap that up when we come back from lunch. But I expect that to be done in

approximately five minutes.

MS. BROWNLESS: I appreciate that. Thank you.

CHAIRMAN DEASON: We'll reconvene at 1:30.

(Thereupon, lunch recess was taken at 12:30 p.m.)

(Transcript continues in sequence in Volume II.)

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	
Proposed Amendment of Rule 25-22.081, F.A.C., Contents of Petition; and Proposed New Rule 25-22.082, F.A.C., Selection of Generating Capacity.	DOCKET NO. 921288-EU

FIRST DAY - AFTERNOON SESSION

VOLUME II

Pages 116 through 273

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN J. TERRY DEASON
COMMISSIONER SUSAN F. CLARK
COMMISSIONER LUIS J. LAUREDO
COMMISSIONER JULIA L. JOHNSON

DATE: Wednesday, September 29, 1993

TIME: Commenced at 9:30 a.m.

LOCATION: FPSC Hearing Room 106
Fletcher Building
101 East Gaines Street
Tallahassee, Florida 32301

REPORTED BY: JOY KELLY, CSR, RPR
Bureau Chief
SYDNEY C. SILVA, CSR, RPR
PAMELLA A. CANELL
Official Commission Reporters

APPEARANCES:

(As heretofore noted.)

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P R O C E E D I N G S

(Hearing reconvened at 1:40 p.m.)

(Transcript continues in sequence from Volu
I.)

CHAIRMAN DEASON: Call the hearing back to order. Ms. Brownless, I think you were inquiring.

MS. BROWNLESS: Thank you.

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THOMAS BALLINGER

resumed the stand as a witness and testified as follows:

CONTINUED CROSS EXAMINATION

BY MS. BROWNLESS:

Q I believe your testimony is that it is extremely difficult to predetermine the scoring criteria, or to determine the scoring criteria, to se the terms and conditions of an RFP, and then it is al difficult to actually score competing bids. Is that correct?

A When you say "set the criteria," do you mea set them so there is very little subjectivity?

Q Set whatever criteria you're going to use t evaluate competing bids.

A No, I think that can be done relatively eas The hard part is how do you take the subjectivity out

of the evaluation? Which is what seems to be certain people want, you want a strict scoring down to the letter where it's a very clear winner it's not subjective either to a third party or to the utility. That's the difficult part. But -- go ahead.

Q Would you agree with me that when a proposal comes back to the Commission at the need determination process, whether it's a bid proposal or a utility bill proposal, that the PSC will be put in the posture of evaluating the reasonableness of whatever scoring criteria was used, evaluating the fairness of how competing bids were scored, and evaluating the reasonableness of the RFP in terms of how it meets the needs of the utility?

A Yes.

Q Okay. Is it any more difficult to perform these reasonableness evaluations and these regulatory functions at the beginning of the process than it is after the fact?

A I don't know if it's any more difficult, but -- and my comments, again, where do you benefit from doing that? In my mind, all you've done is added additional risks to the ratepayers that you are making a decision on a plant before its time. You've added more time to the process and you've made the decision

of how you're going to weight certain things on the front end. That's added more time to the process, which equates to more risk to the ratepayers. In my mind, I don't see any additional benefit, and that's a big concern I have.

Also, it goes to the Commission, by making a decision on the front end, it puts them squarely in management's shoes as opposed at the back end in the regulatory shoes. That's a very fine distinction.

Q Even though they make exactly those same determinations and the difference is the point in time at which those determinations are made --

A Their findings that the utility responded reasonably and handled the RFP reasonably is different than approving the one up front.

Q You believe there to be no benefit at all to be gained from revealing this information on the front end, no benefit for the utility so that they would get some read from the Commission as to what the Commissio would determine to be a reasonable RFP or determine to be reasonable selection criteria? There's no benefit at all to that?

A Oh, no, I see benefits go to both the nonutility generator and the utilities. They get an assurance or a read from the Commission, if you will --

a decision from the Commission, not only a read -- of how to proceed. That removes risk from them, all it does is shift that risk to the ratepayers.

Q But that assurance or that review in your opinion has no concomitant benefit to the ratepayers by producing either a larger pool of bidders that participate because of the certainty or a process that is more conducive to a lower cost bid being produced?

A No. Well, let me take your question in parts there.

By doing this, do we gain a benefit by having a bigger pool of providers?

Q Right.

A Because it's certainty up front.

Q More people play.

A Well, I don't think so. Because let's say the Commission did that and they approved exactly what the utility submitted; that would be no different than if we didn't see it. The people would still respond the same, in other words.

If we're approving the weighting criteria, okay? And the utility submits its proposal what they want as a weighting criteria and they ask the Commission to approve it, and the Commission does approve it, it doesn't change a thing. What have you

gained there as opposed to if the utility just issued the RFP, you kept the same weighting criteria and didn't get the preapproval of the Commission? I don't think you're going to get more participation just because the Commission signed off on it. It's still the utility's proposed thing, it's the same thing one way or the other.

Q Wouldn't you get the certainty that those were the criteria that were going to be used and that those criteria would be maintained throughout the process?

A I think they have to be maintained. If the utility puts down they're going to weight price by 50% and our rule requires them to publish that, that's part of their RFP, they have to stick by it when they come in for the need determination.

Now, the question comes to if the utility has a lot of subjectivity in their evaluation, there's not much we can do about that. And that's the hard line I'm getting. If you're going to have a preapproval of weighting criteria or something, you need to be very specific and go down the line and cover and remove as much subjectivity as possible; otherwise, you're not doing anybody any good. And I don't think you can do that, in my opinion.

Q And your opinion is it would work for objective criteria and perhaps be a good thing but, in your opinion, it would limit the utility's ability in the subjective areas; is that correct?

A I don't necessarily think it's a good idea for objective either, just from the time line involved in it that we go through the administrative process of going through a hearing, to approve it, to issue an order. Even if there wasn't a hearing, I don't think it is necessary unless there is going to be substantial changes. And that would come about in our proposal if an affected party sees an objective criteria that's way out of whack, then that would be brought to our attention and we would deal with it at that time.

Q But an affected party would have no way of knowing what these subjective criteria were until the very end of the process, and neither would the Commission, right?

A Right. But the utility also has the burden to demonstrate why those are in the best interests of the ratepayers.

MS. BROWNLESS: I appreciate your time, thank you.

MR. BALLINGER: Thank you.

CHAIRMAN DEASON: Further questions for

Mr. Ballinger? I don't believe that there are any. Thank you, Mr. Ballinger.

MR. BALLINGER: Thank you.

(Mr. Ballinger excused.)

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MS. RULE: Chairman Deason, I would like to have Mr. Hewitt make a short presentation on the economic impact statement. Very few of the comments had anything to do with it, so I would like him just to keep it short and respond to any comments, if that's okay with you.

CHAIRMAN DEASON: That would be fine.

CRAIG HEWETT

appeared before the Commission and testified as follows:

MR. HEWITT: The Research Division of the Commission did prepare an economic impact statement. Let me point out that we made it on the original proposed rule; and although the alternative has some additional issues or ideas -- for instance, the submission of RFPs -- it is a very complex type of situation and probably the RFPs add some additional cost but we think that the net benefit to the ratepayers eventually through this whole process will be very substantial and overweigh that.

The Commission, of course, will have additional cost of receiving all these petitions and preparing analysis and so forth and there will be additional paperwork involved. These factors are not quantifiable beforehand, because it depends on the number of petitions, the number of participants, et cetera; so we couldn't exactly quantify a number, but the cost will be up and might need additional Staff time.

We point out in the EIS, economic impact statement, which is included in the Composite Exhibit 1, we discuss the different parties that would be affected; and there will be additional costs. There's a table in the back of the EIS delineating the costs of -- the companies identified from our data requests that we sent out to the companies. And there again, they're largely unquantifiable.

The maximum costs for, say, adhering to the original proposed rule was basically $300,000 was the top company cost and approximately 2,000 a year after that. So the costs are not substantial as far as the actual technical aspects of the rule.

I'll be glad to answer any questions.

CHAIRMAN DEASON: Questions for Mr. Hewitt? Mr. Cresse?

CROSS EXAMINATION

BY MR. CRESSE:

Q How much additional cost and time did you estimate for the Commission and Staff as a result of this rule?

A We didn't quantify it. Like I said, it really depends on how many petitions, all the variable that would be involved, so we didn't quantify that.

CHAIRMAN DEASON: Further questions? Thank you.

(Mr. Hewitt excused.)

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MS. RULE: That concludes Staff's presentation.

CHAIRMAN DEASON: Okay. According to the order of presentation, after Commission Staff, we would hear from members of the general public. Yes?

MS. RULE: The appearance list has only one person on it, and that's Mr. David Brown or Dr. Brown from the University of Florida. And as I discussed with you before, I would classify him as a member of the public. You may want to ask if there are any other members of the public who would like to discuss anything with the Commission.

CHAIRMAN DEASON: I'm a little confused. The

doctor from the University of Florida is appearing as a private citizen?

MS. RULE: To my knowledge, he's not appearing on behalf of any utility or utility group. His funding may be another issue. (Laughter)

CHAIRMAN DEASON: Could you identify yourself and tell us who you're representing here today?

DAVID T. BROWN

appeared before the Commission and testified as follows:

DR. BROWN: Yes, sir. My name is David Brown, I'm the Nations Bank professor of finance at the University of Florida. I'm appearing on behalf of the authors of the paper. If the arrangement seems peculiar to you, certain faculty members are funded by the Public Utility Research Center and are directed to do research on various issues; and my specialty being finance, myself and two other authors have looked at some of the 712 issues. And our directive is to do research and disseminate it in whatever forum would be appropriate, whether that be publications or appearing before this Commission.

So we are testifying on behalf of, I think it's fair to say, no one; and I think, simply put, opinions that I'll present today are the opinions of

the author, not of the Public Utility Research Center nor the University of Florida.

CHAIRMAN DEASON: Dr. Brown, let me tell you what my concern is. When I think of members of the general public, I think of people, just that, private citizens who are here at their own expense and to express interest before the Commission. That's why we usually put them at the top of the list.

We've had expressions from a number of parties here that there are a number of witnesses here who have scheduling problems. If you fit into that category, I'm certainly amenable to taking you now. But if you can be with us for a while, I would like to go ahead and take some of those individuals who do have scheduling or travelling conflicts that need to be heard today. So I'll just ask that question to you.

DR. BROWN: The answer is very simple, I have to teach in Gainesville tomorrow morning at 7:30 a.m.. Other than that, I have no conflict.

CHAIRMAN DEASON: Okay. let's go ahead and we'll hear from you.

Are there other members of the public, private citizens who are here at their own expense because they want to express to the Commission their concerns about selection of generating capacity in the

state of Florida? I don't think there are any others.

MS. RULE: Chairman Deason, I have a list that I'm sending up to you compiled from the appearance list, the participants on the list categorized according to the general order of appearance. If there's anybody not signed up on the list, they're not going to be here; and the order is only the order in which they signed up.

CHAIRMAN DEASON: Okay.

Dr. Brown, it may be best if you would come over to where Mr. Ballinger was sitting earlier. Or do you need this facility?

DR. BROWN: I would like to use the overhead. (Pause)

Is this working?

CHAIRMAN DEASON: Yes, it is working.

DR. BROWN: As I was just asked, my name is David Brown, I'm the Nations Bank professor of finance at the University of Florida. My comments today, as well as the paper submitted for this hearing, represent the opinions of the author and not the University of Florida nor the Public Utility Research Center.

My comments today simply summarize the document submitted; and I will give to the Commissioners right now my copies of the overheads, the

two overheads, that I'll use. People can pick up copies from me if they so choose.

The buy-versus-build choice impacts the financial condition of a utility as well as rates charged to consumers. We have evaluated (1) the impac of purchased power of public utility investors and (2) the advantages or disadvantages of competitive bidding for new capacity.

We conclude that the demand risk borne by a utility when it enters into a purchased power contract may increase a utility's cost of capital. Florida's current capacity cost recovery method goes a long way towards eliminating this demand risk. However, in the event of a shortfall in demand for power, maintenance of this capacity cost recovery clause requires allowin the utility to charge higher rates to its customers. Thus, while bond rating agencies recognize Florida's capacity adjustment clause reduces the utility's deman risk associated with purchased power, they do feel tha purchased power may expose utilities to demand risk in the long run.

We feel that competitive bidding refereed by an impartial outsider is important to ensure that the lowest costs and most reliable producer is chosen to provide generating capacity. The most difficult task

of the referee in this process is to evaluate the bids in light of the different risks faced by the utility and the IPP.

Even if the utility is fairly compensated for the risk it bears when it purchases power, the utility faces demand risks that the IPP does not when it builds its own capacity. This demand risk implies a higher cost of capital, which puts the utility at a disadvantage. The referee must consider the cost of capital differentials due to demand risks to compare the bids of a utility and an IPP.

Our analysis distinguishes between demand risk and construction or operating risk associated with building new capacity. Construction risk comes about because there is uncertainty about whether a new plant will be fully operational at all times in the future. If a plant, either built by an IPP or by a utility is not operational, then the party that built that plant bears the costs of any down time.

Thus, if a utility enters into a purchased power agreement, as opposed to building its own capacity, then the utility avoids construction risk which lowers its cost of capital. However, the IPP bears the construction risk which it factors into the negotiated price.

Consumers benefit when a utility purchases power if the IPP's plants are expected to run at a lower cost than the utility-built plant and lose if th IPP plants are less reliable. However, with competitive bidding, the party with the most reliable plant will be the winner of the competitive bidding.

Demand risks comes about because the future demand for electricity can vary over time. If a utility enters into a purchased power agreement, it ma bear the demand risk associated with the new plant. The amount of demand risk borne by the utility depends on how the utility is allowed to recover the IPP capacity cost.

Under Florida's capacity cost recovery clause, the utility's risk exposure is small so long a the commitment is iron clad. While the ratepayer ultimately bears a demand risk when a utility purchase power, the lack of demand risk gets factored into a lower or negotiated price for purchased power supply.

In summary, it is unlikely that a utility's risk will not increase when it purchases power. It must bear some demand risk unless the Commission can provide an iron clad agreement to allow the utility to recover its capacity payments through IPPs even if the purchased power capacity proves to be unneeded in the

future.

Thus, the Commission should consider allowing utilities a higher rate of return when they purchase power and should focus their attention on the demand risk formed by utilities when they purchase power.

Consumers are affected in two ways by the buy versus build choice. First, with regard to construction risks, rates are lower to the extent that competitive bidding for a new generation capacity is allowed. Competitive bidding favors the party with the most reliable technology. A party with a more reliable technology can make a lower bid to provide power.

Second, if power is purchased under a take-or-pay contract as opposed to being built by a utility, ratepayers bear demand risk. However, the IPP factors its capital cost savings from not bearing demand risk into a lower bid. By not bearing demand risk, the IPP should be able to systematically make bids to provide power at below the utility's avoided cost.

Now we turn to the issue of competitive bidding for new capacity. As just mentioned, the IPP does not bear demand risk under current rules and thus should be able to make a lower bid than a utility. Thus, in order to reap the benefits of competitive

bidding, an outside referee must evaluate the bids, recognizing that the utility and IPP do not face the same exposure to demand risk when they build new capacity. If utilities are allowed to bid for new capacity, perhaps to run regulated subsidiaries, then it would be simple to evaluate the bids from a utility against an IPP because the two face the same risks.

Thank you.

CHAIRMAN DEASON: Questions for Dr. Brown? Mr. Childs?

COMMISSIONER LAUREDO: May I ask him a questi

CHAIRMAN DEASON: Surely.

COMMISSIONER LAUREDO: Could you explain to me on Page 8, you just handed me the part about the demand risk, it's Item 2?

DR. BROWN: Before I sit down --

CHAIRMAN DEASON: You may be more comfortable for you to sit down since you're finished with your presentation. I would suggest that you sit where Mr. Ballinger was sitting earlier.

DR. BROWN: Your question refers to demand risk?

COMMISSIONER LAUREDO: On Page 8, your last page, entitled "Demand"?

DR. BROWN: What is demand risk?

COMMISSIONER LAUREDO: Item 2, the utility bears the demand risk when it purchases power and it has two subsections. Semantically, could you explain that? I don't follow it.

DR. BROWN: Yes, what happens is that --

COMMISSIONER LAUREDO: On the one hand you're saying the investors should be compensated for the risk and the next sentence, unless I'm reading it wrong, you're saying that the risk is not only small, but it's borne out by the consumers.

DR. BROWN: The idea is, and the confusion stems from really the genesis of the project. The project and the paper that's submitted to the Commission refer to risks associated with purchasing power generically based by a utility. And the idea is that a utility faces demand risk when it purchases power because it makes a fixed capacity payment to -- the utility makes a fixed capacity payment to the IPP and, as a result, all the fluctuations in demand affect the revenues and the revenues are more volatile divided by a smaller asset base, so the volatility or the risk that IPPs -- or excuse me, of a utility's return on assets is higher when it purchases power generically.

Now, the answer to how much risk the utility faces when it purchases power depends on how the

capacity costs are recovered. And that, I think is t source of the confusion.

Utilities bear demand risk when they purcha power; the amount of demand risk they bear can be ver large or very small depending on how capacity costs a recovered, and a particular -- under Florida's capaci recovery clause, the demand risk borne by a utility when it purchases power appear to be quite small.

COMMISSIONER LAUREDO: So why should you be compensated with a higher rate of return?

DR. BROWN: When a utility purchases power, then it bears no construction risks and bears some demand risk. The demand risk may be small and the amount of the demand risk is really what ought to be addressed in terms of whether or not the utility is allowed a higher rate of return. If the amount of demand risk it bears, which appears under Florida's capital of cost recovery clause, is small, then the higher allowed rate of return when it purchases power should also be small.

COMMISSIONER LAUREDO: Thank you.

CHAIRMAN DEASON: Are you making the assumption that the demand risk, no matter how small, is always larger than the avoided construction risk?

DR. BROWN: There really is a source of

confusion between two separate exercises. The first exercise is evaluating whether or not a utility faces more risk when it builds a plant versus purchases power.

When a utility builds a plant, it unambiguously faces more risk than had it purchased power, because the demand risk it faces, at worst, is the same under both scenarios and it avoids construction cost risk.

The comments I just made were imagining that the experiment was suppose the utility decided to purchase power, would the risk of the entity go up, and the answer is it appears to go up by a small amount due to the demand risk. That's not relative to its alternative, which would be to build the capacity itself and then your points are correct.

CHAIRMAN DEASON: Thank you. Mr. Childs.

CROSS EXAMINATION

BY MR. CHILDS:

Q I think you said that the IPP does not bear demand risk and can, therefore, translate that into a lower price?

A Yes.

Q Doesn't that mean then that the risk hasn't gone away, it's just been transferred to the customer?

A Exactly.

Q And isn't that relevant in evaluating a proposal? It's not what the price is but where the risk lies as well as what the price is?

A I'll answer in two parts: the first, obviously, yes. The second part is that when the risk gets shifted to the IPP or away from the -- I'm sorry, when the risk gets shifted away from the IPP in the demand risk scenario, then the risk that's shifted to the consumer that -- IPP pays that back to the consume in the form of a lower bid. But the risk adjustment should be considered.

Q Well, are you assuming that there is an equivalence there? In other words, that even though the risk is shifted to the customer that it's worth it because the bid -- the cost of the power plant is reduced?

A In fact, most people would suggest that if you could quantify the risk in terms of dollars saved that, in fact, the savings in terms of a lower bid would not fully compensate to you, the consumers, for the risk they bear simply because the consumers are unable to diversify that risk, whereas investors would be able to, although, I don't think the magnitude of that is particularly large. The answer is yes.

Q Now, if you gave, I think your term was, gav

the utility an iron clad guarantee if it had a purchased power contract that it would not bear demand risk, wouldn't you be in the same situation? That is, the customer would be the one that would be bearing the demand risk?

A Yes.

Q Okay. In your discussion of construction risk, as I've read the paper, I gather that it relates primarily to the possibility of there being cost overruns from the power plant. And I think you conclude that the risk is the same for the IPP or the utility; is that right?

A We conclude that the treatment of those risks are the same. We have no idea whether they are, in fact, the same.

Q And aren't you starting from the premise when you say that the treatment is the same, the premise being that cost overruns are disallowed?

A Yes.

Q Isn't it correct that a utility, when it's regulated as to the investment it can include in rate base, does not necessarily have a cost overrun disallowed?

A Yes.

Q And isn't it also true that even if there is

no cost overrun that the total cost of the plant was substantially below what anybody estimated that the utility could, nevertheless, have some investment disallowed?

A Yes, sir.

Q And isn't it correct that when the -- the utilities only recover actual fuel cost, don't they?

A Yes.

Q So when a utility estimates the total cost c the facility, that would include both the construction cost, the return on that cost including depreciation and the fuel cost. But if it did real well on its fue cost, the Commission, in regulating it, would not let it recover something extra for its investment, would it?

A That's correct.

Q But that might be exactly what happens for a IPP; isn't that right? In other words, they could hav a cost overrun on their construction of the power plant, do a good job on fuel and come out ahead?

A That would depend on the terms of the contract. And I think in many cases that would be the case, yes.

Q But I don't think that you've addressed that have you, in your analysis?

A The answer is we have not addressed that. While I will reconsider that issue, just sitting here, it's not completely clear to me how that changes the basic conclusions of our analysis, however.

Q One of the other things that I wanted to ask you about in your paper, or in the paper that you're talking about, there is discussion of the concern that a developer, an IPP, might simply walk away from the project. And I believe you've addressed that by saying that in all likelihood a financially troubled IPP will turn over control of the project to its lenders?

A In fact, that would be true of any business that would default on its credit obligations. Business would be turned over to its lenders.

Q So is your conclusion that since the lenders have control turned over to them, that the lenders will then attempt to continue to operate the project so as to preserve the investment that they've made in the form of debt?

A Yes. In fact, their obligation is, of course, by law a debt obligation, or in name a debt obligation; but, in fact, at that situation in reality, they are the equity investors and they would behave as any equity investors. They would preserve the value of the project, of the investment so long as it was

profitable to do so.

Q Well, in your discussion I thought you were postulating the circumstance where the equity investo decided it was no longer beneficial for them to continue the project and that, therefore, the lenders would step in order to preserve their investment?

A No, I think that what I have in mind as far as -- what we have in mind as far as the lenders' involvement is concerned is not at all unique to or specific to this scenario.

Generically, failure to meet payments to creditors or failure to meet any debt covenant would involve transfers of control rights to the lender. Ar our point was simply that the lender would be -- the lender would not liquidate the project under -- the lender would liquidate the project under the same conditions of that as the equity owners would. So there's really no difference.

Q Well, isn't it true, though, that if the lender took control of the project, because there was default under the debt instruments, that the lender would have absolutely no obligation to honor the contract with the utility?

A Yeah, it certainly has no obligation to, but it has an incentive to, I guess, which is probably mor

important.

Q Well, it may have the incentive but it could sell to anyone, couldn't it?

A I'm sorry?

Q The lenders, if they took control of the project, don't have to sell to the utilities that had the contract. Initially, they could sell to anyone, couldn't they? In fact, they might in order to maximize their return.

A I can't answer that question because I'm not aware of how a condition of default would affect a contract that the IPP had with the utility.

Q But do you think, though, that in terms of reaching a conclusion about whether the proportion of debt used to finance a project creates risk, that it's important to know whether the debtholders, if they take over control, have to honor the underlying contract with the utility?

A Yes, that's obviously important.

COMMISSIONER LAUREDO: Under that scenario that you're outlining to him, I assume that you're assuming the equity capital is wiped out at the time of transfer?

DR. BROWN: Yes. If the equity capital -- our analysis worked under the premise that the entity

-- and, of course, we're in a legal and financial -- had to be particular about the definitions. Our analysis assumed that the entity, the IPP, was still legally bound to the purchased power contract in the fact that the equity may be wiped out and lenders have control does not affect the standing of that contract between the IPP and the utility.

COMMISSIONER LAUREDO: No. But it affects the decision or, as you call it, the incentive of whether to operate it or not.

DR. BROWN: It does not affect the incentive

COMMISSIONER LAUREDO: It does not?

DR. BROWN: No, because essentially you have -- the IPP is project financed. It has one asset and that's this contract with the utility.

If the contract is worth continuing, in othe words, if the revenue streams from the contract exceed the costs, then an all-equity IPP, an all-debt IPP, an IPP with any capital structure mix will continue the business. If the business is no longer profitable, then a rational all-equity IPP, a rational all-debt IPP, and a rational IPP with any capital structure wil walk away from the project. With one source of revenues that generates the company -- the capital structure, as far as affecting the incentives to walk

away from the project, is really irrelevant.

COMMISSIONER LAUREDO: I was really talking about the lender incentive to either operate the facility --

DR. BROWN: That's what I mean. I'm talking about -- when I'm talking about the capital structure, I mean the capital structure of the IPP.

The lender's decision to either continue to honor the contract or walk away, their incentives, the lender of an all-debt IPP or owners of an all-equity IPP, or any mix in between, would all have the same incentives. (Pause) In other words, if the --

COMMISSIONER LAUREDO: If after wiping out -- after having wiped out equity I have a 20% loan to value on the asset, both in terms of the hard assets and the value of the contract, it would be -- it seems to me the incentive would be to turn around and sell it immediately at a considerable discount just to recover my loan, and it may very well in doing that make the project more economically feasible to a subsequent purchaser. So it depends on what the equity that is being wiped out, so the mix of the capital structure is important in your scenario.

DR. BROWN: I'm not sure I follow that. If the loan-to-value ratio is 20 to 1?

COMMISSIONER LAUREDO: 20%. Would it be an

incentive for the --

DR. BROWN: So now I own -- I'm a lender who has taken control of an IPP that is seriously under water. That's the scenario?

COMMISSIONER LAUREDO: Well, you're the owne of a million dollar project in which you have invested $200,000, and there may very well be an easy turnaroun to sell it to somebody for $200,000 replacement value.

DR. BROWN: I agree, but I think that if the company is worth more as an ongoing concern, then you would generally not walk away from that value.

Q (By Mr. Childs) I just want to ask -- I hop it's one more question on that point.

I think you said that it would not make any difference in terms of incentive as to whether it was an all-equity IPP or an all-debt IPP or anywhere in between.

Would you agree that the argument of suggesting that a debtholder would attempt to keep the project going after a default by the project developer that had an equity interest, that that incentive would in fact, be greater the lower the debt investment in the project because the potential return is greater if the proportion of debt is lower.

A Okay. I'll have to -- in financial economic

research there are common parlances, what's referred to as an over- and underinvestment problem, which are incentive effects that result from debt structures. And in your scenario the --

Q Let me try it again.

All I'm talking about is you have one project that's financed with 90% debt.

A Right.

Q Costs $100 million.

A Okay.

Q You have another project that's financed with 50% debt.

A Okay.

Q Costs $100 million.

A Right.

Q If there is a default on the project because the developer finds that his variable costs are sufficiently high, and the debtholder is incented to move in and attempt to take over the project, given a fixed revenue stream from the contract, wouldn't one expect that the debtholder would be more inclined to find that beneficial if the investment in the project were lower?

A Oh, yes.

Q Okay. And isn't that, in fact, an argument

for reduced leverage in the investment of an IPP?

A Actually, it is. But most people would not consider -- or I shouldn't say that. There's another consideration that many people posit as an effect of debt on the decisions that are made by a company.

If an IPP were highly leveraged, then, as soon as the company began to lose money, the entity began to lose money, creditors would take over control much earlier on and make any changes if those are necessary. So that's a common beneficial incentive effect of high leverage is to not allow management to have as long a leash when it's performing poorly. But those comments are not made in our paper.

Q Well, if you suggest that though, if that's a risk, and when a debtholder moves in, maybe even earlier in the project, the debtholder is concerned, nevertheless, about cash flow, aren't they? They are concerned about whether they can obtain sufficient money by continuing to operate the project to protect their investment. Right?

A Yes.

Q And yet given the same size project, they are in a better position if their debt investment is reduced, aren't they?

A The lenders are in a better position, yes.

Q And, in fact, if they move in early on in the project to take control because they are concerned about its profitability or concerned about how management is running it, then I take that to assume some default under the debt instruments. Doesn't that, in fact, invite the possibility for even greater potential for request to renegotiate a contract with an IPP in order to save the project?

A Renegotiate the debt contract with the IPP?

Q No. Renegotiate the payments. In other words, there's concern about the profitability. It's sort of "If you give us another $5 million a year, we can make a go of it."

A Right.

Q "But if you don't, we're going to go under."

A Right.

Q And then the utility is faced with the decision of whether they agree to pay $5 million more --

A Right.

Q -- or whether they go out and pursue some other alternative which may require them starting from scratch, right?

A Yes. In fact, I think that the easiest way to summarize this argument would be that if you have an IPP whose ongoing concern value is $1 million, and it's

somewhat less if you walk away, okay, in a situation where you have a highly levered IPP that has one lende or one consortium of lenders, an individual lender and an individual equityholder, it's very unlikely that those two parties would shoot themselves in the foot o spite each other in order to -- the lender might renegotiate the debt in order to save the project, and it's in their best interest to negotiate the debt in order to save the ongoing concern value. And if there's only two parties involved, in other words, one lender and one equityholder, getting the mutually beneficial outcome would be highly likely.

In corporate Chapter 11 settings where you have hundreds of lenders involved, it's a very different story, but with IPP financing with one lender, the best outcome or the avoiding the cost of the outcome is more likely.

Q But I'm not speaking of the potential of the renegotiation of the debt arrangement between the IPP developer and the lender. I'm talking about the potential for the leverage that an IPP may get by having the contract awarded to it and then coming in later and saying, "We need a little extra money to make a go of it, and if you don't pay us, then you have to start all over again." A brand-new project and a

brand-new investment

A Who is "you" in this example?

Q The utility and the customers.

A Oh. Right. And, again, the answer to that would be there's some potential for that.

I mean, the question is if I'm an IPP equityholder, can I walk up to the utility and say, "I need more money or this lender is going to pull out the rug from underneath me," and the lender really would not have a credible incentive to do that.

Q It might if there's a default on the agreement with the lender and the developer of the project.

A So the lender -- in other words, you're arguing that the lender would -- that the lender would say, "Let's default, let's walk away rather than the lender taking some equity or scaling down his payments"?

Q I'm not presuming any bad faith at all. I'm suggesting that the situation --

A I'm not --

Q -- that somebody made a mistaken and the equity investors said, "It's no longer profitable for us to stay in this business."

A Okay.

Q And they inform their lender. And they comply fully with the agreements and tell them in

advance, and the lender is then confronted with the situation that they've got $800 million potentially invested in a project.

A Right.

Q And they have to make a decision of how do they protect their investment. And they know that they are going to have to run it, and the only way potentially they can run it is to increase the payment received from the utility.

Wouldn't you think there's an incentive for them to do just that?

A Yes. And if it was an all-equity IPP, the all-equity IPP could say, "We're losing money. We're not going to run this company, we're going to walk away." I don't see the point about how the fact that you've borrowed money -- whether it's a debtholder or an equityholder, if it's not profitable, they can walk away from it. And they both have the same incentive to do so.

Q Well, I guess --

COMMISSIONER LAUREDO: May I ask a question, that question a little differently, because I want to get -- may I interrupt you a minute?

MR. CHILDS: Sure.

COMMISSIONER LAUREDO: If a highly leveraged

IPP actually received a demand letter from the bank.

DR. BROWN: Okay.

COMMISSIONER LAUREDO: Because of inability to meet the terms of the loan. He can turn around and go -- the question is, does he have some leverage vis-a-vis the utility, by walking into the utility office and saying, "I have a demand letter. Cash flow does not cover my debt service. You either increase the terms of my contract or I'm walking away."

DR. BROWN: The answer is --

COMMISSIONER LAUREDO: And then who gets stuck with the bad end of the deal at that stage?

DR. BROWN: The answer is that the IPP would have leverage over the utility in that situation if the utility believed that the lender would, in fact, take some action to stop a power plant and --

COMMISSIONER LAUREDO: That's why I used the example of a demand letter so I can bring some finite point to this question. Otherwise, you're going to keep getting away from the question.

DR. BROWN: I would love to.

And the finite answer is yes. And the simple quick finite addendum is, and the point of our paper is to argue that it would be unlikely that the bank would ever send such a letter, would not have the incentive

to do so, but if it did, the answer to your question i yes.

COMMISSIONER LAUREDO: And additional costs that may arise out of this very complex transaction eventually would be borne out by whom, the ratepayer, in the final analysis?

DR. BROWN: In the event of the cost being the default on the debt and shutting down the --

COMMISSIONER LAUREDO: Where is the eventual risk after we play out all of this scenario: i.e., the utility steps up and provides more payment under the contract; amends the contract to increase the payment.

DR. BROWN: Clearly, it would be the ratepayers in that situation.

COMMISSIONER LAUREDO: Thank you.

CHAIRMAN DEASON: Mr. Cresse.

CROSS EXAMINATION

BY MR. CRESSE:

Q Joe Cresse.

Should an electric utility still be held responsible for the Commission's quality of service standards if the failure to meet that quality is caused by a contracted electric supplier who fails to perform in accordance with their contract?

A Is that a question? I'm sorry.

Q I can shorten that a little bit if you'd like.

The Commission has quality of service standards and they are required under the law, the ratemaking law, to consider quality of service when they set rates for an electric utility.

A That's correct.

Q If their quality of service is poor, because of the failure of an electric supplier, an independent power producer, to perform its contract, should the utility be held responsible for that failure of quality of service?

A No, it shouldn't.

Q Who would be held responsible, then, under current Florida law?

A That I don't know. My understanding is that there are penalties in -- typically nonperformance penalties in the IPP utility contract, and, in fact, -- and so the IPP would bear the cost of nonperformance through sets of penalty.

Q That would be some dollars that they'd have to put in.

A Uh-huh

Q Should they not perform.

A Right.

Q Is that correct?

But you can still put the dollars in and still not have adequate quality of service; is that correct?

A Sure.

Q Let me ask you this question: In terms of a default after you've signed the contract, I understood your testimony to say that a lender would do everythin they could to, you know, preserve their investment; is that correct? If they had to take over from a borrower?

A "Their" investment and "the" investment are one and the same.

Q Right.

A They could preserve "their" investment and "the" investment.

COMMISSIONER LAUREDO: May I interrupt. I don't understand that.

You said a couple times irrespective of what the percentage of debt to equity is in the project? (Pause) If I have only 20% loaned to some value, we don't need to discuss how we arrive at value --

DR. BROWN: Right.

COMMISSIONER LAUREDO: -- in this IPP facility, you don't see any difference in how the bank

would behave in protecting that whether it's 20% or 90%, the level of leverage?

DR. BROWN: Oh, I see. Perhaps I missed the step in the argument that's leading to your confusion.

What we think would happen and what normally is thought of as happening in generic corporate environments of this case is, that where you have two parties involved, now equity -- two sets of claimants on the IPP, equity and debt, and there's a situation where an event of default could cause debtholders to take actions that are detrimental to the IPP but in its own best interest. That's what you're after, right?

So would the bank cease service to recoup its investment?

COMMISSIONER LAUREDO: I'm having trouble following you. I just -- common sense tells me that -- see if you can understand my -- the higher the equity in the project, the less likely the equityholder is willing to walk away from the project?

DR. BROWN: Right.

COMMISSIONER LAUREDO: And the reverse is also true.

DR. BROWN: Right.

COMMISSIONER LAUREDO: The lower the equity the easier it is for me to say, "Okay. I'm walking

out. And, lender, you take over."

DR. BROWN: And then when the value of the project falls below the face value of the debt obligation, I think what you're trying to say is that would the lender then just try and get everything they could out and walk away.

My answer is the lender is, in effect, the owner now when the firm is under water and the equity is out of the picture, and they wouldn't do anything t damage the company because they own it now. They are, in effect, the owners. And what would probably happer there would be some kind of restructuring where the lender took some equity or some position like that to avoid the situation.

There's an incentive conflict between the best interest of the entity as a whole and those of th debtholders and you only have two parties, equity and debt. The reasonable people will restructure the debt contract, give the lender some equity position or some way in order to get the incentives aligned in order to avoid just those problems.

COMMISSIONER LAUREDO: Let me go at it one more time and see if I can.

The lower the debt ratio --

DR. BROWN: Right.

COMMISSIONER LAUREDO: -- the more the incentive, that whenever that debt is endangered, vis-a-vis a set value, the quicker I move in to foreclose.

DR. BROWN: Right.

COMMISSIONER LAUREDO: Because I can turn around and sell the asset and get out of the business.

Understand what I'm saying? I'm trying to understand your testimony in the content of reliability of service.

DR. BROWN: We are, too. I think we're --

COMMISSIONER LAUREDO: So if I am the lender that only has 20% of a million-dollar project and it starts defaulting and I have 80% equity that I don't give a dam about because it's subordinated to my --

DR. BROWN: Right.

COMMISSIONER LAUREDO: -- debt, I am quicker to move in so that I can recuperate my 20% by selling the asset, which implies shutting down the plant. Because the first "rule of holes" is, when you're in a hole, stop digging. And operating a company in a deficit implies increasing your debt by making up the deficit in the operating expenses. So if I'm a banker and I have $200,000 in a million-dollar plant, I'll foreclose, get in and shut down the plant for either a

day, two hours, 45 days, depending on what the market will bear until I sell it. I would not be in the business at that level of 20%, just theoretically, of saying, "Let me fund this at $50,000 a month additionally just to keep it running."

DR. BROWN: Right.

COMMISSIONER LAUREDO: So there's a higher danger of interrupting the actual production of the service by the lowering of the debt ratio.

DR. BROWN: If there were multiple lenders where one lender had a small piece and said, "Okay, I'll stop interruptions in order to get the cash flow so I can make a profit and walk away at the expense o the other lenders," that's very likely. But if it's coalition of a single lender, why would the lender do something to damage the company if the --

COMMISSIONER LAUREDO: Let me try it one la time.

All I'm worried about is a time span that could very well be less than one day by which time, when I have a low debt ratio, I'll move into the project and I shut it down and I go to sell it. Now, obviously, at 20% of some value, it's supposed to be very attractive purchase price, both because of the fixed assets and whatever value the contract has. So

it is my incentive to say I'm ceasing operation and I'm going out into the world and trying to sell it.

DR. BROWN: Right.

COMMISSIONER LAUREDO: A $1 million asset, all I want is my $200,000 back because I am definitely in the business of IPP. There is no banker that would ever want to do anything other than get their money back.

So what worries me is what happens to the consumer if that production is part of an equation that is very tight about reliability of service. That's what I'm struggling with right here.

DR. BROWN: Right. And I think your last comment really hits the nail on the head. If the lender was in a situation where they said, "I would rather take $200,000 in cash, satisfy the obligation and go, rather than try and renegotiate, take an equity piece and get a much bigger claim," then the answer to your question is yes and it would --

COMMISSIONER LAUREDO: That's a function of how much exposure I have vis-a-vis the total value of the project. If I have 90% financing, I'm going to do what you suggested; if I had 20%, I'm getting out today.

DR. BROWN: I agree. I'm sorry that I didn't

do a better job of answering that quickly.

COMMISSIONER LAUREDO: Sorry for the interruption.

Q (By Mr. Cresse) If a lender is foreclosed a project, are they obligated to dispose of those assets for the most amount of money they can get?

A No.

Q Are they obligated then just to dispose of at a level that would recoup their investment? (Pause

A Yes.

Q Okay. when they foreclose, wouldn't they sell that at the highest price offered to them?

A Yes.

Q And that may not be the utility who had a contract for the output of that plant when it was completed; is that correct?

A Yes.

Q And, thus, if you had a tight situation on capacity, you would put the utility in a foreclosed project of bidding against a project they already had contract to get the capacity from; is that correct?

A Yes.

Q Given that set of circumstances, would it be appropriate in a utility contract with an independent power producer to have a security interest in the plan

of all interest in that plant in excess of the first mortgage debt --

A I'm sorry, what's the security interest again?

Q The security interest would be the right to take over the project --

A And who has it?

Q The utility, the contractor --

A Okay.

Q -- the right to take over the project by absorbing the first mortgage bonds in the event the contractor fails. Would that be an appropriate term to include in the contract?

A It could be.

MR. CRESSE: Thank you.

COMMISSIONER LAUREDO: May I ask, just if you have it off the top of your head. Is there a typical average of the leverage formula on the IPPs in the United States or Florida specifically --

DR. BROWN: I have never directly compilated those numbers; I have seen them published in a variety of sources that I have heard, 80% or 90%.

COMMISSIONER LAUREDO: Debt?

DR. BROWN: Yes.

COMMISSIONER LAUREDO: Is that debt coming

mostly, if you know off the top of your head, is that coming from traditional lenders or is it venture capital mostly funding that?

DR. BROWN: I have seen a few contracts and they're bank lenders and in working with a venture capitalist.

COMMISSIONER LAUREDO: Thank you.

Is there something, Staff, that we can get? Is there like an average leverage, more or less? He says 90%. Just subsequent to the hearing you can --

MR. McGLOTHLIN: Commissioner Lauredo, some of the witnesses for the Competitive Energy Producers Association can help you with that.

COMMISSIONER LAUREDO: Thank you.

CHAIRMAN DEASON: Mr. Neiser, you seem to always be right around break time. Before you get started this time, we're going to take a break for ten minutes.

MR. NEISER: Thank you.

(Brief recess.)

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CHAIRMAN DEASON: Before we go any further, let me ask kind of a procedural question. We have a number of witnesses who need to be heard today; and I guess my question at this point is how much more

questions are we going to have for Dr. Brown? Because if it's going to be quite a bit, it may need to be that we have to take some witnesses out of order to get them so that they can meet their travel plans.

So I guess my question at this point is, is there going to be extensive questions for Dr. Brown? Or are we close to wrapping up his presentation?

MR. NEISER: Not from me.

MR. McGLOTHLIN: I have about ten minutes, Mr. Chairman.

CHAIRMAN DEASON: Let's see if we can go ahead and wrap up the doctor. I know he has commitments, too. We have a number of people who have commitments, and that's the problem. It seems to me that we're going quite slow; and if we can keep that in mind and try to accommodate everyone and to the extent possible pick up the pace, it would certainly be appreciated.

Mr. Neiser?

MR. NEISER: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. NEISER:

Q Dr. Brown, I'm Dick Neiser with Florida Power.

There has been a lot of discussion already, and I'm sure there will be a lot more before this hearing is over, with regard to the proper recognitior and assignment of hidden costs relating to purchased power. Do I understand your paper to suggest that appropriate hidden costs should be recognized and assigned in the bidding process?

A Yes, that's correct. In particular, the ide is that you would have -- implicit in our analysis is that the bidding takes place on a price basis, the lowest bidder would win the right to produce the power And the lowest bid, the cost of the bid, will be reflected by simply the technology of the plant proposed as well as the cost of financing. And if the IPP has a cost advantage through not having to bear demand risks, then that cost advantage would give it a advantage in the bidding context.

Q Are you familiar with the methods employed b some of the rating agencies such as Standard & Poor's as they assign costs relating to financial risks?

A Yes, not entirely but I've seen them, yes.

Q Are you in general agreement with the methods that they use? And let's just be specific, Standard and Poor's?

A Actually, without being too tongue in cheek, I haven't bothered to worry too much about them. My colleagues at the University of Florida right now are in the process of proposing a study of our own to examine the effect of purchased power on a utility cost of capital. And that's what we're going to go by. I really have not formed a strong opinion about the way in which Moody's and Standard and Poor's -- first of all, that's only a measurement of the risk of the debt, not of the entire capital structure, which would be important for this question.

Q Have you had occasion to read Mr. Wieland's testimony in this proceeding that he filed?

A I got it yesterday and I've looked at it very carefully -- I looked at it very briefly. I've read previous testimony of his.

Q Do you have an opinion as to whether it is an appropriate method for assigning financial risk -- financial cost associated with the purchased power?

A The approach that I've seen him, in concept, is a very interesting and clever way and accurate way to approach the issue. In fact, what he does is he

argues that when a company purchases power, that it -- that that purchased power agreement is, in fact, debt. And then he says, "In order to examine the hidden cost of the purchased power, you have to take into consideration that the company must issue a certain amount of equity at a higher cost than the debt and to get the utility back to where it was."

For example, if it's $100 million outlay for the IPP, then it needs $50 million worth of new equity Whatever the additional cost of equity is over the cos of debt times $50 million is his estimate.

It's a clever way to go about it. My guess would be -- or I shouldn't say that. My opinion is that overstates the hidden cost for a couple of reasons. One is that it implicitly assumes that the entire IPP payment is debt.

Secondly, as is customary in a lot of his testimony that I have read, is that they assume that the new financing, in other words, the new equity that will be issued to finance this project is of the same risk of the company's original -- the utility's original debt. And the securities that would be issue to finance the IPP obligation would have a much lower risk because of the riskiness of this stream of payments to the IPP are much less risky than those of

the existing utility.

So the fundamental approach of Mr. Wieland is a right way to go about it. I think that some of the calculations he makes overstate the size of it. In fact, I think out paper details that.

Q Do you have any opinion as to how the Commission's primary rule that is being proposed dovetails with your paper? Do you have any concerns with the Commission's primary rule as it would dovetail with your paper and your presentation here?

A The bidding?

Q Uh-huh. Is it a good rule?

A That's different than dovetailing with the paper. I think that the, if nothing the discussion this morning was fairly detailed and it seemed to hit the nail on the head. I mean, if a utility is going to bid for purchased power, or, I mean, bid for new capacity, it is going to make a bid that it likes. And it would hope to win the -- it would not submit a bid that it would be disappointed with in losing. So there obviously is at least a potential incentive conflict for the utility to evaluate its own bid.

As far as the cost of having an outside party, that's the tradeoff. If you don't have the utility evaluate the bids and you avoid the incentive

conflicts of the utility picking its own bid, then you need to have an outside party evaluate the bids. And whether or not that would be extremely costly or not, have no way of knowing.

Q Dr. Brown, did you understand that the testimony this morning dealt primarily with the Staff' alternative rule as opposed to the Commission's official proposed rule?

A I was speaking to the Staff's alternative. I'm sorry, I misspoke.

Q My question is: What do you think of the Commission's primary officially proposed rule as an appropriate rule for bidding as you have analyzed it and expressed your opinions? Have you had occasion to read the Commission's --

A I've read it a long time ago and I haven't - I would rather not comment on it at this time. I'm more familiar with the alternative.

MR. NEISER: I have no other questions.

CHAIRMAN DEASON: Questions, Mr. McGlothlin?

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Professor Brown, my name is Joe McGlothlin and I represent Falcon Seaboard Power Corporation. Falcon Seaboard is a developer of cogeneration projects and independent projects, and is participating as a member of the Competitive Energy Producers Association in this case.

I want to first distinguish between the two different questions that I believe that you have posed on answered in your comments and in your responses to other questions. On the one hand there is the question when a utility purchases power from an independent provider, does that arrangement result in the utility bearing either construction or demand risk that the IPP does not; is that correct?

A Right.

Q And --

CHAIRMAN DEASON: Was that a yes?

DR. BROWN: Yes.

Q (By Mr. McGlothlin) And would you agree that that is the subject of your paper and of your submitted comments that you are sponsoring today?

A Yes.

Q And then there is a different question, which,

is a comparison of the overall risk that a utility would incur when it purchases power from an independent, on one hand, compared to the overall risk which the utility would bear if it instead constructed its own capacity?

A That's correct.

Q All right. Now, I want to put the first of those subjects, which is the subject of your paper to one side for a moment and pursue the second one.

With respect to comparison of the total risk of the two alternatives, you said it's your view that the utility would incur greater risk if it constructed its own capacity as opposed to purchasing from an independent; is that correct?

A Yes.

Q Would you agree that an increase in risk translates into an increase in cost of capital?

A An increase in -- generically, yes.

Q All right. The greater the risk, the greater the cost of capital?

A Yes.

Q Doesn't it follow then, from your belief, that the utility bears greater risk when it constructs than when it purchases that purchasing power from an independent would not increase the utility's cost of

capital compared to what it would bear as cost of capital if it constructed its own capacity?

A Yes.

Q And, in fact, because the purchase alternative involves less risk, a purchase would have the effect of decreasing the cost of capital compared to what the utility would incur if it built its own capacity, do you agree with that?

A Yes.

Q All right. Would you agree that in terms of evaluating the two options, purchase versus constructing, the Commission -- the utility and also the Commission should view that from the perspective of what is best for the ratepayers?

A Yes.

Q Would you agree that in making that comparison then it is pertinent to consider not only what risk the utility incurs if it purchases, but also the other side of the coin, which is what is the comparativethe corresponding risk that it would carry if it constructed its own capacity?

A That's correct. In fact, the main thrust of our paper is that the difference between a purchased power agreement and a decision by a utility to build its own capacity is not really what the risks are, but,,

in fact, who bears them, and in some sense, that's eve -- it's not a matter of who bears the risk so much, it's because -- excuse me, it's not a matter of who bears the risk so much because those parties that bear the risk will, in fact, price those out in terms of their required rates of return, in which will be recovered in their bids.

Q All right. In response to a question from Mr. Childs, you said that in a purchasing scenario the independent developer does not bear demand risk. And he asked you to agree then that demand risk was being shifted to customers; is that right? Do you recall that statement, that exchange?

A Yes. And when I answered that question, I meant under a situation like the capital -- like the capacity cost recovery clause we have in Florida, yes.

Q All right. Let me give you a scenario for purposes of the following question. Assume that a utility, based upon the best information available, plans and constructs a new unit. Assume in the following years the projected demand upon which that decision was based does not materialize and it has mor capacity than it needs. Assume that the Commission determines that that decision was made on the best information, it was prudent at the time, and allows the

utility to recover its cost. Would you agree with me that in that scenario, the customer bear the demand risk and not the utility?

A Largely, yes. The question would be there are certainly some present value issues, I mean, if the costs were recovered at the time that they were incurred, yes.

Q Basically, you agree with that proposition?

A Yes.

Q All right. Would you then agree that if the customers bear the demand risk in any event, it is impossible to shift to customers what the customers are already bearing?

A Yes.

Q You were asked some questions that had as their premise a developer that was described as highly leveraged.

A Right.

Q Dr. Roach, and I believe others, have provided comments in which they describe the typical financing arrangements of an independent developer as consisting of 80% to 90% debt over a term of 12 to 15 years; and compare that to the more typical corporate financing, which maintains 50/50, or thereabouts, overtime. For purposes of the question, would you

agree that those are representative?

A Yes.

Q All right. Would you agree that a project that consists of 80% to 90% debt in Year 1 and is financed over a period of 12 to 15 years consists of 100% equity at the end of the loan term, after that loan has been paid off?

A Yes.

Q So in terms of whether a project is highly leveraged relative to the alternative corporate financing, would it be pertinent to know in what year you're looking at?

A Yes.

Q Would you agree that both lenders and the rating agencies take into account not Year 1 but the entire package?

A The lenders certainly would, yes.

Q Well, do you think the credit agencies would as well in appraising the overall risk of utilities that purchase power?

A They should, yes.

COMMISSIONER LAUREDO: Would you run that by me again, counselor? Did you say that the amortization of the 80% to 90% debt would go typically over 12 years?

Q (By Mr. McGlothlin) I'm going to turn now the other subject that you've addressed today, which the subject of your paper and your shortened comments

And that is whether in a purchase situation considered in isolation of the alternative constructi scenario, in a purchase situation, does the utility bear either construction risk or demand risk that the IPP does not? And you say that the utility bears no construction risk, but it does bear some small amount of demand risk; is that right?

A Yes, under the Florida statutes, that's cor

Q And the premise of your statement is that notwithstanding the capacity recovery clause as approved by the Commission, and notwithstanding the practice of preapproving purchase contracts, credit rating agencies and perhaps investors may still entertain some doubt or skepticism about the continued viability of that arrangement in the future if things turn sour; is that correct?

A Yes, in fact, if the capacity clause -- if the capacity recovery clause is iron clad, then a rating agency would have no concern over it at all. It's the nature of whether or not it's iron clad that can be the only source of concern.

Q But you agree that the recovery clause and

the practice of preapprovals do sharply mitigate and reduce the amount of demand risk that you believe utilities bear as a result of purchasing?

A Oh, yes.

Q And on page, which is the first full page of your paper, when you say, "Our analysis yields four major points." And the first one says, "There is a hidden cost to purchased power if your regulators fail to protect or compensate utilities for a demand risk." You are referring to that greater reduced demand risk that remains notwithstanding the regulatory practices of preapproving contracts and providing for timely recovery?

A Right. That demand risk could, under the appropriate regulatory setting, be nothing.

Q And justifying or supporting that view, you offer the -- excuse me.

MR. McGLOTHLIN: I'm almost through, Mr. Chairman, if you'll let me have about two more questions?

CHAIRMAN DEASON: Certainly.

Q (By Mr. McGlothlin) In supporting that view, your point is that if in the future rates go up as a result of excess capacity, the Commission could make some more forceful challenge of what constitutes

prudence and revisit the recovery; is that right?

A Yes.

Q Well, turning, again, to the point of a few minutes ago, would you agree that in the construction alternative the same thing could happen? If credit rating agencies and perhaps investors are skittish about the Commission's commitment to a cost recovery clause, couldn't they be equally skittish about the commitment to continue to recover in base rates and revisiting prudence questions if the utility constructed its own capacity?

A Oh, yes.

DR. McGLOTHLIN: I have no further questions

CHAIRMAN DEASON: Further questions for Dr. Brown?

Staff, questions for Dr. Brown? Very well. Thank you, Doctor.

According to the order of presentation, the next category is nonutility generators. And I believe the Florida Competitive Energy Producers have a number of presenters. The first individual, Mr. Howe.

MS. KAUFMAN: Mr. Chairman, if I might, I'm Vicki Kaufman on behalf of the Florida Competitive Energy Producers Association. I'd like to make a few very brief remarks before we begin our pfesentation.

CHAIRMAN DEASON: That's fine with me. Just realize that a number of your witnesses have planes to catch.

MS. KAUFMAN: I understand and that's why I'm going to be very brief, because I know that they will appreciate that as well as you all.

Commissioners, as I said I am appearing on behalf of the Florida Competitive Energy Producers Association. I wanted to let you know who the members of that Association are. They are Air Products and Chemicals, ARK Energy, Destec Energy, Cogentrix, and Ensearch Development, Falcon Seaboard Power Corporation, J. Makowski Associates and Oxbow Power. These companies are some of the largest independent power generators in the world, and CEPA members and their affiliates have operating and ownership interest totaling over 7500 megawatts worldwide.

We wanted to let you know that we appreciate the opportunity to appear before you today in this rule proceeding, and we want to commend you and your Staff for attempting to move Florida toward a competitive marketplace model for the procurement of generating capacity in the future.

CEPA is going to present to you six witnesses this afternoon, and we hope that these witnesses will

give you some historical perspective on the utility industry and the independent power industry, basicall how we got to where we are today; but more important than that, where we should go in the future in a stat that's continuing to grow and that's going to have future capacity needs that need to be filled.

Our witnesses are going to talk to you about the two Staff rules: The original one and what's called the alternative rule. And in addition, Mr. Huddleston going to discuss with you the alternative rule that CEPA has proposed and included i his testimony.

As I said earlier, while we commend the Staf and the Commission for moving toward a competitive marketplace, we don't believe that either version of Staff's rule gets you to that point in time. But we d believe that CEPA's alternative, which provides for a two-step process with Commission oversight on the fron end, will get you to a truly competitive marketplace model.

In addition, we're going to have two witnesses, Dr. Craig Roach and Mr. Walt Howard, who will talk to you about some of the 712 issues that we've already heard a lot of discussion about throughout the day.

In short, Commissioners, we believe that you're at a crossroad in this proceeding. By the adoption of an appropriate bidding rule, we think that you'll have the opportunity to open up the wholesale market to competition, and to thereby ensure that the ratepayers of Florida get the most cost effective and the most environmentally benign projects to fill the growing capacity needs of the state. You have the opportunity to move Florida toward that model in this proceeding and to enact a rule that will inure to everyone's benefit. We urge you to seize that opportunity and we certainly appreciate the ability to be part of the process. And with that we'll turn to Mr. Howe. Thank you.

MR. MOYLE: My name is John Moyle, and I represent J. Makowski Associates, Incorporated, who is participating in this proceeding with the Florida Competitive Energy Producers Association.

JOHN B. HOWE

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. MOYLE:

Q Mr. Howe, for the record, please state your name and business address.

A My name is John B. Howe. My business addres is One Bowdoin Square, Boston, Massachusetts 02114.

Q By whom are you employed and in what capacity?

A My employer is J. Makowski Associates, Inc., and I currently hold the position of Vice President, Regulatory and Governmental Affairs.

Q And on whose behalf are you appearing in thi proceeding?

A The testimony is filed on behalf of my company, J. Makowski, and also our industry organization, the Florida Competitive Energy Producers Association.

Q And you have previously testimony in this proceeding?

A Yes, I filed testimony with one attached exhibit on September 10th.

Q Would you please summarize your testimony.

A Certainly. And just at the outset, I would like to make a comment that one obviously very troubling issue that we have been grappling with today is how to treat utilities as providers of competitive services and more traditional regulated services in this evolving world that we're facing, and my testimony is intended to address that issue.

The overall purpose of the testimony is to focus the Commission's attention on several significant changes that have taken place in recent years in the electric generation marketplace.

These include changes in federal regulation, in industry structure as well as in the regulatory environments of the states. And there's a bottom line premise in my testimony, a simple proposition. The generation of electricity, which for a period of several decades has been conceived as a natural monopoly, by the early 1970s it came to be recognized as a business endeavor that could be structured along competitive lines. And so because utilities, with respect to the generation function, are no longer natural monopolies, I guess it's my perspective, why should we continue to use the natural monopoly model of regulation? It really is time, in light of the changes that I discuss in the testimony, to revisit that basic

assumption. And so my testimony steps through the basic rationale for why CEPA -- member companies believe that competitive procurement for new generati resources is an idea whose time has come in Florida.

And let me briefly just go through some of the highlights of my argument.

In the early 20th century, with the early growth of the electric industry, we developed this classical system of rate base rate of return regulatic for the electric industry and we applied it across the board to generation, transmission and distribution. And this was a smoothly functioning system that worked well for the country for a period of several decades. But we can't forget the fact that this approach to treating the utility's cost of providing service was truly exceptional, almost unique in our American economic system. In virtually every other sector of economic activity the allocation and pricing of goods is based on the principle of market-based competition. And so my testimony contrasts the systems of monopoly franchises and rate of return regulation with the competitive market structure that governs other sector of activity.

Now, there was a broad -- there were two important reasons why rate base rate of return

regulation was appropriate during the period of growth and maturation of the electric industry.

First of all, electric generation, specifically the function of generation featured economies of scale with the cost of generation declining as the size of generating units increased and there was a steady progression of larger plants, lower unit costs that lasted for several decades. And, second, as to the whole range of electric service, including generation, transmission, distribution, it appeared to feature economies of scope; meaning providing all of these services on a bundled basis could be done by a single entity at lower cost to society. So this system was not challenged significantly for a period of several decades.

But times have changed and the Commission well knows, of course, that beginning a couple of decades ago in states across the country, really in the early '70s and forward, this traditional model for treating the cost of generating plants ceased to ensure least-cost results.

Two things happened: First, where I mentioned economies of scale, that phenomenon appeared to end at that time as it -- it reached its logical limits. And, second, the unquestioning acceptance of

the concept of economies of scope also began to give away. Not just in the electric industry, also in telecommunications and natural gas. Industrial analysts in all of these industries started to questic whether certain functions that had traditionally been part of the vertically integrated monopoly utility structure couldn't be stripped out and performed more efficiently on a competitive basis.

My testimony goes on to discuss the public policy responses to this new environment. And I mention chiefly two landmark pieces of federal legislation. First of all, of course, the Public Utility Regulatory Policies Act of 1978, or PURPA, opened the door to competition in the generation sectc by providing a market for the output of PURPA qualifying projects. And second, building on the widely perceived success of PURPA, the Congress last year, in 1992, passed the National Energy Policy Act, which, in our view, codifies a recognition in the Congress, in the federal government, of the benefits o competition.

The electricity titles of this act are predicated really on two pillars. First of all, the concept that the generation marketplace should be guided, the selection of new resources should be guide

by the principle of competition. And second of all, although generation, because I have been speaking specifically of the generation function, and that's the subject of our testimony -- although the generation segment is a competitive function, the transmission function is now the locus of true monopoly power. That is the residual utility function that only the utility can provide and for which the traditional cost-based rate-of-return model is most likely appropriate.

That approach needs to be -- that kind of oversight needs to be provided so that transmission services is equitable and nondiscriminatory, and so the transmission, the use of the transmission grid does not interfere or obscure the benefits of effective competition in the generation sector.

Now, that's a brief summary of the changes at the federal level. And in response to these federal legislative initiatives and the changes in the generation technology marketplace, a large number of states have enacted competitive bidding frameworks to guide the selection of new resources.

And after 15 years since the passage of PURPA, there is now across the country a considerable body of experience with these new frameworks. And even though independent power has not been a very

significant factor in the Florida marketplace today, c a nationwide basis I can tell you that the independent industry now accounts for well more than half of the new generation capacity that's entering service each year. It was 67% during calendar year 1992 across the United States. A subsequent CEPA witness, Hope Robertson, is well-versed in the state's experience with competitive bidding and we'll address that topic later on.

So my basic conclusion is that the approach of using competition to guide the selection of new generating resources clearly works, as historical evidence now shows, and will spur proponents to offer projects that offer lower costs, higher technical efficiencies and improved environmental characteristics. These are all the natural results of competition in other segments of the economy and there's no reason we can't expect competition to bring similar benefits to this sector.

I believe that using a well conceived competitive framework to guide these kinds of decision will help you, the Commission, to fulfill you're mandate of protecting ratepayers better than the existing rate base rate-of-return system.

I don't think this is an extraordinary or

radical idea that I'm putting forth in this testimony. On the contrary, as I tried to emphasize, I think this approach merely recognizes what is accepted as an article of the faith for virtually every other kind of economic activity in the American economy.

Economic regulation was originally conceived -- now we're going back in this realm, 50, 100 years -- as a tool to be used as a matter of limited exception in situations of natural monopoly that are prone to market failure. The experience of the past several years makes it clear that a workable market for generating resources does exist; and, therefore, my conclusion is that rather than using what we acknowledge is a second-best approach economic regulation to discipline costs, that we should, with all of the troublesome incentives and inefficiencies that result from the use of that system, instead we should strive to achieve a market structure that can harness the benefits of the first-best approach of market-based competition.

Q Do you have any comments or responses to other testimony in this proceeding?

A Yes, I'd like to offer a brief comment in response to the Tampa Electric Company.

While Tampa has not directly disputed the

notion in my testimony that competition is a preferabl system to regulation, it has said that the movement tc competition should be adopted on a phased-in and a deliberate and a case-by-case basis.

Now, I certainly understand the concern of Tampa and many electric utilities, that a wholesale movement of the entire regulatory framework to competition overnight would be disruptive, but that's not what we're proposing here. What we are proposing is an incremental change in which all future generatin resources, whether offered by the utility or from entities in the open competitive marketplace should be subjected to a common market test. Our proposal does not address the cost treatment of existing generating resources. We do believe, however, that the Commissio should adopt a clear, long range view of where it hope to lead Florida's electric utilities through its regulatory oversight over the coming decades. I certainly believe that competitive procurement of the utilities' chief input, the cost of bulk power, ought to be part of that picture. I believe that Florida's utilities will themselves remain more competitive with electric service providers in other parts of the country and the world only to the extent they keep their cost of production down. And as I said in my

testimony, I believe a competitive system should do that better over the long term than the existing system.

Q Does that conclude your testimony?

A Yes, it does.

Q All right.

CHAIRMAN DEASON: Questions?

COMMISSIONER LAUREDO: I have a couple of questions, if I may.

CHAIRMAN DEASON: Go ahead.

COMMISSIONER LAUREDO: Let me, just so that I can then understand the other questions you might be asked. Did you say in your testimony today that you -- that we have abandoned the concept of natural monopoly?

A In terms of generation. There may be some extraordinary generation technology that comes -- I'm not saying a priori that no generation technology might be ever proposed or developed in the future that has monopoly characteristics where it makes sense for all to go in one system rather than to pursue several suboptimal smaller units. Given the range of technologies that are on the plate today, that utilities and nonutility companies are choosing from, I do believe at this point in time the concept of natural monopoly for generation certainly holds less force,

it's far less compelling today to make the argument fc natural monopoly than was the case 30, 40 years ago.

COMMISSIONER LAUREDO: You can't point me tc a time certain period or entity that -- who abandoned that concept of public policy. You're just saying tha we are -- I guess you're saying that we're modifying that concept somehow.

MR. HOWE: Well, I guess I'm saying experience began to show. Unit costs of production from new plants came down and down through the 1960s. It was around about 1970 and into the 70s, and then because of a variety of factors, the larger projects that were proposed at that time became very expensive on an unit basis. They were stretched out. We experienced, of course, high capital costs at that time, and so a premium was placed on developing smaller, modular types of projects with shorter lead times that would provide the utility system with greater planning flexibility. So I'm not making an intellectual argument that the concept of natural monopoly and economies of scale can never exist again in the future. I'm saying experientially it was the experience of the generating industry at that time tha bigger was no longer better, and competition yielded better results than continued reliance on building

bigger and bigger central plants.

COMMISSIONER LAUREDO: I don't want to engage in a semantical discussion, you did not say that we have -- otherwise, we wouldn't have this hearing if we didn't have a natural monopoly. You're just saying that, in your opinion, injection of market forces is moving away from what you term a natural monopoly. But neither this Commission or any other public entity I know of has said that we're moving away or abandoning natural monopolies?

MR. HOWE: Well, I hope I was sufficiently careful to say that I was only referring to the generation segment. I think that what's very troubling and it's caused a lot of the rough patches in the discussion here today.

There is a competitive function of electric generation which is attached to a natural monopoly function; the transmission and distribution system, the grid. And what we're saying is that customers will benefit when that grid is used to provide access to the most competitive potential producers.

COMMISSIONER LAUREDO: Let me just ask you just so I understand your view of history.

I got the impression that your analysis of history is that we start with a natural monopoly in

electric, and I have a different reading of that history. I thought we had -- we started out with a free market concept of utility, and because of some deficiencies in the market, we impose natural monopol: It's a very big difference to me.

MR. HOWE: The market structure that we had was a rip-roaring free market. I mean, it was wide open and monopolies did come to exist. They were not placed under the supervision and control of state utility commissions until the late 19th, early 20th Century.

COMMISSIONER LAUREDO: I understand. But I trying to get to, basically, is that the reasons why have natural monopoly development was because we had some inefficiencies in the market, vis-a-vis the consumer, that we were trying to correct through this so-called natural monopoly. You grant me that, right? Now, the reason I ask you to confirm that is because now you're saying historically we're moving back towards the free market. And if that's the case, I want to ask you what circumstances, in your opinion, have changed.

Now, I heard you loud and clear. You gave a very eloquent explanation on economic forces that sustain you in that conviction, but I did not hear the

social issues -- well, quasi-social issues, like duty to serve, nondiscriminatory practices, reliability. Are you basically looking at it as returning to a free market economy completely in the sector?

MR. HOWE: Yeah. In the generation sector, over time -- I guess what -- the objective of my presentation was to say that using the discipline of competitive market forces -- competitive market forces are a form of price regulation. I mean, the prices of all kinds of goods in our economy are effectively regulated not directly with the hand of government, but through the invisible hand.

COMMISSIONER LAUREDO: But my question -- I agree with you and I'm a free market freak, but I'm talking about the other issues that brought us to a monopoly, which are the -- I guess in layman's terms I can call them quasi-social issues and I outlined some of them. Because one of the fears that some people have are, as we move into this thing, you know, you're going to be looking at bottom line -- we heard discussions early this morning, if the numbers don't match, we'll close the plant down. And that flies in the face of some of the basic underpinnings of why our society, back in the '20 and '30s, corrected that market force to have what you term "natural

monopolies." And I just wondered what in your mind yc can tell me that has changed the very behavior of free market forces whose fundamental efficiency relate to price only and not as to social responsibility or higher goods. I mean, that would lead me to follow your logic to say let's abandon natural monopoly on an of the sectors.

MR. HOWE: Well, I'm not sure I agree with the premise that regulation was initially imposed in order to ensure reliability of service, for example. think that regulation was imposed, I mean, to achieve range of objectives, but the reason we imposed regulation of the electric and the gas and the telecom industries was because of the peculiar monopoly characteristics of those industries.

There are a number of other industries that provide essential services in our economy that we don' regulate and we don't impose a statutory obligation to serve. For example, let's point to bakers and bread. The bread gets delivered to the shelf of the grocery store not because the baker has an obligation to serve but because we have a system of incentives in our economy.

I think there are several mechanisms and I - and there certainly will be other CEPA witnesses that

will be prepared to address this. There's several mechanisms that can be used in a free-market economy to ensure the reliable delivery of goods and services. You can use contracts, and the force of contracts in our industry certainly is analogous to the obligation to serve in many respects that utilities currently have.

Also, there are penalty provisions and so forth. But another important tool that can be employed is diversification. And if a utility has contracts with a number of various suppliers, there may be times when certain of those suppliers fail to perform; but the utility can protect itself against that eventuality by holding a diversified portfolio.

COMMISSIONER LAUREDO: Let me ask you, I disagree with the premise of your historical reading of the industry. I mean, you look at it very strictly from an economic point of view and don't assign enough significance to the social and political reasons that brought about, after all, legislation to create a natural monopoly usually are a function of some sort of public outcry about something.

But we don't need to -- we're already way behind. But what empirical data and/or time period do you use in your analysis to justify the comfort level

you're trying to convey to me that now we're ready to go back to a more competitive environment?

MR. HOWE: I would say the experience of th last 15 years.

COMMISSIONER LAUREDO: Okay. Now, let me a you the follow-up question. Because you did say and think you said the benefits of competitions in other industries are deregulated. I'm aware of two. Are y of the opinion that the consumer and the society in general were served by the deregulation of the airlin industry and the banking industry?

MR. HOWE: Well, I think that the banking industry, there were features of the banking industry -- and I'm not an expert on the banking industry -- b the presence of federal insurance, I think, was a rea threw a monkey wrench into drawing any direct analogy between that industry and the other formerly regulate industries.

I think the electric industry is -- I mean, drew the analogy in my testimony with the telecommunications industry and the natural gas industry, which are industries where I think the consumer has reaped significant benefits from the forces of competition.

COMMISSIONER LAUREDO: So when you meant

other industries, then I misread you. Were not talking about also airline industry and banking; you don't see parallels there?

MR. HOWE: I wasn't specifically.

COMMISSIONER LAUREDO: Okay, thanks.

CHAIRMAN DEASON: Mr. Cresse?

CROSS EXAMINATION

BY MR. CRESSE:

Q You used an analogy in response to a question from Commissioner Lauredo about bread in grocery stores; is that correct?

A I did, yes.

Q The purchaser at the grocery store has options at all times to change suppliers, don't they?

A I suppose so, yes.

Q And if you sign a long-term contract for capacity, you don't have that option to change suppliers; is that correct?

A That's correct.

Q So there's a big difference between buying bread and buying generating capacity, right?

A Oh, I absolutely would be the first to acknowledge that it's not a perfect analogy.

(Laughter)

Q Let me ask you a question in terms of: have

you ever seen a contract crafted appropriately to provide the protection to the consumers that ought to be in a contract between a utility and an independent power producer?

A Well, which specific kinds of protections?

Q All kinds -- economic, reliability. Let's just stick with reliability and economic protection against damage.

I think we heard earlier at least one person's opinion that, if a contractor fails to perfor under their contract, that the utility should be relieved of its obligation to perform or its quality-of-service obligation as under Florida statute Do you agree with that?

A I actually disagreed with that answer. Clearly, the utility does have a continuing obligation to serve. And the utility's obligation in this evolving competitive market, I guess from my personal perspective, is to analyze all available options and t craft a portfolio of supplies that, in its view, will meet its needs reliably over the long term.

Q So, then, it would be your view that if the utility is forced to contract for a new capacity under the terms and conditions prescribed by this Commission and if that contractor fails, this Commission should

penalize the utility for contract failure; is that correct?

A The utility should take steps in developing its portfolio to ensure that in the event that a supplier fails, it has other options or it can, it --

Q Are you suggesting that they have sufficient contracts in excess of what's needed to take care of a contract failure?

A Well, we have in place today a system where utilities have to guard against double contingencies in the event of loss of load from one of their own generating units. So what I'm suggesting is a concept that's not terribly different from what's been historic practice for utilities.

Q Do you think that a utility should increase its reserve margin if a substantial portion of its generation is going to come from contract?

A No, I don't. In fact, over time, depending upon the size of units that the utilities signed contracts with, it may well be possible for the utilities to have smaller reserve margins. Because the kinds of contingencies that they have to guard against in order to meet the reliability criteria of their local reliability council, if your largest unit on your system is 1200 megawatts, that one loss can make a

great difference in reliability to your system.

If your largest units are smaller, if they'
400 or 500 megawatts or 200 megawatts, then that give
you greater resiliency. I think that's been touted a
one of the strongest arguments for diversification of
supplies.

Q Do you think it's appropriate for a utility to craft their contract in such a way that they prote themselves from any punitive damages based on quality of service that may be imposed by this Commission?

A Well, contracts frequently contain provisio on failure to perform. If a supplier doesn't meet a specified availability level, the contractor is penalized. I think that's --

Q Yes, sir. But on the capacity cost recover clause, would not all of that pass through directly t the consumer in Florida, to the consumer's benefit?

A I'm sorry, I didn't --

Q If you have a capacity cost recovery clause -- earlier we heard testimony that the capacity cost recovery clause reduces the risk to the utility. Is that correct?

A Yes.

Q All right. Now, if the utility fails to perform, that would reduce the payments made to the --

excuse me. Should the contractor fail to perform, that would reduce the payments or maybe eliminate the payments by the utility; is that correct?

A Eliminate the payments by the utility to the supplier?

Q To the contractor, to the supplier.

A Yeah, correct.

Q And all of that reduced payment would be passed directly to the consumer, would it not?

A I am not intimately familiar with how the mechanism, the pass-through mechanism, works in Florida, but I know in other states that typically would be the case.

Q Well, you don't think this Commission would allow costs to be passed through there that was nonexistent, would you? Or you don't know this Commission that well?

A Well, I'm afraid not. I'm learning.

Q All right. Well, assume they wouldn't allow that. Where is the protection for the utility when you fail -- if you fail? Excuse me.

A I think what you're putting your finger on is the fact that purchased power entails that there is no opportunity for the utility to -- there is no upside for the utility when it enters into purchased power

contracts. But you're suggesting there may be an exposure on the downside?

Q Yes. If there is a downside cost, if there' no upside exposure and there is a downside because of quality of service, which I think this Commission hold pretty dear, if the utility fails to provide quality o service, they have a statutory obligation for that to affect their rate of return, as I understand the law a I remember it.

Accepting that as being a given, and counsel may correct me, where is the protection for the utility? And all I'm asking you, shouldn't they guard against that in the contract that they have with the independent power producer?

A Well, I understand the problem that you're pointing to, and I think it's a problem that's not satisfactorily addressed. There is an asymmetry, my personal view, in the fact that utilities have upside earnings potential from operating their own generating units but not any upside potential for power purchases. And they certainly are exposed to, you know, the continuing oversight of the Commission to ensure that they procure this reliable portfolio.

I would reiterate my response earlier that the utilities should seek through its portfolio

planning and by looking at the projects that are offered to it to try to ensure that it has as reliable a mix as it possibly can.

Q On that basis, then, you would say that in the analysis of bids, price alone should not be the only factor; is that correct?

A Certainly. Certainly, I would agree with that.

MR. CRESSE: Commissioner, I have about three more questions. I'm trying to get through as quick as I can.

Q (By Mr. Cresse) Do you believe that in the competition between utilities and the independent power producers that there should be a level playing field for both?

A Well, the premise of your question is that there is or ought to be competition between utilities and independent power producers.

I guess the central element of my testimony was the reason we set up utilities as monopoly entities and gave them monopoly responsibilities and monopoly franchise rights was because we perceived that they were natural monopoly entities. I don't believe that's any longer the case. I believe that the generation segment of the industry can be structured

competitively; that utilities ought not to compete in that process with any of the advantages that come in connection with their being utilities.

And so I would hope over the next few years we will evolve a system of regulation where utilities and independents do not compete -- or at least the regulated utility entity ought not to be competing as regulated entity with independent power producers.

Q Do you see any benefit at all to a utility from owning its own capacity as opposed to getting tha capacity under contract, assuming cost is equal?

A Well, the benefit to the utility under today's system --

Q To the consumers of the utility. Forget about the utility, let's talk about the consumers of the utility. The benefit to the consumers of the utility -- the utility to own instead of contract if the cost is equal.

A If the cost were equal and if there were a truly -- if there were a truly equitable system where through an impartial analysis it, the utility unit, wa regarded as the most cost competitive, and if the utility were prepared to commit to the same terms and conditions as the other entities, I suspect that for all those conditions to be met, the utility would have

to participate in this competitive marketplace, not as a regulated utility but through affiliate structure such as an EWG structure as was created in the Energy Policy Act.

All those conditions being met and with the blessing of the Public Service Commission, which would be required in order for the utility to buy from an affiliated EWG, then there may be benefits to the utility owning that generating plant if it's truly the least expensive. But there are dangers inherent in the utility engaging in a transaction with an affiliated EWG, so that's --

Q But I wasn't questioning about an affiliated EWG. Because you would agree that the affiliated EWG ought to have the same benefits and prerogatives of an independent EWG; is that correct?

A I think that's the Congress' intent, yes.

Q In that case, then, it would not be the utility customers that would get the benefit of superior performance, it would be the stockholders of the EWG; is that right?

A That's correct, yes.

Q Let me ask you this: Should a utility be able to bid on a generation project using the same minimum level of equity required of independent power

producers in those projects?

A Sure. I don't see why not.

Q So if it was 90/10 was the minimum level, that the utility could bid on that project with an incremental cost of 90/10; is that right?

A If it could obtain financing on that basis, there's nothing inherently to stop a utility from employing the project finance model that companies in our industry employ.

Q Yeah. If they could just get a first mortgage for 90%.

A Well, you have to go through many hoops in accordance to do it, but --

Q I understand, but if they could do that?

A Yeah. It's a good disciplining process --

Q And backing up that full faith and credit of the parent, not the utility but the parent. Is that okay?

A That's going to make it problematic for the utility, yes.

MR. CRESSE: One other question, Mr. Chairma

(Pause)

Q (By Mr. Cresse) Does the utility have more flexibility in meeting its reliability goal if they ow a generating plant than they would if they have

generating capacity contracted for?

And let me just give you a hypothetical. Most utilities do long-range planning and do planned outage planning. Do you agree with that?

A Yes.

Q And probably all utilities, periodically, their plans don't materialize because they have forced outages. Do you agree with that?

A Certainly.

Q And when we have a forced outage, then they will move a planned outage further down the line. Is that correct?

A Yes.

Q Or they may change one and get a smaller plant outage to take care of the forced outage, because the total goal is to continue to provide reliable service. Do you agree with that?

A Yes.

Q Now, how do you craft a contract? Because all they have to do is call their own plant managers and say, "We just canceled your vacations, we're not going to close it down, we're going to run it until we can get back on line." And it's not a democratic process, management and employees don't vote on that. Do you agree?

A Yes, I agree.

Q All right. Now, when you call a contractor and he responds to you and says, "You know, I'm alread at 85% of capacity and I'm closing her down two weeks from now because that's what my contract permits me to do." Is there any value lost to the consumers as a result of that?

A Well, I think the utility could, you know, can contemplate the need for flexibility in scheduling outages through the contract process. I think, you now, these kinds of situations can, to a certain extent, not an unlimited extent but to a certain extent, can be contemplated and codified in the contract agreement up front so that the utility shall have flexibility within a certain range to schedule maintenance.

As I've said, you know, we've got 15 years o experience under our belts in the independent power industry, and the level and degree and sophistication in our contracts has advanced by orders of magnitude compared to where we were --

Q Now, your proposal to this Commission says, "Commissioners, have them submit the proposed contract." Is that correct?

A Yes.

Q And kind of grace over it there and so forth. Have you got any idea what issues or could you give this Commission a list of the issues that that proposed contract should address?

A Well, there are certainly contracts that are in the public domain that address a broad range of these kinds of issues. I'm not prepared right now to go through them.

Q Should those I have been asking you about be included in the contract?

A I think if the utility wants them in the contract, there's no reason why they shouldn't be in there, and --

Q Well, if I as a consumer appealing to this Commission, they're going to approve the contracts, should the Commission insists that those types of conditions be in the contract?

MR. MOYLE: Mr. Chairman, we have a witness that will be testifying in this area. This exceeds the testimony filed by this witness, So I think it's improper.

MR. CRESSE: No further questions, Mr. Chairman.

CHAIRMAN DEASON: Very well.

CROSS EXAMINATION

BY MR. GADDY:

Q Good afternoon, sir. My name is Rodney Gaddy. I'm with Florida Power Corporation, and I just have two questions for you, two or three questions.

Is it my understanding, and is it correct that you agree that diversification of supplies is wha utilities should do as it relates to fuel and generation capacity?

A I think that's prudent planning, yes.

Q Okay. Is it also your understanding that, when you're talking in terms of reliability, that the availability calculations are the only measures of reliability? Are there other measures?

A Oh, I think that the basis for calculating the reliability of a plant, you know, there are many possible approaches depending upon what the utility thinks is important, be it on-peak performance, for instance, as opposed to annual performance.

All of these are matters of potential negotiation in a contract.

Q And in your testimony you have been constantly referring to your 15-year-or-so experience with these contracts. But we're talking about non-PURPA QF contracts. What's the longest contract

that you're aware of?

A Well, there have been, of course, outside of PURPA, there have been independent power plants in existence since back before the Federal Power Act, from the time of Edison, there was independent nonutility generation. The development of nonutility generation really sort of came to a stop in 1935, and there was very little developed until 1978. But, really, there is approximately 60,000 megawatts of capacity that's been developed over the last 15 years.

Q But as we're talking about the contracts that involve the IPPs, don't we only have about a 10-year experience with these?

A In my testimony, in fact, I said 1983 as a point in time when the industry really began to grow rapidly, so, yeah, I'd say that's fair.

MR. GADDY: No further questions.

CHAIRMAN DEASON: Ms. Swim.

CROSS EXAMINATION

BY MS. SWIM:

Q Mr. Howe, I'm Debra Swim. I'm here on beha of the Legal Environmental Assistance Foundation. An I understand in your testimony that the benefits of opening generation to competition in your perspective would allow both a lower cost alternative and a more environmentally beneficial alternative to be selected And I wonder if you might explain a bit more your opinion about how opening generation to competition i going to enhance environmental values.

A In competing with other companies in our industry, we constantly strive to achieve competitive advantages in a number of ways in terms of gaining favorable host community acceptance and making our plants have lower environmental impacts.

One of the results of this process of competition has been that independent power projects have been truly pioneers in developing low impact systems, building plants with lower emissions. My company developed a plant in Rhode Island which is operated under a zero wastewater discharge permit, fo example, which was an unprecedented requirement, but -- or we built the necessary technology into the plan to achieve that objective. So, you know; when the

carrot of competition, the prospects of rewards are dangled out in front of us, that provides us the incentive to pursue a number of these kinds of innovations. We don't simply sit back and take the current model as a given. We look to refine it and improve it.

MS. SWIM: Thank you.

CHAIRMAN DEASON: Any further questions? Staff? Okay. Thank you, Mr. Howe.

MR. HOWE: Thank you.

(Mr. Howe excuse.)

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CHAIRMAN DEASON: At this time we're going to take a real ten-minute recess and we will reconvene at 25 minutes after the hour.

MS. SWIM: Commissioner, do you have any idea when this hearing might end this evening? Are you planning to go --

CHAIRMAN DEASON: We're not going to work late this evening. For your planning purposes we would probably try to terminate this evening's hearing somewhere around 5:30.

MS. SWIM: Thank you.

(Brief recess.)

CHAIRMAN DEASON: Mr. Neiser, I understand

that you have at least one witness who also has conflicting schedules and travel plans, et cetera, et cetera.

MR. NEISER: We have one who does have a problem with tomorrow. He is here today. He lives i New York, and we'd like very much to try to accommoda him today if we could.

I have not run into anyone yet who has questions for him, but I'm not sure there aren't questions. I have had a few people say they do not.

If there is a way to get him on, I would li very much to try to do that if we could.

CHAIRMAN DEASON: And which individual is this?

MR. NEISER: This is Terran Miller.

CHAIRMAN DEASON: Okay. Let me ask informally at this time, does any party have extensive questions for Witness Miller?

MR. MAY: Mr. Chairman, I do not have extensive questions. I have a couple of clarifying questions that will take about two or three minutes.

CHAIRMAN DEASON: Okay. Any other questions Does CEPA have an objection to having Florida Power's witness come forward and hopefully have his testimony done shortly?

MS. KAUFMAN: I believe that CEPA has some questions for Mr. Miller as well.

CHAIRMAN DEASON: Extensive?

MR. McGLOTHLIN: Not extensive.

MS. KAUFMAN: And we have two witnesses that would like to make a -- really need to make a 6:50 flight this evening, Mr. Howard and Ms. Robertson.

CHAIRMAN DEASON: Okay.

MR. NEISER: That is the same flight he is shooting for. The only thing that I would -- I don't know how firm your departure time of 5:30 is, but it's just something I would ask for you to consider as a possibility of extending that enough to perhaps hear him.

CHAIRMAN DEASON: Okay. We may could extend it for a short period of time. But I can tell you right now we're not going past 6:00 this evening. That's firm.

MR. ERWIN: How about bidding on it?

(Laughter)

CHAIRMAN DEASON: When we start talking about monetary incentives, anything is possible. The free market at work.

Okay. We will proceed with the CEPA witnesses who also have to meet the same flight.

MS. KAUFMAN: Yes, sir.

CHAIRMAN DEASON: And if we can at all accommodate, Mr. Neiser, we will do so.

MR. NEISER: Thank you.

MR. MOYLE: My name is John Moyle. The record reflects my representation.

WALTER Q. HOWARD

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. MOYLE:

Q Please state your name and address for the record.

A I'm Walter Q. Howard.

Q By whom are you employed and in what capacity?

A I'm with the J. Makowski Company as Senior Vice President and Chief Financial Officer.

Q Have you previously filed direct and responsive comments as well as exhibits in this proceeding?

A Yes, I have.

Q Do you have any changes which you would like to make to either your comments or the exhibits?

A I do have a couple of minor typos and

clarifications if you would like to deal with those.

In the original comments, Page 3, Line 1, refers to my former employer as Bechtel Enterprise, in fact, it was Bechtel Power Corporation. And on Line 5 of the same page, I was involved building an industrial facility, not a university.

On my responsive testimony, Page 7, I would add a phrase, on Line 23 saying "As quoted in Public Utilities Fortnightly in a article by Charles M. Studness," comma."

Q Any other changes?

A No.

Q Or corrections.

Okay. Please give a brief summary of your comments filed in this proceeding.

A Well, I'd like to speak to two particular points which relate to 712. First to reliability, more specifically, how the inclusion of nonutility generators will improve the reliability of electric service in the state of Florida.

Second, to whether reasonable assurances of fuel supply should be required before awarding a power sale agreement; and if so, what level of evidence of such would be deemed reasonable? On both of these issues I'll speak from a lender's perspective.

My experience prior to joining Makowski a year ago last July was as senior vice president with G Capital. GE Capital is one of the leading financiers providing both debt and equity to the nonutility generation industry having been instrumental in the financing of over 65 such projects totaling over $5 billion worth of investment. And as a footnote, I was personally responsible for over $250 million of nonutility generation project investments here in the state of Florida.

First, reliability. Let me start out by stating a fact: Nonutility generators do not threaten reliability of electric service. In fact, historical evidence on a plant-by-plant basis proves that nonutility generators have been more reliable than their utility counterparts. This is due to five reasons: One, the use of incentive mechanisms in power sales agreements; two, the parallel interests of both debt and equity in ensuring that a project operates reliably; three, numerous lender requirements that are specifically designed to assure reliable, long-term operation; four, the use of quality engineering design and construction practices; and, five, the use of qualified operators, whose fees to operate and maintain projects are directly linked to plant performance.

The first reason for the high reliability of nonutility generators is the use of incentive or performance-based power sales agreements. Such contract structures are already in use throughout Florida. Effectively, the purchasing utility defines what its need for reliability is; as mentioned earlier, either peak or annual basis. If a nonutility generator does not perform under its power sale agreement with that utility, it does not get paid. Quite simple.

The key point to note is that "not paid," means both equity and debt do not get paid. That is, if a project fails to perform not only is the developer precluded from earning a return, but the project lenders don't get paid either. Conversely, if a utility plant doesn't perform, utility shareholders may take a hit, but the bondholders still continue to get paid. Not so with a nonutility generator. The risk of nonperformance sits squarely on the shoulders of the project developer and its lenders.

This leads to my second point; that is, both debt and equity have parallel interests. As we explored earlier, in the event that the equity fails to make the project operate appropriately, in effect, in a nonrecourse project financing the lenders become the equity.

It should also be noted that the power sale agreement is the project's sole source of significant revenue. Therefore, performance under this contract of paramount importance to both equity and debt alike The goals of the developer and the lender are paralle

The third point, relating to lender requirements is really an offshoot of the parallel interestS of debt and equity. Specifically, lenders structure transactions to protect their investment. The amount of structuring that a lender may require i proportional to the level of risk that it perceives i entering into a transaction.

I think it becomes clear, even after a cursory review of the term sheet that I supplied as o of my exhibits, that the level of structuring lenders require on a nonutility generation project financing extensive, far in excess of what lenders require in similar utility transactions, corporate financings. Why is this the case? As I mentioned, because lender bear the risk of nonperformance alongside the owners a project. Moreover, in the event that the owner fai to make a project perform, the lenders will take over operations, as we discussed before, and restructure t projects themselves to protect their investment. Why Because that's the only way they can protect their

investment is to assure that a project performs under its power sale agreement.

The fourth point relating to design and construction of nonutility generators is often misunderstood. Nonutility generation plants are designed and built by the same firms that build plants for utilities. I used the examples of GE, Westinghouse, ABB, Bechtel, Black & Veatch in my written testimony. You folks know these companies. Their nameplates are on most of the utility plants in this state.

The point is is that nonutility generation projects are not the outcome of second rate design and construction. They're utility size, utility quality power plants built by the same people that are responsible for the reliable electric service that consumers in the state of Florida enjoy today.

Finally, lenders require qualified operators to be used over the long term, whose fees are linked to the performance of the plant. The operator, often itself an affiliate of a utility, major equipment vendor or electric industry engineer or contractor will be financially affected in a major way if the project that operates does not consistently achieve a high level of performance.

In conclusion, the use of performance-based power sales agreements is a proven method of assuring reliability of service from nonutility generators. Such incentive mechanisms effectively allow the utilit to define exactly what its reliability requirement should be.

Then the parallel interests of debt and equity, along with the strict requirements of lenders that must be met by a project prior to financial closing, serves to assure that the projects live up to the reliability standards which are laid out in their power sale agreements.

Q Excuse me. Before you leave the subject, le me just interject a quick question based on earlier testimony.

Being familiar with the power sales agreement, would you comment on the likelihood of thes containing provisions for a lender to take over the project?

A Well, in most competitively bid solicitation that I see these days, and I would expect this to be a few exceptions going forward, the lenders are really i a position where they must assure that the project continues to operate reliably.

You must start from the premise that these

will be facilities that were selected in a competitive arena and have met many evaluation criteria from a number of parties.

Normally the second -- say a project were to start to decline from an economic performance perspective or from a reliability perspective, which translates into the same thing, the first trigger that is normally tripped is a clause providing step-in-and-cure rights to the utility purchasing the power from that particular facility, where that utility has the first right to step in, operate the project, cure the problem, do whatever is necessary to assure the continuance of reliable service.

We talked a little bit earlier, some folks were throwing around the concept that then the lender would step in and shut the place down. Before I get to the shutdown scenario, we should also understand that the exercising of foreclosure rights in a nonrecourse power project financing is, in effect, putting a gun to your own head. Very few power contracts that I see these days don't have cross default provisions. In the event that the lenders threaten the foreclosure, the purchasing utility has the immediate right to void the contract, putting them at a very useful Mexican standoff in insisting on a financial restructuring,

rather than a shutdown of the facility.

We also talked a little bit about how much debt and equity is important on a project, and I thin there was a basic misconception that's applied to tha whole discussion.

The inherent assumption that I heard being tossed around was that somehow there was a value to this plant if it wasn't running; that akin to, you kn an auto report loan repo or something, that somebody could come in and move the plant over to Alabama or something I can tell you that that is really not the case in this type of an installation. It's in one place; it's not likely to move, and the salvage value is a small fraction of the original installation cost. So, really, the financial community, from my perspective and experience, has little option but to, one, make sure going in that the project is going to b economically capable regardless of what the contract provisions are. It must be a first-class competitive piece of hardware that isn't going to end up in a situation where it's outclassed by its utility counterpart plants.

And I guess the last thing I'd like to --

COMMISSIONER LAUREDO: May I interrupt you a second?

MR. HOWARD: Of course.

COMMISSIONER LAUREDO: Since you alluded to two things I said, I just want to make sure you understand them in the content. I was using the example of the foreclosure in the content of a low debt --

MR. HOWARD: I understand that.

COMMISSIONER LAUREDO: Therefore, both salvage -- in fact, I used 20% -- salvage and even real estate would probably cover -- I was taking the case to an extreme to make a point, that there's a correlation.

MR. HOWARD: Commissioner, I understand that. But I would argue that even at 20%, the salvage value of these facilities is unlikely to cover that debt. The project lands are normally leased rather than purchased. There's very little residual value left there. In coal-fired facilities, the value of the foundation civil work and steel superstructure often exceed 50% of the value of the plant. And it's not too different in the gas-fired cogen. There just is not a very good salvage market for this type of facility. And maybe that will happen some day, but the experience in the marketplace, albeit 10 to 15 years of experience, is that these projects do not get shut down. And there are some examples across the country

where projects that were in very deep trouble, where the loan ratios were roaming around that 20% that you were referring to that are operating today.

COMMISSIONER LAUREDO: Under the lender?

MR. HOWARD: Under the lender. In a number of instances the lender has renegotiated the arrangements with the former equity in such a way as t prevent the utility company from exercising its second lien rights. So these are things that have been contemplated in recent power contracts, which, as was earlier pointed out, are becoming very sophisticated instruments to protect the reliability and availabilit of the electric supply.

COMMISSIONER LAUREDO: Can I ask you a coupl of other questions? Are you through?

MR. HOWARD: Of course.

COMMISSIONER LAUREDO: They were talking earlier about the accelerated equity build up on a 12-year amortization. Just typically how is that done is that all the NOI and cash throw-off from the operation is pledged to the lender?

MR. HOWARD: Everything is pledged to the lender.

COMMISSIONER LAUREDO: The equity owner is basically standing at the 12th year.

MR. HOWARD: He gets what is left over and --

COMMISSIONER LAUREDO: At the end of the 12th year.

MR. HOWARD: Well, at the end of the 12th year, in the example that was put forward here, that was assuming a debt/equity structure rather than a sale/lease-back or a partnership arrangement; the developer would end up owning the plant free and clear.

COMMISSIONER LAUREDO: Okay. So he's looking for his return at the end of the accelerated payout of the debt?

MR. HOWARD: Well, actually, he would look for some return in the early years as well. Normally, what happens is that the lenders require a certain debt coverage ratio, a certain cushion, to make sure that they're going to have a little protection that they will indeed be paid on a timely basis. And if the developer is successful in either maintaining that cushion or expanding it, that becomes his equity return, even in the early years.

COMMISSIONER LAUREDO: In the typical, what is more or less the typical cost of a debt on the IPP? We were asking that earlier and --

MR. HOWARD: Well, the construction debt, there's not a whole lot of variance there if you look

at the bonds that are supplied by contractors. But I suspect that you're talking about the long-term debt structures. Most of the --

COMMISSIONER LAUREDO: Is there a venture capital component to the financial package generally?

MR. HOWARD: Absolutely. If you look at the term financing, the 12 to 15 years that was being discussed, I would say offhand that a nonutility generator generally pays about a full percentage point more in interest rate for fixed term 12- to 15-year debt than a rated utility company might for a similar bond issue.

Now, there are exceptions to that. We developed a plant, for example, that we took to the rating agencies and received a single A rating on a project, nonrecourse to anybody. That was a very well structured project and one might say even somewhat unique. In that case, we're paying an interest rate that's equivalent to a single A utility bond.

COMMISSIONER LAUREDO: Is there typical -- I'm just asking you these, I'm trying to learn about the industry.

MR. HOWARD: Of course.

COMMISSIONER LAUREDO: Is there a typical debtholders that have equity kickers or are also

equity, is that also a norm in this industry?

MR. HOWARD: Well, it's hardly a norm, frankly. There's a whole continuum depending on the capability of the individual developer to supply his own equity. For example, one can finance a project through a sale/lease-back mechanism, which is effectively no debt, if it's done as a single investor lease, and 100% equity, but it's not the equity of the sponsoring developer. In the case of my former employer, that was a very popular vehicle. So it was in fact 100% equity from General Electric in that case, GE owned the plant.

COMMISSIONER LAUREDO: And they also funded the construction?

MR. HOWARD: That's correct.

COMMISSIONER LAUREDO: But typically, the lenders or the syndicates that do the lending, let's say other than GE, do they also look in the package to get an equity, they use that equity kicker -- at the end of the 12-year amortization, do they have a residual equity in the project?

MR. HOWARD: Generally speaking, not.

COMMISSIONER LAUREDO: They're just really lenders, straight out lenders.

MR. HOWARD: Straight debt. The fee up front,

and an additional fee on any unused credit line that's attached to the facility, but --

COMMISSIONER LAUREDO: And then my next question is, then, given the high leverage of these projects, what do they look to justify the exposure in not having equity? In other words, when they look at the equity investor, who are they typically? Just the fund it because they have other than -- let me ask you this way. What is a typical equity investor? Is it someone who is technically competent in the area whereby the lender has a comfort level of --

MR. HOWARD: Definitely. Back in the days when there was an investment tax credit and an acceler depreciation attached to some of these facilities, you many more individual investigators involved in partner -- limited partnership-type arrangements.

COMMISSIONER LAUREDO: For tax purposes?

MR. HOWARD: Yes. That's generally speaking a thing of the past. And now, in our own case, for example, we have equity investors on a major project i Massachusetts of ours, who are Tenneco, which is the gas line supplier; Bechtel, which was the constructor; General Electric, which supplied some of the equipment These are very sophisticated partners.

COMMISSIONER LAUREDO: In your experience in

Bechtel and all of that, most -- I know you did some work in Venezuela, was that -- the GE experience, GE capital, is that mostly overseas or --

MR. HOWARD: No, actually that experience of mine personally predated my GE dates.

COMMISSIONER LAUREDO: But the GE capital in the IPP market that you have, is it overseas or is it domestic?

MR. HOWARD: There is great interest in the industry in expanding the model that has proven so successfully here domestically into other countries. I see that to be a challenge. There have been a few breakthroughs; one of the more successful true project financings that I'm aware of was in Columbia just recently. And we're trying to --

COMMISSIONER LAUREDO: But the reason I asked the question and my ulterior motive was to find out if you were able to throw off the risk to the exiting bank with these kinds of projects? Is that happening now?

MR. HOWARD: The project that you're referring to that I worked on did not -- had a 50% government content from Venezuela, it was a partnership arrangement. But we are trying to extend the domestic IPP model into other countries, and it holds great promise.

COMMISSIONER LAUREDO: Would you elaborate --

this is the last question -- briefly in answer to a counsel's question, the utility step-in rights that y say are typical in contracts. I think you also calle it "second lien rights."

MR. HOWARD: That's correct.

COMMISSION LAUREDO: And also the void contract clause to the utility.

MR. HOWARD: Okay. Let me start with the clause defaults, which is the clause which normally provides the purchasing utility with the right to immediately void the contract, declare it null and void, in the event that the developer or his lenders are put into a position of either voluntary or involuntary bankruptcy proceeding.

And the theory behind it, of course, is that if somebody is going to try to seek to use bankruptcy or financial hardship as a reason for being an unreliable supplier, then it's only fair that the utility company, on the flip side, be in a position tc say, "Well, fine, if you pull that on me, I'm not goir to buy from you."

COMMISSIONER LAUREDO: Oh, so I thought it was on performance. It's bankruptcy is what triggers it, not performance?

MR. HOWARD: That's correct. Now, there are

other -- I heard some other examples being put forward that maybe they shut the facility down for a couple of days or a month or something like that. Under most power contracts that I see, that's considered abandonment, in which case the power contract is void anyway. Any time that a developer or its lenders purposely shut the facilities down, that would be a default under the power contract.

COMMISSIONER LAUREDO: And how about this Utility's step-in right, I think you called it, or second lien right?

MR. HOWARD: Yeah. That is normally a heavily negotiated portion of a power sale agreement, as you can imagine, not so much between the developer and the purchasing utility but between the lenders and the utility.

There are a certain group of lenders who see that as a positive -- that is, if the developer stubs his toe somehow, that the utility company will at least have the potential with their vast expertise and resources to step in and say, "We like this plant, we selected it in competitive bid, it's a fine piece of hardware and we're going to continue to run it. So, developer, move aside, we're going to deal with the lenders." And that's been a fairly effective mechanism in a number of events.

COMMISSIONER LAUREDO: That's the exceptio
rather than the norm, I imagine?
MR. HOWARD: Well, I would say it's becomin
more the norm than the exception.
COMMISSIONER LAUREDO: And it's basically
imposed by the lender on the investor?
MR. HOWARD: No, not so much. More from the
purchasing utility, who says, "This is going to be a
fine plant that you guys bid to us here, after all the
smoke clears; and in the event that you don't properly
operate it, we want the right to step in and take it a
one of our own plants."
COMMISSIONER LAUREDO: Is it like a right of
first refusal? It doesn't have an obligation attached
to it, it's kind of a, I have the first --
MR. HOWARD: That's correct. It's an option
on the part of the utility. They have no obligation t
step in. If it's in fact a doggie of a plant,
obviously, they won't; but if it's a Cracker Jack
facility, I would expect them to want to have it
continue to produce on their system.
COMMISSIONER LAUREDO: Well, thank you.
Sorry for having interrupted you.
MR. HOWARD: Not at all.
Q (By Mr. Moyle) Would you go ahead and

summarize your testimony on the reasonable assurances of fuel supply?

A While the fuel supply adequacy should be considered in the power sales agreement approval process, "reasonable assurances," in quotes, should not be implied to mean executed fuel supply and transportation contracts. There are really three reasons for that. Typically, the power purchase contract comes in an early stage of development.

Secondly, the developer, normally in the industry these days, is required to post a cash security deposit to assure that he is in fact going to perform if he's selected as the winner of one of these competitive bidding processes.

And third, again, is the strict lender requirements at financial closing. I think you can be relatively sure that the facility will not go into construction with any kind of financing attached to it unless, indeed, there is a fuel supply arrangement in place.

The power sales agreement, as I said, is usually the first major project contract entered into by a nonutility generator; and that makes perfect sense because it is, in fact, the definition of our marketplace. What kind of power do you want? Do you

want peaking power, base load power? The contract defines what we should build and what other kind of contract arrangements we build around it.

Once the provisions of the power sale agreement are fully negotiated, the developer then may execute other supporting contracts, such as the fuel supply and transportation arrangement, in accordance with the requirements of the power sale agreement.

Executing the other agreements before the power sale agreement would be, in my mind, putting the cart in front of the horse. Therefore, what developer normally do is obtain terms and conditions from fuel suppliers and transporters, in which a general concept is laid out and committed to. Because naturally we ar not interested in putting a secure deposit forward unless we are sure that our suppliers are going to perform. But normally, that term sheet negotiation is incomplete at that time, because we're waiting for the final say from the utility as to what kind of power they're really looking for.

Once the power sale agreement is finalized, these fuel supply transportation arrangements can in t be negotiated and fine-tuned within the boundaries of term sheet to fit the needs of the purchasing utility.

As I mentioned, a developer normally will

have money at risk in the form of a security deposit from the time of execution of a power sale agreement. The requirement to post an irrevocable bond or similar provides significant incentive for the developer to structure a financable transaction. If we fail to do so, naturally we forfeit the security deposit, which is normally numbered in the millions of dollars.

Finally, the lenders require that, along with a myriad of other things, contracts for fuel supply and fuel transportation are executed and binding prior to closing. Before the funding can commence, the transaction must be complete; that is, all contracts -- and permits, I might add -- must be fully effective and enforceable.

So, in conclusion, on this point, while reasonable assurances of fuel supply should definitely be considered as part of the approval process -- that is, I would say somebody should certainly get additional points for having a creative and bona fide fuel transportation supply arrangement in place -- having an executed contract at such an early stage of the development is really inappropriate. And an imperative requirement of the lenders prior to financial closing is that of a project having in place all of its fully executed and enforceable fuel supply

and transportation arrangements. But that would be practically impossible to accurately do prior to the final negotiations on the power sale agreement itself.

Q Would you please give a very brief summary of your responsive comments?

A Nobody has more incentive to be brief than I do at this point, so yes.

I wanted to respond to four conclusions by Messrs. Rosenzweig and Rowe, which I disagree with. Their conclusions seem to be based on a prejudice that nonutility generation is somehow substandard, which I think is certainly contradicted by historical fact.

We at Makowski consider the electric utilities and their ratepayers as our valued customers, and we strive to serve them with low cost and reliable supplies of power. Across the country, we have a number of electric utility partners, in fact, on our projects; and I believe they are, as well, happy with us.

First of all, the power sales agreements with performance incentives and penalties place more pressure, I might argue, on NUG plants than on a similar individual-utility-owned plant.

Second, litigation costs have not been a significant part of administering power contracts in any venue that I'm familiar with. It's an

interesting academic discussion but it just isn't supported by history.

Thirdly, I know of no significant case of a NUG OR its lenders, as I explored earlier, abandoning both assets and reputation and I find the concept to be highly improbable.

Thank you very much.

CHAIRMAN DEASON: Questions for Mr. Howard? Questions for Mr. Howard? Mr. Cresse?

CROSS EXAMINATION

BY MR. CRESSE:

Q Mr. Howard, what time have you got to leave to catch your plane? I know you want to get out.

A About an hour.

Q All right, sir. I won't take very long. I know some other folks that probably have to get out at that same hour, haven't they? I'll try to be fast.

You're suggested on Page 4 of your testimony that every contract includes some milestones, is that correct?

A I think that would be prudent.

Q Would it be appropriate then if a bidder missed a milestone that that contract be subject to cancellation and penalties invoked?

A I was sitting in the audience in that

previous discussion and wondering whether we were doi
a contract negotiation here.

Q Well, as a matter of fact, I think what --
let me see if I understand what we're doing here,
because I may not.

I think what we're doing here is trying to
determine the type of information the Commission
requires to review before they will undertake to
certify a need for new capacity. And I assume that's
what we're all about; because this is the certificati
of need process and my understanding is that they're
required to certify the most cost-effective alternati
available. So that's what we're doing.

A Yes. And I fully understand that.

Q And if you don't have --

A I do believe --

Q -- reliable cost-effective service under a
contract then that couldn't be found to be the most
cost-effective -- (Simultaneous conversation.) Do yo
agree with that?

A I think it's entirely prudent that both the
purchasing utility and the developer understand what
the milestones are and have their feet held to the fi
in terms of making a project go.

Q Under your proposal, the Commission will kn

what those milestones are and will in fact be called upon to approve them in advance, will they not?

A Excellent.

Q Am I correct that that's under your proposal?

A I believe that's --

Q All right. But we don't know what those are today.

CHAIRMAN DEASON: Mr. Cresse, I think that the court reporter may be having some problems, you all are talking at the same time.

MR. CRESSE: All right, sir. Excuse me.

Q (By Mr. Cresse) In your testimony, you seem to suggest that the lender requirements to a bidder provide a certain amount of reliability assurance and so forth for the project; is that correct?

A That was my particular area to testify on, yes.

Q And shouldn't -- should this Commission trust to lenders the appropriateness of those terms and conditions, or should all those terms and conditions be reflected in the performance-based contract you addressed?

A I am not proposing that this Commission rely on lenders to in any way do their job. I'm only filling out one slice of the pie here that says there's another line of scrutiny through the finance community.

Q Should there be a minimum equity requirement

in a contract?

A I don't believe so. I've been in some interesting negotiations and examples elsewhere in the country where it becomes a little bit difficult sometimes to identify exactly what is equity and what is debt.

Q Sure.

A And under a certain set of circumstances I think people have mentioned earlier today that the deb really -- excuse me, the debtholder converts to equity there's a serious problem. But I've been involved in interesting proceedings a bit north of here where we'r arguing about whether 100% equity in the form of a sal lease-back transaction is a debt instrument or an equi instrument. The fact is that the instruments have parallel interests, the project has to run reliably or neither form of investor achieves his goals.

Q Should co-ops and municipalities be allowed bid on all the capacity needs of the state of Florida?

A That's --

MR. MOYLE: Mr. Chairman, I --

A -- outside of my purview, I would have to --

Q Well, it relates to the question of cost of capital. Let me ask you this: Should anybody be prohibited from bidding to meet the needs of an

investor-owned utility in the state of Florida?

A Only if they're incompetent.

Q Pardon?

A I mean, that's a pretty broad question. Yeah, there are probably people who should not be able to bid. I've met some of them.

Q Should a municipality be able to bid to meet investor-owned utilities' needs in the state of Florida?

A I'm afraid that's outside of my area of expertise, I'm not familiar with the municipalities in the state of Florida. I'm not -- I don't know their level of expertise with great familiarity. I don't offhand know their size or what their service territory looks like. I'm sorry, I can't really help with that one.

Q Should all proposed bidders be prequalified if we don't know -- we're not sure all of them are going to come -- we're going to know all of them when they come in.

MR. MOYLE: Mr. Chairman, again, we would respectfully suggest that this area of cross examination is going to be covered by Mr. Huddleston, another CEPA witness.

MR. CRESSE: I'll be happy to wait for Mr. Huddleston.

CHAIRMAN DEASON: Very well.

Q (By Mr. Cresse) On page 8 of your testimony you say that some folks have had performance criteria 83% to 93%. That's on Lines 11 and 12, do you see tha

A Yes.

Q Is a 400-megawatt plant that has a performan guarantee of 93% more valuable to the consumers than a 400-megawatt plant that has a performance guarantee of 83%?

A I guess that would depend on the other provisions of the contracts, all else --

(Simultaneous conversation.)

Q Assuming all other provisions being equal?

MR. MOYLE: Excuse me, Your Honor, Mr. Cress is interrupting and not allowing the witness to finish answer. I would appreciate it if he would let him fin his answer before he starts asking the next question.

CHAIRMAN DEASON: I think that would be best if both the witness and the questioner would wait for each other, because I'm sure the court reporter is having some problems.

MR. HOWARD: I apologize.

MR. CRESSE: So do I. Do you want to go ahe

MR. HOWARD: I think you would have to refresh me with a question.

Q (Mr. Cresse) All right, sir., Is it more

valuable -- is a plant that has a performance guarantee of 93% more valuable to the consumers of a utility than a plant that has a guarantee of 83%?

A I guess in the abstract, I would say yes. I think it's much more important that during the evaluation process one look at the characteristics of the plant that are being built. Providing a reliability guarantee of X% is no panacea, if the underlying engineering technical capability of the plant and its operators is insufficient to get to that number.

Q I understand that, sir. Then maybe I can rephrase my question. Is a plant that performs at 93% of more value to the consumer than a plant that performs at 83%?

A I believe so.

Q All right. And in that case, then, should specifications in the bid process include minimum performance and then you weight something above minimum?

A I have seen a number of very well put together contracts that provide incentives for performance for availability above certain thresholds and below certain others. Those thresholds have to differ based on the characteristics of the plant being proposed. If you have a multiple-unit combined cycle

facility that statistically is more likely to be available over time than a single-boiler coal facilit; for example.

Q Are contracts generally constructed that th purchasing utilities is entitled to all of the output of that plant?

A There's quite a bit of diversity on that issue. I'm not familiar with the regulations in the state of Florida relative to selling to other wholesa buyers. I know in certain jurisdictions there are -- the capability exists to sell to a new steam host if he's a partner. And some, he doesn't have to be a partner but you might sell him a couple of megawatts regardless. So there is quite a diversity there; I would think that would come more under the policy decision than it is a financial consideration.

Q Are you familiar with Florida's broker syste

A This is the power brokering system?

Q Yes.

A There was a time in which I was somewhat familiar with it when I was involved with a project down here, but I can't say that I'm terribly familiar with it now. It's supposed to be a least cost --

MR. CRESSE: Counselor, would Mr. Huddlestor be the person who probably would be more familiar with

that, you think? I'll trust that he will be since I know he probably is, in view of where he was born.

I have no further questions.

CHAIRMAN DEASON: Mr. Neiser?

CROSS EXAMINATION

BY MR. NEISER:

Q Mr. Howard, good afternoon, I'm Dick Neiser with the Florida Power Corporation. I have just a couple of short questions.

I'm intrigued by your statement on Page 12 of your testimony, Line 23, which says, "Specifically, many utilities are able to maintain current debt service and earn some return on rate base even if every generating unit exhibits subpar performance." The word "many" and "all" generating units catches my attention. Do you have some specifics on what utilities they may be?

A No, I don't, but I can follow up if you would like.

Q Where did you come up with your comment?

A I had some assistance from my staff in putting that together.

Q Okay. You were having a discussion earlier with Commissioner Lauredo with regard to certain rights of who steps in in the event of trouble with a

developer and the possibility of bankruptcy and that t of thing. Did I understand your comments to be that j developer is in difficulty, that the developer could declare bankruptcy without permission of the lender?

A Well, normally, there are provisions in loar documents that prohibit that. But my understanding -- and I'm not a lawyer -- but my understanding is that it's pretty hard to prevent a party from declaring bankruptcy. It's sort of a fait accompli at that point; and you can forcibly insist that he get out of bankruptcy, but you wake up in the morning and he's done it to you.

Q But wouldn't those rights be written in the contract so that the lending institution would have th right to step in and either continue operation of the plant or shut it down, one of the two?

A Yes.

Q As their choice?

A Yes.

Q And then as to the priority of rights with regard to the utility having a right to step in in those difficult days of the developer versus the lender, what is your experience with regard to who comes first? Does the lender have the right to step i if the developer is in trouble, or does the utility

have the first right to step in before a bankruptcy situation occurs? From the contracts that you have seen.

A Well, I guess strictly speaking, the first mortgage holder has the first right subject to a right of cure and step-in provided to the second lienholder.

Q Which would be the utility?

A Correct.

Q In other words, the utility follows behind the lender rights --

A No, --

Q -- as to their decision to step in?

A -- I don't believe that's -- and I excuse for interrupting again.

Q You've seen more contracts than I have.

A My understanding is that, in effect, the second lienholder has the right to take over the project. What he has to do, of course, is to deal with the first lienholder within a certain period of time. The first lienholder grants him the right to step in and cure a problem before a -- and in the event that he does so, the foreclosure is null and void, in effect.

Again, I'm not a lawyer, but that's how the mechanism works.

Q Okay. And again, from your observation of contracts that exists with independent power producers,

are there performance criteria tied to what the lende
dictates or what the utility dictates with regard to
performance?

A They are tied to what the utility dictates. The lender normally comes in at the eleventh hour or l and observes what the power contract and related other support agreements provide to him and makes a decisior to whether or not he likes that package or not.

Q Okay. And then this is more of a curiosity question than anything else: If those performance criteria have been met by the independent power producer, but the utility is in need of that capacity or that plant in order to meet needs of the customers, but it would be an extra expense to the plant to operate, what's the plant to do in a case like that?

A Well, normally, the contract provisions provide to an earlier point that was discussed today - normally, the contract provides that the nonutility generator will basically run the plant at any time, at any capacity short of damaging the equipment when the purchasing utility so requires. And in the event of a system emergency, I think there are provisions that arguably might even step across that line where they are required to postpone scheduled maintenance to the extent practicable.

Q I have good news. That's the only questions I have.

COMMISSIONER LAUREDO: I need to ask you one very brief question. I'm confused now about the step-in clause, which I think you also call second lien clause.

I'm not a lawyer either, but aside from the normal rights of liens and the order, of course, first lien, second lien, all the rights -- I thought that was an independent right by contract, which meant literally step in.

MR. HOWARD: That's correct.

COMMISSIONER LAUREDO: Okay, They are not the same then as lien right --

MR. HOWARD: Speaking more precisely, and, again, I'm not an attorney but there is a contractual obligation, an executory contract obligation between the power buyer and the power seller that provides the buyer with the ability to step in and cure. And that right --

COMMISSIONER LAUREDO: Well, the step in and cure is a legal concept. The reason I'm --

MR. HOWARD: That right -- excuse me -- is secured by a second lien. So that it's a bankruptcy-proof right. An executory contract, of

course, says a bankruptcy trustee could do things to it, but he can't do anything to a filed lien. So the right to step in and cure is secured by second lien.

COMMISSIONER LAUREDO: Okay. I'm sorry I misunderstood. I thought it was a more practical nonlegal right of running -- I'm focusing on it from the reliability point of view. And I thought what you were bestowing through contract was not a modified lie right but a right to say this event causes a right to arise by which you can literally, in the practical world not -- send your managers over and run the thing tomorrow at 9 o'clock in the morning. And that's what I thought you were talking about.

MR. HOWARD: I am talking about that. In fact, that is what exists.

COMMISSIONER LAUREDO: And operate irrespective of all the lien rights and all of that stuff? Okay. Thank you.

CHAIRMAN DEASON: Mr. Erwin?

CROSS EXAMINATION

BY MR. ERWIN:

Q Yes. I'm David Erwin on behalf of Kissimmee Utility Authority.

I believe you indicated in your testimony that you were not familiar with municipals and co-ops in Florida.

A I'm really not; I have not any depth of experience with them.

Q Could you indicate to me why not, why you're not familiar?

A In my experience I've never personally done a deal with a muni or a co-op.

Q Do you have any comments, then, about the attempts in this proceeding for the requirement that each of the municipals and co-ops engage in the RFP process since you're not dealing with them and haven't in the past?

MR. MOYLE: Mr. Chairman, we respectfully object to this questioning. I think the witness has indicated that he's not familiar with that and it far exceeds any part of the comments or testimony that he's filed.

CHAIRMAN DEASON: I think the witness is free to answer that. If he doesn't have knowledge, he

doesn't have knowledge, and he can on so state.

MS. BROWNLESS: And if I can make one furth comment, Commissioner, CEPA, the organization on whic Mr. Howard is testifying, does not believe that municipalities or co-ops should have to competitively bid, and we've so stated in our proposed rule. So to the extent that the Staff has another position, that's their position and not the position of our organization.

CHAIRMAN DEASON: Mr. Erwin, if you want to restate your question, please, proceed.

MR. ERWIN: Well, I think I could just as easily have asked Ms. Brownless and she has answered m question very adequately, thank you. (Laughter)

Q (By Mr. Erwin) I believe also you indicated that if you were in Florida, you would find that Black & Veatch and other well-known companies would have built plants for both IPPs and IOUs and I assume municipals as well; is that correct?

A I would assume.

Q So there wouldn't be a great deal of difference in the kinds of plants that your organization would be offering as opposed to, say, a municipal.

A I'm stretching but no, I wouldn't see great

differences.

Q So if that is pretty much the same, then does the cost of money for the financing of those plants become a significant element in anyone's decision making?

A Amongst others, yes.

Q Okay. And at any given point in time, could you indicate to me which would be a more favorable or lower cost rate for financing between a municipality and IOU or even an IPP out on the market?

A I think generally speaking IDBs or industrial revenue bonds, that I've seen tax-frees are backed up by a letter of credit from a single A or better institution. Given that and their tax free nature, certainly that's going to be a lower cost of debt financing. When you roll in the cost of the guarantee from this single or double A institution, it puts a wrap around the credit quality, then I think there's significantly more variation in the marketplace. If it's a municipality that has historically had problems, the cost of that credit guarantee becomes the dominant factor in how much that debt costs.

If I had more specifics about the particulars of the Florida muni community, I might be able to get a little closer to accuracy. I know there are some munis,

nationwide who can't raise funds regardless of costs. It's quite a broad spectrum.

Q Then you're unable as a general proposition to indicate whether the cost of money to a municipali would be less, more or greater than that of an IOU, fo example?

A Well, I think if you tried to broad brush it and take a well-run IOU versus a well-run muni and consider that one had a tax free source of debt, then certainly the tax free would be cheaper.

MR. ERWIN: Okay. Fine. That's all I had. Thank you.

MR. MOYLE: Mr. Chairman, one question.

REDIRECT EXAMINATION

BY MR. MOYLE:

Q Mr. Howard, you were asked about the lender requirements and substituting in some way for Commission requirements.

I'd like to ask your opinion about whether these lender requirements, do you believe that they supplement or assist the Commission in carrying out regulatory responsibilities, both as to the cost, the quality of service, and reliability?

A Yes, I do.

Q Thank you.

CHAIRMAN DEASON: Any further questions for Mr. Howard?

COMMISSIONER LAUREDO: I just want to ask him. Makowski and Company, it's one of the largest in the IPP?

MR. HOWARD: We're up there. There are several measures that people apply to IPP, but yes.

COMMISSIONER LAUREDO: Are you a publicly traded company?

MR. HOWARD: No, we're not.

COMMISSIONER LAUREDO: Is there something on the record about the -- I'm trying to learn generically about a typical IPP. Could you provide me with some background on the Company, for example?

MR. HOWARD: I'd be happy to.

COMMISSIONER LAUREDO: That is not confidential? Thank you.

MR. HOWARD: Thank you.

CHAIRMAN DEASON: Thank you, Mr. Howard.

(Mr. Howard excused.)

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CHAIRMAN DEASON: Ms. Kaufman, you may call your --

MS. KAUFMAN: We have one more witness that we'd like to get to today. That's Ms. Robertson.

CHAIRMAN DEASON: Please be advised that 6: is the bewitching hour.

MS. KAUFMAN: Thank you, sir.

HOPE E. ROBERTSON

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MS. BROWNLESS:

Q I'm Suzanne Brownless. Suzanne Brownless, as previously identified on the record.

Can you please state your name and address for the record?

A Hope Robertson. My business address is 129 Upper Creek Road, Stockton, New Jersey 08559.

Q By whom are you employed and in what capacit

A I'm the publisher of Robertson's Publishing Services, and I work as a consultant in the energy fie

Q Have you previously filed direct and respons comments as well as exhibits in this process?

A Yes, I have. And I filed two exhibits labeled HER-1 and -2.

Q Okay. Do you have any changes which you'd like to make to either your comments or your exhibits at this time?

A Yes, two very minor ones. On Page 4, Line 4

the last word in that paragraph should be "achieve," not "alleviate." And on Page 6, Line 16, it should say "bidding procedures ensures more fairness."

Q Okay. Thank you.

With these changes if I asked you the same questions found in your comments today, would your answers be the same?

A Yes.

Q Thank you. Can you please give a brief summary of your comments?

A Sure. My filed comments cover four areas. One is the history of competitive bidding in the United States, the results of bidding, lessons learned from other bidding processes and then the next step needed to make bidding more competitive.

Briefly, right now, 74 utilities in the U.S., in 31 states, have used some form of competitive bidding to fill capacity needs for power. And I might add based on some comments made this morning, 14 states have competitive bidding rules, and the majority of those states use a process which approves the RFP in the beginning before it's actually issued on the streets and they also establish the need for the capacity before an RFP is issued.

Based upon my review of competitive bidding ,'

systems in the U.S., I have several conclusions about the use of competition to meet future electric capacit

First there's no question that bidding has not only provided state commissions with a tremendous amount of competitive pricing information that was previously not available, but it's also required that bidders as well as utilities have had to sharpen their pencils due to the high level of competition in this market.

The second conclusion I'd like to mention is bidding also provides a very flexible tool for commissions. It allows you to shape the state's resource mix, such as the size of the projects that yc wish to see, the types of technology, the capacity type. It provides an opportunity to have a wide choic of which supplier may provide the future capacity need which could be either the utility or the nonutility, and, therefore, meet your consumers' and ratepayers' needs the best.

Whether Florida can realize the maximum benefits from bidding will depend upon whether or not this Commission plays a very active role in developing and reviewing the RFPs in an open public process and equally important in having your utilities committed t competitive bidding.

Therefore, in my opinion, it's key that this Commission develop a rule that makes the process fair to all players, which includes allowing the utilities to participate on an equal basis with all the other competitors should they choose to.

The competitive bidding rule proposed by CEPA will allow Florida to move beyond what other states have done and take the next step towards implementing a more competitive process.

Q Thank you, Ms. Robertson.

CHAIRMAN DEASON: Questions for Ms. Robertson. Mr. Cresse?

MR. CRESSE: Mr. Chairman, I just have one question.

CROSS EXAMINATION

BY MR. CRESSE:

Q Ms. Robertson, on Page 4 of your testimony you outline some of the experience that you had around over the country.

A Uh-huh.

Q Am I reading this correctly, that you say on the bottom of Page 4 that 19,000 megawatts have been selected through bidding?

A Correct.

Q And approximately 15% of those have been

canceled?

A I don't have my calculator with me but I think that's correct, it's about 15 but it's almost 3,000 megawatts, so, yeah.

Q And do you know whether they were canceled because the utility backed out or the bidder backed ou

A It's a combination; there are a whole host o reasons they have been canceled. Some of the recent cancellations last year were actually when the utilit chose to buy out the contract. I've included them as canceled projects because that's the way the utilities report them to me.

In some instances -- in the majority of the instances where the projects have been canceled, it's been before a power purchase contract was signed. So it's in the very, very preliminary stages.

Sometimes it's because, you know, the bidde decided -- didn't understand the bid process or bid something that they decided after analyzing it is not going to work. Sometimes it's the utilities' choice. It just depends; every project is different. But overall it has been the bidders that have canceled in the very preliminary stages in the process.

I know of no case so far of any project that's resulted from competitive bidding, where a

project has been canceled during construction or after it has come on line. It's always been in the very, very early stages. So from a planning perspective, that's been great for the utilities.

Q So in those cases they just rebid it and go forward or are they allowed to negotiate with the second, No. 2 bid?

A Sometimes. In Massachusetts, when one of the bids has dropped out, they've actually taken the next one on the list and negotiated. It depends on how much time has elapsed. If it's been too long, then they would have to rebid it.

In a number of cases there were projects that had been canceled, and I certainly found this in a recent survey of the utilities. They were actually delighted the project was canceled because the capacity needs have changed in so many areas and demand has dropped in a number of areas. But they were glad that the project disappeared because they didn't need the capacity at that time. So it's actually worked to the advantage of the utility.

So overall the experience reported by the utilities has been that the cancellations have not been a hardship, especially since a lot of them design, in their RFP process, they anticipate. For example,

Virginia Power anticipated, I believe it was 20% of t projects would drop out, so they oversubscribed the capacity block.

MR. CRESSE: Thank you.

CHAIRMAN DEASON: Mr. Neiser?

CROSS EXAMINATION

BY MR. NEISER:

Q Ms. Howard, excuse me, Ms. Robertson, on Pa 13 and 14 of your testimony you are talking about a couple of choices that a utility might make with rega to how to proceed with the bidding. One would be to say I want to participate and, therefore, put a seale bid in and participate like everybody else. Otherwis decide I don't want to build and you can evaluate it that situation, but plan not on participating yoursel as a utility.

Am I reading your testimony correct?

A That's correct.

Q Okay. Compared, then, to the bid proposals, the bid rule proposals that have been submitted, firs the Staff's, the Staff's alternative bidding rule, do you see how that would work in sync with your firs choice of where the utility would try to say "I want t participate and I want to be on the same basis as eve else." Do you think it would work under the scheme o

Staff's alternative proposed rule?

A Let me think about this for a minute.

I haven't memorized the Staff's proposal, and I think Mr. Huddleston might be able to respond to this more effectively than I can. But under the Staff's proposal you would have to put out pricing information.

Q That's correct.

A And under the proposal in what I'm talking about is you would not.

Q Correct. So my question is it's oil and water, isn't it? Isn't the Staff's alternative proposed bid inconsistent with your suggestion that the utility compete on a level playing field with everyone else?

A Right. But I'm assuming for the purpose of this discussion, that the CEPA rule would be adopted. You would operate under that procedure.

Q Okay. But do you have an opinion as to whether the Staff's proposed rule would work with your first concept?

A I don't think it would.

Q Okay. Basically I agree with you. I just wanted to see if I'm reading your testimony the same way.

Going now to the CEPA proposed bid, does it

not require the disgorgement of a lot of financial da by the utility prior to the bidding process?

A I'd rather defer to Mr. Huddleston to answe specifically. I think it would be better if Mr. Huddleston answered that. But it's my understanding, just briefly, that it would not.

Q For the sake of fun this afternoon, if it did, would that square with your suggestion that the utility and all other bidders should be on the same playing field?

A Well, it doesn't so I think --

Q Well, I think we'll find that out from some other witnesses whether it does or doesn't, and I'm nc asking you to explain the rule in detail.

A Right.

Q As I read it, it does require that, and that

A As you read the CEPA rule?

Q Uh-huh.

A Well, I would disagree based on what I've learned about what the CEPA rule is about. It does nc require you to reveal all of your pricing information.

Q No. But if it required the utility to disclose any financial pricing data that was not required of the other potential bidders, would that be inconsistent with your first proposal here that all

should participate equally if the utility does not grade its own report card then?

A First of all, the utility is always in a -- I mean, the utility is in a different position than any of the other bidders. You know what all of your costs are and what your next planned capacity is going to be. So you're the one putting out the RFPs. You have the upper hand in terms of knowing exactly what it is you want and how you're going to structure it, et cetera. So the bidders can only respond to the information that you give out. So I don't think that it's unfair that the utility has to reveal some basic -- their assumptions for how they would meet their future capacity needs, including some basic assumptions about pricing.

I'm not saying exactly what your price would be for a 500-megawatt gas plant, but I think some basic parameters are critical so that everybody is operating on the same level.

Q And perhaps that's the point of some disagreement then for the future, as to what would be reasonable for a utility to have to disclose in advance of the bidding if we were saying everybody is to participate on the same basis. Do we disagree on it?

A I think those things could be worked out. It,

has been worked out in other areas.

Q Okay. That's all I have.

CHAIRMAN DEASON: Other questions for Ms. Robertson? Staff?

Thank you, Ms. Robertson. I think you can make your flight.

MS. ROBERTSON: Thank you.

MS. BROWNLESS: Excuse me, Terry, I just hav one question to follow up on.

I just have one follow-up question. It's very brief.

REDIRECT EXAMINATION

BY MS. BROWNLESS:

Q Are you aware of any states that have a bidding system where avoided cost information or financial information is provided on the front end where the utility also bids?

A It has happened, but it -- for example, in New York state, the utilities -- all bidders know, you know, what the avoided cost is, et cetera, before they bid, and utilities actually submit a bid. Niagara Mohawk Power submitted a bid in their own solicitation they also selected their own project as well as an IPP So it has happened.

MS. BROWNLESS: Thank you.

CHAIRMAN DEASON: Thank you, Ms. Robertson.

WITNESS ROBERTSON: Thank you.

(Mr. Robertson excused.)

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CHAIRMAN DEASON: I know that there are a number of witnesses who would like to be heard today, but it's just not possible. The hour does not permit it, and I apologize for that but it's beyond my control.

I propose that we conclude for today, and that we reconvene tomorrow morning at 8:30, not 9:30, 8:30.

MR. ERWIN: Excuse me. Could I just make an announcement?

I'd like to leave copies of comments and testimony up here on the banister for people who didn't get it because we didn't distribute it to everybody, so I'll do that.

CHAIRMAN DEASON: That's fine.

MR. ERWIN: Thank you very much.

CHAIRMAN DEASON: Reconvene at 8:30.

(Thereupon, hearing adjourned at 5:40 p.m. to reconvene at 8:30 a.m., September 30, 1993, at the same location.)

(Transcript continues in sequence in Volume III.)

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	
Proposed Amendment of Rule 25-22.081, F.A.C., Contents of Petition; and Proposed New Rule 25-22.082, F.A.C., Selection of Generating Capacity.	DOCKET NO. 921288-EU

SECOND DAY - MORNING SESSION

VOLUME III

Pages 274 through 415

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN J. TERRY DEASON COMMISSIONER SUSAN F. CLARK COMMISSIONER LUIS J. LAUREDO COMMISSIONER JULIA L. JOHNSON
DATE:	Thursday, September 30, 1993
TIME:	Commenced at 9:30 a.m.
LOCATION:	FPSC Hearing Room 106 Fletcher Building 101 East Gaines Street Tallahassee, Florida 32301
REPORTED BY:	JOY KELLY, CSR, RPR Bureau Chief SYDNEY C. SILVA, CSR, RPR PAMELA A. CANELL Official Commission Reporters

APPEARANCES:

(As heretofore noted.)

DOCUMENT NUMBER-DATE
10823 OCT-8 93
FPSC-RECORDS/REPORTING

I N D E X

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JOHN SEELKE

Direct Examination by Mr. Watson	382
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EXHIBITS

Number:		Identified	Admitted
3	(Late-Filed) (Roach) Copy of a well-crafted contract)	305	
4	((Late-Filed) CEPA) Information re Independent Power Producers	382	

PROCEEDINGS

(Hearing reconvened at 8:30 a.m.)

(Transcript continues in sequence from Volume III.)

CHAIRMAN DEASON: Call the hearing to order, please.

MR. McGLOTHLIN: Mr. Chairman, the next witness for the Competitive Energy Producers Association is Dr. Craig Roach.

DR. CRAIG ROACH

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. McGLOTHLIN:

Q Sir, would you please state your name and business address for the record?

A Craig R. Roach, 1225 I Street Northwest, Washington, D. C.

Q Dr. Roach, by whom are you employed and in what capacity?

A I'm a principal with Boston Pacific Company. Incorporated.

Q And for whom do you appear today?

A For the Florida Competitive Energy Producers Association.

Q Dr. Roach, I have two documents. The first is captioned "Comments and Exhibits of Craig R. Roach, containing testimony and ten exhibits. The second is captioned, "Responsive Comments of Craig R. Roach. Did you prepare these documents and do you adopt them this morning?

A Yes, I do.

Q I checked the exhibit book and these documents have been incorporated. Dr. Roach, would you proceed with your summary at this point?

A Yes, I will.

Good morning. My comments go to three issues. The first two are out of Section 712 of the Energy Policy Act. Those are the possible effective purchases on the utility cost of capital and the effect of leveraged capital structure. The third issue that I speak to is the proposed cap on competitive procurement.

Turning first to possible cost of capital effects, if I could make just one point today it would be this, and that is that the same cost of capital concerns must be raised for both the buy and the build option.

In the proposed debt equivalent analogy that Florida Power has in its testimony, that is not being

done and, therefore, that method is biased toward the build option and would chose building even if buying would be to the significant advantage of Florida's ratepayers.

That opinion is based on my understanding of what the cost of capital concern is all about. I think it's all about disallowances. In other words, I think the bond rating agencies are concerned that at some point the utility would pay capacity payments to a private power producer and then not be reimbursed for those payments, that is, not gain rate recovery.

I think it's important that we see that this is all about disallowances because as soon as we mention the word "disallowances," we understand that there's a risk of a cost of capital effect when the utility builds, too. In fact, the history of disallowances is a history when the utility builds.

So I think the question before us today is not is there any risk when the utility buys power, but whether is that risk higher or lower than when it builds? And in my view, I think you would find that the risk of disallowance is consistently higher with building simply because the utility takes on more classes of risk: Notably construction and operating risk. And that's not only my view but it's the view of

others too.

Virginia Electric Power Company, VEPCO, is one of the utilities that, it's been said, has been downgraded because it has purchased so much IPP power. In its Section 712 proceeding it stated bluntly that things would have been worse had it built instead of bought. In fact, in its testimony in Section 712, and I quote "In fact, the Company, VEPCO, believes that the downrating of its securities discussed above would have occurred much earlier if the Company had undertaken the massive construction program that would have been required in lieu of purchasing."

It's also important to see that we're talking about disallowances because I think it puts us on the right track for a way to mitigate the concerns about cost of capital effects.

In the utility approach the only remedy is to increase their return on equity. But if you think about it correctly, if you think about disallowances, then you see that the correct remedy is to minimize the chance for a disallowance and the best way to do that is to preapprove contracts. That remedy is already in place in this state.

The bond rating agencies, in my testimony I cite that they recognize the importance of preapproval,

they recognize the importance of cost recovery. I cite and quote two recent credit ratings, one for Consolidated Edison in New York and the other for Southern California Edison. In both of those ratings, Standard & Poor's went out of its way to say that preapproval or assured cost recovery mitigates to a substantial extent any cost of capital concerns that they might have.

So what we would ask is if you want to consider cost of capital effects, if for example, you take the Staff's approach and look at them on a case-by-case basis, we ask that you please do it the correct way. We would ask first that you would reject the debt equivalent analogy proposed by the utilities become it is bias toward the build option. We would ask that when you do look at cost of capital, you put it in terms of the relative risk of disallowance. That you ask not only is there any risk with purchasing, but is that risk higher or lower than with building? And finally, we would ask that you recognize the import of the regulatory procedures you already have in place to minimize the risk of disallowance with purchasing.

Turning to the effect of leveraged capital structure, I want to start with a point of clarification.

While it's true that private power producers start out with an amount of debt which may be close to 80% of the total investment in the power plant, it's important to see that that number declines rapidly over the term of the loan, usually 12 to 15 years, so that by the end of that term it is a 100% equity financed project.

I raise that point because project finance is fundamentally different from corporate finance used by the utilities. The utilities will generally maintain a 50/50 split between debt and equity. But in project finance, the apportion of debt declines throughout the first 12 to 15 years of project life. That means that the high leverage occurs only on Day One, and that soon into the term of the loan the project finance or the IPPs actually have a lower percent of debt than the utility corporate finance.

The concerns raised about high leverage in Section 712, there are two of them: One is reliability and the other is whether there is an unfair competitive advantage gained by high leverage.

Speaking to reliability, we can theorize about all kinds of scenarios, things that could happen, but the record for IPPs on reliability is really quite clear. It is a superior record. In my testimony I

cite four separate sources which report IPPs having availabilities in excess of 90%. IPPs are paid to perform, they are paid to be there when the ratepayers need them, and they have been there when the ratepayers need them. I think we can put aside the concern with the reliability based on the facts.

The second concern with high leverage is does it give some unfair competitive advantage to private power? As a threshold matter it does not because project finance is an option for utilities. They can go out and do it too.

We can expound a little bit on this. There's some talk in the testimony that I've seen that somehow project finance is gained by IPPs and it is at the expense of the utility's credit worthiness. Well, this brings us full circle back to the first question, the cost of capital issue. And the answer is no it's not at the expense of the utility's credit worthiness if there is a well-crafted, preapproved IPP contract done in the context of IRP and competitive procurement. In other words, a contract of the sort that can be done right here in Florida.

One other issue that has is come up and that is a question of, "Well, if utilities only get 50% debt, why doesn't IPP get 80? How do they do that?

Well, the answer is that if they are able to achieve it, and it is not easy to get project finance, but if you do get project finance and you do get 80% debt, you get it because investors perceive lower risk.

And I think they perceive lower risk with an IPP for four reasons. First and most importantly, the IPP has a contract that efficiently allocates risk. Now, that means that the risk of construction is put on a construction company. The risk of operation is put on an operating company. The risk of fuels management is often put on a fuels manager. In other words, the investor is shielded from risk because this risk has been placed on a party who controls or has responsibility for the matter under risk.

A second reason investors perceive lower risk is that they sometimes prefer to invest in a single asset where they can get their arms around the risk. They prefer that as to investing in a utility that has invested in several power plants and perhaps has diversified into unrelated ventures.

Thirdly, I think investors perceive lower risk because they prefer the before-the-fact risk allocation of a contract to the after-the-fact risk allocation of a prudence review.

And, finally, they preperceive lower risk

because we do a lot of things for them. Specifically, we have debt reserves. We always assume that the lender will require that over on the side there's the ability to pay six months of principal and interest payments if something goes wrong. Also, we shorten the term of the debt; again, 12 to 15 years is typical.

Turning finally to the proposed cap on competitive procurement, I don't find any justification for a cap in this proceeding. I don't see anything in the two Section 712 issues that I've looked at that would lead me to propose a cap, and I don't buy into the arguments that I've seen in the testimony here.

There are three arguments that I've reviewed.

The first is a portfolio or a diversification argument. It's a "don't put all your eggs in one basket" argument. That's a good argument in general. It certainly applies to stocks, but we have to understand that buying and building are not two different resources. They are simply two different ways to go about securing supply side capacity. And one of those ways, if you're looking at ratepayer risk, if your goal is to minimize ratepayer risk, one of those ways, namely buying, is consistently lower risk for the ratepayer. When you buy IPP power, what you've done is you've shifted construction and operating risk

to the IPP and away from the ratepayer. That's not true with traditional cost-of-service ratemaking. The ratepayer still bears those risks limited only by imprudence. Since buying is consistently lower risk a mix of buying and building does not lower the risk for the utility.

A second justification for the cap is that utilities should be allowed to accumulate cash. Well, in a competitive business, that's not the way it works. In a competitive business you get cash flow the old fashioned way: You earn it. That is to say, you offer the ratepayer the best deal in terms of cost, risk and reliability, and the cash flow follows.

I don't think there's any reason to simply choose the utility, even if it's a higher cost producer, just to accumulate cash. There is no reason for the Commission to be concerned that capacity needs would go unmet. The RFP experience in this state shows that there are many well-established IPPs ready, willing and able to provide power plant capacity when the states need it.

The third and final argument for a cap is that there should be a cap on competitive procurement. It should be equal to 15%, which is the capacity reserve that the utilities maintain. The premise of

that justification is that private power is somehow terribly unreliable and that they need to be backed up. Once again, the facts are that IPPs have a superior record for reliability, and there is no need to limit them to some capacity reserve on the presumption that they are not.

One final comment on the cap. There's a remark by the gentlemen from Merrill Lynch that I agree with and I think it speaks to the issue of cap. He says that increasingly on Wall Street in the bond-rating houses they are looking to the competitiveness of the utilities to say how they view that utility. Competitiveness means that the utilities have to keep their cost low, so they keep their large industrial customers on line. I agree that competitiveness is increasingly the focus of Wall Street, and I also would believe that the best way to keep a utility competitive is to competitively procure all of its supply side resources. That concludes my summary.

MR. McGLOTHLIN: Dr. Roach, is available for questions.

CHAIRMAN DEASON: Questions for Dr. Roach.

COMMISSIONER LAUREDO: May I ask him a couple?

CHAIRMAN DEASON: Sure.

COMMISSIONER LAUREDO: Dr. Roach, and I should have said this yesterday, my questions are not in any way leading. I'm trying to understand this industry, as a fairly recent Commissioner, so I'm not -- I hope you don't misunderstand, but I want to tap your long experience in this area.

In your view, when you discuss high leverage, just normally in business, what is the value of equity, particularly if you're a lender, or if you're looking at the viability of a project, in your view?

DR. ROACH: The value of equity to a lender is that it serves as a cushion so that if things go wrong, before you get to the level where the debt service cannot be made, you've cut down through that equity cushion.

COMMISSIONER LAUREDO: And isn't it, in fact, the only real and tangible evidence of somebody else valuing the project by putting their money at risk, and so the higher the equity, the more there is a confidence level if you're a lender that somebody else besides you is making a judgment that this is a good project?

DR. ROACH: Your point is well-taken; stand alone it's right. But not in private power, it's not

the sole evidence.

When you develop a project all of the pieces of this puzzle are in place. You can take confidence when a company like General Electric takes equipment risks or a company like Bechtel takes construction risks or a company like any of the several operating companies --

COMMISSIONER LAUREDO: Excuse me. How does Bechtel take a construction risk?

DR. ROACH: When we build these, we get an EPC agreement, an EPC; engineering, procurement and construction agreement, and what will go on is they will say, "This plant will be built to these specifications at this price."

COMMISSIONER LAUREDO: In other words, it's a contract price guarantee?

DR. ROACH: Correct.

COMMISSIONER LAUREDO: Is that unique to the IPP business?

DR. ROACH: No.

COMMISSIONER LAUREDO: Because Bechtel does it all the time, both here and overseas. Isn't it a -- it's not a standard but it's relatively standard on project financing?

DR. ROACH: It's standard in project finance.

It's one of the advantages of project finance.

COMMISSIONER LAUREDO: So it's not unique to this industry. It's generally -- but you agree with me, then, in general that equity does. As I focus on this issue and I try to understand it, it tells me something about the confidence of people putting money in at a loss.

DR. ROACH: Certainly it's one piece of evidence that there are others who have confidence, but it's not the only piece of evidence.

COMMISSIONER LAUREDO: From your experience, so that I can relate percentages a little bit to capital at risk, what is the typical, let's just assume a 20% equity, what is the total project cost if I were an investor, what the actual dollar amount is? I mean, I won't hold you to it, just off the top of your head.

DR. ROACH: If you do -- let's just get some rough numbers. If I gave you ballpark -- if you do a combined cycle system today, you do 100 megawatts, it's got to be $100 million. It's about a -- you know, it will be, plus or minus, around $1,000.

COMMISSIONER LAUREDO: So private investors are risking $20 million?

DR. ROACH: Something like that on that machine.

COMMISSIONER LAUREDO: Okay. Well, that helps because I can understand millions.

When you were explaining -- do you equate investors and lenders in the same breath? When you were making your presentation, you were talking about investor's evaluation of risk, you mean lenders or the equity --

DR. ROACH: I think of both.

COMMISSIONER LAUREDO: Of both. How do you reconcile your statement that investors, which includes lenders, consider IPP projects to be lower risk with previous testimony from Mr. -- one of your witnesses, upon my questioning, that these projects typically have a capital venture component, which as you know capital venture is high risk venture, lending money, and that, in fact, I think he said about a point, the rate is usually about a point over what you would otherwise get. How do you reconcile those? Usually lower risk means lower interest rates.

DR. ROACH: I'm sorry. There are two separate questions being asked. My comment says that it is lower risk for the utility. Mr. Howard, yesterday, was saying that if you compare the risk and the cost of capital, that yeah, the private power producer takes on more risk. But we're talking about

-- in cost of capital here, we're talking about the risk to the utility. And in purchasing with well-crafted preapproved contracts, the risk of any disallowance is very low to the utility.

COMMISSIONER LAUREDO: So you did not mean to say that the lender, independent of the utility, the lender of the IPP looks at the IPP as, I guess, versus using those monies for some other project as a lower risk project financing? Because that wouldn't logically fit with the, I guess, accepted proposition that lower risk in lending means lower interest and vice versa.

DR. ROACH: Well, again, there's two separate questions. My primary point on cost of capital is that buying is lower risk for the utility. Now, if you ask --

COMMISSIONER LAUREDO: I'm asking as the IPP.

DR. ROACH: Right.

COMMISSIONER LAUREDO: Forget about the utility for a minute.

DR. ROACH: Okay.

COMMISSIONER LAUREDO: I thought I heard that it has a higher interest rate. I thought I heard that it has a capital venture component. So it follows, correct me if I'm wrong, that it has to have a little bit of a higher perception of risk.

DR. ROACH: It does. My comments were to this point: That if there is a cost of capital advantage, it is because investors perceive a lower risk for the project. Investors in total perceive a lower risk for the project. And I listed several reasons why that might happen. Okay.

It is not always true, though, that the cost of capital is lower for a private power producer. Sometimes the risk is not lower. But it's not -- if it does happen that we get a lower cost of capital and a private power development project, it's because they perceive lower risk and they perceive it, I think, for those four reasons that we stated.

And one other little technical clarification, I agree with Mr. Howard that debt costs are higher and a hundred basis points is a good estimate, but the cost of capital, you know, the overall cost of capital, equity plus debt can still be lower even though the --

COMMISSIONER LAUREDO: Because debt is always cheaper than equity?

DR. ROACH: Assume that the lender will require that over on the side there is the ability to pay six months for principal and interest payments if something goes wrong. Also, we why that might happen. It is not always true, though, that the cost of capital

is lower for that we stated.

COMMISSIONER LAUREDO: But I was impressed that in your analysis of this lower risk scenario, you did not allude to what I would call, just as layman's terms, the cash flow element here. In other words, if I were lending money on a project like this, where I have a -- are IPP contracts, they're pretty unilateral; I mean the utility, except for failure to perform, has to buy the power; is that a correct assumption?

DR. ROACH: The utility agrees to buy the power if the performance is as contracted.

COMMISSIONER LAUREDO: So using nontechnical terms, we do have a captive, almost guaranteed cash flow over the period of the loan. I mean, you know, they all started too big to fail.

You all know that we can't let Florida Power and Light and Florida Power Corp fail. So if they have a commitment to a contract, it guarantees cash flow, so you can make really a dedicated schedule of payments and that's what drives this argument that I've heard now for two days about the quick buildup of equity by reducing debt. Don't you agree that that's a plus for the IPP, an advantage of an IPP project?

DR. ROACH: There's no doubt that to build a power plant, we need a contract to sell the power.

We're in a monopolized or more precisely monopsonized market. We have a single buyer. No one is going to loan us money if we don't have an agreement with that single buyer to sell the power. But that's no different, I think, than the utility itself. No one would loan money to the utility if it didn't have some indication that it had a market. Its indication is it's monopoly franchised. So there's really no difference. All investors want to see some indication that there is a market there for the product. And when it's a monopolized market, you need a strong indication like a contract.

But again, you know, I think you're raising the fundamental question raised in Section 712. Does the fact of that contract somehow hurt the utility's cost of capital? And again, the answer is the same. No, it doesn't, with well-crafted, preapproved contracts.

COMMISSIONER LAUREDO: One other question on the debt reserve which you talked about a six-month principal of interest, I imagine, is that funded out the loan or is that part of the equity normally? Is that out of the loan, basically; a reserve out of the loan?

DR. ROACH: No, it's more often a letter of credit.

COMMISSIONER LAUREDO: Letter of credit by

the equityholder.

DR. ROACH: It can be cash by the equity, but it's more often a letter --

COMMISSIONER LAUREDO: But it's not funded by the loan?

DR. ROACH: No.

COMMISSIONER LAUREDO: Okay. This is a philosophical question so don't -- I'm trying to figure out, Mr. Howard left before I could ask him this. I'm struggling with how -- and he kind of touched on it a little bit and I'm going to try to look at some contracts if we have access to actual contracts.

How can you transfer through commercial contract some of the what I call social contract responsibility? That's something that bothers me as a Commissioner. You know, the duty to serve, reliability, all that kind of stuff.

From your experience, do you see legal, commercial mechanisms that can transfer some of those social responsibilities, in your experience?

DR. ROACH: I do see them transferred. I hesitate to call them social responsibilities.

Take the most important one, reliability. In a contract, reliability becomes a primary concern and it's addressed through explicit requirements on

availability. For example, you don't get paid if you don't achieve an availability that you've stated in the contract, typically 90%. The contract can be canceled if you abandon the project. There are limits on force majeure, limits on how many hours you can be out. There are requirements to schedule maintenance with the utility. There are requirements to perform when the utility declares an emergency. These are all standard parts of a contract, almost these days, boilerplate, that gives the IPP a strong financial incentive to be reliable. I don't really see that as any different than the incentive that the utility faces too.

IPPs have to be reliable because they won't get paid. But if you want to get into this notion of responsibility, remember that the private power producers here have to maintain a reputation. If they do something terribly wrong in Florida, they'll never compete any place again. Reputation is very important. So in that sense, too, I think there is just a great deal of pressure to always provide for the ratepayer, to always do the best.

COMMISSIONER LAUREDO: Thank you very much.

DR. ROACH: Thank you.

CHAIRMAN DEASON: Questions?

MR. WILLINGHAM: Yeah.

CROSS EXAMINATION

BY MR. WILLINGHAM:

Q Mr. Roach, my name is Bill Willingham. I represent the Florida Municipal Electric Association and the Florida Municipal Power Agency. Does your testimony also apply to municipals, as far as the risk?

A I have not really thought about whether there's any special concerns with municipals. Some of the principles are generally true. The concern of cost of capital being a concern about disallowances, for example, yes, that would apply. But if --

Q I guess what I'm specifically asking is a municipal that issues a bond, based on its electric revenue requirements to fund a new plant, would the risk for that be higher or lower for the ratepayers?

A Higher or lower than --

Q Right. If we have a bond basically that's tied only to the electric revenues from that plant, would our risk -- would the ratepayer's risk be higher if we issued that bond or if we came in with your contract?

A I think the risks are probably similar. What you're saying is that -- naturally this is a very relevant point. What you're saying is that if you build something that the ratepayers bear the risk of that, the demand risk of that, and if an IPP were to

build, the ratepayers bear that risk too. And I think that's correct.

MR. WILLINGHAM: Okay. Thank you.

CROSS EXAMINATION

BY MR. CRESSE:

Q Mr. Roach, I'm Joe Cresse. How would reputation be considered in bid evaluations if the Commission adopted CEPA's proposal?

A I don't know that the CEPA proposal speaks to the details of the RFP. I can give you an example in other RFPs.

For example, right now on the street is a RFP from Baltimore Gas and Electric. It is one of the RFPs that more heavily than any others asks about reputation. It asks about a track record with the technology being proposed. It asks about the people and their experience in terms of the people who are building the plant, operating the plant, supplying the fuel. There are -- in that RFP and in many other RFPs, there are ample pages given to tell us about who you are and what you've done and why we can think that what you've proposed here is doable and that you'll live up to the commitment you've made.

Q You're suggesting, though, that the -- if an RFP is proposed by a person that has a bad reputation,

that that would not be considered in the bid evaluation?

A Did you misspeak there? Is it -- you're saying if a bid was put in with someone that had a bad reputation?

Q Yes, would that be just thrown out on its face because of a bad reputation?

A I don't know that it would be thrown out on its face, but it would be considered.

Q Page 17 of your testimony, Lines 15 through 18, would you read that, please, for the Commission? That's your original comments.

A Uh-huh. It's at Line 15, "Preapproval of IPP contract shields the utility from disallowance due to risks such as demand risk; the risk that the power will not be needed or that the power will become uneconomic is a primary concern for utilities and preapproval mitigates or eliminates that concern."

Q Yes. In that case the utility is protected. What protection should a contract contain to protect the ratepayers, the consumers, from failure on the part of an IPP?

A It should contain many of the provisions that are already in most contracts. The way I see this, the ratepayer and the IPP cut a very fair deal. The IPP says, "Look, we'll live up to our commitment to deliver,"

this power when its needed, as it's needed, at this price. And if we do that, ratepayers, you'll buy it." I think the kinds of provisions in contracts that are already out there state that deal. Again, unlike utilities, private power producers do not get paid if their power plant is not on line, if it's not available for a guaranteed amount of time. They do not get paid if there are cost overruns, either in construction or operating. So there are a variety of protections for the ratepayer in a private power contract that do not exist for the ratepayer in traditional cost of service ratemaking.

Q Would a well-crafted contract provide that if the IPP fails, all additional costs imposed upon the consumers would be the responsibility of the IPP, if the increased cost was due to the contractor's failure?

A It would depend on the contract. But, again, let's immediately do what's fair, let's draw --

Q My question, sir, is would a well --

MR. McGLOTHLIN: Excuse me, Mr. Cresse. I believe he was in the middle of an answer. Let him complete his thoughts, please, sir.

MR. CRESSE: If he'll answer the question, yes.

CHAIRMAN DEASON: Hold on a second. This is not typical cross examination, Mr. Cresse, so I'm going to give the witness some latitude. The main purpose is

he's here to try to clarify the issues, but if he doesn't answer your question, please feel free to repeat it.

MR. CRESSE: All right.

A The answer to your question is it could be included in the contract.

One of my judgments on whether it should be included in the contract is a fair look at how utilities are treated. If the utility's nuclear power plant goes down for a year or more, do they pay for replacement cost power? If that's consistently true, then in a private power contract, maybe there should be a provision for paying for replacement costs. Now, we've just gone through this in a couple of states. You'll recall that in many private power contracts, there are security requirements, $15, $30 per kilowatt. It's an amount of money off to the side that can cover costs if the private power producer does not live up to the performance requirements. I think that's already a provision which covers some of the consequences if the private power producer does not perform as expected. But, again, it's a negotiable item. I would look to the treatment of utilities as one issue of equity as to what I would do with private power producers.

Q On Page 2 of your responsive comments you

state on Lines 19 through 21 that "A well-crafted power purchase agreement shifts to the IPP. Many of the risks ratepayers bear under traditional cost of service ratemaking." Is that correct?

A Can you just give me a cite real quick again? Is it Page 2?

Q Yes, Lines 19 through 21, part of 19, part of 21?

A Right.

Q Do you have a copy of what you consider to be -- or could you provide the Commission with a copy of what you would consider to be a well-crafted power purchase agreement?

A I can do that.

Q Would a well-crafted contract requires substantial equity after 12 to 15 years?

A I don't think it -- I don't think the contract should dictate the financing of the project. I think the selection of the bid should focus on cost, risk and reliability. And if the IPP is able to get a financing deal that's to the benefit of the ratepayer in terms of cost, they should be -- they should have the flexibility to do that. No, I don't see financing restrictions in a well-crafted contract.

COMMISSIONER LAUREDO: Mr. Cresse, hold on a

minute. But it is a fact, so that I understand, that most of the ones that you know in the United States are, in fact, through the loan agreement drafted along the lines that we've discussed yesterday and today, which is about a 12-month amortization period, which is rapid buildup of equity. Is that pretty much a standard with some of --

A We're still at 12-year to 15-year debt.

COMMISSIONER LAUREDO: So that would be the norm?

DR. ROACH: That's what we're still seeing.

Q (By Mr. Cresse) Should the Commission permit joint bids by co-ops and investor-owned utilities, or munis and investor-owned utilities?

A I haven't given that any thought. I don't know. I'd like to think it through before I give you an answer.

Q Should municipalities be permitted to bid on all capacity needs in the state of Florida?

MR. McGLOTHLIN: I would suggest that Dr. Roach has confined his testimony to the cost of capital impacts and purchasing versus building. I think this goes beyond the scope of his presentation.

CHAIRMAN DEASON: Well, he was certainly very willing to expand on other matters that Mr. Cresse was

asking about and if he has an opinion on this, he can express it.

DR. ROACH: I haven't given it a lot of thought. I'd rather reserve an opinion until I do.

Q (By Mr. Cresse) Is it your opinion that municipalities have lower cost of capital than investor-owned or investor -- investor-owned projects?

A I'd agree with Mr. Howard's comment yesterday that certainly the tax subsidy enables a municipal to get a lower cost of capital. If there is a letter of commitment required or a letter of credit required, you'd have to figure in that cost. But, yes, there are definitely opportunities for tax subsidized munis to have a lower cost of capital.

Q Do you think you ought to be required to compete with them?

A If you're asking would clients that we have like the opportunity to compete against munis, yes.

Q I'm asking you: Should this Commission permit or require -- permit you, the munis, to compete for all power needs in the state of Florida?

A My answer earlier was I'd like to give that some more thought.

MR. CRESSE: Mr. Chairman, I think the witness has agreed to submit a copy of a well-crafted

contract. Could we get a number for that or is that appropriate or --

CHAIRMAN DEASON: I assume it is. Ms. Rule? It would be No. 3.

Mr. McGlothlin, when would that be appropriate to submit that?

MR. McGLOTHLIN: Dr. Roach, when would it be appropriate to submit that?

DR. ROACH: I can I get it to you the first part of next week. What I'm going to do is get a contract that's in the public domain that I think has many of the elements of a well-crafted contract and get it down to you.

COMMISSIONER DEASON: Mr. McGlothlin, would you take it upon yourself to get that and make sure all parties have a copy of it?

MR. McGLOTHLIN: Yes, sir.

CHAIRMAN DEASON: We'll identify that as Exhibit 3.

(Late-filed Exhibit No. 3 identified.)

Q (By Mr. Cresse) I want to explore, if I can, some benefits that may inure on ownership versus lease or purchase for just a moment with you, if I might. Typically, are contracts with independent power producers, what is the length of those contracts for

base load plant?

A 20 to 30 years.

Q At the end of that period of time, am I correct that the independent power producer would be free to sell any capacity that that plant might produce in the competitive market at the conclusion of the contract?

A It depends on the contract and it depends whether there is a competitive market to sell into. But at the end of the contract, they own it and would be able to take it to a competitive market if that exists.

Q If the utility owns the project and it's fully depreciated, do they still have to provide it at zero cost for the benefit of the ratepayers?

A Certainly not zero cost. I think --

Q Or, if it's fully depreciated?

A And it requires life extension or repowering cost?

Q No, if it's fully depreciated.

A If it's fully depreciated and -- I'm just trying to fill in the real world here. There are a lot of utility plants that are now at the end of their life. The ones I see are requiring extensive life extension or repowering, or something that enables them to continue on. And so I'm just trying to fill in to get a real world example. If that's the case, then the

ratepayer can have that power plant, if, you know, if it pays for the life extension to repower.

Q Yesterday one of the witnesses said that typically sites are leased. Did you hear that testimony?

A Yes.

Q Is that correct, based upon your experience also?

A It was generally true with cogenerated sites. With EWGs or stand-alones, we're purchasing sites more often now.

Q Would a well-crafted contract require that the contractor either on own the property or have an opportunity to acquire the property some time in the future?

A It may or may not. Well done RFPs now require, as part of the bid, at least a letter of intent to purchase or lease. So some indication of site control is required even when the bids go in.

Q If this Commission requires utilities to own property that power plants are built on, should that same requirement be imposed upon independent power producers?

A Again, I don't see that as an essential requirement to deliver low cost, low risk, high reliability power. So I wouldn't say that I would see

it as a real key part of a contract, no.

Q Under a contract, if new technology comes along that a person can repower that plant, say cut their heat rate 30%, an independent power producer would do that, would he not, if that was cost effective over the remaining life of his contract?

A Correct.

Q Would not a utility do the same thing?

A They may or may not. But let's --

Q Let me ask you this --

MR. McGLOTHLIN: Excuse me, I don't think the witness has finished his thought.

MR. CRESSE: Excuse me, I thought he was through.

DR. ROACH: This is an area that not only you raised, but I believe Mr. Foley raised, and it's an important one. It says that there may be technological progress over the life of a power plant, and that the heat rates might improve. Output, megawatt output might go up, that sort of thing.

There's no reason for me to believe that the ratepayer is in any better position to realize those when there's traditional cost to service ratemaking as opposed to buying power.

When we work with a client to prepare a bid,

for example, we try to anticipate all the changes that we think are realistic.

On heat rate, for example, generally heat rate in a power plant degrades over time. But private power producers have developed maintenance methods that keep it at a level. So we anticipate all these technological changes. If Mr. Foley or any of the utilities, want -- you know, really believe that these changes were a certain thing, they could put those in their bid. A bid is a great place to put your money where your testimony is on these kinds of things.

So technological change, improved heat rates, increased megawatts, all of those things can be reflected in a bid in order to give you a competitive advantage so that you'd win. So I don't think the ratepayer has any -- it's any more likely to see those with traditional ratemaking than it is with the bid.

Q Are you saying that a well-crafted contract would provide for repowering or the advent and implementation of new technology for those benefits to flow through to the customers?

A No, I'm saying that when a private power producer develops its bid in order to gain a competitive advantage, if it feels that there are such technological changes, there are such improvements,

that it can reflect those in its bid to win the bid.

Q Do you know of any utility or nonutility that's willing to predict the technological changes that may take place in the next 20 or 30 years?

A If they're not -- you know, if they're not, then why is it that we're going to sit here and choose the utility over a private power bid for an unpredictable technological change? Why would we do that? I'm saying that if -- as some of the testimony is stated here -- if a utility or private power producer sees technological changes or thinks that the technology will improve in the near term, and they have faith in that forecast that they can reflect it in the bid and win the bid. It's a great way -- bidding is a great way to get away from promises and get back to commitments. If it's for real, you can put it in the bid.

Q Do long-term contracts lock in a cost of capital in that contract, imputed in that contract?

A Implicitly, yes.

Q And the risk of increased cost of capital would be with the independent power producer, the contractor; is that correct?

A Correct.

Q And the risk in an ownership situation by a utility of increased cost of capital would rest with

the customers, is that correct?

A Correct.

Q And is it also correct that the risk of a decreased cost of capital, benefits and decreased cost of capital would flow to the independent power producer under a contract, and the benefits of decreased cost of capital would flow to the ratepayer under a utility-owned plant; is that correct?

A That's correct. Risk is defined as a chance for variation from what's expected. And it's both an upside and a downside risk. And you're right, that the ratepayer bears the risk of cost of capital increases and decreases when the utility builds, but they are protected from that risk when an IPP is building a power plant.

Q Typically, based on your experience, what equity requirement would investors in these plants of independent power production expect?

A Could you please tell me what you mean by "equity requirement"?

Q Yes. I understand from prior testimony that typically these projects carry from 15% to 20% equity?

A Correct.

Q And those equity investors have an expectation of earning a rate of return?

A Correct.

Q And typically -- what I'm asking you is what is typically the expectation of those investors' rate of return on equity?

A It varies greatly by project, but since the equity investors take on substantially more risk with an IPP project than a utility would -- they take on construction risks and operating risks, because of the higher risks, they require a higher rate of return. A real rough ballpark is that as you pull in a bid, you'll be looking in the range of 15% to 18%.

MR. CRESSE: Thank you, Mr. Chairman. No further questions.

CHAIRMAN DEASON: Mr. Childs, did you have questions?

MR. CHILDS: Commissioner, I'd like to ask a few if I could.

CROSS EXAMINATION

BY MR. CHILDS:

Q Is there an optimum capital structure for electric utilities?

A There can be -- I mean certainly the practice is, the belief is that the 50/50 break is an optimal capital structure.

Q Can you tell me what factors determine the

level of debt and equity that is optimum for a utility?

A Well, what you're trying to do is when you choose a capital structure is to minimize your capital costs, and, you know, there's a full assessment of risk. And from that you can determine what mix of debt and equity gets you the lowest cost of capital. That would be the primary goal.

Q Well, then is it fair to conclude, for example, that if 50/50 is roughly an optimum capital structure, that 90% debt would produce higher overall cost of capital for the utility?

MR. McGLOTHLIN: Are we speaking in terms of corporate finance in both of those examples or project finance for one and corporate for the other?

MR. CHILDS: I'm really speaking for the utility, normal operation nonproject finance, just the capital structure of 90% debt as opposed to 50% debt.

A For just utility corporate finance, with the norm being 50/50, if you went to 90%, based on that it would seem that the cost of capital would go up. That that would not be your optimal capital structure.

Q Isn't that because of the investor's perception of risk, that the total cost would be higher when you increase the proportion of debt in capital structure?

A Yeah.

Q Even though debt is cheaper in a 50/50 ratio generally than equity, when you go to 90% the overall cost would be higher?

A Right. I would expect that both your cost of debt and your cost of equity would increase.

Q Okay. When a utility builds a power plant, the total cost is affected by the cost of capital for the utility, but let's focus on capital structure. Isn't it also affected by the capital structure for the utility?

A I'm not sure that I understand your question.

The cost of building a power plant reflects the Utility's cost of capital, and the cost of capital does embody a capital --

Q A capital structure.

A Right.

Q So when a utility is proposing, for example, in a competitive situation to construct a power plant, I think you would expect it to be using as close to an optimum capital structure as it could obtain?

A If it chooses to use corporate finance, but it's free to choose project finance, too.

Q Let me ask you on that, is there any reason that a utility could not pursue a project finance basis

for a new power plant without creating a subsidiary to do that?

A I think a subsidiary or some variation on a subsidiary would be required because project finance is nonrecourse, and so you need to have an entity that owns the project, a separate entity.

Q And you're familiar with the requirements of most utilities' indentures as to what property is subject to those indentures, are you not?

A I don't know that I'm an expert on indentures. I do observe that much of the project finance in the electricity business is done by utility subsidiaries, so I'm not sure that there's anything that would prevent -- I don't see in reality, in the real world anything that has prevented a utility from pursuing project finance.

Q Well, I'm asking about it to try to be clear, project finance without -- for the utility or a project finance approach for the utility which does not require the creation of a subsidiary. In other words, the utility would simply treat one asset, this power plant, as though it were constructed on a project finance basis. Is there anything that would prohibit that that you know of?

A Well, I'm familiar with project finance being,

established through a subsidiary because of the nonrecourse nature. I still don't see a problem with the utility as a utility adding a project finance portion. I think it's been done with fuel facilities, fuel transport facilities, that sort of thing. I certainly don't see -- I'm trying to see if I'm answering your question. I certainly don't see a problem with the utility accepting fixed prices, as in a bid, and continuing under normal corporate finance. You know, the biggest example is Pacific Gas and Electric. Their Diablo Canyon power plant is not in rate base. It's financed -- you know, it's financed normally, but it's not in rate base. It's paid for on cents per kilowatt hour. So I don't see any problem with the utility having to bid and being held to those prices and continuing, if that's what you're asking.

Q Well, I was asking, I think, a variant of that. When the utility pursues competitive bidding, at some point, if the utility participates by proposing to construct its own power plant, there will be a point in time when the comparison is going to have to be made between the cost of the utility-constructed plant and the cost of the bids. You would agree?

A True.

Q And what I'm saying is that in making that

comparison, the cost of the utility-constructed plant will be dependent in part upon the capital structure that is optimum for the utility, won't it?

A Yes, unless you pursue project finance.

Q Unless you pursue. And if project finance is not available to the utility, then it cannot take advantage, if there is one, of the benefits of project finance, if it wants to continue to provide service through the traditional utility-owned method in the future.

A That's true. If it's not available. But the point is that I see no reason why it's not available. Most of the project finance has been done by, or a good share of it has been done. If it's not available because the utility has not put together a project development which earns project finance, and it's hard to get project finance, then that's just a competitive advantage of private power.

Q When you say -- I think you said, "When its unavailable." You meant that it's unavailable to the utility because it either chooses or for some reason it cannot pursue through a subsidiary.

A Right.

Q I'm trying to get to the question of is it available at all to the utility? That is, is project

financing available at all to the utility unless it creates the subsidiary?

A Again, the project finance that I know about involves a subsidiary. But I know of no prohibition broader than that.

Q Okay. I think you said that, "Utilities continue to earn a return on investment in a power plant even when that power plant ceases to operate"; is that correct?

MR. McGLOTHLIN: Could I hear that again, Matt.

Q I think you said that "A utility continues to earn a return on an investment in a power plant even when that power plant doesn't operate."

A I said that that is one of the considerations that I would make in judging whether a well-crafted power purchase agreement should cover the cost when -- or the consequences for the utility, if that IPP does not live up to its contract.

Q Well, do you know whether in Florida that utilities continue to earn a return on a power plant when it ceases to operate?

A I don't know any particular point, but we could raise an example. I'd like to know.

Q Well, if a utility, it bears or it faces the

possibility of not earning a return on a power plant that ceases to operate, wouldn't you expect that that would be translated into some perception of risk by the investor?

A Yes.

Q And, therefore, if the utility's cost of capital reflects the risk that it may not earn a return on its investment in the future, when you do that comparison to the IPP proposal, you might see that the utility's cost of capital reflects the risk of not earning a return on an asset that doesn't operate, wouldn't you?

A I'm not sure I follow the logic of what you just said.

Q Well, I mean, if there's a risk that an investor is not going to earn a return on an investment when the investment, which is the power plant, ceases to operate, then the investor is going to request, all other things being equal, some sort of a premium or increase in the return that's necessary in order to make that investment, won't they?

A That could be true.

Q Okay. And so that to the extent the utility bears that risk, or the investors and the utility bear that risk, wouldn't you expect, all other things being

equal, that the cost of capital for the utility would be higher than if it didn't have that risk?

A In general, yes.

Q Okay. Have you heard of this Commission's consideration of the treatment of certain nuclear power plants and the potential for exclusion from rate base if they didn't operate in the future?

A I've heard -- in general I've heard that there's been problems. And my understanding is that so far they have earned a rate of return even though the plants didn't operate, but I'm not really up on it.

Q But you're not up on what the Commission said about if they continued to not operate, what it would do.

A Well, let's just make it clear because we started out asking the question -- you're agreeing that as of now, in the past, and as of now, unlike a private power producer, the utility does get paid even though it doesn't perform. But you're saying the Commission has put the utilities on notice that in the future that might not be true.

Q Actually, yeah, I think that's what happened. But I'm asking you if you know.

A I do now.

Q Okay. Do you know in terms of the range of

rates for debt securities that one might reasonably expect, given a particular credit rating or rating on the bonds, so if you had an A-rated set of bonds or an A rating classification, what might be the expected range of interest rates on those bonds?

A I don't have them right in front of me. It does vary. My understanding is that right now it's a fairly narrow range, but it matters.

Q And at times it's a fairly broad range, isn't it?

A Yes.

Q So that you could have a A-rated company that trades at one rate and another company that's also A-rated and it trades at a significantly higher rate. Fifty basis points maybe.

A What you just said, you have two A-rated utilities and they have different costs of capital. They have different debt costs.

Q But they have the same rating on those debts.

A That can happen.

Q That can happen. Okay. So it's not just the loss of a rating that is going from double A to single A that can affect the utility's cost of capital; it's the trading within the range that it has that can affect its cost of capital, would you agree?

A Again, I agree -- you said two things. I agree that a bond rating doesn't dictate cost of capital, and I agree that within a class you can have two utilities, both Class A, or whatever class, and the debt cost can vary.

Q Now, let me ask you in terms of the decision that the Commission would be asked to make if competitive bidding is required, or in any case, even if competitive bidding isn't required but there's a competitive bid. When the decision is made to select an alternative, that will have to be evaluated at least to consider the comparative cost of the alternatives, will it not? In other words, which is the cheapest alternative?

A Correct.

Q Do you know what the construction period is and the planning period is for the -- or the installation of the combined cycle unit?

A For IPPs?

Q For an IPP.

A Yeah. It varies, but for planning purposes we would definitely like to think in terms of 24 to 33 months. I mean it really varies.

Q And that includes all aspects, such as financial planning, environmental licensing, et cetera?

A No.

Q Okay. I mean isn't it true or correct that you could expect, even for a combined cycle unit, that you would need, from the date that you said let's go to the date of the in-service date, of the in-service of the unit of three to four years.

A You could.

Q Okay. Now, when you make a decision about what is the cheapest alternative, that is either an IPP proposal or a utility proposal, you will of necessity be making that decision, oh, three to four years, at least, before the unit is placed in service.

A Correct.

Q Okay. What cost of capital should the utility use for its own proposal in that circumstance?

A It's going to bid now?

Q It may just say, "We'd like to build a unit and here is what we think it will cost."

A It should use the cost of capital it has confidence in. If that's the cost of capital that it quotes from its investors today.

Q Right.

A That's fine. If it's the cost of capital, if they feel confident that in four years they'll get a lower cost of capital, they can put that into their

A I'm sure someone did.

Q The market generally didn't, did it?

A I don't know that we have anything here that let's us know that. But costs were higher and now they are lower, that's right.

Q Do you know what this Commission was approving three or four years ago as the assumed cost of debt for the construction of a power plant?

A I don't.

Q Okay. Would you look at Page 26 of your testimony? I think that's the page where you talk about the rejection of the penalty.

CHAIRMAN DEASON: Mr. Childs, how much more do you have for this witness?

MR. CHILDS: This is about it.

COMMISSIONER LAUREDO: What line, Mr. Childs?

MR. CHILDS: It's the -- I think the September 10th set.

COMMISSIONER LAUREDO: What line?

MR. CHILDS: Your comments -- I'm sorry, Page 26, starting at Line 6 and running through the bottom of the page. Do you have that?

A Correct, yeah, I do.

Q (By Mr. Childs) I think what you're suggesting there is that -- particularly looking at the

sentence starting on Line 10, is that, "Despite all exaggerations, commissions have consistently rejected arguments for penalties." Is that the idea of treating the IPP purchase as having a penalty because of the impact on the capital cost to the utility?

A It's the -- yes, if you mean by that it's the debt equivalent analogy.

Q Right. Okay. And then you cite the decision of the California Commission there as supporting that. I take it that you cite the California decision as supporting your conclusion that commissions have consistently rejected arguments for a penalty against IPP purchases; is that right?

A I cite the California Commission not for that explicitly, but I cite it because the California Commission boldly says, look and I'll quote them. "It's clear that the credit rating agencies are now treating PPAs, power purchase agreements, as debt equivalents. This does not mean that we must do so as well, because our regulatory focus is broader than the focus of the rating agencies." And I quote that to support the point I'm making at this point, which is that the Commission, when choosing between buy and build, should ask a broader question, and that is what is the best deal for ratepayer in terms of cost, risk

and reliability?

Q Didn't the Commission say in the very next sentence of that opinion, "We believe it is premature based upon the record before us to determine now whether PPAs are debt equivalents in our ratemaking capital structure."?

A If you're reading it, that's what they said.

Q So they weren't talking about a penalty against IPPs at all, were they?

A Oh, absolutely they were.

Q Wasn't this a rate case and the utilities asked for a increase in their authorized cost of equity to reflect the risk associated with power purchases?

A Absolutely. The utilities were asking to implement the same debt equivalent analogy as proposed by Florida Power. And as I've argued in my testimony, it results in a penalty against buying, a bias against buying even when buying would be to the benefit of ratepayers.

Q But didn't they also say -- I mean in what I just read, it's not that we reject it all, but we're not going to decide now based upon the record before us?

A Sounds like a rejection to me. Did you read the whole case?

Q Yes. I've got it here too.

A I know. Then you've seen, it was a full court press by the utilities. Absolutely. And they rejected it based on an extensive consideration.

Q Well, they didn't, sir. I mean if you agree with this sentence that I just read, they said that, "Based upon the record before us now, we think it's premature to decide."

And let me ask you if you recall from this opinion as well, whether the California Commission didn't say, "There are many factors that we consider in setting the capital structure and the cost of equity capital for utilities that are not necessarily matters that the market recognizes in determining the risk of the utility." It said that, didn't it?

A Correct.

Q And if that's true, then it may mean that they have other factors that affect the premium that they are already giving utilities in California for the return on equity. In fact, they discuss those, don't they, in this opinion?

A And what does that mean for the fact that they did not buy into the debt equivalent argument?

Q They were already giving the utility a premium on its cost of equity or other factors that are

not necessarily recognized by the market, and at this point they considered it premature to give them another premium.

A Is that what they -- is that what you think that says? You think that decision says -- you think that decision is not a rejection of the debt equivalent argument?

Q Yes, sir. I think it is not. I think it does not reject it. I think it says it's premature to decide, which is the sentence I just read.

A And so they could revisit it, but for the moment they didn't buy it.

Q That's right.

CHAIRMAN DEASON: I think the order probably speaks for itself. Any more questions, Mr. Childs?

MR. CHILDS: No, sir.

CHAIRMAN DEASON: Okay. Like always, Mr. Neiser, you're right before the --

MR. NEISER: I'm happy to oblige.

CHAIRMAN DEASON: We will reconvene at five minutes after the hour. Thank you.

(Brief recess.)

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CHAIRMAN DEASON: Call the hearing back to order, please.

Mr. Neiser.

MR. NEISER: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. NEISER:

Good morning, Dr. Roach. My name is Dick Neiser representing Florida Power.

A Good morning.

Q Dr. Roach, I'd like to start with the capital structures, I guess, that are used or the structures of the organizations that are generally used by IPPs, and I guess just question a little bit why nonrecourse type structures are usually used if these projects are so -- are viewed by investors as being very sound and prudent.

From my observation of most of them, they are usually set in the context of partnerships or other off-balance sheet type arrangements, project financings type arrangements, where the parent company is more or less immune from any liability that may result from these projects.

I would just start by asking why is that traditionally done as contrasted with the utility type building of generating plants where the whole company's assets are available to assure the completion of that plant?

A Private power producers went to project finance because they had to in part and because they wanted to in part.

If you talk to chief financial officers who started early in this business, they'd tell you that they had to go to project finance because a private power producer takes on so much more risk than a utility, construction operating risk, that the required return on equity is higher. So we're in order to compete against the utility they had to get a higher debt, they had to get a higher percentage of debt. They identified project finance as a way to do that, and in the early years it enabled them to compete; it was a necessity.

As we got into it more, we saw that we could want to do it because it gave the ratepayer a lower cost. We found how to do it better. I think what the financial officers do is a very sophisticated marathon set of sessions with the financiers. And as I said, every piece of this puzzle has to be in place.

So as private power producers got better at it I think they found that it was a way to compete. It's a way to get a lower cost of capital and to offer a lower cost to the ratepayer.

Q Did I hear you testify a little earlier here ,'

today that one of the reasons that these projects are attractive to investors is that there is a lot of risk shifting done by the IPPs and this setting up of the structure, such as operational risk, fuel, supply risk, construction risk, and perhaps demand risk. Why then are you characterizing these as particularly risky organizations?

A I'm not sure what your question is.

Q I'm just asking did you not earlier state that in the setting up of these organizations, does an IPP not shift risk to the fuel supplier, to whoever the operator of the plant might be, to the constructor of the facility, and the demand risk to the utility, so as to make them attractive projects to the investor? Did I not hear that.

A You did not hear that, especially the last part which said that you shift demand risk to the utility.

Q Did I hear the other parts?

A You did. And let's make it clear what was being said.

That if the IPP is able to get a lower cost of capital, it is because the investor perceives lower risk. And one of the reasons they perceive lower risk is that an IPP efficiently allocates risk or shifts

risks to the people who can do something it. The construction firm takes construction risk; operating risk goes to an operating firm, et cetera. So, yeah, that's my I point.

Q Okay. But then why does the IPP need a high return on equity to compensate it for risks if these have all been shifted?

A Not all risk has been shifted. You know, for example, I mentioned earlier an EPC agreement, the construction agreement. It specified what goes into that agreement. A Bechtel or another construction firm takes many of the important risks. But if there's something that goes wrong, for example, you can't get water so you need a pipeline to a wastewater system, those sorts of things, then the equity investor would probably -- that would be a change in the scope of the construction and the investor would take that risk. So there are many risks that remain with the IPP developer, the equity investor.

Q Does the demand risk remain with the IPP?

A In a state like Florida with preapproval, the demand risk is shifted to the customer.

COMMISSIONER LAUREDO: I want to make sure that I don't contradict what I already filed away. I thought in my questioning you told me that construction,

risk has shifted via the contract fixed price mechanism was not unique to the IPP, that that was, in fact, fairly standard in project financing and certainly in power plant building. Is that still -- did I interpret that right?

DR. ROACH: Yeah. I don't think I contradicted that.

COMMISSIONER LAUREDO: No, because I think you're making the case that that is shifting risk. That is something unique to the IPPs, that they came up with this brilliant idea of contract pricing in project financing, and that's not unique to project financing. And maybe we're not understanding each other. So if it isn't unique, how is it you're shifting -- what's so unique about the lower risk that you're trying to articulate?

MR. McGLOTHLIN: May I ask a clarifying question that I think will bring it together.

COMMISSIONER LAUREDO: Yes.

MR. McGLOTHLIN: Dr. Roach, is your point that the project financing characteristics of IPPs is different from the way utilities have traditionally built power plants and, therefore, there's a difference in the way construction risk is allocated or dealt with?

DR. ROACH: Correct.

COMMISSIONER LAUREDO: Specifically by -- in other words, you're telling me then, therefore, that utilities traditionally do not have construction contracts that have price penalties. In other words, fixed price mechanisms by contract. That shift, the cost overruns to Bechtel, for example.

DR. ROACH: In the past, my understanding is that the utilities had their own construction departments and built their own power plants. Recently the utilities have done some turn-key contracts. They can do that, but the point I'm making here is that a turn-key contract is a good way to shift many risks but it doesn't shift all risks.

COMMISSIONER LAUREDO: Well, I'm sorry. I'm just still not clear, Counsel. Maybe I'll just give it another shot later. My stuff its very simple.

Do utilities heretofore -- and I thought -- I'm sorry, maybe I'm just ignorant. I thought they did, in fact, use a lot of outside contractors. Most nuclear power plants that I know of were built by Bechtel, as a matter of fact, specifically. And now you're telling me that utilities build their own plants.

My point is if I'm going to build a plant and,

I take away my sign that says I'm a utility of an IPP and I go to Bechtel, I'm going to get the same kind of terms: Namely you shifting the cost overruns by having a fixed price contract.

DR. ROACH: Let's take -- the answer is that you can get turn-key contracts if you're a utility or an IPP, you can do it.

I wouldn't, based on experience, I would hesitate to say that the kinds of contracts that were used for nuclear plants prevented cost overruns being passed on to ratepayers. So that's a little different. But I'm not trying to say that you can't go out and get a turn-key contract if you're a utility. I've seen utilities do it on some gas-fired plants. But I'm saying it's one way that an IPP uses --

COMMISSIONER LAUREDO: The point I need to know is they don't do it as a matter of norm? Or you just don't know?

DR. ROACH: I don't know exactly what they do.

COMMISSIONER LAUREDO: I'll ask them then later.

DR. ROACH: Ask them, yeah. No, we, IPPs do it as a matter of course.

Q (By Mr. Neiser) Dr. Roach, it's the absence

of specifics that's troubling me. You are saying that the demand risk has been shifted from the IPPs to the customer. That the fuel risk has been shifted to suppliers. The operational risk has been shifted out of the IPP, and the construction risk has been shifted out of the IPP. What's left in terms of risk to the IPP? I've just not heard any specifics. You say there are lots that are left, but I haven't heard any what they are.

MR. McGLOTHLIN: I'm not going to object. I would like to clarify one thing, Mr. Neiser. I don't think that Dr. Roach said that demand risk has been shifted by the IPP to the customer.

MR. NEISER: Well, he has said that it has shifted to the customer.

MR. McGLOTHLIN: He said the customer bears it. I don't think he said that it got there by way of a contract.

MR. NEISER: Let's him what he said.

DR. ROACH: I said that the customer bears it by merit of the regulatory procedures in place.

MR. NEISER: But the IPP -- excuse me.

DR. ROACH: Sir, I have been specific. I've given you the specific example of a risk that may not be shifted in a construction contract. I even talked

specifically about water, not being able to get water supplies, so you need to use gray water from a wastewater treatment plant. There are other examples. I guess I don't understand what the point of your question -- why is it that you're concerned with the return on equity for an IPP if it offers a lower price to the ratepayer, so be it.

Q (By Mr. Neiser) You have indicated that there's a lot of interest of the investors to the IPP projects. Would the interest be there for those projects absent a 30-year contract or a long-term contract with a well-financed utility?

A I answered this before. No, the investors would not invest if there was not a power purchase agreement. This is a monopsonized business. An investor would not invest if there was not a strong indication that there would be a market for the product. Just like investors would not invest in electric utility if there was not an indication that there would be a place to sell it and that's what a monopoly franchise does for them. There's really no difference. There is a market commitment both for the utility and the IPP.

Q If the utility were financed on a leveraged basis of say 80% debt and 20% equity, and still give a

long-term contract, would the same interest of the investors be there?

A I don't think so. I don't think that the PPA alone justifies higher leverage in a private power contract. Again the full development of the project is required to justify the higher leverage. Some of the risk shifting, the nature of the investment of single asset investment, the nature of the transaction, the fact we have before-the-fact risk allocation through a contract as opposed to after-the-fact risk allocation through prudence, debt reserves, length of term. Those are all things that are required to get the higher level.

Q Do you know of any way in which the utility is compensated for the use of its credit standing that allows the IPP to go into business in the first instance?

A I disagree with the premise of your question. The credit worthiness of the utility does not allow the IPP to go into business. It's the first issue that we addressed in Section 712.

The credit worthiness of the utility, okay, is at risk more when it builds than when it buys. You just heard Mr. Childs asks me, he said, "Well, what do you know about what's going on with nuclear power

plants down here? Do you know that we used to be able to get a return even though we didn't perform, but in the future we might not be able to." Okay.

When you built those plants you risked your credit worthiness. Okay. And I'm saying that the risk to your cost of capital, when you buy, in a state with the progressive policies of this Commission is very low, if not zero.

Q Okay. Let's pursue that for just a second. If the utility pursues the build option, yes, it risks its capital rating or its credit worthiness. Is it in any way compensated under the build option to help absorb the absorption of its credit rating?

A No.

Q It is not?

A It is not, and that's why it's so important to see how the cost of capital effect occurs. That's why it's so important to see that we're talking about disallowances. Okay.

There is no protection to the ratepayer against a cost of capital increase that results from a disallowance. So if the utility builds and something goes wrong and there's a disallowance and investors respond by saying, "Well, we're going to have to have a higher cost of capital," okay, there is nothing that

protects the ratepayer against that. There's nothing in normal traditional ratemaking that protects the ratepayer against that cost of capital increase. And that's the issue here. This isn't a rate of return hearing. We're not saying what's a fair rate of return. That can all be done when you set a return on equity. The question here in Section 712 is: Is there a risk of cost of capital increase when the utility buys? And is that risk greater than when it builds? And there's nothing that protects, because it's all about disallowances. Because the only way buying can hurt the financial standing of a utility is through a disallowance because the whole issue is about disallowances. There's nothing that protects the ratepayer when you build.

Q Let's switch from the ratepayer to the shareholder of a utility.

In a purchase power option, what compensation does the shareholder of a utility receive to give it some shock absorber to the potential of disallowance of purchased power contract payments?

A First of all, you and I agree the question you just asked me is not at issue in this proceeding. That's not a 712 issue. It's a rate of return issue.

Q No, I think it fits here. I think we're

trying to distinguish if there is a distinction -- first of all, you are saying the issue is disallowance, and you are saying that the utility faces the potential of disallowance, whether they build or whether they buy. Have you not said that? They stand the potential of having a disallowance whether they buy or build.

A That's correct.

Q Okay. And what I'm trying to elicit from you is to whether or not from the shareholder perspective of the utility, has the shareholder received some compensation in the build option, which is a return on his investment, to absorb any potential disallowances as contrasted to disallowances from purchased power, which are generally straight pass-throughs with absolutely no mark up, to have the ability to resist some disallowance. Is there not a meaningful distinction there from the shareholder perspective?

A Again, even from the shareholder's perspective, the shareholder isn't compensated for a disallowance. Yes, they earn a rate of return on their investment when they build, and since they have no investment when they buy they don't earn a rate of return. But, again, it's all about disallowance. Again, if there was a disallowance, if you take -- again, Mr. Childs' point, if there was a nuclear power

plant, it doesn't get shut down for a year, okay. So there's no return, no debt coverage, no return on equity. Are you saying that that doesn't hurt the investor, that they wouldn't fight that? That they would say, "Well, we earned a rate of return on the investment so far, so we're not going to fight this disallowance, we'll accept it." I don't think that's true.

Q Of course not. And I'm not sure whether we have communicated yet, and I'm not staying with it other than the point of just not being sure that you understand where I'm coming from.

When a utility builds something it goes into rate base, they make an allowed rate of return which includes a return to the shareholder for their effort. When a utility purchases power, the cost of that purchased power is flowed through directly to the IPP from the ratepayer, and there is absolutely no dollars to the shareholder to have in a pot to potentially withstand a disallowance for purchased power. They do have some dollars in the pot to potentially withstand a disallowance when they have a project which they own and have built. Is that not a meaningful distinction from the perspective of the shareholder to stand the risk of disallowance of purchased power but to have no

opportunity to make any money to offset that? As opposed to the opportunity to make some money if you build something? Am I not clear on this?

A You're very clear. Again, you're asking a rate-of-return question. The question in this proceeding is about whether the risk is higher or lower in buying or building, okay?

If you in a rate-of-return proceeding say that the rate of return that's determined through whatever method is used is not adequate, you know, you're free to make the case. It's just not -- what I'm trying to do is you keep arguing a rate-of-return case and that's not what's at issue here. We're trying to decide whether -- how to choose between buying or building. And the Commission needs to know, if we go forward with the potential to buy, does that put the utility's cost of capital and, therefore, ratepayers and rate increases more at risk than if they built? And since it's all about disallowances and since the utility takes on more risk when it builds, the answer is no. It consistently will find that the cost of capital of a utility is more at risk when it builds.

Q Okay. I think we've had our fun with that.

CHAIRMAN DEASON: I need to ask a question. Given that scenario, is the investor going to

put a higher risk upon the utility if the utility purchases, and that investor realizes there is a risk of disallowance but there's no investment there to earn a return on.

DR. ROACH: It could -- if the risk of purchases is substantial. The utility could -- or I'm sorry, the investor could look for some protection. But your question involves this relative notion. Relative to what? A cost of capital higher than when they build? I don't think a cost of capital increase is likely, again, because the build option has that higher risk.

COMMISSIONER LAUREDO: Let me ask you, if I may, because you said something very pleasant to me when you said "the real-world experience."

The real-world experience, the investor, what we're going to be having here is a shift in money. If I were an investor, I would be looking at IPPs.

DR. ROACH: Absolutely.

COMMISSIONER LAUREDO: If I'm getting 15 to 18%, you know. So the investor is actually a human being sitting and making a shift. And if there is industry shift in terms of investment, a parallel industry, theoretically, there will be an ancillary increase in the cost of equity on the utility, because

we're chasing the same investors. Would there not?

DR. ROACH: I think I agree that if I were an investor and I wanted to invest in the electricity business, that I would -- and invest in someone building power plants, that I would choose the IPP over today's traditional ratemaking utility. So I agree with that. It's not just because the rate of return on equity could be higher because it's also risky. It could also be riskier for me. But because I think it's a better deal, there's just all the things that I've said make it a better investment.

COMMISSIONER LAUREDO: I just keep coming back to it because we're talking about very narrow issues, but I'm trying to focus on the historical issue. I mean, we happen to be at historical crossroads in this industry, and it has a lot of ramifications, one of which is flight of capital. There just may very well be a flight of capital away from utilities, because capital is a rational chase to a higher return.

And now, my question that I will conclude eventually is, how does that affect the senior citizen in St. Petersburg? Because I know that the investor takes care of himself with his advisors and the two people -- the two parties represented here basically

have their own resources.

The question I think this Commission has to grasp was eventually -- and that's why I know you try to bring it back to the proceeding, we're trying to look at it broader is where are we going to be five years from now and how does that impact the ratepayer in St. Petersburg or Tampa? That's the question.

DR. ROACH: That's the question you should focus on.

If the IPP -- what I think buying does for the ratepayer is it results in lower cost, lower risk and higher reliability. It's just a better way to go about selecting supply-side resources. I don't think that it -- I think that's -- the question you have is the same question. I'm saying when you choose between buy and build, look for the best deal for the ratepayer.

COMMISSIONER CLARK: While Mr. Neiser is interrupted, I wanted to make sure I understood your answer to a question from Mr. Childs.

Do you agree that in order for utilities to be a viable player in this competitive generation market; that they will also have to be able to do project financing?

DR. ROACH: I'm not making that firm of a

statement. I'm saying that they are welcome and able to use project financing.

COMMISSIONER CLARK: Well, it's all competitive and financing is a cost to them.

DR. ROACH: Correct.

COMMISSIONER CLARK: I thought you conceded that in order to be competitive in terms of financing costs, they're going to have to do it through project financing and not the traditional way.

DR. ROACH: No, I don't -- if they can make corporate finance lower cost, if they can build a company that investors want to invest in and perceive lower risk, then corporate finance will beat project finance.

I've consistently said that project finance doesn't necessarily give you a cost of capital advantage. Okay? It can but it doesn't always. So I'm not precluding the continuation of corporate finance for a utility and still have them compete. If they can make that work, if that's what the market likes, if the market prefers to invest in a utility that's well managed and diversified, then they'll get a lower cost of capital, and they can compete on that basis as well as any basis.

I'm not precluding competition with the

utility corporate finance. I was trying to make the point that there's nothing that blocks them from doing the project finance.

COMMISSIONER CLARK: Well, let me ask it a different way.

How would they go -- what would be competitive with project finance? If given the fact that you agree with the notion that a well -- the ultimate or the optimum financial structure for a utility is 50% debt and 50% equity, how can that compete with project financing when it's 90 and 10%?

DR. ROACH: It can compete -- remember that when -- there are costs to doing project finance. You heard Mr. Howard yesterday say that the cost of debt can be higher and he gave an estimate, maybe it's a point higher in today's market.

The cost of equity is higher for project finance, too, because you take on more risk than a utility.

There are other things that I mention in the testimony: cash reserve off to the side, a shorter term of debt. These are all things that push the cost of project finance up. You can't just look at the fact that they use 80% debt and say debt is always cheaper so the cost of capital is always lower. There's a lot

more to it. It is not always true that project finance beats corporate finance in cost of capital. It depends on how well you do both.

COMMISSIONER CLARK: So you could have a situation where you're going to do -- a utility proposes to do a project that's corporately financed, meaning -- and that would carry with it a 50% debt, 50% equity, and represent a lower financing cost than a project finance that was 90% debt and 10% equity because of these other factors?

DR. ROACH: Correct.

COMMISSIONER CLARK: Okay.

COMMISSIONER LAUREDO: Mr. Roach, let me ask you another philosophical question. I hate to do this but, you know, these proceedings are mostly for our benefit and we're all struggling; at least I'm struggling.

DR. ROACH: I'm happy to answer whatever you have.

COMMISSIONER LAUREDO: And I don't represent any party. I'm trying to figure out what's best for --

DR. ROACH: Yes, sir.

COMMISSIONER LAUREDO: If we have all these scenarios now we've talked about in the micro sense. For example, I alluded to the flight of capital. There

may be, what is that word, "paradigm shift" here; we're moving -- and there's a realization in the rational investment community moving away from IPP.

Logic tells me that the next step is that the utility's stockholders themselves are going to be following the same shift. And let me just give you a parallel with another industry, and maybe you have already read about it and, if not, I encourage you as you deal with these things: The largest airline in the United States -- Mr. Crandall, who heads American Airlines, I don't know if you saw in the New York Times recently where he's basically reached a conclusion now. He's saying, "There's such a shift in this industry, I'm getting out the industry. I'm losing money flying people around; I'm making money breaking up the pieces. I made $300 million in my software reservation system. What in the world am I doing owning planes, having union contracts, having union fights, worrying about maintenance and all those kind of complications?"

All of this leads me to the conclusion, I see a flight from the core.

And so the next step is, if we make IPPs attractive enough, we see a breakup of the utility itself. Who takes care of reliability? Who takes care of that? And I'm not telling you, I'm asking you, you

know.

DR. ROACH: Sure.

COMMISSIONER LAUREDO: You see what I'm saying? The forces we're creating economically are shifting away from -- I know you don't like the word "social responsibility," but there is some sort of social contract that got us to where we are today.

I know Mr. -- the other gentleman who testified on historical and I disagree. We got to natural monopolies because of certain things. And now we're moving away from that, and I just wonder where we're going.

Do you see the same parallel I made with the airline industry, for example, where these forces, if given enough time, will, in fact, just like Mr. Crandall says is what -- "I'm getting out of the airline industry"?

DR. ROACH: I hear you. Let's first narrow the issue.

First of all, no one is talking about getting rid of the utility as a natural monopoly for the distribution and transmission of electricity. It's just generation, okay?

Now, let's talk about flight of capital. If the IPP is a better investment, it's because it's a

better deal for the ratepayer. They're winning in a bidding system, and through extensive scrutiny, they're offering lower costs, lower risks, higher reliability, they win. So if the utility in the generation side is not competitive and investors don't choose to invest in utility power plants, it's a flight not too far away; it's right to the IPPs. And in a state like this, there's no reason to believe that you won't have ample players, well-established players, well-financed, experienced IPPs to build your power plants.

There's no evidence that I see that we're anywhere near risking unreliability. You're getting down here, I'm sure, like any state, ten megawatts to one in these bids. You've got ten people willing to build every one megawatt that you want, okay? So there's none of that risk really going on.

In terms of social responsibility, delivering reliable power, that sort of thing, again, I think that's all built into the contract. I don't think that there is anything that a private power producer is not incentivized to do. And beyond that, private power producers, just like a utility, have a reputation to maintain, maybe even more important than the utility, because a utility just works here in one area. A private power producer has to maintain a

responsibility, a reputation, because they have to go to all 50 states and around the world to compete.

COMMISSIONER LAUREDO: So you don't see a problem or a parallel with the example I used that what could be happening here is, if profitable aspects of this sector, called the electric sector, is being spinned off and the core is getting left behind as the less profitable one, but is a key part of the reliability and social contract kind of, you know, maintaining certain systems on which you can tap in independent power; you don't see that, that what we're discussing today is what's happening, historically speaking? I mean in terms of -- if you could just take your hat as a consultant and --

DR. ROACH: Yes.

COMMISSIONER LAUREDO: -- that doesn't worry you, you're confident that the reliability is there and you're confident that market forces somehow, because of self-interest, which is the only interest, market forces -- you agree with me on that -- follow. But somehow they're -- that's why I'm perplexed about this contract. The social response may flow somehow.

DR. ROACH: I'm confident that IPPs can offer reliable service because they do offer reliable service. The record -- I'm not theorizing; I'm not an

ideologue. I'm not saying do competition because it's ideologically correct. I'm saying do competition, it's working; it's delivered reliable power to the customer. It's driven prices down. It's shifted -- it's done -- you know, in historical perspective, it has done an important risk shift.

Remember the concerns in the '70s and '80s where the utilities did not bear construction and operating risks. Well, private power producers came in and assumed that risk. That was a good, low-risk way to build power plants. The utility -- I'm sorry, the ratepayer has benefited from that. I'm really not theorizing. Competition is working. It's driving costs down, lowering risks to the ratepayer, and reliability so far, after many years of experience, is very high.

Q (By Mr. Neiser) Dr. Roach, just picking up on those comments that you're making about it's working and it seems to be providing a good opportunity for ratepayers: Are you familiar with what's going on with Central Main Power Company currently and a hearing examiner's proposed recommendation?

A Generally.

Q Could you recite that if you're familiar with it?

A I've not read any of the documents. I understand that there is a concern with the recovery of purchase costs.

Q Do you know how much money is involved?

A I don't.

Q It's my understanding it's about $42 million as a recommended amount for disallowance to the utility for imprudence as a result of not finding the appropriate time when the contract with the IPP no longer became economically viable, and that they did not act soon enough to get in and change the conditions of the contract. That's my understanding of it, and that the Commission is intending to vote on it sometime in early October.

That is the kind of concern that I am trying to express to you here from the utility's vantage point. And you have indicated there is the risk of disallowance.

Absent any direct compensation to be able to stand disallowances of that magnitude, a utility has to have some kind of a jaundiced eye to these arrangements. And that's the give and take that I'm asking you to at least acknowledge from the utility's vantage point is real, not imagined, if that goes through.

MR. McGLOTHLIN: Mr. Neiser, so that the witness can answer in context, can you supply whether or not that contract was preapproved by the Commission?

MR. NEISER: It is my understanding that it was and that it is not a matter of imprudent contract to begin with, but that it became so during the course of its operation, and the imprudence is being found on the utility for not then aggressively trying to change the terms of the contract. That's the way I understand it. I, too, do not have the documents in hand.

DR. ROACH: Okay. You asked for an exchange.

My point has always been that it is not an issue as to whether there's any risk with purchasing. There can be some risk.

Central Main Power, if we read into it, we may find as an example. But the question is, what's the relative risk to building? Why is it not -- if you raised Central Main Power with me, why isn't it fair for me to ask you. "Are you familiar with River Bend power plant? Are you familiar with the fact that that's a nuclear power plant built by Gulf States and that today, today, the ratepayers face $3 billion of litigation risks with that plant?"

I mean, the orders of magnitude are amazing here. So my point isn't that Central Main Power stuff

never happened. I'm saying that let's get the relative risk of disallowance and consistently we will find, based on the past, based on understanding the current situations, that you risk, you as a utility, risk cost of capital increases and, therefore, rate increases for the ratepayer, far more when you build than when you buy, because you take on more risk. That's my point.

Q Okay. Would you kind of restate what you said with regard to the VEPCO contractual arrangements, the purchased power arrangements there, how they're working?

A My comment about VEPCO is that it was VEPCO's view that their cost of capital would have been hurt sooner if they built. That was my only reference to VEPCO. Are you asking me more broadly?

Q Well, but that you conveyed the impression that things are going well in those purchased arrangements? Is that -- did I not hear you correctly?

A No, it's the utility's view, it's VEPCO's view that things are going well. That does not mean that there have not been things, lessons to be learned and missteps.

Q Okay. I just am wondering if you are aware of an annual report, or at least a quarterly report, issued in August of '92 by VEPCO, where they are filing

for relief with the Virginia Commission for overcompensation to cogenerators which comprise 17% of their capacity? Are you aware of that dispute, so to speak?

A Yes, I am.

Q Okay. So that perhaps all is not sweetness and light with regard to the VEPCO purchase power arrangements?

A And, of course, all is not sweetness and light with what they've built. But let's go back and ask ourselves, again: Is that different from Florida? Are contracts preapproved? Is the RFP approved? Is there any of the mechanisms that this Commission or the Florida Commission has put in place? Are those in place in Virginia? And the answer is generally no, the Commission has not gotten involved in these things.

So a lot of the things that mitigate this allowance risk with purchases that are in place in this state are not in place elsewhere.

Q Can we revisit for just a moment your conversation with Mr. Cresse and his kind of hypothetical where capital costs may come down from the time of the beginning of a project, which would afford an opportunity to an IPP to refinance and perhaps keep those gains with regards to lower capital costs?

Is it not truly a one-way street with regard to IPPs and capital cost risk? Is there any real vulnerability to an IPP with regard to increases in capital costs once a project is financed?

A Generally an IPP will lock in its finance, but -- so that it's not going to suffer changes, but not all of them by any means. Some have taken market base plus markups.

Let me give you another example. If you think it's very important that cost of capital risk from the point of bid, to our mind, is shifted to ratepayers, you know, that's what utilities do, if you think that's very important, IPPs will give it to you. There's a contract -- and maybe I'll send this one as the well-crafted contract -- there's a contract where the capacity price for the utility is indexed to T bills, okay?

If you want that, let it be known; private power producers can do that. I don't know that that's the best deal for the ratepayer, but if you want that, that can be done. It's been done.

Q But the traditional project financing arrangement that you're familiar with, usually they lock in the financing to isolate themselves from increases in cost of capital. That's the traditional

way?

A A lot of them do, not all of them do.

Q Who in this proceeding is asking for a cap in terms of purchase power?

A I see a cap, and I make this point about it being implied in Mr. Rosenzweig's testimony. I see it implied in Mr. Foley's testimony with the "We should limit the 15%." And I see it implied, and probably the least clear argument for a cap is with the cash flow argument, that the utility needs to accumulate cash.

Q Did you ever see the word "cap" in Mr. Rosenzweig's testimony?

A No, I did not, and I explained that in my testimony. I'm sorry.

Q Did you see the word "cap" in Mr. Foley's testimony?

A I'm not sure that I did, but that's clearly an -- clearly a statement that we should limit private power or limit purchases to 15%.

Q So it's simply your interpretation that it's a cap?

A Correct.

Q All right.

MR. McGLOTHLIN: For clarification, Mr. Neiser, are you saying that Florida Power Corporation

is not asking for a cap?

MR. NEISER: That is correct.

DR. ROACH: Good.

Q (By Mr. Neiser) Let's just switch over to contracts for a moment.

Is it your position that well-crafted contracts can, in fact, dispense with most disputes for a 30-year term?

A That's hard to say. It's my view that a well-crafted contract gives you a better basis for dispute resolution than prudence does, again, buy versus build. You can't anticipate everything that could go wrong in the 30 years. You know, that's too much to ask.

Q So you would then, basically, agree that in spite of best intentions on the part of two parties to a contractual arrangement, that it is virtually impossible to foresee the difficulties in a 30-year slice of future, to see all that will crop up during that time?

A Correct, there are no facts about the future.

Q Would it surprise you to know that with regard to the purchased power contracts that Florida Power presently has, that there have been contractual disputes with a very high percentage of them, perhaps

all of them? Is that surprising in terms of what you have seen elsewhere?

A If it's contractual disputes about interpretation of the contractual and you've worked them through, then I'm not surprised. That's how business people work through any contract lots of times to get together.

Q I guess here what I'm trying to drive at is, do you acknowledge there is a different dimension to trying to run a power plant through a contract versus running a power plant through a telephone call to your plant manager? Is there greater complexity and difficulty and expense in administering a power plant through a contract than through a phone call?

A I really don't think so, and I think a couple of points have to be made.

There's a lot of talk about picking up the telephone and calling your plant operator. It's no different with a private power producer. I think by now there -- I know in the contracts I've been reading lately, telephone or -- let's say telecommunication links are required. So there's no physical difference.

If a contract is fully dispatchable, for example, in Virginia, ever since they started, any project over 100 megawatts has to be on AGC or

automatic generation control. Increasingly, in peaking RFPs, the same thing, all projects are on automatic generation control.

So in these fundamental things, you know, the ability of your dispatcher to control the output of a private power producer, I don't see dramatic differences, I really don't. I see things actually being stated more clearly and the rules being more explicit.

Q Would you refer to Page 7 of your testimony, please? Are you there?

A Yes, I'm sorry.

Q on Page 7, Line 3, you make the statement that, "In the absence of a disallowance, the buy option has no financial effect on the purchasing utility." Do you stand behind the validity of that statement?

A Right.

Q Have you talked with the rating agencies as to whether they agree with that position?

A I've talked with them. I've been on panels with them and I've spoken with them. I guess I've never gotten a direct answer that says, "Yes, I agree," or, "No, I don't agree."

But, again, I mentioned this earlier, that if you read credit ratings, as I have done, and you read

the literature, there is explicit mention by Standard & Poor's, for example, and especially Standard & Poor's, that regulatory remedies really make a difference to them, the ability to have preapproval, the specific cost recovery clauses: that all makes a difference to them.

Q You're basically saying the only risk to the utility is the risk of disallowance?

A Correct.

Q Let me give you a hypothetical of a friendly utility going bankrupt. It stops payments to the IPP. Would the IPP make a claim to the utility for the unpaid and unmet payments?

A I think it's going to depend. The first thing the IPP would do is try to keep the project delivering and getting paid through some other mechanism, either through -- you know, through selling directly, in effect, to the ratepayer or something. That would be their initial response. Would they make a claim that if they live up to their performance, they're owed the capacity payments? I would imagine they would do that also.

Q Would that not be another financial risk to the utility, other than disallowance?

A The utility is bankrupt?

Q Yes, but yet you say they would probably make a claim, which would be some evidence of debt that they are basing it on. So is that not a potential risk in terms of acknowledging vulnerability to the utility, other than disallowance?

A Well, that may be a risk, but not in the context of what we're discussing here. We've said -- we've said here that we have a utility and that according to your witnesses, for example, they would like to put some recognition of that purchase on the financial statements of the utility. And I'm saying that in the absence of a disallowance, there's no -- there's no place for that on the financial statement. That goes back to --

Q I don't know that we need to plow this into the ground, but that's exactly my point, is that if there are financial auditors, and so on, that are registering concern, if there are investors registering concern of this outstanding obligation to IPP, would it not be in part because of those debt obligations that arise through contract that would be immediately due and owing at the time of bankruptcy, as an example?

A Again, I'd have to disagree with the premise your question. You've declared the contract to be debt. And I've gone on in my testimony and in the debt

rating reports too, it's -- a contract and capacity payments are not debt-like, because they are conditional, they are based on delivery of power.

Q I don't know what other word to use. What would you file for recovery in a bankruptcy proceeding? It's not an asset. I mean, I'm just searching for an answer as to what right would the IPP have for recovery of those unmet payments, if it's not viewed as a debt owed to the IPP?

A It's a contractual right. I don't think you have to use the term "debt." You know you can use -- there's other instruments where other suppliers would say, "Look, we delivered telephone poles to you; we're in line too." So in case of a bankruptcy, is a private power producer in line with everybody else? Yes, they are? Are they at the head of line or the back of the line? That's a tough question.

Q Is "liability" a good word? Does the contract represent a liability?

A In the case of bankruptcy?

Q Yes.

A Yes, it may, but you're take you're taking a really severe case. What about an ongoing -- no, really. What happens to the debtholders when that utility goes bankrupt? Are they in line? They're in

line, too, right?

Q Oh, absolutely. I'm simply having a little difficulty with your statement that says, "In the absence of disallowance, the buy option has no financial effect on the purchasing utility." Obviously, I don't agree with you. And I'm suggesting an example of bankruptcy would be another instance when there is a claim made against the utility because of that contract. It is a financial concern. It is a financial viability from our perspective. I hear you do not agree, but I'm just trying to see why.

A I'll agree that the premise of this question is that you're not bankrupt. That you are, as you've said before, passing through the cost of purchases as allowed under regulation, and that in that case, it has no financial effect, the pass-through has no financial effect.

Q Okay. Could I ask you to turn to Page 2 of 2 of your Exhibit No. 2 that appears to be a Standard & Poor's Credit Week piece of paper. And at least what I have been provided does not appear to be a full document. Is that intentional or oversight?

A No, that was intentional. I think all I'm referring to here is a couple of statements that I quoted, one about the range of debt-like qualities,

And I wanted to use Figure 2, which is on that second page. And then I wanted to quote a statement about the type of contracts, that IPPs usually have conditional contracts. So that's why I provided two pages.

Q Okay. What, from your use of this piece of paper from Standard & Poor's, what is your view as to the minimum percent risk factor that Standard & Poor's uses for off-balance sheet obligations such as take-and-pay arrangements?

A The chart shows zero.

Q Right. I see that. What is your understanding as to the minimum percent that they use?

A Well, it depends. It's not clear to me that in every utility that's purchasing power they do any of this -- that equivalent. But for those that they do, I've heard people like Curtis Moulton talk in terms of 10%.

Q Does this paper not reference 10% over there in the right hand column about the second paragraph from the bottom?

A Yes. As a practical matter it says 10 to 50%.

Q Okay. Is it your suggestion that Standard & Poor's has a different standard for different utilities in different states?

A I think they look -- they try to look at different utilities in different states.

Q So they would not uniformly apply this method in all states?

A Well, I think they've given themselves a lot of flexibility, especially in this range. I mean, they do, as I've quoted in my testimony, they do take account of regulatory treatment and that sort of thing.

Q Do you get the Standard & Poor's Credit Week on a regular basis?

A No.

MR. NEISER: Mr. Chairman, may I give him a piece of paper, if I may?

CHAIRMAN DEASON: Surely.

Q (By Mr. Neiser) Dr. Roach, what I have provided you is the June 1993 issue of this Standard & Poor's publication. The one in the exhibit is May of 1992. Would you indicate, if you can determine, what is the difference in the percent that is used in their chart that is contrasted from the one that is used in your chart?

A Yes, I chose -- this chart now shows take and pay contracts as being in the 10 to 50% range.

Q As contrasted to the zero to 50%, which is consistent with what they have said in the narrative of

this particular illustration?

A Correct.

Q But you're not sure they do that consistently is simply what you're saying?

A Well, I'm saying -- what do you mean consistently? Is every utility looked at and penalized or talked about in terms of debt equivalent? I don't think they do it for everybody, but it's their methodology, you're right. I'm not -- I've read all this, and the bond rating agencies are trying to raise some concern and they've used the debt equivalent analogy to do it. That's all a matter of record. The question, though, when you come down to a commission, where your witness, for example Mr. Wieland used 10%, the question isn't, "Well, what do the bond rating agencies do?" It's not enough to point to them and say, "They're using 10%." The question for the Commission would be, "Well, why did they do it?" Why is Mr. Wieland saying that in Florida with all the regulatory protections in place, with all the contracts that shift risk away from the utility in place, why is he saying that the utility is at risk for 10% of all the capacity payments? What is it? What is he predicting will happen that will make these result in a disallowance? And, more importantly, if these events

happen and cause a disallowance for purchases, what are they doing to the build option? What kind of disallowances are they a causing for building?

Q We'll come back to that in just a second. Let's go over to Page 1 of 3 of your Exhibit No. 3, which is, "Remarks by Curtis Moulton" of Standard & Poor's. Would you read the fourth paragraph of that, please?

A This is the third paragraph of the one page I have -- the first page.

Q Fourth paragraph down from the top, Page 1 of 3. It, again, appears to be just a portion of his remarks.

A Yeah. This quote, "But purchases are not risk free. When a utility enters into a long term purchased power contract with a fixed cost component, it takes on financial risk. Heavy fixed charges reduce a utility's financial flexibility, and long term contractual arrangements represent -- at least in part -- off balance sheet equivalents. Utilities need to take these, 'financial externalities' into account so that buy and build options are evaluated on a level playing field."

Q Does that statement square with your statement back on Page 7 of your testimony that says

their right to say that, "Hey, debt investors, purchases may impose some risk." I don't begrudge them that at all. That's what they do for a living. What I disagree with is the method that they've used and the method that your utility has adopted to express that concern. The debt equivalent method is not the right way to do it because its one-sided; it only asks about buying and it misleads us in terms of what remedies are appropriate. It leads us only to a higher return on equity. Whereas, regulatory remedies like those that are already in place, are the better remedies for ratepayers. So my quarrel is not with the intent; it's with the method.

Q Okay. And you're saying that the Commission need not buy into these philosophies, as you're suggesting the California commission has not yet chosen to do?

A Correct.

Q What about money lenders, do they look to Standard & Poor's to assess the financial credit-worthiness of a utility before they loan money to them?

A That's one of the factors they look at, yes.

Q All right. And in the real world of what a utility must pay for its financial instruments, debt

equity, would not what the rating agency does and views the credit risk to be influence the price the utility must pay for those financing instruments?

A It could, but, again, does it really? In my testimony, once again, there's another quote from Virginia Power. And if I find it, I'll quote it; if not, I'll paraphrase it, which says, "We know we've been downrated, but the market has shown that purchases are not the equivalent of debt." So do they look at this? Yes. Do they always -- are they always influenced in a particular direction? Generally --

Q Did you read the testimony of Terran Miller in this proceeding?

A I did.

Q All right. Do you not observe his testimony to be the effect that they, in fact, do adjust the cost of money based upon what rating agencies say?

A I read it to say that here's what the credit rating agencies are doing, they're using this debt equivalent method, and that there is some risk with buying. I don't even quarrel with either of those points. I'm saying, though, it's half the job you have to do. What about the cost of capital risk with building? History has shown that that's significant. And as we look at it, we're going to find that it's

consistently greater than the risk with buying.

Q One more effort --

A Just --

Q Excuse me.

A Because I didn't get to quote it, it's on Page 23, the statement by Virginia Power, and I'll just take the last sentence. Quote, "That is, the market has decided that the company's, VEPCO's, purchased power contracts, bear little resemblance to traditional debt."

Q All right. I'm going to try just one more time to see if you will agree --

CHAIRMAN DEASON: Mr. Neiser, I don't want to cut you short, but you've tried many, many times. I'm not so sure you're going to get the answer you want from this witness. It may be better to make your point with your own witness. Time is at a premium, but if feel compelled, please proceed.

MR. NEISER: You'll be pleased to know this is my last question, or at least my last little bit of a line.

Q (By Mr. Neiser) Dr. Roach, again, you're saying that the only risk, financial risk, to a utility is with regard to disallowance, with regard to purchased power. Are you aware of what New York State

Electric and Gas incurred in the way of a payment to excuse itself from a purchased power arrangement for an unneeded 134 megawatts of purchased power?

A I'm generally familiar with the buyouts.

Q It is my understanding that they have paid $45 million to be excused from that contractual commitment. Would that not be a financial risk to a utility with regard to purchased power?

A We can check this. It's my understanding that it's not, that the buyouts in New York are sanctioned by the Commission. So it's an issue, once again, of recovery and disallowance.

MR. NEISER: That's it. Thank you, Dr. Roach.

DR. ROACH: You're welcome.

CHAIRMAN DEASON: Ms. Swim? Any further questions for Dr. Roach? Ms. Rule?

CROSS EXAMINATION

BY MS. RULE:

Q Dr. Roach, you've been referring repeatedly to a well-crafted contract. What process do you envision negotiation playing in crafting that contract?

A I think Mr. Huddleston is probably in the best position to answer that, and specifically within terms of CEPA's proposal, the extent to which

necessary, I'm going to give you that latitude.

I can express to everyone here in this hearing room at this time, the bench is getting a little bit concerned about the amount of time we're devoting to what appears to be cross examination and now to what appears to be redirect. This is a rule hearing. And this is not sworn testimony. We are getting information to base some policy on. So with that warning, I'm going to give you the latitude to proceed, but I would just request that you make it as brief as possible.

MR. McGLOTHLIN: Yes, sir, and I appreciate your concern about the time factor, but the need for my questions arises because there has been what amounts to cross examination. I'm try to cull it very quickly if I can.

REDIRECT EXAMINATION

BY MR. McGLOTHLIN:

Q Dr. Roach, you were asked several questions that had as their premise supply of power at zero cost from a utility -- from a fully depreciated plant. If you know, is it more typical that over the life of a plant, there are additions and capitalized repairs that result in an ongoing capital value with those plants?

A Yes. It's more typical for capital

additions. I mentioned life extension, and I believe Mr. Ballinger mentioned yesterday that they submitted some evidence here which showed that the plants don't get fully depreciated, that later on in the life that because of what I call capital additions, you have the same amount as the original investment.

Q You were also asked some questions regarding whether IPPs benefit if the cost of capital goes down. On the flip side of that, where the utility has constructed or cost of debt and equity reduced to the utility, unless there is a change in rates or unless there is a rate case where return of equity is modified, would you agree that the utility may stand to gain from decreases in cost of capital as well?

A That's correct.

Q It was suggested that there's greater complexity in running a unit through a contract as opposed to owning it. In your opinion, is there any experience that demonstrates that that can be done successfully?

A Ample experience.

Q And Mr. Neiser referred you to some S&P documents regarding the use of the debt equivalence. Have you seen any statements by Standard & Poor's which indicates that they are not doctrinaire about the

application of that where such things as preapproval and cost recovery is firmly in place?

A Absolutely, and I've quoted them in my testimony.

Q Mr. Neiser referred you to some testimony by his witness, Mr. Miller. If you recall, would you agree that Mr. Miller also said that in a given case the buy option can be the least risk alternative and can enhance the utility's risk profile?

A Yes.

MR. McGLOTHLIN: No further questions.

CHAIRMAN DEASON: Thank you. Thank you for making that brief. Thank you, Dr. Roach.

DR. ROACH: Thank you.

(Dr. Roach excused.)

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CHAIRMAN DEASON: Mr. Moyle, you have further witnesses? Call your next witness, please.

While he's doing that, let me make an announcement as far as lunch plans are concerned. At a convenient time we do intend to break for lunch, but it will be for only a half hour. So if that means that you need to make arrangements about having something brought in, please feel free to do so.

MR. MOYLE: Mr. Chairman, while this witness

is getting ready, I think Commissioner Lauredo requested some information about independent power producers, specifically Jay Makowski. May I have permission to submit that as CEPA Exhibit 4, and can I put that together sometime next week and give it to all parties?

CHAIRMAN DEASON: Yes, we'll identify that as Exhibit 4 and please make sure that all interested persons have a copy of that.

MR. MOYLE: Thank you.

(Late-File Exhibit No. 4 identified.)

MR. WATSON: May it please the Commission, I'm Ansley Watson of MacFarlane, Ferguson, appearing for Ensearch Development and CEPA.

JOHN SEELKE

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. WATSON:

Q Mr. Seelke, could you state for the record your name and business address?

A My name is John Seelke. My business address is 4727 Royal Palm Circle, Northeast, St. Petersburg, Florida 33703.

Q How are you employed, Mr. Seelke?

A I'm employed by Skyway Power Corporation.

Q And what's your position with Skyway Power?

A I'm president.

Q Mr. Seelke, did you prepare and prefile comments and a four-page exhibit in this docket on September 10 on behalf of CEPA?

A Yes, I did.

Q Do you have any corrections to make to your comments or testimony?

A There are a few minor corrections to the exhibit, Page 1 of the exhibit, which I'd like to make now: For the CFR Bio-Gen contracts, Bio-Gen 1 and Bio-Gen 2, that are in about the middle of the exhibit, the "Contract Length" should be 30 years for both of those instead of 20. In addition, for the projects that are near the bottom of the list, LFC-Madison and Lake County Resource Recovery, there was some data that was transposed in the last two columns. The "Total Cost Savings" -- excuse me. Excuse me, I gave you the wrong projects. They were Pasco -- it's Pasco Cogen and LFC-Madison that has the data that should be transposed. Under the "Total Cost Savings," the Pasco Cogen has $1,038,000 savings and LFC-Madison is zero. Those are transposed. And likewise, under the "QF Cost As a Percentage of Utility's Avoided Cost," the

"Footnote E" applies to Pasco Cogen and the "100" applies to LFC-Madison.

Q Mr. Seelke, did you also submit a corrected Page 6 to your comments, the original filing of that?

A Yes, that was filed as well.

MR. WATSON: Commissioners, we just want to make sure that everyone has that. The corrected page says "Corrected" below the Page No. 6.

CHAIRMAN DEASON: Yes, I have it.

MR. WATSON: It's my understanding Mr. Seelke's comments and exhibits have been made a part of the composite exhibit.

Mr. Seelke, with those corrections, do you adopt those comments as the comments you would give here today?

A Yes, sir, I do.

Q Would you please summarize your testimony?

A My testimony addresses three areas: First, I address the Section 712 issue regarding whether this Commission should implement procedures or advance approval or disapproval of purchased power contracts. The answer is yes. And this objective is accomplished by the proposed CEPA rule that is contained in Mr. Huddleston's testimony. This Commission already has a policy of preapproving power purchase contracts between

investor-owned utilities and qualifying facilities, both standard offer contracts and negotiated contracts.

Second, I describe the benefits to Florida's ratepayers from contracts between investor-owned utilities and qualifying facilities. To date, 44 contracts totaling about 2300-megawatts have been approved that have resulted in savings with a present value of over 296 million to Florida's ratepayers.

Finally, I address the requirements of CEPA's rule that the utilities make certain data, including computer models and databases, available to parties. Let me say that from the questions that have come up on my prefiled comments, it's obvious that the intent of this requirement has been misinterpreted. CEPA's intent is not to require the utility to disclose its bid in the bid package that the Commission approves. We feel that this would be unfair to the utility. And I hope to clarify that during the course of my remarks here today, and also to work with any parties that have any concerns about that misinterpretation.

Our rule has two distinct phases in it. The first phase, which identifies the timing and amount of capacity required by the utility, and the second phase which selects the company or companies to construct this capacity in a bidding process. During the first phase,,

the utility must disclose the planning assumptions, such as load forecast and fuel forecast, including computer models and databases, that it relied upon in reaching the conclusions about its capacity requirements.

For the bidding phase, the utility is required to disclose its evaluation criteria, weights, evaluation methods, including any models and databases that will be used to evaluate bids. These criteria and evaluation methods become part of the utility's proposed bid package that this Commission approves.

CEPA believes that the information required by its rule must be available to both the Commission and the utility's competitors in order to obtain a truly level playing field, thereby assuring that competitive capacity selection benefits the ratepayers.

Q Mr. Seelke, in line with your comments about CEPA's intent with respect to the data disclosure requirements, what types of information would be required during the first phase of CEPA's rule from the utility?

A Under the rule as we've proposed it, the utility should be required to provide the type of information that the Commission has previously required from utilities when it reviews generation expansion plans. This includes conceptual plant, capital cost and performance data for capacity alternatives, fuel

forecasts, load forecasts, including the impact of utility-sponsored conservation programs, and computer models and data bases used to determine its capacity expansion plan.

Q And you've already indicated that you would not expect the utility to reveal its bid at this stage?

A That's correct. As Mr. Foley pointed out in his direct testimony on Page 14, Lines 16 to 18, generation expansion plans are based upon conceptual cost and performance data that are reasonable for planning purposes. These data are not bid quality information. The utility, if it desires, would submit its bid under the RFP, along with all the other bidders.

Q Mr. Seelke, why aren't the utilities planning data and forecast bid quality as opposed to planning quality at this particular stage of the game?

A To answer that question, I'm going to first briefly describe how a utility selects its next capacity addition. The utility, when it's evaluating the next type of capacity that it would install, evaluates alternative generation expansion plans over a 20- to 30-year planning horizon. In doing so, it must look at the economics of the next edition in combination with the operation of its existing capacity and its future plant additions over this 20- to 30-year,

period. The utility's objective is to select a plan, enhance the next capacity addition in that plan that minimizes the present value of revenue requirements over the period.

Conceptual cost and performance data is acceptable and appropriate for this evaluation. Keep in mind that bid quality data is, on the other hand, very detailed data. It is site specific; it is vendor specific. And it's simply not practical to develop bid quality information for 20 years of power plant additions that are used in the planning process. That's why conceptual data is relied upon at that phase.

Q Then why wouldn't the Commission just skip the need identification stage under your rule and go right to a bid?

A Because without a baseline or reference capacity expansion plan, neither the utility nor the Commission would be able to determine how the various bids would impact the present value of the utility's future revenue requirements. A baseline plan is a must for evaluating the economics of each bid.

Also, by addressing the assumptions used to develop the baseline plan before an RFP is issued, the Commission benefits in two ways: First, it has the benefit of the collective input of all parties in

reviewing the utility's plan. And second, it avoids the problem of potentially invalidating the bid process by addressing key assumptions after the bid.

This problem occurred in the Cypress energy docket. FPL's evaluation of the Cypress energy project and alternatives was based upon a natural gas forecast that the Commission stated was not reflective of market trends.

Q Mr. Seelke, could the utility, if it bids -- if it has indicated it will bid under CEPA's proposed rule, during the second phase under the rule, submit a bid for a plant that's based on capital cost and performance data that is different than it relied on in the capacity identification phase under the rule?

A Of course. In fact, its bid would be based upon much firmer site-specific project-specific data, since under our rule its cost recovery will, like other bidders, be confined to its bid.

Q Well, now what if the utility has indicated that neither it nor its affiliate is going to bid, why should the utility be required to disclose its evaluation criteria, including the models and databases?

A By disclosing this information, bidders will be able to prepare better, sharper-conceived projects for the bid. They'll be able to develop more

responsive bids.

MR. CRESSE: Mr. Chairman, may I ask a question? Mr. Ansley, is this your witness?

MR. WATSON: Yes, sir.

MR. CRESSE: It's been unusual -- I didn't know for sure. It's kind of unusual when a person cross examines their own witness after they've summarized their testimony. I'm not objecting to it, I just --

COMMISSIONER LAUREDO: Glad you asked.

MR. CRESSE: Y'all can object at this point, though.

MR. WATSON: If this were a 120.57 hearing, I might be talking back to you, Mr. Cresse. But we're just trying to get this information as clear as we can for the Commission that's going to have to make a policy decision in this docket.

CHAIRMAN DEASON: Well, let me ask a question at this point since you've been interrupted. The question of what information should be provided, by whom, when, and in what format and all that, isn't that the subject of another docket?

MR. WATSON: I don't believe so. I believe it is clearly one of the key issues in a docket that is considering whether capacity selection should be made through competitive bidding. In other words, how to

the potential providers of capacity know what it is that they're bidding on? And if they don't have the proper data to know just what it is the utility says it wants, says it needs, how what it is it wants and needs is going to be used, dispatched, how this thing, whatever it may be, that is needed is going to impact, under different scenarios, the utility's overall revenue requirements, I don't know how people can frame truly responsive and competitive bids, sharpen their pencils to put out their best offer to the utility.

CHAIRMAN DEASON: I can understand that. Let's just make sure that we're honing in on the bidding rule and how information requirements relate to the bidding rule.

MR. WATSON: We see these information requirements as key in the bidding process.

Q (By Mr. Watson) Mr. Seelke, Mr. Niekum of Florida Power Corporation, in his rebuttal testimony takes issue with your comments regarding the CEPA rule's requirement that a utility soliciting bids for new capacity be required to furnish the information mentioned in your rule. First, he states that you're challenging the Commission's June 1993 order denying your Company's access to certain computer models of Florida Power. First, are you challenging the

Commission's June order?

A Yes, I am. But in a separate proceeding, not in this proceeding.

Q Then why did you raise the Commission's decision in your comment?

A For one reason: The Commission's order cited competitive concerns as the issue it relied upon in denying Skyway access to FPC's modeling data. These same competitive concerns are present in this proceeding.

Q You don't expect the Commission's decision on your complaint which is pending in another docket to have any impact on the decision made by the Commission in this docket?

A No, I do not.

COMMISSIONER CLARK: Why not? It would seem to me that it would have an impact. I mean, we would want to be consistent in what we decide to do.

MR. WATSON: I would hope you would.

COMMISSIONER CLARK: I mean, I would view it as that proceeding we're going to get into more of the detail of precisely what it is you want and why you want it and why you think you should have it. And it provides us more background for this.

MR. WATSON: I may have incorrectly phrased it, Commissioner Clark. I know the Commission would

want to be consistent. We are not seeking a determination by the Commission on Mr. Seelke's complaint and request for an evidentiary hearing in this proceeding.

COMMISSIONER CLARK: Okay.

Q (By Mr. Watson) Mr. Seelke, Mr. Niekum, at Page 5 of his rebuttal testimony, Lines 17 to 23, states that "Florida Power opposes the release of computer models and data sets because a utility could never compete effectively and win a bid if it must release this information." Do you agree with this statement?

A No. And as I've earlier explained, during the capacity-identification phase, we only require that they release the planning data and planning models that they relied upon in reaching their decision to go for new capacity. The utility, if it elects to bid, will submit its bid like other bidders.

Q Now, is the same true of the information required in the second part of CEPA's rule that requires disclosure of information, including computer models, that will used to evaluate the bids received in response to a solicitation?

A That's correct. The Commission should not confuse the utility's disclosure of its evaluation criteria, which includes models, with the bid itself. The

evaluation criteria and models will be used to evaluate all bids, both utility and nonutility. If only the utility has access to the evaluation models and criteria, then they have an unfair advantage in the process.

CHAIRMAN DEASON: Let me ask a question at this point. Are we summarizing something that has been filed before or are we plowing new ground here?

MR. WATSON: Mr. Chairman, this does go somewhat beyond a summary, but in the rebuttal comments to Mr. Seelke's direct testimony, to which we've had no opportunity to respond under the prefiled comment procedure, there was some apparent misinterpretation of what our rule would require and I wanted Mr. Seelke to clarify that in the hopes that we could allay some of these concerns.

COMMISSIONER CLARK: Can I make a suggestion? I don't think you need to ask him questions. Why doesn't he just clarify what he needs to do? I mean, we could eliminate some time there. I agree, we're in a 120.54 proceeding, and so there isn't really the strict adherence to summarizing and things like that. You're concerned that by what other people have filed, they've misinterpreted. Why don't we just let Mr. Seelke identify those areas and go from there? We might be able to shorten it.

MR. WATSON: I think we've just concluded doing that.

MR. SEELKE: We're at the end.

MR. WATSON: Does this conclude your testimony, Mr. Seelke?

MR. SEELKE: Yes, it does. (Laughter)

CHAIRMAN DEASON: Mr. Childs?

CROSS EXAMINATION

BY MR. CHILDS:

Q Mr. Seelke, in your testimony, Page 13, you address the developer's need to offer the most cost effective bid, and in doing so, it needs to obtain the weights assigned to fuel supply security and fuel price risk. I think you used that as an example --

A Right.

Q -- of not only the kind of data that the bidder needs, but why the bidder might need that data; is that correct?

A That's correct.

Q What do you envision in terms of the fuel price component of a bid? What do you envision the bidder supply that would give rise to your concern about knowing the weighting criteria for fuel price security?

A Well, there are two criteria here I'm proposing, fuel supply security and price risk, which

are nonprice factors. Those are judgmental factors. And to the extent that those can be graded differently -- in other words, there can be an A grade on fuel supply security, or B grade, or C grade -- how you respond to that, versus trading off of price itself for your fuel is important to know. In other words, if 20% of the evaluation is tied up in fuel supply security, you need to know that because if 80% is in price, you're trading off between those two variables so that you can then develop the best bid.

Q Well, I'm not sure I understand one of the comments you made. I think you said that these factors were subjective. But let's -- and I will focus on the issue of fuel price. What I'm trying to find out is are you proposing that the bid that would be submitted would not be a fixed price or a forecast price for fuel, that would be translated into an energy payment by the utility?

A It could have a fixed price, it could have a formula price or it could have -- what I'm talking about here, Mr. Childs, maybe there -- is price risk is one of the criteria.

Q Well, I took that to mean that when a bid is submitted, that one of the components of the bid would be the energy payment to be made to the IPP.

A That's correct.

Q And that therefore, since -- when we're trying it decide whose bid is best, that one of the things that we would all want to know is what is the risk that a particular forecast of fuel price would, in fact, eventuate?

A That's true.

Q And we would also want to know not only whether the forecast that's submitted is risky, but we would like to know as well, as best we could, what the potential variation in fuel price might be, given the risk that it would vary at all.

A That's true.

Q And in that scenario, wouldn't you believe that the IPP would assume all of that risk and make up its own mind about what price security it was comfortable with and what availability it was comfortable with?

A Not necessarily, and let me give you the example. Suppose that someone had a fuel -- an energy proposal that said, "I'm going to tie my proposal to -- I'm going to index it to the price of coal, the index for coal variation. Here's my starting price. It's going to be $3 a million times my heat rate and we're going to index the coal." Now, there's another

proposal that says, "I'm going to index my price to the spot market of natural gas. But my price proposal starts at $2.20 and ties that index up." There's clearly different risk between a coal index and a natural gas market index. So there is a risk variable there. And there's also a difference in price proposals that have been put on the table. So, unless you know how price risk is going to be judged by the utility versus its overall economics of the bid, you can't distinguish which the utility will consider a better bid.

Q And all I'm suggesting is that isn't there a way around that, by saying, "We'll remove that from consideration," and simply say, "If you make a bid to us, the IPP will bear all of the risk as it relates to fuel availability and fuel price"?

A That's possible, too, yes.

Q And, in fact, don't you think that in terms of attempting to assign weights to both fuel security and fuel price, just as you've mentioned, you have different risks depending upon the type of fuel that's involved?

A That's right.

Q And you have different risks, depending upon the IPP and their potential arrangements with fuel

suppliers and fuel transportation.

A That's correct.

Q And you will have, I assume, different qualities of information from each of these IPPs as to their fuel availability, that is supply, and the fuel price.

A That's true.

Q How is that all going to be evaluated?

A Well, that's a good question. I took these two categories, fuel supply security and fuel price risk from Florida Power and Light's evaluation criteria for the Cypress Energy docket.

Q Sure.

A I didn't know what the weights were or how they were evaluated and that's really part of the puzzle, but they were assigned some score in the evaluation process.

Q Sure. But I think I'm asking or I hope I'm asking the questions to you. I know those exist and the Commission does as well. But I'm asking the question to you in terms of your suggestion, at least, that these criteria and the weights assigned to them must be known in advance. And it seems to me that in order for them to be known in advance, for example, that the utility would have to be making or attempting

to make some judgment itself about fuel supply and fuel price risk.

A Oh, definitely. And, in fact, those are proposed under our rule as part of the bid package.

Q But we really won't know at that time what kind of bids we're going to be evaluating and what factors we may need to add in that area for evaluation.

A You're saying because you don't have the bids coming in, you can't assign -- you can't judge risk until you've seen what comes in on the bids.

Q Perhaps not. I mean, wouldn't you agree that the fuel availability or fuel supply risk for coal may be less than the availability risk for natural gas, at least in certain parts of the state? And it could change.

A It could change, that's true.

Q So that in certain parts of the state the risk on fuel availability, at least in the near term, may be less for gas than for coal, depending on transportation.

A I guess what I'm having a little problem with is the premise that you can't decide how you're going to weight various factors until you see the bids coming in.

Q Well, how can I weigh various factors until I

know how you're going to price it? If you're going to assume all the risk, that is, you being the IPP, then maybe I can reduce my concern about price but I may still be concerned about availability.

A Well, again, the risk that the IPP would assume would be defined in its bid. If it said -- if its bid said it's going to be $2.20 for natural gas floating it as the market index, that risk would then be translated into the contract terms which eventually the ratepayer would bear, but that's part of the process.

I guess my question would be how can I, as an IPP, know what to bid if I don't know what you're assigning various categories in terms of your own wants?

Q Well, that's why it takes me back to the question, which I think we've already addressed what the pricing would be. You would agree that when a utility operates a power plant, that the cost that it gets to recover for fuel is actual cost, would you not?

A That's right.

Q It doesn't make any difference whether it has an absolutely wonderful contract for fuel price, it gets that wonderful price and nothing more from its customers.

A Correct.

Q But if the IPP has its own forecasted fuel price for its own unit, the price that it charges the utility is not necessarily what it pays and it's not necessarily tied to achieving a wonderful fuel price.

A Well, again, if it's bidding against other bidders, it will achieve a wonderful fuel price or a wonderful total price because if it doesn't, someone else will underbid it.

Q Does the utility have the option to obtain the wonderful total price, or wouldn't you agree that it, in fact, is regulated on the basis of price segments?

A Under the traditional way of doing business today, you're right, it's regulated under traditional price segments. But in our proposed rule, Matt, the utility would be able to come in and propose a total price package that might not be right in both categories but still could be an overall profitable venture.

Q Would you envision that the utility could do that and still propose it as a utility proposal as opposed to a proposal submitted by a subsidiary?

A Yes. But it would have to be -- let me say yes and no. If you're talking about an affiliate's

subsidiary in another part of the holding company, it certainly can do that.

Q Yeah.

A The other thing it can do is it can propose it as a utility-owned subsidiary. And recalling your questioning of Craig Roach about whether that could be done without jeopardizing bond indentures and those kind of things, Matt, when I was at Florida Power that, in fact, was an area that was explored very thoroughly. And at that time there was very serious consideration given to investing as a utility in an unregulated power project. And the question of bond indentures, for example, came up; would that investment be in conflict in some way with the bond indenture? For that specific case there was no problem. I don't know what it would be in other utilities, but it was no problem with Florida Power. So, yes, it could do that. It would have to set up a separate entity to do it if it were considering bidding probably.

Q That's my point, though, is that when you say there's no problem in doing it under the indenture. I'm really trying to get an understanding of whether the proposal of bidding and the discussion of the relative positions of the utility and the IPPs, in fact, potentially forces the utility to change the way,

even if it's going to be successful, in offering the best project at the best price, that it will not be done so through the utility with the typical utility financing and the typical regulation by the Commission.

A Well, let me correct my previous comment slightly, Matt.

There's no reason it could not be -- well, we didn't propose -- the question of could it be done under the utility with its utility financing was not addressed with the previous answer I gave you. Whether that would be a problem with the bond indenture or not is something we didn't research. But I see no reason why in theory that investment could not be excluded from rate base rate-of-return regulation. I think the question you're posing is could that be financed as utility property. I don't know that that would be a problem.

Q Okay. You have given some -- and you've made some statements, Mr. Seelke, about the savings that have been achieved through various contracts with the various utilities, and you have an exhibit or your exhibit shows the information on those.

A Yes, sir.

Q Would you turn to the one for Florida Power and Light Company?

A Okay.

Q Before I ask about anything specifically, would you agree that you have done your calculation on the basis of the estimates of costs that were in existence at the time the contract was approved?

A Yes, sir. That's correct.

Q So when you say it saved money, it's fair to take that to mean it saved money on the basis of the estimates available at the time it was reevaluated.

A That's correct.

Q Do you know, for example, whether, take the top one, AES Cedar Bay saves money on the basis of current estimates?

A I haven't done that calculation.

Q Okay. You've compared AES Cedar Bay to a 1994 combined cycle unit.

A Yes, that was the avoided unit in the filing.

Q Wasn't the avoided unit a 1995 pulverized coal unit?

A I believe that unit was probably the avoided utility unit, Matt, as opposed to the avoided statewide unit.

Q Beg your pardon?

A I think that was the utility's avoided unit as opposed to the statewide avoided unit.

Q But, I mean, when the Commission approved the contract, didn't they approve it on the basis of comparison to the 1995 pulverized coal unit?

A I believe it was done against both a combined cycle and a coal plant, but I don't have that information in front of me right now, Matt.

Q Okay.

A I will acknowledge that it was not -- that a coal plant was the statewide void unit at the time.

Q Do you know what fuel price forecast for gas was used for the combined cycle unit?

A No, I do not.

Q Do you know whether it's the same one that was rejected in the Cypress proceeding as not reflecting the market conditions?

A No, I don't.

Q That really ought to be near-term current market conditions, wouldn't you say?

A You mean in terms of the PSC statement in the Cypress docket?

Q That's right. And the acid test.

A I'd have to pull the order. I think it just said not reflective of current market trends. I think you're right, it said "current markets trends."

Q Okay. Just -- not to question the level of

savings that you've quantified here, but you have set out numbers and have reached a conclusion that these negotiated contracts have saved money.

A That's correct.

Q Is it -- and I think there is a lot of testimony about the preapproval of contracts and the necessity for preapproval of contracts, would you agree? And that's part of your proposal: there would be a preapproval of contract and you never look back.

A Yes, sir. Yes, sir. Right.

Q Just as a reaction, independent of the availability of bidding, do you think the utility -- a utility would ever be able to obtain a commitment from the Commission to preapprove a generating alternative and preapprove at the same time a return on equity for that investment over the life of the unit?

A Again, I think you're looking at -- are you considering a traditional utility build option?

Q Sure.

A It couldn't -- I don't think it would be fair. I think it could get preapproval on a price but not necessarily a return, because that's where I think the difference is between an independent and a utility, traditional regulation.

Q But when the Commission approves a price, and,

it approves it for a utility, implicit in that, if not explicit in that, is some particular return on equity for the utility investor.

A That's true.

Q When it's a utility project.

A That's true. But the utility investor is not taking the risk that that price will be -- in other words, in an independent power project the utility investor, there's an implicit rate of return on its investment, too. But it's taking a risk. It's taking the risk that it may make that investment or it may not make that investment -- it may make that return or it may not make that return.

Q Well, when a utility makes a proposal, Mr. Seelke, and I really want to focus on the utility in the traditional sense, but consider, nevertheless, that it's making a proposal. When it makes that proposal --

MR. WATSON: Matt, let me just clarify, because I'm not sure I understand and I want to make sure that the witness understands. Are you talking about a utility proposal in terms of a bid under some form of bidding, or are you talking about a utility proposal that I guess in the past has simply been built and the question becomes does it go in rate base and how much do we earn on it? Which type of proposal, are

we talking about here?

MR. CHILDS: I'm talking about a proposal by a utility that may be in connection with bidding, all right; or it may be that it's independent, simply a utility proposal that says, "Instead of applying the traditional regulation to us, which limits us to recovery cost, we will propose a price. We will provide 435 megawatts of this unit at this price for 30 years, approve it. It's a good deal." Which is essentially what you would be doing in a competitive bid as well.

MR. WATSON: Okay. That's the clarification I wanted because that's what's contemplated by the draft rule that CEPA has submitted in this proceeding.

Q (By Mr. Childs) And all I'm trying to find out is independent of bidding, would the utility ever be able to obtain that preapproval regulatory treatment?

A Independent of bidding?

Q Yes, sir.

A I wouldn't recommend the Commission to approve it independent of bidding, because there may be a better deal out there, basically, that could serve the ratepayer's interest better. If the utility submitted the best bid, on the other hand, yes, I think

the Commission could and should approve that.

Q What if it's the only bid?

A If it's the only bid then it's the best bid.

Q So there's a potential of once we go into this of a situation where we have competitive bidding, and there's definitely a need for capacity and no one proposes any alternative but the utility.

A Matt, while that's possible, given the typically massive responses to RFPs that have been happening in the past where someone puts 500 megawatts for bid and receives 20,000 megawatts of bids, I don't think it's probable, but it is possible.

Q Okay. Let me come back and this is the last area, Commissioner, I want to ask about. And if you or your counsel think I'm far afield from your testimony, tell me and I'll stop. I thought it related and I intend it to relate to the point you're trying to make about needing weighting criteria and criteria in advance of the bid. You would agree that there's a lot of information that the utility may need in order to evaluate a bid.

A No doubt about it.

Q And would you agree that at the time it receives the bid there will be no commitment for financing the project?

A There will be no commitment for financing the project.

Q Yes, sir.

A That's correct. Generally, the bidder will generally not have loan documents finalized.

Q And there generally will be no contract for fuel.

A That's true.

Q And there generally will be no contract for anything else, will there?

A That's true. But there will be a security deposit that will be submitted.

Q Now, independent of the security deposit, in terms of information, I really mean it in terms of information, that when a proposal is made to the utility that says, "We propose to use coal or we propose to use natural gas for this unit. This is the size of the unit, this is how we intend to operate it. And you should expect that we're going to obtain financing, and you should expect that we're going to obtain fuel and you should expect that we know what we're doing about fuel price," but none of that information is available.

A Well, there's two parts to that. I think the evaluator of the bids can certainly request information,

that is available to be, you know -- that it feels is necessary in the evaluation process. And, again, that gets to the -- all of that will be preapproving the RFP, but to the extent that some of that information is to what the basis of the bid was and why do you feel you can do this, if it's pertinent and agreed to in the RFP process, that can be made available. But the actual contracts themselves for financing or fuel or other factors are not going to be finalized.

Q Well, I mean even to obtain assurance that -- some assurance, that the project is financeable and/or that fuel supply is as secure as you say and available at the price you represent.

A I think there's -- where you get to the tension on that information, Matt, is going to be where a bidder has concerns about disclosing information that it feels is competitively sensitive.

Q Right.

A And there will be information that it feels free to divulge that doesn't compromise its competitiveness in not only this market but other markets that it may have.

Q Right.

A And I think the way to get this Commission and others comfortable with that is the security

deposit.

If you look at a 400 megawatt bid, for example, and what's been required typically in contracts -- and I'll have to go back to our rule to see what we limit it to. I think it's $15 a kilowatt. I'm not sure. I think it's $15 a kilowatt, subject to check, but a 400 megawatt bid would require a $6 million security deposit to be paid.

Q Right.

A And when a company comes in and says, "This is my bid and this is my check," its ability to perform that is going to go through a lot of rigorous review. And, in fact, the fact that it has performed in other contracts in other areas is giving it that comfort and that feeling that it will submit a bid and it will submit it with money behind it as a guarantee.

Q I thought I was to my last question until you brought up the $6 million.

A Okay.

Q Do you think the $6 million figure that you've suggested -- actually, you suggested a rate based upon your assumption as to size of the unit would produce 6 million. Do you think that that is a fair approximation of the impact on cost of compressing the construction unit of a 400 megawatt unit by nine months,

or so?

A I haven't done a calculation on that, Matt. I don't know.

Q This is the last question.

A Okay.

Q Why should bids not all be public? Why should not every single item or aspect of a bid be public?

A As long as it's not competitive information that's being disclosed it should be public. I don't have a problem with that. You may want to -- there's some ways that -- in other words, the bid itself --

Q The bid and the assumptions that go with it.

A To the extent that, like I said, there's not a compromise in competitiveness, which I view as a security deposit, sort of taking care of that area, I don't have a problem with public disclosure of the bids themselves. As an alternative, if some people are sensitive to having all the bids out on the table, the winning bid can certainly be disclosed. Everyone else knows what they bid and they can check. In our process, the only protest that one has -- the only reason for protesting is whether the evaluation process was not conducted in accordance with the criteria and methods agreed to in the bid package. So someone could

evaluate their own bid and see if the winner were properly chosen.

But if the Commission decides in the RFP process to make all bids eventually public, that's a decision that can be made and argued during that process, during the bid package process.

MR. CHILDS: Okay. Thank you, Mr. Seelke.

CHAIRMAN DEASON: I propose that we break for lunch at this time. We will reconvene at 12:45.

(Lunch recess.)

(Transcript continues in sequence in Volume IV.)

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	
Proposed Amendment of Rule 25-22.081, F.A.C., Contents of Petition; and Proposed New Rule 25-22.082, F.A.C., Selection of Generating Capacity.	DOCKET NO. 921288-EU

SECOND DAY - AFTERNOON SESSION

VOLUME IV

Pages 416 through 564

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN J. TERRY DEASON COMMISSIONER SUSAN F. CLARK COMMISSIONER LUIS J. LAUREDO COMMISSIONER JULIA L. JOHNSON
DATE:	Thursday, September 30, 1993
TIME:	Commenced at 9:30 a.m.
LOCATION:	FPSC Hearing Room 106 Fletcher Building 101 East Gaines Street Tallahassee, Florida 32301
REPORTED BY:	JOY KELLY, CSR, RPR Bureau Chief SYDNEY C. SILVA, CSR, RPR PAMELLA A. CANELL Official Commission Reporters

APPEARANCES:

(As heretofore noted.)

DOCUMENT NUMBER-DATE
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PROCEEDINGS

(Hearing reconvened at 12:45 p.m.)

(Transcript continues in sequence from Volume III.)

CHAIRMAN DEASON: Call the hearing back to order, please. Mr. Cresse?

MR. CRESSE: I believe it was Mr. Willingham.

CHAIRMAN DEASON: I'm sorry. Mr. Willingham.

JOHN SEELKE

resumed the stand and testified as follows:

CROSS EXAMINATION

BY MR. WILLINGHAM:

Q My name is Bill Willingham. I represent the Florida Municipal Electric Association and Florida Municipal Power Agency.

I believe in your testimony you implied that potential bidders would like to obtain more information from the utilities in the bidding process. And the question I have is: Are you aware of any instances in which a municipally owned electric utility in Florida has refused to disclose information regarding its generation selection criteria?

A No.

Q Thank you.

CROSS EXAMINATION

BY MR. CRESSE:

Q Joe Cresse on behalf of TECO.

A Good morning, or good afternoon.

Q Mr. Seelke, on Page 2 of your testimony you said you spent 14 years working for FP&L; is that correct?

A 14 of those years were with two Florida utilities, 11 with FPL and three with Florida Power Corp.

Q Where were you in 1980?

A I was with Florida Power and Light.

Q Florida Power and Light. If you had used the forecasts that were being used by all utilities in 1980 as a basis to enter into a fixed-price contract with an independent power producer, do you have any idea what the price of fuel the utility would be paying for today, through the independent contractor?

A If you had entered into a fixed-energy price contract? Is that what --

Q A fixed-price contract, yes, sir, 1980.

A Because I'm asking about the energy portion, are you talking about the fixed-energy portion?

Q Yes, sir, the energy portion.

A If you had based that on a forecast of fuel

at that time, you would be paying a considerable amount, probably, because the energy price would be based on IPP's own forecast, which would probably be fairly similar. But let me point out that I have not seen a contract in Florida that has an energy component that is fixed and not tied to an index.

Q Would you suggest that if we ever get to that contract phase where utility submits their contract, that this Commission prohibit fixed prices for energy?

A I think that if it -- if it took a fixed-price energy contract, it would have to evaluate the upside and downside of that risk. I mean, there you have an example where fuel risk to the ratepayer, or price risk, if you will, excuse me, price risk, is zero, because it's known that the energy price is fixed. However, whether that's going to be a good deal to the ratepayer or not is another question. So I think that's where bidding and evaluating criteria, that those decisions could be traded off.

Q But in the rule proposal made by CEPA, the actual contract that's going to be signed with the independent power producer or the low bidder has to be prepared and submitted with the bid specs, don't they?

A It does.

CHAIRMAN DEASON: Let me interrupt for just a

moment. I've got an indication there may be a problem with the portable microphones.

MR. STONE: I think it's Mr. Seelke's microphone is not on.

CHAIRMAN DEASON: Oh, okay. Sorry about that, Mr. Cresse.

MR. CRESSE: All right, sir.

Q (By Mr. Cresse) But you would agree that if we had entered into a fixed-price contract with independent power producer that included the cost of fuel in 1979 the ratepayers would be paying now for the energy component, far more than the actual cost to producer; is that true?

A That's quite possible.

Q Am I correct on Page 4 that what you're seeking is a truly level playing field for utilities as well as independent power producers?

A Yes.

Q And am I also correct that the guiding principles this Commission should follow is what's in the best interest of the consumer?

A Yes, sir.

Q Did you participate in the development of the rule sponsored by Mr. Huddleston?

A Yes, I did.

Q Did you have any legal advice in the development of that rule as to whether or not your proposed rule is legal?

A We had some legal advice, yes, sir. And I believe that -- my conclusion would be that our proposed rule is legal.

Q Well --

A But I'm not a lawyer, so.

Q I'm not either.

A There's a lot of them in this room, though, we know.

Q Some of us have some advantage, don't we?

A That's right.

Q All right, sir.

Did you receive any legal advice as to whether or not this Commission has the ability or the authority to order the acceptance of a specific bid submitted to a utility?

A I would like to defer that question to Barry Huddleston, who is really going to talk about the substance of the rule, if I could.

Q All right, sir. On Page 6 of your testimony on Line 3 through 6.

A Yes, sir.

Q Isn't it correct that you have left out an

important word in this language, that what you did in here is the present value of "estimated" revenue requirements and the present value of "estimated" revenue requirements, as opposed to the "actual" revenue requirements?

A That's true. And that was brought out by Mr. Childs earlier.

Q And it's also true in Line 10 that when you say, "the negotiated contracts were less than the utility's avoided cost," you really mean "estimated avoided costs," don't you?

A For the dollar figure, yes, sir.

Q All right. And so at the time that we make decisions regarding who is the cheapest or who can provide the most cost-effective electricity, is it true that the Commission will really be dealing not with actual figures but with estimated figures?

A That's true, and that's exactly the same figures they're dealing with when they're deciding on a need determination petition.

Q That's correct. The utility comes in, they make some forecasts, and based upon those forecasts, which are based upon estimates, one project appears to be the most cost-effective?

A That's right.

Q And that may not turn out to be the most cost-effective in fact; is that right?

A That's correct.

Q You mentioned that you need PROSCREEN on Page 8 of your testimony, on Lines 20, 21 and 22. You say "Thus, PROSCREEN is capable of calculating the total revenue requirements of a particular generation expansion alternative." PROSCREEN cannot do that; can it?

A I'm sorry, where are you at? Which line?

Q On Lines 20 through 22.

A Yes. Let me correct that. The PROSCREEN looks at the revenue requirements of additional facilities, total revenue requirements of new plant, and the fuel and operating costs of existing plants.

Q And here again, that's estimated data, not actual; is that right?

A Yes.

Q Is the proposal that you all are putting forth essentially a change, a dramatic change in the way electric costs are passed on to consumers from one of actual prudently incurred costs to one of hopefully prudently incurred estimated costs?

A I guess that's one way of phrasing it, but I would prefer to phrase it as "prudently determined

competitive costs." In other words, we're passing on those costs which were committed to and approved by this Commission in a competitive bid process.

Q If people's estimated costs turn out to be dramatically wrong, an independent power producer is faced us with a situation where his incremental costs are less than his incremental revenue, what is that independent power producer most likely to do?

A First, it has a commitment under the -- under its power sales contract that it must meet in order to maintain the validity of that contract. However, if you're referring to a situation where the continued performance is causing the project to lose money, is that --

Q Every day, incremental cost is less than the incremental revenue.

A In that case the project would get to a point where it could not meet its obligations. And when that occurs, the investors to that project lose, including not only the equityholders, but the debtholders. But the -- but the project continues -- it winds up getting sold, in general, is what happened -- is what happens. The equity investors lose all their equity, the debt -- the lenders wind up losing -- they made a bad loan in effect, so they lose, may not recover from the sale of

the amounts of their loan, but someone else eventually picks that project up. It's got a new market -- new price associated with it. It's a used project, but it's at a lower price, and it's at a price that can work under the power sales agreement that's in place. So the power sales agreement will stay as is; and the project, financing and ownership structure, will adapt to that condition.

Q The potential benefits that the ratepayers might have achieved, had that contract been fulfilled, will be lost; is that correct?

A No, that's not. What I'm saying is the contract is maintained and the project continues, owners change, and they wind up losing value in their investment, but the project will continue.

Q Who would take over a project when the incremental cost exceeds the total revenue?

A Are you saying --

Q If your fuel cost is so high --

A You're saying a project that would be sold -- that could be sold at zero cost, still could not make its -- okay. I see what you're saying.

Q Yes.

A So it's got -- in that particular case, no one would want to take that over. You're correct,

Q And so the -- wouldn't, in fact, the independent power producer declare bankruptcy?

A It would, yes.

Q And the utility would be in line, like everybody else, for whatever was left over?

A If the project had any obligations to the utility, yes.

MR. CRESSE: Thank you.

CROSS EXAMINATION

BY MR. GADDY:

Q Good afternoon, Mr. Seelke. My name is Rodney Gaddy, and I'm with Florida Power. I have a few questions for you.

A Yes, sir.

Q And so you've advocated in your direct testimony, prefiled testimony and your testimony today, and also in response to Mr. Cresse's question, that you are in favor of a truly level playing field for all competitors; is that correct?

A That's right.

Q And my understanding is you don't oppose a utility being one of the competitors in this competitive bid situation; is that true?

A That's true. In fact, we encourage utilities to compete.

Q Okay. So, then, am I correct in concluding that you would not propose requiring a utility to provide any information that would put them at a competitive disadvantage; is that correct?

A That's true.

Q Okay. I'll ask the Commission to indulge me for a moment. I know they asked a few questions about this, but Florida Power is, in fact, a party to this other docket involving Skyway Power. And I'm not sure that I understand what the distinction is or the difference between what you asked in that docket and what you are asking for here.

And in that docket, if you recall, in the Commission's notice of proposed agency action, they stated, "The generation of electricity is becoming increasingly competitive, requiring a utility to provide PROMOD and PROSCREEN databases to a developer would create a significant disadvantage for the utility."

I'm trying to understand, sir, what the difference is between what you're asking for here today and what you're asking for in that docket?

A That's one of the reasons that I'm bringing this issue up, because PROMOD and PROSCREEN are used by the utility to select its own generation plan. And in

the evaluation of bids, I would expect, although it's not required in our rule, that those same models would be used to evaluate bids. And that's really the distinction here. Those are evaluation models, they do not describe the bid, per se, but they describe the evaluation of a bid.

Now, I can develop a model to evaluate my bid, and you can use your model to evaluate your bid, but when someone comes to comparing two bids, whose model is going to be used, I don't have a problem in an evaluation process using my model, but I'm sure you would want to know what my model is if you're bidding and that's being judged to assess the economics of each bid.

Q So if, in fact, when a utility would not be using that as a part of its evaluation criteria, you would not be asking for that; is that correct?

A That's correct.

Q In your earlier testimony you mentioned that the only protest in the proposed CEPA rule, if I understand it correctly, deals with the time of the evaluation process, at the time the competitive -- the competitor would be selected; is that accurate?

A There is a provision for protest. I know I wandered into this and I'm --

MR. WATSON: Let me get clarification of that question.

Are you talking about the only protest contemplated by the entire CEPA rule or the only issue involved in a bid protest hearing?

MR. GADDY: It's my recollection that he testified that the only protest available in the CEPA rule.

MR. SEELKE: I misspoke earlier. What I was talking about was a protest that would be -- once a winner was announced or selected, a protest could follow that, the selection process. And the only criteria that one could protest on -- and I'm looking through our proposed rule -- is whether or not the selection was based upon the criteria that were established in the evaluation process. In other words, was there a mistake in the evaluation process?

Q (By Mr. Gaddy) And that's the only time you're suggesting that a protest would be available, sir?

A Well, there are other -- there are various -- and I'm going to have to defer to Barry Huddleston on that issue because the rule steps through a number of different phases where someone could potentially protest various Commission actions. But I was

specifically referring to the selection of the winner, the final decision.

Q Okay. You did talk about phases earlier in your testimony also?

A Yes, sir.

Q Because as I understood it, I thought what you were saying, this information that you're requesting, you're requesting it not in the bid submission phase but rather in the first phase, the need determination phase, is that --

A There's two phases, and information is being requested in both phases. And it may be very similar.

For example, in the first phase, we're asking for all the assumptions, including models and databases that were used to determine the power plant, timing, type and capacity, that's being -- going to be bid. And that, basically, sets the framework for the -- since that sets the framework for the bid, it's important that we decide that up front and make sure we're not going after something that later on we'll decide is not required. And that information is very similar to what could be used in the evaluation process.

Q But it's my understanding of the CEPA rule that at the time that you submit this information that

you're requesting is at the same time a utility, if, in fact, that utility was intending to participate, the utility would also at that time have to submit its bid?

A No. It would just have to submit -- tell whether it intended to bid or not.

Q Will you please turn to the CEPA rule, and let me just tell you where I'm getting that. (Pause) And it's behind Mr. Huddleston's testimony.

A I have it.

Q All right. Now, Page 2 of that rule, subsection 2(a) talks about when a utility has to file information on its determination of need; is that correct?

A That's correct.

Q And then if you'll turn to Page 3 of that same rule, subsection (d), that is also referring to what a utility has to file. Section (d), if I'm correct, says, a utility's notice filed must be accompanied by a bid package which shall include all those other things?

A That's correct

Q All right. May I ask you, part of your justification for wanting this PROMOD, PROSCREEN information, as you testified in your direct testimony, was so that a potential bidder, or as you state, "a

substantially interested party," might have this information. I have two questions: First, what is meant by "a substantially affected party would be entitled to receive this information"?

A I believe that what we intended that to mean -- and I think I'm going to ask Mr. Huddleston to try to comment on that as well -- that anyone who had entered into this proceeding would be a substantially affected party.

Q And I guess I'm just not clear the point of entry, but perhaps I need it take that up with Mr. Huddleston?

A Yes, I would appreciate that.

Q In your suggestion on getting this information, it is contemplated, I think, by the CEPA rule, that an interested party could, in fact, challenge the determination of the utility that, in fact, they need new generation; is that correct?

A That's true.

Q And if, in fact, that interested competitor disagrees with the utility's position on that, who should decide that issue?

A The Commission decides the issue.

Q Okay. And, in fact, if you disagree with the Commission's determination of the need, is this one of

the points in your proposed rule where a competitor can, in fact, file a protest for the Commission determination?

A Again, I would rather ask that Mr. Huddleston address that particular point.

MR. GADDY: I have no further questions.

CHAIRMAN DEASON: Further questions for Mr. Seelke?

Thank you, Mr. Seelke.

(Mr. Seelke excused.)

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CHAIRMAN DEASON: I believe Mr. Huddleston is next.

MS. BROWNLESS: I'm Suzanne Brownless and previously entered an appearance on behalf of Destec, Air Products Chemicals and CEPA.

BARRY N. P. HUDDLESTON

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MS. BROWNLESS:

Q Can you please state your name and address for the record?

A My name is Barry Huddleston. My business address is 2500 City West Boulevard, Suite 150, Houston, Texas

Q By whom are you employed and in what capacity?

A You cut off my zip code.

Q Sorry

A 77042.

Q Have you previously filed direct and responsive comments as well as exhibits in this proceeding?

A Yes, I have.

Q And would those be exhibits that you've previously labeled BNPH-1, BNPH-2 and BNPH-3 attached to your testimony?

A Yes.

Q Do you have any changes which you would like to make to either your comments or exhibits at this

time?

A A few changes to both the direct testimony and responsive testimony.

First the direct, Page 23, at the bottom, Line 25, carrying through to Page 24, Line 1, the same line is repeated twice.

Then on responsive testimony, Page 2, Line 13, the word "meet" should actually be "met". Page 5, Line 17, the first "no" between "have" and "little" should be omitted. I think that's it.

Q Thank you. Can you please give us a brief summary of your comments.

A Certainly.

Generally my comments cover three areas. First, the need for a bidding program to fill the state's additional electric capacity requirements. Second, I am the sponsor of CEPA's proposed bidding rule, and third, some comments related to Staff's proposed rules.

Any capacity procurement process must be administratively fair. It must result in closure and it must produce the most cost effective means of meeting the capacity needs of the state. Given the development of the bulk power market, competitive bidding in the format proposed by the CEPA rule meets

these goals. Other rules in this proceeding do not. And as the Cypress Energy case demonstrated, the current method of procuring capacity does not meet these goals either.

Regulatory change, and not just a Band-Aid on the current process, must be initiated by this Commission to ensure that all of the many benefits of competitive procurement go down to the ratepayers of the state of Florida.

As proposed, the Staff's initial rule does little but codify the disastrous Cypress Energy result. The Staff's alternative rule is a step in the right direction. However, it also falls short of the ideal. Most notably, CEPA disagrees with the following provisions in the Staff alternative.

Number one, the waiver provisions.

Number two, the incompleteness of the proposed process, and the lack of a clear point of entry.

Number three, the lack of PSC oversight prior to and during the capacity solicitation.

Number four, the use of short list negotiation following the bid solicitation and evaluation.

Number five, the lack of an independent

evaluator if a utility or utility affiliate intends to participate in the solicitation.

And number six, the fact that a winner is not necessarily selected pursuant to the process.

The CEPA rule incorporates five fundamentals intended to address our concerns. It incorporates a bifurcated planning and procurement process. It incorporates a requirement the utilities fill their capacity needs through bidding solicitations. It incorporates an up-front disclosure of price and nonprice bidding factors. It restricts parties in the protest phase to those that have participated in the solicitation, and it provides equal cost recovery limitations and mechanisms for both utility and nonutility projects.

CEPA appreciates the opportunity to provide this rule, and I guess me to answer all questions regarding the proposal and testimony. Thank you.

Q Mr. Huddleston, there's been a lot of questions today about exactly how CEPA's proposed rule works. Could you quickly step through that process for us?

A Sure. Rather than using an overhead, I figured it would be simpler and easier if everyone just turned to my direct testimony, Attachment BNPH-3,

beginning at Page 1, which is the CEPA proposed rule time line. It serves as an outline for how the process would work as we envision it.

In the beginning the utility files a capacity addition report similar to the generation expansion plan that currently is filed yearly by the Florida utilities. Along with that the utility would file its notice of addition and the bid package. Note that that indicates the bid package. That's the RFP and the method by which they would acquire capacity. It does not relate to what their bid might or might not be should they decide to participate.

Following that, there would be a deadline imposed for a hearing on the notice for addition and the bid package. If no hearing were requested, the Commission would then evaluate and go forward from that point. If a hearing is requested, that's the point at which parties could come in and we would have a evidentiary proceeding to determine whether or not the capacity addition itself and the RFP package were appropriate.

Once we make it through the evaluation and the Commission blesses the RFP and capacity addition, we then go to Part III, the bid solicitation process. The utility would be required to notify the registered

persons and publish in the Wall Street Journal and, as well, in the Florida Administrative Weekly its intent to solicit and receive bids. The bids would then come into the utility pursuant to the schedule that was approved in the RFP in Part II.

Following an evaluation period, the bid winners are announced. I might note that there is a slight misprint on No. 8 of the time line in that bids are not solicited at Day 314 and announced on the same day. The bids are solicited pursuant to the schedule that is approved in the RFP, and then announced on Day 314 or by Day 314.

Following the announcement, the notice would be published, and then if there was a request by one of the affected parties in the proceeding for a hearing, there would be a hearing on the results at which time, as Mr. Seelke pointed out, it would be debated whether or not the utility actually evaluated fairly based on the preapproved RFP.

If no hearing is requested, then the winning bid is, I guess, stamped for approval. The utility is then required to sign the previously approved power agreement with the winning bidder and the winning bidder would begin its permitting, either through the Power Plant Siting Act or other mechanisms.

MS. BROWNLESS: Thank you, Mr. Huddleston. We tender him for questions at this time.

CROSS EXAMINATION

BY MR. WILLINGHAM:

Q Yes, my name is Bill Willingham. I represent the municipal electric utilities.

FMEA and FMPA filed comments with recommended changes to the Commission's proposed rule. Our comments recommend a rule that requires municipal electric utilities to employee a RFP process, but basically leaves all the details of that process up to the different utilities. Our comments are based on the distinction between municipal electric utilities and investor-owned which, for example, municipal electrics are subject to the Public Records Act. We really don't have a incentive to build our own plants.

There's basically a laundry list of concerns, including things in your rule that you would like more PSC involvement, independent contractor evaluation, things like that.

Does your association believe that the existing rules are adequate to ensure that its members will be fairly considered in a municipally-owned electric utility's generation selection process?

A Yes.

Q And also does your association believe that either of the rules proposed by the Commission is necessary for CEPA's members to be fairly considered in a municipally-owned electric utility's generation selection process?

A No. We believe that the regulations in place, both federal and state, adequately address the issues as they relate to municipals and rural electric cooperatives.

MR. WILLINGHAM: Thank you very much.

CROSS EXAMINATION

BY MR. CRESSE:

Q Mr. Huddleston, you worked at the Public Service Commission when and in what capacity?

A From 1987 to 1991, in the Research Division as planning and research economist and economic analyst.

Q Under the current law, isn't the Commission required to determine that the proposed plant, under the Power Plant Siting Act, in order to get a certificate of need for them, they must find it to be the most cost-effective alternative?

A As I recall, not being an attorney but recalling the language, they are required to consider the cost-effectiveness of the plant.

Q Is your rule designed to assist the Commission in following the mandate that they have under the law?

A I believe so, yes, sir.

Q But you don't know what that law says?

A I just indicated that I believe it says they consider. Not being an attorney, I don't know whether that means they can choose the next most inexpensive project, assuming that other intangibles weigh more heavily.

MR. CRESSE: Mr. Chairman, just for purposes of everybody's understanding, I think the Staff could read that section of the law just to help all of us proceed, because I think an understanding of what the current law requires is critical to determining whether or not the rule proposed is in compliance with the law. I think counselor has the current law, if she could just -- she could advise us what the law requires the Commission finding to be.

CHAIRMAN DEASON: I have no objection to -- if Staff wants to do that or if the witness wants to, we can look at the statute.

MS. BROWNLESS: Excuse me, Mr. Chairman Deason. If Commissioner Cresse wants to ask a question like normal people who conduct cross examination ask

questions --

CHAIRMAN DEASON: Ms. Brownless, this is not normal cross examination. We're here just trying to understand things. If Mr. Cresse wants to give Mr. Huddleston a copy of the statute, that's fine. Let's just forget about the objections and let's just get on with this.

MS. BROWNLESS: Well, excuse me. With all due respect, if his question -- he can frame his questions. People are familiar with the statutes. We're going to make the assumption, Commissioner Cresse, that everyone has read the statutes and we also are going to have it fairly stated here that Mr. Huddelston is not an attorney rendering a legal opinion. Now, if you want to ask a question which has an opinion in it by all means do so.

MR. CRESSE: Well, I believe I'll run my questioning the way I'd like to until the Chairman or one of the members of the Commission prohibits it, if it's all right with you, Counselor.

And what I'd like to know -- I asked the witness if he knew what the present law required the Commission to do, and whether or not the rule complied with it. He said he wasn't sure. I thought it was a matter that we should get cleared up.

MS. BROWNLESS: And the objection is that requires a legal opinion. If you'd like Mr. Huddleston to tell you his understanding of the law he certainly can.

CHAIRMAN DEASON: I think that the witness -- if we're going to get into this, we're going to get into it.

The witness has said that he designed rules which he thinks is going to aid the Commission in complying with the statutory responsibility, so he must have some opinion as to what the statute says. It's a fair question. The only question is are we going to give him a copy of the statute and let him look at it no now or are we going to look at it ourselves? It doesn't matter to me. But he says that he has reviewed the statute and he's designed rules that are going to comply with it.

So, Mr. Huddleston, are you familiar with the statute?

MR. HUDDLESTON: I'd like to see it to refresh my memory.

CHAIRMAN DEASON: Well, I have a copy of it right here. I'll bring it to you.

MR. HUDDLESTON: Thank you. (Chairman Deason hands document to witness.) (Pause)

CHAIRMAN DEASON: Have you had time to review the statute, Mr. Huddleston?

MR. HUDDLESTON: Yes.

CHAIRMAN DEASON: Can you now respond to the question?

MR. HUDDLESTON: Yes. As I read it, it says, "The Commission shall be the sole forum for the determination of this matter," which is the determination of need, "which accordingly shall not be raised in any other forum." Further down, "In making its determination the Commission shall take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost and whether the proposed plant is the most cost-effective alternative available."

I believe that confirms the answer I said before, that they should take into account, they shall consider the cost-effectiveness. It doesn't say that it must be the most cost-effective plant.

Q (By Mr. Cresse) So you think that the Commission can certify a need without determining that that plant is the most cost effective?

A I believe if they take it into account and determine that there are other considerations, it may not be the least cost plant, yes.

Q Under your proposal would the Commission have to adopt another rule to determine need for co-ops and munies?

A No, as I stated in response to Mr. Willingham, we believe the current rules would be sufficient.

Q Are there current rules on the subject?

A For munies and co-ops?

Q Yes.

A Yes, sir.

Q Current Commission rules?

A For munies and co-ops' need determination?

Q Yes.

A Yes, sir.

Q There is?

A Yes, sir.

Q All right. In the proposal that you have made, would there be three opportunities for a hearing by -- a request for a hearing by an affected party? One, when the capacity requirement was determined to be needed.

A Yes.

Q The other hearing could be on the question of whether their proposed evaluation criteria or contract was appropriate.

A No, that would be the same hearing.

Q Would there be a hearing on the site plan?

A On the site plan?

Q Yes.

A You mean their proposed bid, should they decide to bid?

Q My understanding of your proposal is you say seven years prior to the need as found in some other document, they must come in with the bid specs and so forth; is that correct?

A The bid specs would be brought in with the capacity addition plan -- excuse me, not the bid specs, but the RFP that would solicit capacity would come in with the capacity addition plan, and there would be a single hearing should one be needed to evaluate the RFP, its criteria, and the determination that capacity would be needed.

Q All right. And the seven-year date would flow from what document?

A From whenever the utility believed that it was seven years ahead of when it needed capacity.

Q Would that be based upon their estimated need in the Ten Year Site Plan?

A Well, I assume that the utility has an ongoing process to determine when it needs capacity.

In our proposal every two years the utility would come forward with a site plan. That is the capacity addition report. For capacity additions that would be needed seven years hence, they would have an RFP associated with that capacity addition report.

Q Have you prepared any analysis of basic benefits to ratepayers from owning or purchasing?

A To ratepayers?

Q Yes, consumers.

A Not for purposes of this proceeding, but I've been following the debate, yes, sir.

Q Did you work on that any while you were working for the Florida Public Service Commission?

A Not directly, no, sir.

Q Did you work on it indirectly?

A Yes, sir. I did a report involving cogeneration deferral tariffs, which was called load retention, and evaluated tariffs being offered across the country to defer cogeneration and the arguments used to justify such.

Q Under the bidding process you're proposing, where would the benefits of fully depreciated property, who would that flow to?

A We're assuming that it is, in fact, fully depreciated to zero.

Q Yes, fully depreciated property that was still operating, who would get the benefits from it?

A It depends on who owned it.

Q In that case, if it was owned by an independent power producer and they could resell it -- you build a plant under contract, at the end of 20 or 30 years they could resell that capacity. The benefits of the resale would flow to the independent power producers; is that correct?

A Again, it would depend on the alternatives. If the alternative were a more expensive utility plant going forward, then a resale by an independent power producer at a fully depreciated rate, presumably much lower than a Greenfield rate for a new utility unit, then the benefits would flow to the ratepayer in comparison.

Q The benefit would flow to the ratepayer how?

A In comparison to a new Greenfield site.

Q You mean -- yes, but in comparison to a utility owned, where would the benefits flow?

A Well, that assumes that the utility plant actually has depreciated to zero.

Q That's the assumption, yes.

A Well, as Mr. Ballinger pointed out, in reality that's not the case.

Q Just accepting for purposes of assumptions.

A If we do assume it and we assume that there would be no ongoing capital additions to keep that plant running, and the utility only priced it at variable cost, then, yes, the ratepayer would benefit by virtue of having a fully depreciated plant.

Q If new technology is developed that makes it cost effective to change out a combined cycle engine --

A Yes, sir.

Q -- where would the benefits of that flow under a purchased power agreement as opposed to a utility owned?

A If an independent power producer were able to change its technology mid-stream.

Q Yes.

A Presumably the independent power producer would reap the benefits of having been efficient pursuant to the incentives in the contract.

Q Do you know of any plants built in Florida since 1960 that have been retired? Are they still serving consumers needs?

A There are some that have been in cold storage, but actually retired, to my knowledge I can't think of one.

Q Do you know of any that were built in 1950 to

1960 that have been retired?

A Well, I know of at least one that continues to operate, but --

Q Do you know of any that have been retired?

A Not to my knowledge, no.

Q Under current procedures, assume one had been retired, would that site still be available to serve the public at the 1950 cost of the site?

A The site proper, yes. However, I would assume that in order to bring it back into service, there would be capacity additions and modifications that might require additional permitting and additional capital, but, yes, the site would continue to be available. And I might point out, the ratepayers had carried it for all that time.

Q In your testimony on Page 9, responsive comments. You point out that when this regime is followed, utilities do not need to earn a return on fully depreciated plant. You say on Line 14, "Simply stated, the utility's customers have already paid the utility what it was due. Isn't that statement also true after a 30-year contract has been entered into and implemented by an independent power producer?

A Yes, for the 30-year period. The utility has passed through to the ratepayers pursuant to the actual

benefits that accrued based on the contract.

Q And, therefore, if it was owned by the utility, the customer would continue to get the benefit; if it was owned by an independent power producer, they could resell it at market prices at the end of the contract period; is that right?

A Yes, that's right.

Q Should a electric utility be held responsible for quality of service if the quality declines because of failure of a contracted electric supply?

A Yes.

Q Do those contracts impose any financial risk, then, on the investor-owned utility?

A Assuming that they're penalized for not sharing quality of service, I don't believe it's the contract itself. It's the lack of managing resources that imposes the financial penalty potentially on the utility.

Q They didn't manage the contractor properly?

A It's not just the contract.

Q Excuse me, is that what you're saying? Let me get my question out, Barry. Is that what you're saying, if they didn't manage the contractor properly, if the contractor failed?

A If you assume in all cases that you can pinpoint that it was that specific project, which assumes then that

the rest of the utility system operated optimally, then, yes, if that contractor fails to provide service that degrades the utility's quality of service, the utility did not manage its supplier appropriately.

Q And, therefore, then this Commission should penalize them under the quality of service provision of rate setting; is that right?

A No, that doesn't necessarily follow. If they were imprudent in their management, then, yes, they should be penalized. However, if it was not within their control, they should not be penalized. Just like with a utility plant that operated either prudently or imprudently.

Q Then the Commission has to go further if we have a contract than just look at the quality of service, they have to look at who caused the quality of service not to be adequate; is that right?

A Or what caused, yes, sir.

Q And if the Commission determined that the independent contractor was the cause, what recourse does the Commission have to the independent contractor?

A Well, I presume that the contract that the contractor has with the utility would take into account actions that interrupted service. So the penalty would flow from the utility to the independent. And it would

be immediate, I might point out, that if an independent does not provide capacity or energy, the payment immediately ceases. It doesn't wait until the review is completed.

Q That may not provide adequate compensation to the ratepayers; is that right?

A Well, in that case, in my opinion, the utility inappropriately contracted.

Q So this should be taken care of in a well-crafted document?

A Yes, sir.

Q That would be attached to the utility's proposal?

A Yes, sir.

Q And that would be in the contract, right?

A Yes, sir.

Q Under your proposal, in the decision-making process, as I understand it, if the utility bids, then an independent party would evaluate those bids and make a recommendation; is that correct?

A Yes, sir.

Q If the utility does not bid in your proposal, the utility would evaluate and then make a decision; is that right?

A That's right.

Q Wouldn't the utility be obligated to evaluate whenever they made a bid also?

A I would assume that the utility would in parallel with the third-party evaluator be looking at the bids that had been proposed, and would presumably compare its conclusions with those of the evaluator and make a case at the Commission on whether or not the evaluator's recommendation was appropriate.

Q The ultimate decider as to the adequacy of the evaluation would rest with this Commission, would it not?

A Yes, sir.

Q Now, wouldn't it be a better procedure for the utility to do the evaluation, come to a conclusion, let that conclusion be challenged before this Commission and then if the Commission needed an independent evaluator, let them hire him?

A I'm not sure that's the most efficient method of achieving the result.

Q Let me ask you a question about efficiency. My understanding is is that you expect an independent evaluator to do his job in three days; is that correct?

A In how long?

Q Three days?

A Three days? No, sir.

Q How long?

A I don't believe -- as I indicated in my summary, the Commission, on Day 120, approves the final order, or in a final order approves the bid package in which the schedule is set out. So that the utility would, in its bid package, in its RFP proposal, propose a schedule for soliciting and evaluating bids. So anywhere between Day 120 and Day 314, which to my calculations is 194 days, the evaluator would have a great deal of time. You know, assuming 30 days, or even 60 days for solicitation, that still leaves anywhere between four and six months for evaluation.

Q Of the winning bids?

A Of the bids, yes.

Q I'm sorry, I thought somewhere in your testimony you said that the evaluator would -- that the proposals would include a $10,000 fee for evaluation?

A Yes, sir.

Q And the evaluator would have three days?

A I hope that's not what I said.

Q Maybe I misread it.

CHAIRMAN DEASON: Mr. Cresse, on your proposal, if the Commission does the evaluation, do we get the $10,000 fee?

MR. CRESSE: Actually, the Commissioner, I

think it would work like this: You're going to get about three times in the process to do an evaluation and hold a hearing, is the way I understand it. And his proposal would be to submit -- each bidder would submit $10,000. I guess that money could be used by the Commission to do their evaluation, which you've already paid for, so you would probably have to use some of it to hire an independent evaluator. Or if you wanted to keep the difference in your trust fund, that would probably work out too. I didn't go into that with him. It's worth pursuing, though.

COMMISSIONER CLARK: Just so I understand, what are the three times for the Commission to evaluate, first, when the --

MR. HUDDLESTON: It's actually two, --

COMMISSIONER CLARK: Okay.

MR. HUDDLESTON: -- as I think I indicated. The first is when the capacity addition report or generation expansion plan and the bid package come in.

COMMISSIONER CLARK: All right.

MR. HUDDLESTON: At that point, a hearing could be held to determine whether or not the criteria in the RFP and the specification in the expansion plan are appropriate.

The second and last would come at the

conclusion of the bidding process when the winning bids were announced, then dissatisfied losers could petition the Commission for review of the process.

COMMISSIONER CLARK: And who does the evaluation again? Who does the --

MR. HUDDLESTON: Evaluation of the bids?

COMMISSIONER CLARK: Yeah.

MR. HUDDLESTON: It depends on whether or not the utility itself is participating in the bids. If the utility has submitted a bid of its own, and in our view it would be inappropriate to have the utility be both buyer and seller, judge and competitor. So we recommend that a third party be chosen. We didn't recommend a method for choosing a third party but, for example, the utility could specify three well known independent evaluators and --

COMMISSIONER CLARK: And then they'll have to live with who they choose?

MR. HUDDLESTON: Right.

COMMISSIONER CLARK: Will they be able to negotiate different terms than the bid? Here -- let me be very frank about my concern. I still view delivering retail electric service to be the obligation of regulated utilities.

MR. HUDDLESTON: As I do.

COMMISSIONER CLARK: And I do want to provide a point of entry for competitive bidding. And one thing I'm struggling with is the nature of -- is whether or not -- how much into the management or decision that this is going to be the plant and this is going to be the person who builds it, do I want to -- how far down that path do I want to go, or do I want to continue to be in the mode of reviewing what the utility did and saying whether it was prudent or imprudent to do that? But likewise, giving those people who were unsuccessful bidders the opportunity to prove that it was imprudent.

MR. HUDDLESTON: I understand. I think what we're wrestling with, really, is a result of changes in the industry that have put the utilities in the position of being both purchaser and potential competitor. And until that potential conflict is resolved in some way, not to be so radical to recommend that we break up generation from the rest of the utilities, or from the rest of the utility company, but I think that's, in essence, the only way that there can be a clear division between the purchaser and the seller. And so what we've attempted to do is recommend a process where the utility could continue to compete, but not be placed in the position of having that

conflict. And it would be very difficult, I would suspect, for a utility to explain to its management why it chose an independent power producer that it wasn't going to earn a rate of return on. Not only do they have you to answer to but they have the management to answer to, you know, "Why is it we're not going to earn $12 million a year for the next 30 years? It's because we chose somebody else. And we decided that our project wasn't good."

So I think that what we've attempted to do is remove the conflict that is represented by that necessity of a choice.

COMMISSIONER CLARK: And you've removed it by an independent --

MR. HUDDLESTON: By having an independent evaluator, so that it's the independent then that takes a hard look at the projects and chooses the one that in his view, minimizes the -- in my view it ought to, minimize the revenue requirements and costs that would flow through to the ratepayers, regardless of whom the provider would be.

COMMISSIONER CLARK: But after that point, it becomes the utility's responsibility to manage and enforce that contract to get the best deal, despite the fact that they may not have thought it was -- if they had

been able to choose it, they would not have chosen it.

MR. HUDDLESTON: In one sense you're right, in that the utility is faced with a project that it may not have chosen. However, it knows what the terms and conditions of the contract that it is presented with, and it knows how to run an electric utility business. So that it knows the conditions up front. It should then be able to manage the conditions that it's presented with, regardless of who chose it.

COMMISSIONER CLARK: You mean by what it needs in terms of an addition and how it forms its bid package, gives it some assurance that what is ultimately chosen will be something that they can manage?

MR. HUDDLESTON: Yes, that wasn't, I guess, what I was saying, but, yes, that takes you back one step further.

What I was indicating is that once a project is chosen, a little bit like being out on a bike ride, you may have thought that it was going to be a nice easy ride, but when you come across a hazard in the middle of the road, you pretty much know when to swerve. And that's what we're talking about here is that the utility went out for a nice ride, that's the contract that it has, and it should be able to negotiate the little hazards in the road. If it doesn't, then it's

going to crash and it's nobody's fault but the utility's, assuming that it was imprudent.

COMMISSIONER CLARK: Well, maybe other people thought they could have managed it.

MR. HUDDLESTON: I was going to say, assuming that it's imprudent.

COMMISSIONER CLARK: Thanks.

Q (By Mr. Cresse) Going back to that selection process, do you agree that both the utility and the independent evaluator would have to evaluate all of the proposals?

A All of the ones that make it through some minimal qualification standards, I believe, yes. In fact, I believe that -- well, in an ideal world, all proposers would evaluate all proposals, so that everyone could provide its input in the process. However, since we're talking about commercially-sensitive information, I suspect that no one will be willing to provide its information to the other participants.

Q I guess the losers can compare their proposal with what is ultimately accepted by the utility commission, or whoever is going to make the final decision. Compare theirs with what was ultimately assigned and determine whether they think theirs is better than what was ultimately assigned; is that correct?

A Yes, sir.
Q And they could request a hearing on that?
A Yes, sir.
Q That's how the hearing process would start?
A Yes, sir. The final hearing process.
Q But in the final analysis, the Commission would be the ultimate decider; is that correct?
A Certainly, just as they are today.
Q Under your rule, would the Commission then order the utility to enter into that contract?
A Well, I would presume that the utility would be eager to sign a contract that --
Q That's not my question.
A -- optimally met its needs. Yes, sir.
Q Let me get you to answer the question instead of what you presume. Under your rule, would the Commission order the utility to sign that contract?
A If the utility refused to sign it on its own, then, yes, sir.
Q All right. Did any of the attorneys that you talked to in the development of that rule tell you that the Commission had that authority?
A Yes, sir.
Q I won't ask for any names.
A They mentioned a grid bill, which I know from

past experience was a fond bill.

Q Should a contractor who fails to perform pay a penalty for such failure and should that be a part of the contract terms?

A Yes, sir.

Q Should the penalty be designed to cover the additional cost imposed on the utility's customers for the failure of the contractor to perform?

A It could.

Q Should it?

A It depends on the other terms and conditions of the contract. Assuming that the risks balance in a contract that includes that kind of a provision, then the answer would be yes.

Q Should all contracts with electric generators be designed so that the utility can take over the project if the contractor fails?

A Again, if it fits within the balanced parameters of a contract, then that might be a provision that could be included, yes, sir.

Q And if the provisions of that contract held the first mortgage holder harmless, do you think lenders would object to that type of provision?

A Harmless, as in --

Q Harmless as in, if the utility took it over,

they would assume the liability to the lender?

A Assuming that the lender believed the utility could operate it as well the independent, then the lender probably would have no problem with that kind of a clause.

Q If you assume the utility had the obligation to pay off the lender as a second mortgage holder, would that work?

A It might.

Q Would it be appropriate for the utility to consider a proposal from an independent power producer that afforded a utility the right to purchase at the end of the contract period for a specified price?

A Again, it might.

Q How would you evaluate that, the worth of that, in the evaluation process?

A Well, I suppose it's a great deal like evaluating whether or not to buy a car or lease it. You would look at your needs, your desires; whether or not you wanted a new car every two years or whether or not you wanted an old car after ten years. I think that the evaluation is not all that much different and it's something that people do routinely. You would look at the net present value, the salvage value, what you presume the plant would be worth and how it would

run, and whether or not going forward it would be a good investment for the utility.

Q Mr. Huddleston, I'm not sure you understood my question. All we're talking about at this point in time is to have a right to purchase at the end of the contract period, not the decision as to whether to purchase at the end or not, but the value of the right to purchase for a fixed price at the end of the contract period the entire assets of the unit?

A Well, I would assume just like any clause in the contract, attorneys can figure out some way to evaluate the worth of it.

Q Would that be an attorney's role or an economist's?

A Economists assume you can do anything. So I guess it would be a combination of both.

Q Should a utility require an independent power producer to have backup fuel capability for all gas-fired generators built in this state?

A Our projects do. So I think it's a prudent practice. However, certain companies might be willing to take the risk of not having backup. Our company is not one of those. So if the utility valued the service and was willing to pay for the lack of uncertainty, then, yes, it's a prudent thing to do.

Q But if you're putting out your specs up front, as you're suggesting in your rule, are you not, wouldn't that be a minimum requirement on all, or would you design specs that allowed those options to be presented?

A Well, if the utility valued it, then, yes, it would be part of the up-front specs.

Q Should a utility require central dispatch on all contract baseload plants capability?

A I think that's a condition for a term of a contract that would be subject to negotiation.

Q Should a utility be entitled to all of the output of the contracted plant?

A It should be entitled to the output that it has contracted for.

Q Are you familiar with the Florida broker system?

A I knew this was coming since somebody passed it to me yesterday.

Q I didn't hear that?

A I said I knew this was coming since somebody passed it to me yesterday.

Q I'm glad Susan was on her toes.

A Generally, yes. Yes, I am familiar with it.

Q And under the Florida broker system, if a plant has excess capacity and that capacity is the least-cost available in the state of Florida, that,

plant can sell it, can it not?

A Yes, sir, and split the savings with the buying utility.

Q And that sale benefits the purchasing utility's customers, as well as the selling utility's customers; is that correct?

A Yes, sir.

Q Should this Commission rely on a structure of any purchase agreement that did not provide those same benefits to those same customers or have any new capacity built in the state of Florida?

A I think our members would love to be able to sell on the broker system.

Q If you sell on the broker system and the utility sells on the broker system, how do you evaluate the cost of the utility of owning the plant?

A The value of the utility owning its own plant?

Q The cost to the utility or to the ratepayers of owning their own plant?

MS. BROWN: Can you perhaps rephrase that question again?

MR. CRESSE: Sure.

Q (By Mr. Cresse) Are proposed broker sales taken into consideration in any long range forecast, the revenue requirements of a new power plant?

A No, sir, I believe the broker system is an economy interchange.

Q But the benefits in the economy interchange all flow -- not all, but 100% on the purchasing side and 80% on the seller side all flow to the customer, don't they?

A Yes, sir, they help offset the cost of carrying unneeded capacity.

Q Unneeded?

A At that given point in time, yes, sir. If I have capacity that's not being needed by my native load customers, then I'm able to sell it on the broker system and earn a profit on it which helps offset some of the fixed costs that those customers would have faced.

Q And that's what the utility ought to do, isn't it?

A Yes, sir.

Q They ought to maximize the entire investment to provide that minimum cost service possible; is that right?

A Yes, sir.

Q Now, when the utility pays fully estimated avoided cost for capacity, they give up the opportunity to maximize that benefit of those sales; is that correct?

A It would depend on how much that capacity is needed at a given point in time. If that plant would

have run otherwise for the native load utility, then there is no impact.

Q Yes, I said the opportunity.

A The opportunity on --

Q They give up the opportunity?

A Yes.

Q Would it be inappropriate to require utilities to bid their new generating capacity on a price-only basis?

A You mean a utility bid?

Q Yes. Your bid on a price-only basis, would that be inappropriate?

A Yes, sir. I believe there are other considerations besides price only.

Q Under your proposal, if a contract had an 83% availability factor on a rolling 12-month basis, and the utility had met that -- I mean, excuse me -- the independent power producer was meeting that 83%, but they were requested to run more. Should they be required to do that if that was necessary to meet the utility's load requirements?

A I would assume that if it was necessary to meet the utility's load requirements then the as-available payments associated with it would be attractive enough to induce them to run more, yes, sir.

Q Would you translate that? Does that mean the as-available payments would be attractive enough for them to run more. Is that something over and above, a payment over and above what was initially contracted for with that independent power producer?

A In most contracts that I'm familiar with, at least that Destec Energy has, once you've met minimum load requirements, there are bonus provisions for running in addition should it be necessary. And that's a part of an RFP proposal that could be incorporated if the utility believed that it was important to have that flexibility.

Q Do you think if the utility's own plants are operating in excess of the minimum requirements, that they should receive a bonus?

A It's an interesting question.

Q I always try to make them that way. I don't always succeed.

A Being an economist I believe that incentives matter; although I don't believe we're talking about reforming the way rate-of-return regulation is done here for existing plants. But in my opinion incentives do matter, and if the utility is able to perform better than required or better than anticipated, yes, incentives are appropriate.

Q They are a little scarce right now, are they not?

A They certainly are.

Q All right.

COMMISSIONER CLARK: Mr. Huddleston, I did not understand the response or the questioning on the broker.

MR. CRESSE: Commissioner, let me --

COMMISSIONER CLARK: And since this is rulemaking, what was the point you're trying to make?

MR. CRESSE: The point I was trying to make is that if you have availability of plant at any time, if you own it, you can have the opportunity to sell on the broker.

COMMISSIONER CLARK: Right.

MR. CRESSE: And the benefit from those sales flow 80% --

COMMISSIONER CLARK: To the ratepayer.

MR. CRESSE: -- to the ratepayer of the selling company; 100% to the ratepayer of the purchasing company; and 20% to the selling company's shareholders. That's your present policy.

If you have an independent power producer you cannot have that opportunity.

COMMISSIONER CLARK: Why not? If you can

dispatch it, can't you -- you know, you're buying it from him at one price and if you can get a better price --

MR. CRESSE: If an independent power producer has operated, is already operating at his minimum required effort under the contract, you can't tell him to turn up so you can sell his capacity. He will respond, "What premium are you going to pay me if I perform in excess of the minimum required of the contract? " So, therefore, there's a lost benefit from having an independent contractor, in my opinion. And that's the point I was trying to bring out.

COMMISSIONER CLARK: Well, then let me ask Barry, would it be possible to take that into account in the contract, that independent -- you can contract to allow the utility to dispatch the power?

MR. HUDDLESTON: Yes, actually --

COMMISSIONER CLARK: And you can put in there that they have to respond or under certain conditions they will respond to providing more power.

MR. HUDDLESTON: Well, there might even be a circumstance under Mr. Cresse's example where it would be prudent to pay the independent the bonus and sell it to the other utility on the broker system, assuming that their cost was even higher than the bonus paid to

the independent.

Since what we're talking about in the bonus circumstance is generally not capacity and energy, it's associated with the energy, so that you could pay a bonus based on an energy component, prompt the independent to operate at a higher capacity factor, and still come in under the other utilities' costs so that you could still split the savings.

COMMISSIONER CLARK: Would it be appropriate to have 80% of the savings going to the ratepayers and letting 20% go to the independent power producer?

MR. HUDDLESTON: I imagine that's something that could be worked out, yes.

COMMISSIONER CLARK: Would it be appropriate or should the utility get a share of that?

MR. HUDDLESTON: Well, I suspect the utility should get a share of it.

I think the utility provides a function in a purchased power setting that isn't compensated for in most circumstances. So if the utility manages -- extraordinarily prudent management, then, yes, they should receive something for that.

COMMISSIONER CLARK: Okay. Thanks.

Q (By Mr. Cress) Mr. Huddleston, should a utility be allowed to bid for a new project using the

minimum equity in their capital structure that is required of all other bidders?

A They would be bidding as a regulated utility?

Q Well, let's take the first bid as a fully separate subsidiary and the second bidding as a regulated utility.

A I think bidding as an unregulated subsidiary, they are free to bid however they would like. Bidding as a utility, I suspect the Commission would have something to say about the optimal capital structure of the utility going forward.

Q My question is not what the Commission may have something to say about, my question is should they be allowed to do so? I know the Commission has got a lot to say about capital structure.

A I guess I haven't spent any time determining whether or not the current split of debt and equity typical among utilities is optimal. I suspect that in a competitive environment it may not be.

Q Should utilities electric-owned -- excuse me -- investor-owned utilities be permitted to joint bid with munies and co-ops in the state of Florida?

A I don't see why not.

Q Should a muni and co-op be able to bid on an investor-owned utility's needs?

A Again, I don't see why not.

Q If that's permitted, isn't the munies' cost of capital on project financing about one-half of the cost of capital that the independent power producer would incur?

A I think that was discussed earlier by other witnesses. As I recall, there was an agreement that munies and co-ops face a lower cost of capital.

Q You are requesting that, I think, am I not, that someone other than a utility should be able to be an applicant under the Power Plant Siting Act?

A I'm not sure that that's contained in my testimony.

Q I can ask questions that aren't contained in your testimony. I'm asking that question.

A In other forums I do believe that entities other than utilities should be considered applicants, yes.

Q Yes. I'm in that other forum and that's the reason I'm participating in this is that I thought -- I'm not sure I'm going to be able to get to ask you anything in that other forum, with the Chairman sitting down there on the end.

And why should someone other than a utility be an applicant under the Power Plant Siting Act?

A Well, I think entities other than utilities have been applicants under the Power Plant Siting Act in other agencies.

This agency looks at need determinations for utilities. And because it's a separate piece, it seems to present a -- I guess the logic that they are not applicants for one portion of the Plant Siting Act, and are for another portion eludes me.

Q Do you understand why the economic decision making have been bifurcated from the environmental decision making in the Power Plant Siting Act?

MS. BROWNLESS: Excuse me. I don't mind these questions, but they really are quite beyond the scope of the bidding rule and beyond the scope of the testimony of Mr. Huddleston. I'm happy to talk to Mr. Cresse about these in that other forum, and I'm certainly sure we will discuss that at that time.

MS. RULE: Chairman Deason, if I may, it seems like the parties are getting into quite a bit of questioning and objecting that you would normally hear in 120.57 hearing.

The scope of the testimony is absolutely irrelevant as regards your policy consideration. If you care to entertain questions, you may. If you don't care to, you're not required to entertain any of this

questioning as long as you allow the parties the opportunity to inform you of their concerns.

I would suggest in order to hurry things along and to make them clearer, that if somebody has a point to make, they do not attempt to make it through questioning a witness. They state their point. It's not required that it be prefiled. They don't have to be under oath. If they then want to invite the witness to say whether they are right or wrong, they may do so. But what we seem to be doing is by inverse questioning, trying to reach a point that could most easily be stated, brought to your attention and discussed the way it should be.

CHAIRMAN DEASON: I think that's an excellent point you make, Counselor.

Mr. Cresse, why don't you state your point and then ask him whether that's right or wrong.

MR. CRESSE: Thank you, Mr. Chairman.

Mr. Chairman, let me kind of state my position a little bit; that might help.

I really didn't intend to come over here to this hearing because of the role I was playing in the Governor and Cabinet deal. And they appointed a task force to look at the Power Plant Siting Act, streamline it, and come up with a competitive, some sort of

competitive process for the acquisition of new capacity in this state.

Some other members of that task force are sitting here and I felt like I needed to get involved in that. I don't know the extent that we'll hold as extensive a hearing as you're holding here.

My position is, is that you're in the process of transitioning to a different type of need determination process. And as is true with most transitions, you're kind of treading a little water and not show which direction to go and so forth, and so developing a rather detailed set of rules may not be the thing for you to do.

The thing for you to do is maybe to try to determine what is it that you want to see or what conduct do you expect of a utility in order for them to carry their burden before you that it's the most cost-effective alternative available to them.

From my process of thinking, that burden rests with the utility applicant to demonstrate to your satisfaction that that's the most cost-effective alternative.

I think you shouldn't adopt a rule that says you've got to go through a bid process in all circumstances. I think you ought to adopt a rule that

recognizes that the burden of proof is on the applicant. And I think you ought to adopt a rule that tells them "Yes. And bidding is really the best way for you to do that unless you can demonstrate otherwise." And the Staff's initial proposed rule permits that. They say, in essence, and I don't want to go into the language -- I'll let the lawyers take care of that -- in essence, "You better bid it unless you can demonstrate that bidding is not in the public interest." That gives them the opportunity to come to you and say, "I want you to certify the need for this plant for whatever reason that we can't anticipate now may come up."

If you require a bidding rule up front before they come to you, I think you'd be making a mistake.

Now, obviously, when you get the bidding, there's a lot of factors that I think you have to consider, and some of those I've tried to bring out in this cross examination.

There is value, from my perspective, from a utility owning that capacity; the ratepayers have paid for it at the end of its estimated useful life, and they get it from that point on free, or with minimum cost. I don't want to say free because there's nothing really free but with minimum cost, minimum investment.

I contrast that with if a contractor comes to the end of his contract, he can market that product output from that plant again in the competitive market. And that has the potential of at the end of that period costing the ratepayers substantially more than if that plant was owned by a utility.

These are factors that I think you ought to consider and leave open to the people who are coming before you to justify their application under this law. Leave that issue open for them to argue about; don't close it up front.

So my whole purpose of my whole question is to try to suggest to you that keep for yourself as much flexibility as you can. As you have more experiences under this law, you will gain and start developing how much more tighter you want to tighten it up. But don't put yourself in a straitjacket now, right up front, until you have some experience in the certification process.

You will get a lot of intervenors regardless of any process that you take. And is it sufficient to tell a utility, "Hey, when you have a determination of need, come to us when you want to."

The first time that this issue got really addressed was when Seminole Electric came before this

body and told this body that they needed a certain amount of capacity and they said, "Commission, please certify the need." And they said, "We're going to go out and bid it."

One of the Commissioners suggested, "Well, that's a good idea, go out and bid it, but I can't give a certification until I get the bids back because I can't tell you what's most cost effective until after you have been through the bid process."

And so that, in essence, started the bid process or prove otherwise before this Commission. I don't know how long ago it was because time goes buy a lot faster than it used to.

But Gunter started it, and you all have been involved in it, but there's been exceptions. You had Tampa Electric come up and say, "We've got a federal grant. We don't need to go through a bid process." And I don't think there was much objection to that, and you all certified that need. Don't close that door. Don't close that door in this bidding process.

And in closing I would say that the Staff's original draft -- and I'm sure it can be improved in wording and I'm sure the second draft could be improved in wording, but don't forget that there is some intangible as well as tangible benefits that come from

utility ownership over a long period of time that are not existent in most contracts. I'm not saying a well-crafted contract could not take care of some of these things. And I'm really looking forward to seeing a well-crafted contract form that one of the witnesses agreed to send to me.

Thank you, sir.

MS. RULE: Chairman Deason, having opened my mouth to suggest this procedure, I would like to point out that none of that seemed to be addressed to the witness, who was then not asked to comment on it; a wonderful, rousing closing statement, but offered during CEPA's time period.

I don't think we're going to be able to move this hearing along unless the parties direct their comments to the witness. If they want the witness' response to it, fine. There is more than ample opportunity for people to put comments in the record, to talk here today, but I'm not seeing the hearing move along. I'm not seeing the information being presented to the Commission in a very helpful fashion.

CHAIRMAN DEASON: I just think we made some progress because I think Mr. Cresse now has no further questions.

MR. CRESSE: Pardon?

CHAIRMAN DEASON: Do you have any more questions, Mr. Cresse?

MR. CRESSE: No. That wound mine up. Even I recognize my last statement was not a question.

CHAIRMAN DEASON: But that has raised some questions in my mind so I'm going to ask Mr. Huddleston about it.

I take it that the rule that you are suggesting or recommending does require bidding in all situations; is that correct?

MR. HUDDLESTON: In all supply addition situations, yes.

CHAIRMAN DEASON: Now, Mr. Cresse has suggested that we not have that requirement, there be some flexibility. What is your feeling on that?

MR. HUDDLESTON: Well, I assume that the flexibility would be because of some extraordinary opportunity. Otherwise, I'm not sure why a waiver would be in the best interest of the ratepayers, since in my view competition is the way to bring costs in at their lowest level.

If it is for a extraordinary opportunity, it would occur to me that a process that was appropriately designed would allow an extraordinary opportunity to win, so that in a solicitation that extraordinary

opportunity would be the winner. So I'm not sure why it shouldn't be subject to market pressures.

CHAIRMAN DEASON: Let me ask you this: Would you agree that the burden should be on the utility to either bid for new capacity or else have the burden to show why they chose not to bid?

MR. HUDDLESTON: You mean rather than requiring them to bid in each situation?

CHAIRMAN DEASON: Yes. Assuming there was flexibility to that degree, you would agree the burden would be on the utility. If they chose not to bid, if they had that flexibility under the rule, that it would be their burden to show why they chose not to have a competitive bidding process.

MR. HUDDLESTON: Yes, sir. A similar question arose in the context of a bidding proceeding that the Ohio Commission is -- they are actually in the process. And one of the things they considered was assigning a presumption of reasonableness with an RFP and a presumption of unreasonableness for, and outside of, an RFP opportunity so that the utility had a greater burden than would normally be the case.

CHAIRMAN DEASON: Let me ask you this: Do you think it would be preferable if there was going to be some flexibility envisioned in the rule, that there

would be a requirement for a competitive bidding but that there could be a waiver requested if circumstances were such that the utility felt that it would be a waste of time and resources to go through a competitive bidding process? I know -- because it certainly is costly to the participants in a competitive bidding process.

We were talking about security bonds, we were talking about a lot of costs in responding to a RFP. And if we had a situation similar to TECO's where there was a federal grant involved and it appeared there was no need for a competitive bidding process, do you think a waiver, a provision to get a waiver in the rule would be adequate?

A Well, I'm not sure -- I have a little bit of the trouble, I guess, with the concept that an opportunity can be cost-effective outside of an RFP and deemed so, without having evaluated all possible alternatives.

If you've come in with this extraordinary opportunity that is represented by a grant or represented by a breakthrough technology, then, if it's deemed sort of in the social interest sense that the ratepayers should subsidize that process, even if it's not the most cost-effective alternative, I think that

needs to be explicitly decided. I don't think you can assume that there are no alternatives and grant a waiver without having evaluated whether or not there, in truth, were alternatives or are alternatives.

CHAIRMAN DEASON: If a waiver is requested, isn't there an opportunity -- I may be wrong and maybe counsel can correct me, but if there is a request for a waiver from a rule, isn't there an opportunity for other parties to protest that waiver in this situation and say, "Even though we know that there's a federal grant involved, we think we can still beat that, therefore, we think there needs to be a competitive bid process."

MR. HUDDLESTON: I'm not sure that was contained in the proposal but, yes, I would hope there would be, if that flexibility were granted.

CHAIRMAN DEASON: Now, let me ask you another question.

Mr. Cresse raised the thought that -- I know this is not his position, but the thought that an independent power producer should have standing under the law to file its own determination of need. I take it that's your belief; is that correct?

MR. HUDDLESTON: Yes.

CHAIRMAN DEASON: Given that's your belief,

how does that tie into or mesh with your proposal as far as competitive bidding?

MR. HUDDLESTON: I think the simple answer is that if that entity does not have the ability to be an applicant, then in a need determination proceeding, which, in essence, the CEPA rule is, you will not be able to choose anybody except the utility. So making other entities possible applicants is necessary to have a proceeding that can result in a winner. Otherwise, all you can do is deny the utility, tell them to go forward and sign a contract and then do the process all over again.

CHAIRMAN DEASON: Well, I guess I'm at a little bit of a loss. You're saying the threat of somebody coming in getting their own determination of need is needed for the bidding process to work effectively?

MR. HUDDLESTON: No. What I'm saying is the status as an applicant -- assuming that the Commission's stance is correct, that nonutilities cannot be applicants, then you need to have status as an applicant in order to have the Commission give a need determination for that party prior to the signing of a contract with a utility.

If the utility is the only entity that can be,

an applicant, then the need determination process cannot be -- cannot be included within the bidding scheme.

CHAIRMAN DEASON: Is that because of your bifurcated approach?

MR. HUDDLESTON: No, I believe it's because of the Commission's decision that nonutilities cannot be applicants unless they have a contract.

If you had a need determination hearing following the signing of a contract with the winner and the utility brought forward the winner, then that satisfies the Commission's ruling that the utility has to be an applicant with its winner. However, if you had the need determination prior to the signing of the contract, then pursuant to the Commission's ruling, the utility is the only one that can bring in the winner. And if they haven't signed a contract, then why would they do that?

CHAIRMAN DEASON: Would your concern be addressed if it were clear that other parties other than the utility would have standing to make a showing that there is the need for additional capacity?

MR. HUDDLESTON: Assuming that the Commission could choose them as the winner or give them a need determination.

CHAIRMAN DEASON: If an interested party made that filing and convinced the Commission that there was the need for additional capacity, and then ordered the utility to initiate a competitive bidding process, wouldn't that party be able to participate in that process? And if they were the most cost effective, supposedly win that competitive bid and then be an applicant by sake of the fact that they have a signed contract?

MR. HUDDLESTON: By having the utility be the applicant.

If you took the CEPA rule, for example, and just went to the time line, the problem we're talking about is that in the CEPA rule the Commission determines in the final orders, step 12, the winner. And, in essence, gives the need determination for that -- the certification for that winning project. However, the utility doesn't sign the agreement until No. 13.

If the utility were forced to sign the agreement before the Commission's final order, then all you have to do is flip 12 and 13. You know, it's just a process of actually getting that ticket stamped. And under the Commission's ruling in the Cypress case, the utility was the only one that could get their ticket

stamped. Even if, for example, the Commission had determined that the ARK Energy project was the best, the Commission couldn't stamp their ticket pursuant to their ruling.

And all the CEPA rule tries to do and the applicant issue tries to do is give the Commission the ability to stamp the ticket of the best project or the most cost-effective project. And that's all the applicant issue really is.

CHAIRMAN DEASON: But you're in no way suggesting or envisioning that there would be a circumvention of the bidding process to get that ticket stamped?

MR. HUDDLESTON: Well, I'm not sure any of our member companies would be willing to go out on a limb and build a project and try and get it certified if they didn't have a customer. So I think probably not. I mean most likely not, not probably not.

CHAIRMAN DEASON: Mr. Neiser?

CROSS EXAMINATION

BY MR. GADDY:

Q I'm Rodney Gaddy with Florida Power. I'd like to ask you a few questions, generally first, and then I'll refer you to the specifics of the CEPA rule.

Is it your basic premise that the current process doesn't work, either because the current Commission, in particular, or commissions in general just fail to, or they are either unwilling or unable to find the most cost-effective alternative?

A Yes. I think I'd stress unwilling -- excuse me, unable, not unwilling.

Q Not unwilling. Let me refer you to your direct testimony on Page 16. Will you read Lines 13 through the first part of 17, please?

A That's Page 16?

Q Yes, sir.

A Yes.

Q Will you read that aloud, please?

A "A natural monopoly does not respond to the normal market forces of supply and demand and will consistently provide service at the highest possible cost. And, unfortunately, its regulators do not routinely force it not to do so."

Q So then on the contrary to the Commission's statutory obligation to find the most cost-effective alternative, does this mean that they just allow a utility to build for the highest possible cost? Is that what you mean by that?

A No, this responds to natural monopolies that,

in essence, are not regulated. Then in that case, the regulator comes in and attempts to force that natural monopoly to a price at either average cost or marginal cost or whatever the regime is that's been chosen. And my comment here is that regulators do not always eliminate all, what I call "monopoly rents."

Q Okay. Well, I guess along the same line, in your proposal you're suggesting that if, in fact, a utility participates in the bid process by submitting a bid proposal that a third party should evaluate that bid; is that correct?

A Yes, either the utility or a utility affiliate.

Q Okay. And is that because you don't have the confidence that a commission, in fact, will come in and review that selection process?

A No, I believe commissions do a good job of reviewing the information that they're provided. I believe, though, that there are -- there is the ability, and occasionally the perception, that evaluations performed by utilities that have participated in their own bids were not fair. And that may or may not be something that a commission would uncover. And all we're attempting to do is to eliminate the possibility or that the postbid

evaluation perception that that bias was there.

Q And in Florida bidding has, in fact, occurred successfully; has it not?

A Yes, it has.

Q In fact, in 1991 Florida Power put out an RFP for 500 megawatts of capacity and evaluated those bids themselves and selected people to -- entities to provide that energy; is that correct?

A That's true, yes, sir.

Q And Destec, your company that you presently work for, has a contract with Florida Power presently?

A Yes, it does.

Q Let me ask you, does that contract have a backup fuel source, the contract that Destec has with Florida Power?

A To tell you the truth, it's been a while since I looked at the contracts, but the project does intend to have a backup fuel source, yes, sir.

Q It does intend to?

A Yes, sir.

Q In your direct testimony on Page 9 of it, if you wanted to look at it, you seem to be critical of the subjective nature of the evaluation process involving a Georgia Power RFP. Yet, on Page 7 of your testimony, where you are talking about the factors that

should be included in a successful RFP, you specifically mention at Lines 22 through 24, that subjective criteria are an essential component of an RFP. Can you reconcile that for me?

A Yes, sir. I had wanted to attach the testimony from the Georgia Power proceeding but was convinced not to by attorneys. I think --

Q Probably a smart choice.

A The real problem that I perceive in the Georgia Power solicitation isn't so much that they have subjective criteria, but that the parties did not know what that subjective criteria or what the weightings were going into the process. I liken it to having a race. You've got an eight-lane track and you're running a 100-yard dash. And everybody who participated saw one person cross the line first. But the utility looks at the photo at the finish and decides that it likes the legs of the guy who finished fourth, and they choose him. If no one knew that legs were an important part, they might be a bit perplexed by the choice.

Q Of course in that example finishing first is normally the criteria, the only criteria, that is given?

A It normally is, yes, sir.

Q Let me ask you about the proposed rule, proposed CEPA rule. If you would, if you could turn to that.

A I have it.

Q All right. In Section 25-22.080, Subsection (1), I presume that underlined language is language you're proposing to add?

A Yes.

Q All right. As it reads without that language, it says, in essence, "Proceedings to determine the need for proposed electrical power plant as defined in," the section listed, "shall begin with a petition by a utility." Can you tell me what the significance or the intent of adding the language, "by persons other than investor-owned utilities," means and who those persons might be please?

A Well, the persons would be -- I suppose in one respect it should be affected parties, but persons or entities, for example, like municipal utilities, independent power producers, perhaps the Public Counsel. So that parties other than utilities could initiate proceedings that would allow the Commission to determine whether the utility's need is appropriately being planned.

Q So this is the provision that you're adding

-- that you're referring to earlier that would allow or enable those entities or interested persons, as you're saying now, to follow a need petition themselves?

A Not entirely, no. This -- the applicant issue is somewhat separate. The applicant issue would allow the Commission to choose an entity other than the utility if, in fact, in a proceeding it were determined that that entity were the most cost-effective alternative to meeting the utility's need. What this section refers to is the need determination, in a sense the need for the generation addition plan, so -- unlike the old annual planning hearings that everyone so fondly remembers.

Q I guess, Mr. Huddleston, I'm still having some difficulty in why it's inserted where it is. I'm not sure what it's intended to do.

A Well, it's just intended to allow parties other than investor-owned utilities to begin a process.

Q The further language, of course, says, "shall begin with a petition by a utility or on the Commission's own motion." At any rate --

MS. BROWNLESS: In an effort to be helpful here, may I just make a comment? It might clear things up.

CHAIRMAN DEASON: Surely.

MS. BROWNLESS: This language was added to distinguish our rule, which applies to investor-owned utilities, to say that municipalities and co-ops who wish to utilize the Power Plant Siting Act would continue to use the current rules that the Commission has on the Power Plant Siting Act now, so they wouldn't be subjected to the bidding requirements, but instead would file -- would follow the process that the Commission uses now for power plant siting. That's all it's intended to do.

COMMISSIONER CLARK: You're talking about 22.080?

MS. BROWNLESS: Yes, ma'am, that is the Commission's -- .080 and .081 are the Commission's existing rules on power plant siting.

COMMISSIONER CLARK: And the way you've changed it, the only people that can apply are people other than investor-owned utilities.

MS. BROWNLESS: Yes, ma'am, so everybody else would follow the existing information requirements and the existing procedure that's in place now. Investor-owned utilities would be required to bid and would follow the bidding scheme that we have set out. That's all it was intended to do, sir.

Q (By Mr. Gaddy) Now, your rule doesn't

contemplate a negotiated contract provision. I mean, there's no provision in here to negotiate with finalists, or anything like that, as you've seen it in other bidding rules, is that correct?

A That's correct.

Q In fact, when I looked at your timetable which is the last page of your direct testimony, you say in Part V, No. 13, that a utility shall sign a previously approved power agreement with the winning bidder; is that correct?

A Yes.

Q And that contract, that power agreement that you're referring to, would have been submitted by the utility -- I'm trying to find on your timetable where it's --

A Day 1.

Q Day 1.

A Yes.

Q Now, isn't it important in these power purchase agreements to tailor the agreements to the specific proposals that you receive?

A Yes, sir.

Q And it's not possible to do that if you don't even know what you're going to receive because you'd submit it at the same time that you submit the RFP

package is, is that correct?

A Well, by specifying up front what it is the utility thinks it needs, presumably the winning bidder would have satisfied what the utility's need was, so the proposal that you've gotten would be the proposal that you wanted.

Q However, the specifics of the contract, all of the different things that we were talking about as far as reliability, dispatchability, and just those other things that we were talking about, may have to be tailored to the specific proposal that, in fact, becomes the winning bid. Would you agree?

A No, I think that can be specified ahead of time. If you specify ahead of time that you want a black car and I bring you a red one, I don't win.

Q I guess if we were GM talking about cars, that would be appropriate. I just don't see the appropriateness here, but no problem.

A Well, I mean, if I'm given a proposal to evaluate and I'm bringing forward a bid to satisfy that proposal, presumably my bid is fashioned to take into account the terms and conditions that you have presented me in the proposal. As I understand it, that's how Florida Power Corporation did its last bid.

Q Going back to the rule, I asked Mr. Seelke --

and the next portion of the rule, 25-22.081 refers to substantially interested parties that would receive the cost information. I'm sorry, I'm looking at the wrong section. I should say Subsection (2)(c), refers to the information, cost information that Mr. Seelke testified about. And it talks in terms of a person whose substantial interest may be affected would be entitled to that information upon request. I asked Mr. Seelke who are substantially interested persons for that, and he asked me to refer the question to you.

A I thank him for that. As I understand it, the statutes define who substantially affected parties are. In my nonlegal opinion, they would be parties who would be bidding, perhaps Public Counsel, should it be deemed important for Public Counsel to monitor the proceedings, and presumably to the Commission.

Q Now, when you're trying to refer to the definition in the statute -- and I appreciate the fact that you're not a lawyer, and I'm not going to really ask you a legal question in that regard --

A I have them here, though, if you would like me to refer me to them.

Q No, sir, I'm not trying to ask you a legal question.

CHAIRMAN DEASON: You got to give those back

now.

Q (By Mr. Gaddy) Because your proposed rule is substantially different than what exists presently, it seems to me that substantially interested parties, as it is provided in your proposal, can mean any entity that's interested, whether they want to bid in the present proceeding or not; is that accurate?

A I would hope not. I would hope not. But if it needs to be defined more directly, I think that can be accomplished.

Q I want to compare two statements you made and ask you to reconcile them for me again, and then I want to come back to this specific section, if I may. On Page 8 of your testimony, Lines 5 through 7, to which you are again talking about what factors should be included in an RFP, Lines 5 through 7 suggest that you ought to keep proprietary business information confidential from other bidders and other competitors, including the utility itself. If I compare that to a statement that you made on Page 32 of your direct testimony, Lines 8 through 14, it would suggest that the utility would have to disclose its proprietary confidential information.

A Again, I would think not. As Commissioner Clark and I discussed, I think we're in a difficult

position here where the utility is both buyer and seller. And what we're attempting to do is set up a process where the information to optimally serve the ratepayer needs can be available to all of the potential alternative suppliers, so that they can design their project to give the utility and its ratepayers what it needs or what they need.

So what we've attempted to do is identify the minimal amount of what I would call "system information." And the system relates to distribution and transmission, it would seem to me, more directly than the utility's generation component, to serve the utility's need. And that information does not require the utility to provide, you know -- for example, just off the top of my head -- how they would intend to structure the capital structure of their bid, or how they would intend to contract for fuel supply, or how they would intend or who they would intend to buy a turbine from and what the price of that turbine would be. What it requires is that the utility provide the information that would allow the competitors to model the system and propose a project that serves the system. And I would think that that would be the ultimate objective of all parties to best serve the ratepayers.

Q Some of the information that I understood Mr. Seelke was requesting, however, under this provision, dealt with PROMOD and PROSCREEN models.

A Well, I think that individual parties can acquire PROMOD and PROSCREEN from vendors. They don't need it from the utility. What Mr. Seelke, I think, intended was that we would know what model it was that you would be using, so that we could duplicate the evaluation, so that in the end process, we could act as an auditor as well, see why it was we lost, learn from it just like everybody else.

Q So you're not requesting the PROMOD or PROSCREEN, just the raw data?

A Right, at least that's my understanding.

Q Very well. In the Phase I of your proposed rule, where an interested competing bidder, one who would submit a bid, would get that raw data, and I guess make some evaluation of the need, of whether or not the utility has a need?

A Yes, sir. What it does, in Florida, the utility is the sole -- I don't know, sole -- the sole modeler. The utility is the one who does all of the estimations, brings it to the Commission, and the Commission evaluates it. The independent other affected parties can also evaluate it. All we're

attempting to do is structure a process where all parties have the opportunity to become as expert, in a sense, at modeling and be able to help in the evaluation of needs.

Q And if, in fact, one of these competing entities disagrees with the utility's determination of their need, at that point a hearing can be requested, right?

A Yes, sir.

Q Now your rule doesn't specify what type of hearing that would be. Are you talking about a 120.57 or 120.54, or some other type of hearing?

A No, sir, it doesn't specify.

Q Yes, and I'm asking you what do you contemplate by that?

A I'm not certain what we contemplate.

Q All right. Do you know if you contemplate that after the Commission makes a determination of need, if an interested party still disagrees with the Commission, whether your rule would contemplate an appeal to Department of Administrative Hearings and subsequently to the District Court of Appeals? And perhaps that's a legal question.

A It probably is. I would assume that no one gives up their rights, though.

Q Very well. And I'm just trying to understand the rights that you're trying to create, if there are some in addition to what exist presently.

A I don't believe so, no, other than being an applicant, that would be nice.

Q If there are ten potential bidders, could there be ten hearings, or do you contemplate one?

A It would be a single hearing.

Q All right.

A Now, if there are ten potential utilities with RFPs, we could have ten hearings, I suppose.

Q Understood. Do you have an exhibit that you've provided by the National Independent Energy Producers?

A Yes.

Q That's in your direct testimony, I believe. And I wanted to refer you to Page 36 of that exhibit, if I may, in fact, the very last paragraph of that article you submitted.

A Yes, sir.

Q Are you in agreement with that last paragraph which essentially states that when cost of capital impact results from purchased power, that the Commission should acknowledge that and compensate a utility and the ratepayers? Do you agree with that?

A I think in the current rate of return regulation environment, if you can show a direct correlation, yes. However, in a competitive framework, it seems -- again, the logic eludes me of rewarding a utility for having lost a competition and having to purchase from the winner.

Q Does that mean you disagree or you agree?

A No, as I said, in the traditional rate of return regulatory environment, I think it would be appropriate. However, in a competitive environment, which we're talking about potentially going forward -- if you'll note, the NIAP report was written in late '91, so that things have changed since '91. In fact, they have recently released a subsequent report on incentives, which I didn't include since we weren't addressing that in this hearing.

Q Very well.

MR. GADDY: I have nothing further, Mr. Chairman.

CHAIRMAN DEASON: Further questions for Mr. Huddleston? Staff.

CROSS EXAMINATION

BY MS. RULE:

Q Mr. Huddleston, I'm Marsha Rule, representing the Commission Staff, and I have some procedurally oriented questions about CEPA's proposed rule.

I'd like to ask you first some questions about the timeline, your Exhibit 3?

A I have it.

Q Administratively, some of it just doesn't sound doable. How did you come up with these times?

A Well, I think you're probably right, some of them are ambitious. However, setting ambitious targets seems to me to be a prudent course. If for some reason some of the dates have to slip, I think there should be provision for that as well.

Q Well, for instance, I'm very concerned about Days 1 to 20, because I don't think that 20 days for a decision of this magnitude, particularly by a collegial body, is possible.

The Commission would first have to decide whether or not to have a hearing, on its own motion, or whether to go ahead and approve the bid package in that time if nobody requested a hearing. And due to the way the Commission operates, if the -- let's say, for example, the first day was Monday, Day 1 is a Monday.

In order to give ample public notice before the Commission meets to make its decision, the Staff would have to file a recommendation on Day 4 in order to get an order out on Day 20. And because the Commission has an independent duty to make an investigation and make a regulatory determination here, I don't see how the Staff can possibly do that in three to four days. Can you tell me what your thinking was about how the Commission was going to approve this within 20 days?

A Well, having worked for the Commission, I suspect it's a bit ambitious. However, it seems to me that the proposal is an example -- excuse me, the timeline is an example. And we attempted to show how the proceeding and procedures could fit within the current Plant Siting Act timelines. And that was the real goal for setting it out the way we have. If any of the individual components need to be shifted, it would seem to be possible to do.

Q Well, the problem I have with it is I think almost all the individual components relating to the Commission's duties have to be lengthened. For example, and not talking any particular time periods, because the Commission must exercise its independent regulatory judgment over the decision whether or not to approve the bid, we're going to have to have something

to base it on. So it seems to me that anything, even if you stretch this out or double it to 40 days, you're either reducing the Commission to rubber stamping whatever proposal the utility brings in, or blanket -- making a blanket decision to hold a hearing on everything, because there's not going to be any record basis to make a final order. We have to let people have a clear point of entry to contest it under Chapter 120, and if we do our usual procedure and issue a PAA order, then somebody has the right to protest it afterwards. I'm not trying to say that an expedient disposition isn't possible. I'm just not sure how this works with the APA.

And also, for example, okay, on Day 120 we're supposed to issue an order and publish in the Administrative Weekly 14 days later. Yet, we have to have the notice over there 11 days in advance of publication, and unless you guys have some split-second timing on exactly the minute you file it, we may not be able to do that. I'm not sure that, even stretching some of these things out a lot, you'll fulfill your needs.

Are some of these things intended to give comfort to people, but you don't really think they're useful?

A Well, not being an expert on administrative procedures, I don't believe that I can comment on whether or not it's doable or required. I think with consultation of counsel, we determined that this timeline was, in fact, within the -- within the framework of present administrative code. And if you don't believe that it is, then I guess those are your evaluations and your comments.

Q Okay. So your statement, then, is that you think it is doable or at least flexible enough that it can be done?

A Yes.

Q Let's turn to Page 3 of your rule proposal. It appears to me -- and please correct me if I'm wrong -- that the purpose of having the Commission publish a notice of filing in newspapers is to meet the requirements of Section 403.519; is that correct?

A Yes.

Q Okay. But under Section 403.519 the notice we publish is where the plant is proposed to be located. Under your rule we would have to publish notice in every newspaper where a plant may be located. What would --

A That's correct.

Q How is anybody in any of those counties to

know if they're a substantially affected person for the purpose of requesting a hearing?

MS. BROWNLESS: Counsel can answer that, if you'll allow me to.

MS. RULE: Please.

MS. BROWNLESS: The notice that would be published would say that this could be the beginning of the first part of the power plant siting process, because, remember, we're tailoring this bidding rule to accommodate existing statutory requirements. It would be a lot simpler if the statute is rewritten, but we're trying to work with what we've got now. So the noticing requirements are in all 67 counties, to start with. And the notice would merely indicate that the utility has filed an indication to bid, an indication that capacity is needing, there will be a bid process; this plant may or may not be located in your county; be put on notice that this process has started.

COMMISSIONER CLARK: Do we do that now? Is it done in all 67 counties now or --

MS. BROWNLESS: No, ma'am. As the process works now, it's very similar to the type of notice that would be given in Phase II of our proposal, which is the bid protest phase. At that time, you would have -- the bidders would obviously know where their proposed

projects were. If the utility were selecting itself or had won the bid, it would obviously know where it's project was. So notice at that time would be published in the counties where the bids were. It was an effort to accommodate the existing publication rules in the existing statute.

MS. RULE: But the problem I see with it is you publish notice in every county and the people there will get nothing really useful from it, and indeed, this may be the last notice they get. If the Commission then approves the bid package and there is no bid protest, that's it. Where's their point of entry?

MS. BROWNLESS: Their point of entry is right then. In other words, what you tell them is we're starting this process. It may be in your county. We're putting you on notice; if you're interested follow the process. That's not unlike what is done now, for example, in certificate of need cases for hospitals.

COMMISSIONER CLARK: But they don't give them in all 67 counties.

MS. BROWNLESS: Certificate of needs, I believe are --

COMMISSIONER CLARK: Are in all 67 --

throughout the whole state?

MS. BROWNLESS: Throughout the whole state.

MS. RULE: The environmental problems associated with a hospital don't generally cover all 67 counties. However, the environmental problems associated with a power plant might, in which case --

MS. BROWNLESS: I honestly believe that there is notification and a notice that can be written that will put people on notice that this process is starting and it's beginning, and for them to get in and follow it. I don't think -- I mean, if the Commission would like to amend our rules so that when the bid protest hearing is held, if any, notice is also given in all 67 counties, that's lovely too. We're trying to conform with existing statutory language. This is certainly not the type of notice we would recommend if we could change the statute.

MS. RULE: Well, I'm assuming that we're all working on the statute as it is right now. And in any event, the statute says you give notice where the power plant will be located. I'm just concerned that this notice is overkill, and at the same time, doesn't provide anybody with a significant opportunity to contest the siting of a plant in their county. I'm not asking you to say, "Yes, it is. It's wonderful." I'm

trying to point this out and make you aware of the concern.

MS. BROWNLESS: And I guess my response to that would be that when the bids are selected, whomever gets selected, there will be a second notice published, and that will be published in the affected counties, in the counties that may be affected, and, therefore, will give meaning to the original notice.

MS. RULE: Another question that, Suzanne, it may be better if you answer this. On Page 5 of the rule, Section (b) begins, "If a hearing is held pursuant to Section (3)(a), the Commission shall issue a final order within 120 days."

MS. BROWNLESS: Marsha, you got drowned out. You'll have to start again, the page flipping.

MS. RULE: Page 5, Section (b) at the top of the page --

MS. BROWNLESS: Yes, ma'am.

MS. RULE: It talks about a hearing being held and the Commission issuing an order. One thing that was not clear to me looking through this rule is who has what burden during the hearing process. Are you saying that the utility has the burden, let's say, during the bid package approval process to get its package approved and then the burden thereafter to show

that it's properly selected the winner?

MS. BROWNLESS: Yes, because I think that corresponds with the burden that the utility has now. In other words, now when the utility comes in with a proposal to -- whether it's the Cypress scenario where FPL came in with Cypress and said Cypress was a correct choice, or whether it was the prior FPL power plant siting for Martin Units 3 and 4, they carried the burden of proof, both on the manner of selection, as well as on the projects ultimately selected.

So in our process, all you're doing is dividing, in essence, the two big issues in every need determination, which is: What do you need and how are you going to fill that need? We're just dividing that up. The "what do you need?" is still the utility's burden. So they would be responsible for proving up that they needed X number of megawatts in X year, and that the RFP that they were putting out was appropriate -- was appropriate. And, of course, they would be responsible and allowed to put any type of term or condition in that RFP that they deemed was responsive to their needs.

MS. RULE: Moving on down -- I'm not sure -- these aren't marked with line numbers, but it's about two-thirds of the way down, the rule says that the

order that the Commission would issue would constitute the Commission's findings under Section 403.519. If there's no hearing being held, upon what basis would the Commission make those findings?

MS. BROWNLESS: They would make those findings based upon the paper work that was submitted.

MS. RULE: And in that case, just procedurally, you would anticipate that the Commission would issue a PAA order?

MS. BROWNLESS: No, ma'am, I would anticipate that, pursuant to the rule, the Commission would issue a final order based upon that documentation.

MS. RULE: And you would anticipate that's because you offered people a point of entry in that newspaper notification in every county some months before?

MS. BROWNLESS: You also gave the Commission the ability to hold its own hearing if it deemed that was appropriate, too.

MS. RULE: Right, but I'm considering the interests of substantially affected parties.

MS. BROWNLESS: You offered them the clear point of entry by the notice in the 67 counties, as well as by the F.A.W. notice, as well as you gave people the ability who were on the short list to be

notified too -- I mean, who were on a mailing list at the PSC to be notified too. And you gave the notice to Public Counsel.

MS. RULE: On the next page, Page 6, either one of you --

COMMISSIONER CLARK: What's going to result, though? I have this vision of Hillsborough County, the problem that Florida Power Corporation has encountered in trying to get their lines sited. And Hillsborough County has just, you know -- their continuing complaint that they weren't given adequate notice, there wasn't adequate time for them to respond to it. And I can't help but thinking, in this scenario where you give notice to 67 counties, nobody really knows where it's going to be. And then when the bid is decided on, they're not going to have an opportunity to come in and protest where its sited?

MS. BROWNLESS: Sure, Hillsborough County can, sure.

COMMISSIONER CLARK: And when will they do that?

MS. BROWNLESS: They will do that along the same time frame with everybody else, just like they can now.

COMMISSIONER CLARK: No. Tell me when. Not

when everybody else does it; when is it? Is it after the bid goes -- After Florida Power Corporation has decided that you're the successful bidder and the plant is going to be here, will the county then be able to come and protest that?

MS. BROWNLESS: Yes, ma'am, just as Public Counsel can, just as any ratepayer of the utility who has made that selection.

COMMISSIONER CLARK: And they would be able to protest that choice and that site?

MS. BROWNLESS: Yes, ma'am.

COMMISSIONER CLARK: Okay. But when are they going to be notified of who the successful bidder was and where it is?

MS. BROWNLESS: They're going to be notified by notice in the F.A.W. They will have already been put on notice because --

COMMISSIONER CLARK: Okay, but after the bid is decided, and then as you start the certificate of need process, you --

MS. BROWNLESS: If, for example, let's use the Hillsborough County -- that's a good example. I assume Hillsborough County, nine times out of ten, is not going to care if this generation facility is located in Dade County.

COMMISSIONER CLARK: Right.

MS. BROWNLESS: So if it's located in Hillsborough County, the second round of general publication notices will have been published in newspapers of general circulation in Hillsborough County, and they will be aware that it is in their county. And at that point in time they have a clear point of entry to get in and protest that aspect of it.

COMMISSIONER CLARK: Okay.

MS. RULE: But -- to jump in on that line of thought, but by that time the Commission would have already approved the utility's bid package which conceivably told people about where they wanted it.

MS. BROWNLESS: But Hillsborough County had the ability at the very beginning because of the notice given in all 67 counties, which notice will say, "This is the beginning of a process; we're selecting an RFP, which could lead to capacity additions in your county." One presumes if Hillsborough County is concerned about that kind of thing, they will keep up with the paperwork.

MS. RULE: I guess the problem I see at the time is I can just imagine what Staff might recommend if somebody from Hillsborough County comes in after one of those statewide notices and says, "We want to make

sure it doesn't occur in our county." We would say, "It's just preliminary at this point. We don't know where it will be. Go home now."

MS. BROWNLESS: I hope you wouldn't. I hope you would say, "Thank you very much. You get in and you get to play."

COMMISSIONER CLARK: We're going to have all 67 counties in here right from the beginning?

MS. RULE: And then a year and a half later when they find out who the bidder is, then what?

WITNESS HUDDLESTON: Don't you have a more expanded hearing room planned?

COMMISSIONER CLARK: Not for that, Barry.

MS. RULE: I don't want to belabor the point. It just seems to me -- it seems to me I would not want to be in the position of being over at the court and trying to defend this as offering a clear point of entry for people in whose county it was actually built.

MR. DONELAN: Commissioner Clark, I'm Richard Donelan with DEP, and I couldn't help but to hear this colloquy and had to interject myself, because I did defend, in fact, this Commission in the first of the federal court actions about the Hillsborough County transmission line.

And in that case the "beef," if you want to

use that term, of Hillsborough County was that all property owners along the route of the entire transmission line, some 35 miles, were not notified that the transmission line might run somewhere near their house. But the power plant site, you are talking, in the main, about a discrete piece of land which will be located in one county and not strung out in a linear facility.

And the same problem exists today in the Commission's determinations, which are all -- which are made, although notice is given, that there is no notice given to the people who might run along associated facilities like transmission lines and gas pipeline laterals and things like that.

But my actual point is that when the time comes to actually construct the plant, you know, when this need determination process is over, there is extensive notices that are required to be published under the Power Plant Siting Act. So it's hardly the case that you're going to have the same problem with a power plant site as opposed to a transmission line.

COMMISSIONER CLARK: But correct me if I'm wrong, under a determination of need currently, you come forward with a -- I guess, at the same time -- at the time you're deciding what will fill the need,

you're determining that there is a need.

MR. DONELON: Yes.

COMMISSIONER CLARK: And in the bifurcated one you're going to decide there is a need.

MS. BROWNLESS: Yes, ma'am.

COMMISSIONER CLARK: And then determine who will fill it.

MS. BROWNLESS: Yes, ma'am.

COMMISSIONER CLARK: It would seem to me those people in the 67 counties are going to have to get involved at the front end to determine -- if they wait, they will not get the opportunity to say, "we don't think you need it."

MS. BROWNLESS: I'm sorry, Susan, I didn't hear that.

COMMISSIONER CLARK: The way it's currently structured it's one proceeding.

MS. BROWNLESS: It's one-stop shopping and you get to litigate all of those issues at once.

COMMISSIONER CLARK: And the people who are likely to be most affected by it cannot only argue it shouldn't be here, we don't need it.

MS. BROWNLESS: Yes, ma'am, that's true.

COMMISSIONER CLARK: But if you bifurcate it, then you're going to have 67 counties in here saying we

don't need it. On the off chance they are going to be the people selected to host it, because in the second proceeding they won't be able to say, "We don't need it."

MS. BROWNLESS: That's right.

CHAIRMAN DEASON: Or you could have 67 counties saying they do need it hoping it's in their county.

MS. BROWNLESS: Yes, that's true.

MS. RULE: May I continue?

CHAIRMAN DEASON: How much more do you have?

MS. RULE: I have about three or four more questions. I don't know how many answers there might be to them.

CHAIRMAN DEASON: We need to take a break. We have been going for quite a long time and I'm sure Mr. Huddleston is quite tired.

Just go ahead if you think you can finish up in just a short period.

Q (By Ms. Rule) Okay. On Page 6 there is a sentence that may be unclear. Perhaps it's unclear only to me. About three-quarters of the way down.

The rule speaks to the refund of the initial security deposit. And it says, "The initial security deposit shall be refunded together with interest calculated in accordance with Rule 25-6.109(4) or

returned to any bidder." What's the difference between the refunding and returning? I didn't understand that.

A To tell you the truth, neither do I.

Q To your understanding is there meant to be any difference or did you just mean give it back.

A Just give it back.

Q Give it back and give it back with interest?

A Yeah.

Q Okay. I was concerned that perhaps "refund with interest" meant give it back with interest and "return" meant just give it back, and you got your choice. I wasn't sure.

A Well, I take the first one, with interest.

Q Well, it depends on who you are. (Laughter)

Okay. Actually, I think some of the answers we had before may have answered some of my questions.

Yes. On Page 8, at the very bottom, Section 6, it says, "If the utility did not bid or is not a winning bidder, the utility and the winning bidder shall execute a power purchase agreement which is consistent with the winning bids."

Now, in your comments at Page 11, you seem to say that negotiations should play no role in this process. If that's the case, then what do you mean by a contract consistent with the winning bid? How would

it be different?

A Well, consistent in the sense that there is one addition to the contract that was proposed in the RFP, and that is the price. So it's consistent in the sense that the price is now inserted pursuant to the bid. And you have the contract proposed in the RFP now complete.

Q Well, in connection with that, we've heard a whole lot today about the well-crafted contract. I have never seen this well-crafted contract. But isn't the free-market approach to crafting contracts to negotiate them?

A Well, I think in many cases it is. However, in many cases it isn't.

Q But here what you have as your well-crafted contract is basically a regulatory decision by the Commission, isn't it?

A The well-crafted contract is proposed up front as a means of -- in essence, it expresses the needs and desires of the utility and its ratepayers pursuant to the policies that have been developed by the Commission over time.

And that contract then comes before the Commission; the Commission rules whether or not it's an appropriate representation of the policy guidance that

it has given; whether or not it adequately balances the risks and rewards associated with the purchase.

So in that sense the contract is in a way negotiated through the proceeding.

Q Gosh, it sure sounds regulated to me, if you can't do it without the Commission's approval and the Commission has to approve each and every item in there.

A The commission does that today, they just do it at a different point.

Q Yes. And are you familiar with some problems that have arisen under standard offer contracts?

A I don't believe this is a standard offer. Each utility proposes a separate and specific contract with each separate and specific RFP. They are not the same. It's not standard offer in the sense that the price being offered by the individuals is not set ahead of time.

As I indicated in response to the Florida Power Corporation questioning, it's, as I understand it, the way in which their bid was run. The parties were presented with a contract and asked, in essence, what can you do this for.

Q I'm certainly not as familiar with the field as you are so I can't come up with a good example. But what would happen if, let's say in a contract dispute

down the road after one of these allegedly well-crafted contracts is approved and executed, you get into a contract dispute and it turns out that the utility is perhaps not adequately protected or it's not even a subject of the contract at all, whatever the dispute is. Isn't the Commission likely to -- or isn't the utility likely to say, "The Commission approved this, we have no liability"? And isn't the Commission likely to say, "Utility, you should have negotiated something else"?

A I think if the Commission adopts this proposal, then they have adopted the policies inherent in the proposal. And presumably, if at some point in the future it was determined that the contract that had been approved was faulty in some sense, I would hope that business partners would be able to achieve some accommodation and remedy.

Q Are the contracts that you see being executed now quite a bit different from those that were in existence ten years ago?

A Certainly. They are much longer.

Q Why is that?

A Because parties have learned and recognized that there are complexities that weren't initially envisioned.

MS. RULE: Thank you.

CHAIRMAN DEASON: Any other questions for Mr. Huddleston?

Thank you, Mr. Huddleston.

We're going to take a recess until 4:00.

(Brief recess.)

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CHAIRMAN DEASON: Call the hearing back to order, please.

It's my understanding that Mr. Bob Reilley has to catch a flight and that he's made the request that he be taken at this time, so if there's no objection to that.

MS. BROWNLESS: Commissioner Deason, I have no objection to that. I just would like to make three short points in response to Mr. Huddleston's testimony rather than asking redirect. This would be a lot quicker.

CHAIRMAN DEASON: If it's quicker, that sounds great to me. Please proceed.

MS. BROWNLESS: Thank you, sir.

First of all, I believe Ms. Rule asked about the statutory authority under the APA for issuing a final order if no protest filed. That statutory would be found in 120.572; that's the APA procedure where

there is no disputed issues of material fact, and the decision would be supported by the materials submitted to the Commission.

Second, there was a question for Mr. Cresse about the statutory ability of the Commission to require the utility to sign a contract or the previously approved contract with the winning bidder. I believe that is found in Chapter 356 under the Commission's general ratemaking authority also enumerated in the Grid Bill.

And I would point you to your current rule on good-faith negotiations in which the remedy when the utility is found to have negotiated in bad faith, is to require them to sign the tendered contract with the QF or IPP with whom they have negotiated in good faith.

With regard to the notice problem, we would say that currently the general publication notice is 45 days prior to the need determination hearing. So that's one notice very late in the process.

Under the CEPA proposed rule there would be two notices, one of which would be coming at the initial, very initial stages of the process, so the public would have more clear points of entry rather than fewer, and those points of entry would be earlier on in the process.

And finally, with regard to the data issue, I think there was some confusion about what type of information would be provided or could be provided if one requested it under our rule.

This would be both models and data input, not only raw utility data. But the point I want to stress here is that if that information is provided, it would not reveal the utility's subsequent bid price. Bid price is not directly correlated to the data input put into the generation expansion plan.

Thank you very much, Commissioner.

CHAIRMAN DEASON: Thank you.

MR. MAY: Mr. Chairman, thank you for the consideration.

Bruce May on behalf of Enron Power. I'll move this along.

Bob Reilley, the Director of Regulatory Affairs for Enron Power, prefiled comments with attachments and exhibits in this docket. Those comments and exhibits are part of Composite Exhibit 1 and are part of the record in this rulemaking.

Mr. Reilley is prepared to briefly summarize his testimony and answer questions if appropriate.

CHAIRMAN DEASON: Please proceed, Mr. Reilly.

ROBERT REILLEY

appeared before the Commission and testified as follows:

MR. REILLEY: My name is Bob Reilley. My business address is Post Office Box 1188, Houston, Texas 77251.

By way of introduction, Enron Power is one of nation's largest nonutility power generators. We operate about 3200 megawatts of generating capacity in this and three foreign countries.

Given our vital interest in utility planning issues and the power market in Florida, we have been involved in this rulemaking since January, and I appreciate the opportunity to appear here this afternoon.

Any of the proposed rules would be an important step forward from the current situation. I only have a few comments related to those rules. They deal mostly with the goal of the process rather than specific wording.

First, as is proposed by the Staff, the final rule adopted by the Commission should reflect the importance of both price and nonprice factors, such as reliability and dispatchability.

Second, face-to-face negotiations between the

power supplier and the purchasing utility are the best way to assure that a long-term business relationship, like that that we enjoy with our customers, develops.

Additionally, negotiations better reflect the operation of a competitive market than a mechanical scoring mechanism.

Third, we think that there is merit to a bifurcated need determination process. And perhaps we have some notice problems that I'm confident can be worked around one way or another. But responding to a major request for proposal often requires the expenditure of hundreds of thousands of dollars. And before competitors are willing to do that, they need to have some assurance that the Commission indeed will find that the capacity is needed. Essentially, I think with a bifurcated process you'll have a broader response to a RFP, and more competition means lower prices for ratepayers.

Our main interest in this proceeding is really the Section 712 issues. The most important point I'd make is that we believe the Commission should not adopt generic standards in this docket. Instead, should adopt a case-by-case approach to these matters, as is suggested by the Staff in their proposed rules.

We believe that a case-by-case analysis will

allow greater flexibility, more innovation and ultimately lower prices than if competitors are forced to operate under potentially irrelevant generic standards.

Should the Commission elect to pursue these matters on a case-by-case basis they really don't have to make any decisions on these issues at this time. However, in light of all you have heard so far, and I imagine what you're going to hear later today and tomorrow, I would like to briefly outline our position on each of these issues.

First, I think it's important to remember that power purchases and construction must be compared to one another, not look purely at the risk of purchase. Power purchases are not risk free but they are less risky to utilities in the construction and generating plants. Well-crafted contracts -- and I'll be happy to provide one -- and the contract preapproval process and capacity cost recovery mechanism provided by this Commission eliminate virtually all of the theoretical risks identified by the utilities.

Consider that when a utility builds a power plant, it and its ratepayers are the only parties available to share the risks. When power is purchased, the power supplier assumes considerable risk leaving

less for the utility and its customers.

Lots of the arguments that you hear on this matter are based on financial theory. Let me give you a real-world example that I believe demonstrates the risk of purchasing versus building capacity.

Texas-New Mexico Power Company is an investor-owned utility that used to be 100% reliant on purchased power, including the considerable amount purchased from nonutility generators. During that time TNP enjoyed stable single A bond ratings.

In the late 1980s, about five years ago, TNP began construction of a two-unit lignite-fired generating unit that currently serves about one-third of TNP's load.

The financial and regulatory problems associated with constructing that plant have caused its ratings to drop to the double B level, well below investment grade, despite the fact the Texas Commission has provided two sizable rate increases.

So I think the example provided by the construction of this plant clearly demonstrates the risks that are associated with construction versus the purchase of capacity.

On the second issue, I do say briefly, that in our view there is no credible evidence that the

capitalization exempt wholesale generators has any impact on the reliability of power supply or represents any sort of unfair advantage over utilities.

Enron Power believes that the merits of nonutility generation should be based on the cost of power to ratepayers and operational factors, especially reliability.

Speaking to reliability, there's a study cited in our written comments by the Gulf Coast Cogeneration Association. And that study demonstrates that in Texas and Louisiana the cogeneration facilities have been in operation there, some for up to 50 years, have an availability factor of 95%. And that very high level of reliability has been achieved with absolutely no regulatory oversight of the financial capital structure of those cogenerators. On the third issue, I don't believe this point is controversial, but essentially, we believe there's no need for any additional preapproval mechanisms other than those that are currently in place or would be put in place as a result of the rules that you're considering.

Finally, on the fourth issue, we maintain that it is inappropriate to impose any fuel supply requirements on nonutility generators that are not imposed on utilities. All power suppliers operate in the same

fuel markets and have access to the same means to ensure an adequate fuel supply for their generating facilities.

In conclusion, I would refer you to our written comments which provide considerable more detail on our positions on each of these issues.

Thank you. That concludes my summary and I'm available to answer your questions.

CHAIRMAN DEASON: Questions for Mr. Reilley.

MR. CRESSE: Mr. Chairman, I think I have two questions.

CROSS EXAMINATION

BY MR. CRESSE:

Q You're not a member of CEPA; is that correct?

A Yes, sir, that's correct.

Q You disagree with CEPA on the question of negotiation; is that correct?

A Yes, we do. We believe that competitive negotiations has a place in power procurement.

Q Would you explain to the Commission the benefits that you see from a that, please?

A Well, the two that I just mentioned are, first, that negotiation is how deals are cut in the real world in competitive markets. And to the extent that regulation is attempting to be a substitute for competition, it just makes good common sense to include

a basic element such as negotiation.

Secondly, we're talking about long-term power supply contracts here, and that means a long-term business relationship which everybody wants to be successful. And we don't think that it's possible to -- well, we think it's unlikely, I think is a better way to put it, to create such a long-term business relationship if one party is dragged to the table kicking and screaming.

Q It's kind of like a shotgun wedding?

A Just a little bit, yes, sir.

Q Thank you. No further questions.

CHAIRMAN DEASON: Questions?

CROSS EXAMINATION

BY MR. NEISER:

Q Mr. Reilley, Dick Neiser with Florida Power.

I am just wanting to know whether you have had any opportunity to discuss your belief that there is no impact of the cap structure of a utility with purchased power with any of the rating agencies. And do you just disagree with them, or are they wrong from your viewpoint?

A Well, I don't believe that I've testified there's no impact to the capital structure of the utilities. Could you refer me to a specific passage in,

my comments?

What I've testified to is that there is less risk and, therefore, less impact on the cost of capital of utilities when they purchase than if they build.

Q My question really is, should a cost be assigned to the purchased power bid for this, quote, "hidden cost" of the impact to the utility's capital structure resulting from purchased power?

A Only if a similar cost is added for the hidden cost associated with building a new generating facility. And I think if you're going to be adding such a cost on the purchase side, and adding such a cost on the build side, perhaps we'd be better off just to ignore those costs.

Q All right. So you're not denying that there is that cost impact. You're just saying it perhaps is less than if the utility chose to build.

A That's correct, yes, sir.

MR. NEISER: That's all I have.

CHAIRMAN DEASON: Mr. Moyle? Staff? Commissioners? Mr. Reilley, you've done something that I've been wanting a witness to do all day.

MR. REILLY: Glad to be of service.

(Mr. Reilly excused.)

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CHAIRMAN DEASON: And that's finished within five minutes. Thank you, sir. Glad we could accommodate you.

I've had a request that we take Mr. Tim Woodbury out of order to accommodate him. I would certainly like to accommodate him if at all possible, but there may be some objections to that. Are there any objections? Hearing none, Mr. Woodbury.

MR. MELSON: Mr. Woodbury is Director of Corporate Planning with Seminole Electric Co-op. He has filed both direct and rebuttal comments, and I'm going to ask him just to briefly summarize his comments and then ask any questions that the parties or Commissioners may have.

TIM WOODBURY

appeared before the Commission and testified as follows:

MR. WOODBURY: Good afternoon. Seminole is the -- I guess in the words of Mr. Cresse, started all of this. We were the first co-op in the country to engage in independent power bidding. We were the first utility in this state to do it. We did it without anyone telling us to do it, and we did it without anyone telling us how to do it.

Seminole's comments on both the Commission's proposed rule and the Staff's proposed alternative rule,

are based on our experiences from our two prior bid solicitations.

One of those solicitations was initiated in 1988 and resulted in the award to TECO Power Services, an independent power producer, in 1989, for approximately 440-megawatts of capacity, which went on line in January of 1993. The other solicitation was initiated in 1990 and has resulted in a award in 1993 to a consortium of Westinghouse and Black and Veatch for the turn-key construction of a combined cycle unit with an expected in-service date of January of '99.

Seminole endorses the Commission's proposed rule. The proposed rule provides utilities with the flexibility to conduct a sound bidding process that protects the interest of all stakeholders. But most importantly, the consuming public, whose interest is to ensure that utilities obtain reliable low cost power supply resources to meet their needs.

In my written comments, I note that there appears to be some ambiguity as to the timing of the required point of entry for the NUGs into the bidding process. The rule says, "Within two years of the start of construction." Our experience shows that the bidding process must start substantially before two years prior to the construction start date, and we have

suggested some language in my prepared comments to address this point.

Seminole also endorses the provision of the proposed rule that prohibits NUGs that did not participate in the process from contesting the result in a need determination hearing.

As to the Staff's alternative rule, Seminole has a number of concerns. First, we object to the requirement that the utility provide detailed pricing information on its billed alternative to prospective bidders. We believe this requirement may have the undesired effect of precluding parallel turn-key capacity solicitations.

Second, we object to the requirement to specify in the RFP the detailed evaluation criteria and methodology for ranking and scoring alternative generation proposals. We believe that this requirement, as well as the early requirement I just mentioned to provide detailed pricing information, will promote gamesmanship among bidders.

We also know from experience that it is extremely difficult to anticipate up front all of the unique features of various proposals that will be considered in making the evaluation. We believe the process should be flexible enough to give utilities a

leeway to adopt the evaluation process to meet -- to adopt to the evaluation process to meet legitimate needs. A rigid cookbook approach is counter to the public interest.

Finally, we object to the requirements that preference be given to certain types of facilities. Seminole questions the Commission's authority to require nonregulated utilities such as Seminole to give preference to high efficiency cogenerators, solid waste facilities and renewable energy resources.

As a nonregulated utility under PURPA, we're only required to purchase at our avoided cost. Requiring preference be given to any one bidder would appear to require purchase at greater than net avoided cost.

Apart from the unfairness of imposing higher costs on consumers, Seminole notes that the Commission may well put Seminole in a position of being able to obtain other necessary approvals. REA must approve any power purchase agreement resulting from a bidding process. REA has issued rules on bidding.

REA's rule require that we select the least-cost alternative.

The proposed alternative rule creates the opportunity for Seminole to be in the untenable

position of having REA refuse to approve a higher cost contract, yet having this Commission refuse to approve the need determination for the lowest-cost alternative.

My last comment relates to either the proposed rule or the alternative rule.

Seminole believes that any rule adopted by the Commission should make it clear that it does not apply to any utility that has begun a bidding process prior to the rule's effective date.

That concludes my summary.

CHAIRMAN DEASON: Questions for Mr. Woodbury.

CROSS EXAMINATION

BY MR. CRESSE:

Q Tim, let me ask you a question in terms of relation to Page 3 of your testimony.

A Yes, sir.

Q Those three steps are a brief outline of the procedures you follow; is that correct?

A Yes, they are.

Q Are those the procedures that you followed in your 1988 application to this Commission?

A Yes, sir.

Q Did it result in a satisfactory relationship between you and proposed bidders?

A Yes, sir.

Q Did that procedure receive REA approval?

A Yes, it did.

Q Did that procedure receive approval of the Public Service Commission?

A Yes, it did.

Q Do you see any reason to change it?

A It also received approval of the Federal Regulatory Commission, and I don't.

MR. CRESSE: No further questions.

CHAIRMAN DEASON: Mr. Neiser?

MR. NEISER: None.

CROSS EXAMINATION

BY MS. BROWNLESS:

Q Mr. Woodbury, in that 1988 need determination case which resulted, I believe, in TECO Power Services providing you with capacity; is that correct?

A Yes, sir.

Q Did you reveal your costing information when you filed your need determination application initially in that process?

A Could you repeat that for me?

Q Did you reveal your build option for two, 220-megawatt combined cycle units, I think, when you filed your need determination application initially with the Commission?

A Well, initially, we went into the Commission with the idea that we were going to go with two, 220-megawatt units. At the same time, we had put out an RFP and we did not have the results of that RFP yet, and that's why the Commission bifurcated the hearing.

Q Right. But in the materials that you filed initially, did you file your avoided cost information, the pricing information that was associated with your build option, which were two, 220-megawatt units?

A I think in that proceeding, in the initial docket, we probably did include our estimates of the cost of those two units.

Q And then your -- and you had -- I think by that time had developed a short list of bidders, had you not?

A To be quite honest with you, a test to my memory on that, I really don't remember.

Q Well, you certainly hadn't gotten through the bidding process.

A We had not gotten through the bidding process, I know at that point we had a couple of people that we were talking to, I just don't remember whether or not we notified people on a short list or what.

Q Okay. The people that you were talking to at that time would have had access to that information

filed at the Commission because that would have been public record; would they not?

A Yes, but I don't think what we filed with the Commission necessarily represented the lowest cost. We weren't saying that that was necessarily the final price for that -- if it had come in lower, we would have obviously built it for lower. We don't have any incentive to not take -- build things for the lowest possible cost.

Q But there were reasonable planning assumptions that allowed you to develop that --

A Sure. Well, in all of our RFPs we do indicate what our intent is to the bidder as to what Seminole's build alternative is contemplated to be, and we let people know if it's a combined cycle unit and what we expect to operate it at. We think that's helpful information to them.

Q Right. But those reasonable planning presumptions are not necessarily your fine-pencil price were you to build that facility?

A Well, in our 1990 solicitation the fact that we simultaneously -- and it's part of the same solicitation -- included turn-key offerings, we attempted to address coming up with the best market-based price for our own build alternative by

including turn-key in that solicitation.

Q But one couldn't have gotten that information from the planning assumptions is my point.

A Excuse me?

Q You did the turn-key solicitation at the same time that you did the RFP capacity solicitation in order to fine-tune your assumptions; is that correct?

A I'm not sure we're talking about the same RFPs. For 1990, the one that we're currently engaged in, the one that we just issued an award, we had one RFP. And in that RFP we sought purchase power options, as well as turnkey options for the construction of 440-megawatts of combined cycle that would represent Seminole's ownership option. When all the bids come in, we get turnkey options, purchase power options, we compare them and we make decisions.

Q But I guess -- I mean I have a simple point to make here: That the planning assumptions that you provided as a routine part of your filings in the 1988 case, and the planning assumptions you provided as a routine part of this latest solicitation for people who participated in your RFP, do not necessarily correlate to your, your price to build that capacity.

A Well, we haven't filed anything yet in the 1990 solicitation and that, I think, is part of your

question. Maybe I'm trying to address --

Q You're putting too much in this. Let me ask it this way: Did TECO Power Services come in with a cheaper option, and the most cost-effective option in your opinion for the first bid?

A That's why we went with them, yes.

Q And they had the planning assumptions that were revealed, had they not?

A TECO has some witnesses here probably that can address what they used in making their proposal, but they had -- at least had access to the first docket relative to Seminole's two 220-megawatt combined cycle unit options, yes.

MS. BROWNLESS: Thank you very much.

CROSS EXAMINATION

BY MR. BALLINGER:

Q Tom Ballinger with the Commission Staff. I have one question. You mentioned disclosing your price would preclude turnkey proposals. Can you explain that?

A I'm sorry, could you repeat that?

Q Yes. You mentioned that disclosing a utility's price, if Seminole put out its best price, that that would preclude it from accepting turnkey proposals.

A I hate to be dense, but I'm missing the last part of your -- I do have a hearing problem, so you'll

have to bear with me.

Q Okay. You stated earlier that if Seminole disclosed its price of an RFP, that that would preclude any turnkey proposals from being submitted. And I'm trying to tie those two together. Why is that so?

A Well, it's hard for us to imagine how we could disclose what our price was until we had gotten it. In other words, the turnkey responses represent the Seminole price.

Q I understand that, but why does that preclude them from submitting a bid?

A No, it precludes -- if we have to include that price in our RFP, I don't see how we can do that if we haven't gotten it yet. In other words, the turnkey is the result of the RFP process, yet you're asking us to file what that result is as part of the RFP. That's at least the way we interpret it.

Q No, I understand that a turnkey proposal would become your build option. I understand that. I guess maybe I'm reading too much into it. Why -- what would preclude Seminole from taking its best guess of building it itself, not as a turnkey proposal, but still accepting turnkey proposals as an alternative? It would still be both Seminole-built options, but --

A If you're asking why couldn't we include in

the RFP "We think that it's going to cost us X hundred million dollars to build a combined cycle unit, although we don't know what it's going to cost because we haven't gotten the results of the turnkey bid," I suppose one could do that. I suppose, though, that any IPP in the business has a fairly good idea of what it costs to build a 440-megawatt combined cycle unit.

Q Well, that's what I'm getting at.

A And I don't think they really need our help in that regard. I hope they don't, otherwise they shouldn't be bidding.

Q That's all I was getting at. It seemed to be that if the Commission's rules required a disclosure of your price, that that would preclude turnkey proposals representing a build option and --

A I don't think that including that number that I gave you would be disclosing our price. I mean, what I would do would be able to give them some EPRI tag number or something that's a generic, but I, you know --

Q Well, do you also understand --

A I'm sorry?

Q Do you also understand that it's Staff's intent of their alternate rule to not hold the utility to that price that it discloses, that that is --

A Well, those are the kinds of clarifications,

I guess, we were looking for. We didn't read that into what Staff said. We read it as Staff wanted included in the RFP the utility's price for its own build option. And we think that that is precluded if you're going out and soliciting turnkey options at the same time.

MR. BALLINGER: Thank you. That's all.

COMMISSIONER CLARK: I didn't understand that. Go through that again.

MR. BALLINGER: The Staff -- well, I don't know how far you want me to go. The Staff's proposal, or the alternate proposal, while it says to disclose a price, it is not a fixed price, it is not a bound price. That is why the intent to having negotiations at the back end to fine tune it; also the utility still maintains the ability to come in, in a rate case or whatever, to -- if there were cost overruns, to justify those things it see. So it's not a bound price. And I know that was brought up in comments, and I wanted to make that clear, that is not the intent of that.

MR. WOODBURY: If I could just say one thing. I guess the one thing I would be concerned about is that anybody being misled that that price had any meaning. I wouldn't want someone to say, "Well then I guess then if I come in a couple of dollars below that, I've made it to the short list." I just don't think

it's helpful to put numbers in RFPs that have no meaning.

MR. BALLINGER: I understand.

CHAIRMAN DEASON: What does Staff believe is the purpose or the benefit of having those numbers included in the RFP?

MR. BALLINGER: In my opinion, at that time, it is the utility's best estimate of what they can build a plant for. What you're saying is they can't do that if they're going to do a turnkey proposal as their build option, as opposed to them contracting it themselves.

COMMISSIONER CLARK: And why can't they do that, if that's going to be their build option?

MR. BALLINGER: I think they can. And I don't understand why if they disclose their best estimate of doing it, why a turnkey proposal can't come in and beat that it. That's all I'm having trouble with your statement of saying that it would preclude that, and I want to know how. I don't want to preclude it, I guess, is what I'm saying, and I want to find out how to do that.

MR. HUDDLESTON: Commissioners, one thing I've found out over the -- I've been heading up Seminole's IPP process for a while now, and I've dealt with a lot of independents and QFs. And the one thing

I've found is that they are not interested in Seminole getting the lowest cost alternative for its members. They're really interested in winning the deal at one dollar lower than the next lowest cost alternative. I'm interested in making sure that we get the lowest cost deal for our members. And if I put out a bogey price, I think I'm promoting bidders to possibly use that bogey price to maybe not come in as low as they might otherwise come in. And I don't want them to extract that rent; I want to extract that rent.

Q (By Mr. Ballinger) But doesn't that -- when you say -- I agree with you, I wouldn't want a utility to put out a bogey price either, but isn't that a decision made up front that the utility's build option will be a turnkey proposal as to a utility-built proposal?

A We made that decision at Seminole in this last bid solicitation that if we built, it would be through turnkey, yes.

Q Okay. So that's a conscious decision before an RFP would be let?

A That's what we did. I don't think that has to be the way to do it, though. I think other utilities can reasonably choose to not go the turnkey route.

Q But does that necessarily mean that the turnkey route is always cheaper than a utility doing it itself?

A No, it doesn't. I think that there's some risk that you -- you never know. I mean, if you don't go the other way, you don't know what the price would be. We decided in this case, because there had been questions in our '88 solicitation as to, well, how did we know what the market price was for Seminole building two 220-megawatt combined cycle units? And we couldn't answer how we knew for sure. We had our best engineering estimates. We decided in this solicitation was to let the market tell us what it's going to cost, and that's the way we went.

MR. BALLINGER: Thank you.

COMMISSIONER CLARK: I have a question. If the rule requires you to disclose the price at which you're willing to be the owners of it, will a turnkey -- will anyone who would propose a turnkey operation to you be willing to provide you that price, and that information, knowing that you're going to turn around and bid it?

MR. WOODBURY: My experience is that they don't want their proposals disclosed anymore than the IPPs or QFs want their proposals disclosed. So, no, I don't think they would like that. And as a matter of fact, what it would do is it would require two -- it would extend the period of time, because we would now

have to go out for a bid solicitation for turnkeys first, get the best turnkey estimate, put it in an RFP and then go out for the best purchase power alternative. So we would end up with two RFP processes, I suppose. And we try not to --

COMMISSIONER CLARK: So as part of any bidding process, turnkey proposals ought to be allowed and they ought not to have to be disclosed ahead of time?

MR. WOODBURY: I think they shouldn't have to be disclosed at anytime until we get to the Commission with a need determination, if it's our best option, and justify to you that we've got the most cost-effective proposal.

COMMISSIONER CLARK: In your exchange you had with Ms. Brownless, I understood her questions to try to solicit your concurrence that information about what type of need and how you would intend to fill it needs to be disclosed, so people can bid.

MR. WOODBURY: Commissioner -- and in my written testimony I've said I think that's a helpful thing to do, is to give a general understanding to the IPPs of what your intentions are, without giving estimates of how much it's going to cost to build it; let them know your plans are, the plant capacity factors. We do that, and we've done that in both of our RFPs.

COMMISSIONER CLARK: Do you know if the information you give out is comparable to what Mr. Seelke has suggested be presented?

MR. WOODBURY: My recollection is is that Mr. Seelke went far beyond anything that Seminole would include in an RFP.

COMMISSIONER CLARK: Okay.

CHAIRMAN DEASON: Further questions? Thank you, Mr. Woodbury.

(Mr. Woodbury excused.)

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MR. ERWIN: Excuse me, Mr. Chairman.

CHAIRMAN DEASON: Yeah.

MR. ERWIN: I apologize for having to ask this. But I do have one witness who has indicated to me that he would not be able to remain in Tallahassee for tomorrow. I wondered if there was any possibility of having him testify? I think it would be very brief.

CHAIRMAN DEASON: This is --

MR. NEISER: This is Mr. Sharma, Kissimmee Utility Authority.

CHAIRMAN DEASON: Is there any objection to taking Witness Sharma at this time?

MR. NEISER: Mr. Chairman, how late do you envision us going this evening?

COMMISSIONER DEASON: We're going to go 18 more minutes.

MR. NEISER: We have no objection then. (Laughter)

MR. SHARMA: So I'll be here just 18 minutes.

CHAIRMAN DEASON: Sounds good.

MR. SHARMA: Thank you.

ABANI KUMAR SHARMA

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. ERWIN:

Q Mr. Sharma, could you please state your name and address and your employer?

A Yes, my name is A. K. Sharma, and generally I'm known as "Ben." My business address is 1701 West Carol Street, Kissimmee, Florida 34741. I work for Kissimmee Utility Authority as the director of power supply.

Q Mr. -- Excuse me, Mr. Sharma, did you file -- prefile some testimony in this docket, both in response to the original rule and the comments of Mr. Ballinger?

A Yes, I did.

Q And are you able to give the Commission a brief summary of your comments?

A I certainly will do it. In fact, the primary point in my testimony is to prove that we believe that this bidding rule is not for the municipal utilities.

We should not be subjected to these bidding rules. And to prove that, I have three points to prove. And the first one is that municipals can finance a project with tax exempt bonds. The interest rate for municipal bonds are much lower than that of either investor-owned utilities or independent power producers. For instance, Kissimmee Utility Authority, last week, we sold a $20 million bond issue at a true interest cost of 5.36%, which is real low. Therefore, it is very unlikely that the bidding procedures will result in any less expensive power than the municipal utilities can produce themselves.

The second point to prove is that governing bodies of municipal utilities have no motives for profits. Their only objective is to provide lowest cost reliable power to the ratepayers. Therefore, the governing body of any municipality will not take the decision to build new generating facilities unless it is the lowest cost option.

As a result, a bidding rule will only add cost to the municipal utility's selection option process. Actually, that is, if I recollect, when we went in for a Stanton Tool OUC, we are participants in Stanton Tool, OUC, and we all went out for solicitation process, and that cost more than $200,000, and to no avail.

My third point is as a relatively small utility, in the past, KUA, that is Kissimmee Utility Authority, has benefited from its ability to quickly respond to offers from other larger utilities for joint ownership and purchase power agreements. Such offers remain available only for short periods of time. If KUA has to go through a bidding procedure every time it evaluates an offer, there may be quite a few lost opportunities and lot of unnecessary costs.

Before concluding my testimony, I like to add that in the event the Commission decides not to exempt the municipalities from the bidding rule, at least the final rules should clarify in more details few issues that I have described in my prefiled testimony. Namely those are -- one is that the requirement of a point of entry within two years. Two is, I think -- want to give -- would necessarily mention, it should be not less than two years, or something to that effect, because two years sometimes is not long enough time if the utility has to build something of its own because of the environmental licensing and permitting time requirements.

The second thing would be the requirement of having a signed purchased power agreement within one year from the beginning of the selection process. There again, many times, the negotiations go on. So to

stipulate to one year, we do not think it is proper to have that kind of clause.

And the third one is the requirement of maintaining a list of nonutility generators, because, there again, you know, you treat it like even ours, we are a small utility, we almost know what's going on in every department. But many times nonutilities and other municipalities may contact, sometimes me, sometimes somebody else in another department. So not having the proper procedure on how to keep that list, it may cause problem. So those are a few things that needs to be clarified in our appointed rule.

This is my brief summary of my testimony. If anybody has any question.

CHAIRMAN DEASON: Questions for Mr. Sharma?

(No response.)

CHAIRMAN DEASON: Staff?

CHAIRMAN DEASON: Thank you, Mr. Sharma.

MR. SHARMA: Thank you, very much.

(Mr. Sharma excused.)

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CHAIRMAN DEASON: Thank you, Mr. Erwin.

I take it that the next witness is Mr. Wright. Mr. Wright, I anticipate your testimony taking more than 12 minutes.

MR. WRIGHT: That is up to interrogators, Mr. Chairman.

CHAIRMAN DEASON: Okay. I think now would be a good time to break.

MR. CRESSE: Excellent idea.

CHAIRMAN DEASON: In all seriousness, I don't -- if your testimony is going to be short, I'll be glad to take it this afternoon, but I don't think it's going to be. Do we have an indication? Are there going to be questions for Mr. Wright?

MR. CRESSE: Mr. Chairman, he will not get through in 12 minutes.

CHAIRMAN DEASON: Okay. Very well. That's what I anticipated.

COMMISSIONER CLARK: Not if you have anything to do with it, huh?

MR. CRESSE: If you allow reasonable questions, I should have added.

CHAIRMAN DEASON: We're going to begin tomorrow morning, like we did this morning, at 8:30 a.m.

MR. MOYLE: Mr. Chairman, do you have any indication of how we will -- the presentation tomorrow, who will go?

CHAIRMAN DEASON: Well, we're -- according to -- we're going to still go down the same list and we'll

be hearing from the competitive providers --

MR. MOYLE: The investor-owned utilities will come after Mr. Wright?

CHAIRMAN DEASON: That's my understanding. Well, unless there are others in the nonutility generators who are not part of your organization who still wish to present their comments.

MR. McGLOTHLIN: We were interested in knowing whether the IOUs have designated who is going to go in that order?

CHAIRMAN DEASON: Yes, the IOUs will follow the nonutility generators.

MR. MOYLE: I mean, who will -- of the IOUs, what will the order be?

CHAIRMAN DEASON: Oh, my tentative list shows Florida Power Corporation, Gulf Power, TECO and then Florida Power and Light.

We will conclude for today and we will reconvene tomorrow morning at 8:30.

(Thereupon the hearing adjourned at 4:50 p.m., to reconvene at 8:30 a.m., October 1, 1993 at the same address.)

(Transcript continues in sequence in Volume V.)

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	
Proposed Amendment of Rule 25-22.081, F.A.C., Contents of Petition; and Proposed New Rule 25-22.082, F.A.C., Selection of Generating Capacity.	DOCKET NO. 921288-EU

THIRD DAY - MORNING SESSION

VOLUME V

Pages 565 through 684

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN J. TERRY DEASON COMMISSIONER SUSAN F. CLARK COMMISSIONER LUIS J. LAUREDO COMMISSIONER JULIA L. JOHNSON
DATE:	Friday, October 1, 1993
TIME:	Commenced at 8:30 a.m.
LOCATION:	FPSC Hearing Room 106 Fletcher Building 101 East Gaines Street Tallahassee, Florida 32301
REPORTED BY:	JOY KELLY, CSR, RPR Bureau Chief SYDNEY C. SILVA, CSR, RPR PAMELA A. CANELL Official Commission Reporters -and- LISA GIROD JONES, RPR, CM

APPEARANCES:

(As heretofore noted.)

FLORIDA PUBLIC SERVICE COMMISSION

DOCUMENT NUMBER-DATE
10907 OCT 12 93

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P R O C E E D I N G S

(Hearing reconvened at 8:30 a.m.)

(Transcript continues in sequence from Volume IV.)

CHAIRMAN DEASON: Call the hearing to order please. Mr. Wright, I see, has already taken his place before somebody gets in front of him.

MR. WRIGHT: Okay. The light wasn't working, Mr. Chairman; I wasn't sure whether the microphone system was on.

CHAIRMAN DEASON: I think your microphone is on.

MR. WRIGHT: Yes, sir, thank you.

CHAIRMAN DEASON: Just go ahead and proceed, Mr. Wright.

MR. WRIGHT: I'm both my lawyer and my presenter this morning

CHAIRMAN DEASON: Maybe that will speed things up.

ROBERT SCHEFFEL WRIGHT

appeared before the Commission and testified as follows:

MR. WRIGHT: I hope so. I don't plan to object to any questions. My name is Robert Scheffel Wright. I'm employed by the law firm Fine, Jacobson,

Schwartz, Nash & Block, Tallahassee. I've represented ARK Energy in various matters for about three years, and in the absence of Mr. Siderewicz who filed ARK's comments in this proceeding, I've been asked to make a brief presentation in ARK's behalf. I'll proceed to do that and answer any questions thereafter.

Thank you for the opportunity.

ARK filed a proposed rule in March of this year and also filed responsive comments on September 20th. I have discussed with Ms. Rule the responsive comments which were filed in letter form and she's assured me that they have have been incorporated into the record of this rulemaking proceeding.

ARK basically believes that the Staff's alternate draft is a reasonable starting point for establishing a workable framework for bidding, and ARK does suggest several modifications to improve Staff's alternate draft. I'd like to summarize these and then hit the high points, and then I'll take questions.

The first suggestion would define "avoided unit," for the purposes of the bidding rule, as any capacity additions including repowering, refurbishment and so on, of more than ten megawatts.

The second suggestion would substitute the word "finalization" or the phrase "contract

finalization" for the term "negotiations" in the rule. The point of this suggested change is to reflect ARK's belief that the bidding, or RFP process, as implemented pursuant to this rule should produce a winner or winners rather than a set of finalists for subsequent negotiations.

CHAIRMAN DEASON: What's the distinction you're trying to make there? I don't really quite follow that.

MR. WRIGHT: That the bid process, when scored, should produce a winner or winners to serve the identified need, as opposed to -- resulting in a set of finalists who would then proceed to further negotiations. This was one of the high points I wanted to hit, and I'll go ahead ahead and explain why I think this is important right now.

I fear that if you come out with a set of finalists for negotiations, rather than winners determined by an objective scoring system, you will see the following scenario. Let's say there are five finalist seats selected for negotiations. The utility will negotiate with one, two, three, four or five, but eventually it will hone in on wanting to negotiate with one. I foresee that the other four will keep coming to the utility and saying, "We can make you a better deal.

You want it bigger, we can make it bigger. You want it smaller, we can make it smaller. You want a lower price, we've got a lower price." The utility may be in such a position in its negotiation process that it does not want to talk to these folks, and yet, they the clearly, by the terms of the Staff's rule, and I think the other rules on the table in this proceeding, have standing to come into any subsequent need determination proceeding -- well, not the CEPA rule, because that would be done at the end of the bid disputes. They would have standing to come into the need determination proceeding and say, "We were a finalist; we tried to make better offers; they wouldn't listen to us. Here's our better offer." And it may well be cost effective.

And frankly, I'm afraid you will be right there in a need determination with the unsuccessful negotiators potentially knocking out the number one. And depending on how you're going to continue to interpret your rules, and Section 403.519, you may or may not get a winner out of the need determination.

CHAIRMAN DEASON: You mean we would have a process similar to what we have in Cypress?

MR. WRIGHT: I'm afraid that that is possible, Mr. Chairman, yes, sir. And a real simple point is this: I think that when you tell my client

and the other nonutility generation developers that this is their chance to lay their best price on the table, they will do it. If you tell them that they must do it in their response to the RFP, they will do it at that point. If you tell them that they must -- that all they have to do in response to the RFP is satisfy qualification criteria and have a price that's within a reasonable range of the lowest price so that they can go on to the next round of negotiations, they will probably do that. And then at some point down the line, and it may well be the first day -- it won't be the first day, but it will be the testimony filing date in the need determination proceeding, then they'll give you their best price.

ARK also suggests some procedural changes to the rules, including that the Commission use the information submitted in the utility's ten-year site plans as the starting point for proceedings to procure needed additional capacity; that the Commission open one docket to address each identified need, and that the Commission give an early point of entry to all affected persons, parties, et cetera, and approve the RFP on the front end of the process.

ARK makes some other procedural changes, including requiring an independent evaluator to score

and rank the bids if the utility issuing the RFP or a sub of that utility wishes to submit a bid in response to the RFP.

ARK's suggestions would expand subsection 6 of the rule to provide more specific procedures regarding evaluation and scoring of proposals and resolution of disputes as to scoring assigned by the evaluating party.

ARK also suggests strengthening the waiver provision of the rule by requiring a utility to seek a waiver from the general requirement to bid -- by requiring the utility that seeks a waiver from the general requirement to bid to demonstrate by clear and convincing evidence that the -- that not following the bidding procedure would be contrary to the public interest.

ARK's proposal would also provide what we consider to be a meaningful financial incentive to utilities to pursue competitive procurement of new generation resources by authorizing the Commission or by declaring that the Commission would have the authority to grant an incentive reward, if you will, of up to 10% of the differential between the final price paid to the nonutility generator and the utility's otherwise avoided cost.

COMMISSIONER CLARK: What was that incentive for?

MR. WRIGHT: To encourage them to bid, to encourage them to use the process.

COMMISSIONER CLARK: Encourage the utility to use the process?

MR. WRIGHT: Yes, ma'am. For example, in round numbers, ARK's contract in the Pahokee case offered nominal revenue requirement savings of about $1.5 billion over the life of the contract as compared to the Cypress contract. In the context of this incentive, had it gone to a bid, let's say FPL's avoided cost was slightly higher than the Cypress avoided contract, FPL would have been eligible, subject to Commission approval, to receive an incentive payment on the order of $150 million over the life of the contract, again subject to your approval. If you all didn't think it was appropriate in a given case, you wouldn't have to give it. It's permissive, not mandatory.

The final proposed change would simply assure that any decision allowing the utility to build its own unit would not wind up costing ratepayers more than the projected or proposed cost of the unit upon which the decision was based. So if the utility comes in and

says, "We want to build Unit X," and it's -- let's say the present worth revenue requirements of that unit over its projected life are $2 billion, and there are other options on the table in the 2.1 to $2.2 billion range in present worth revenue requirements, there's no argument that the utility's proposed unit in that context is the most cost effective, and it's the one that should be built. What I think the Commission should strive to avoid is making that decision and then letting the utility add costs in down the road where they wind up being greater than the next best alternative, whereas the ratepayers would have had the certainty of the contract price with one of the slightly higher proposals.

In conclusion, I mention in the course of my testimony one of our main points, and that is that we think the bid process ought to produce winners by an objective system, by an objective scoring system that is known to all on the front end.

My second major point is that Public Service Commission involvement on the front end of the process is, in my opinion, and in ARK's opinion, essential to achieving closure on the back end of the process. I don't think that a process that predicates a party's participation in Public Service Commission proceedings

on prior participation in an undocketed bid proceeding run by a utility satisfies the point-of-entry requirements of Florida administrative law. And, in effect, I think it would delegate a developer's point of entry to the utility requiring that they exercise that point of entry in the bid process. If they subsequently come in -- you know, say they've got a better project -- I don't see how under Florida's administrative law, you can keep them out. And frankly, I think that having the Commission approve the RFP on the front end, would: A, not be all that difficult; and B, would benefit everybody, would let all the developers know what the rules are and it would give y'all and the utility assurance that if the RFP process were followed as approved by the Commission, that on the end there would be no further challenge to it. The only thing that would possibly be challenged under that scenario is the actual scoring.

COMMISSIONER CLARK: Well, if that's the case, why do we need a third party to review it when the utility is also bidding? It seems it me if you set out the parameters, the utility can go ahead and evaluate every project, including yours, because they're going to have to justify the one they chose to us. In other words, they make the first cut at it, but

we're still going to look at it. Why do we need a third party? Because there will be a review of how they reach their decision.

MR. WRIGHT: I think that the third-party evaluator will help you avoid some back-end reviews.

COMMISSIONER CLARK: Aren't we the third-party evaluator?

MR. WRIGHT: Well, frankly, that's how I think it ought to work, Commissioner Clark. I think the Commission ought to be a third-party evaluator, and if you need a contractor to assist you in doing the evaluation, then that's how I think you ought to do it.

COMMISSIONER CLARK: Why shouldn't the utility make the first decision and then we review that? And everybody has that point of entry at the time they come in and say to us, "This is what we need and this is how we propose to fill that need"?

MR. WRIGHT: If the scoring criteria were 100% objective, that would probably work, but even with objective criteria where there are ranges of points to be assigned to individual factors, there is going to be some room for subjective assignment of points. And frankly, my expectation is that most developers are going to bid fairly similar projects, and it really will come down to price competition. But depending on

the weight assigned to nonprice factors, there could be an extra quarter of a point here or an extra half point here for whatever factor you're talking about, and that could make the difference.

In a case where the utility says, "Well, we're going to give our sub's bid an extra half a point, and not the NUG projects -- you know, we'll give them seven out of ten, we'll give ourselves seven and a half out of ten." Whether that's right or not, it's going to be very hard for you all to say at that point that what the utility has done was unreasonable, even though it may have been unfair. And I think that having a third-party evaluator going into the process will take that type of problem out of the realm.

COMMISSIONER CLARK: How is "unreasonable" different from "unfair?"

MR. WRIGHT: Well, it's the way the issue would be framed when it comes to you. If the question to you is: "Was the utility's assignment of 7.5 points on Criterion B unreasonable?" You are going to be hard put to say that it was. But if the issue is --

COMMISSIONER CLARK: But if the person who came in and bid and who got less points has the opportunity for coming in and saying they shouldn't have scored it any differently.

MR. WRIGHT: That's true, but again, it comes down to what issue you all are going to be faced with addressing in this context. And if it is, was the score assigned to the utility's project unreasonable or were the scores assigned to all the projects unreasonable? I am afraid that if the range of scores is 6.5 to 7.5 over six projects, you all are going to be hard put to say that the assignment of scores was unreasonable.

I really think that having the Commission, either through its Staff or through a contract or an independent evaluator, do the evaluation, will take that type of problem out of it.

COMMISSIONER CLARK: It sort of brings me to an issue that I continue to struggle with and it is whether or not we're going to manage power supply in this state or the utility is going to manage it. Or are we going to regulate it?

MR. WRIGHT: Well, I'm not sure that I understand exactly the distinction you're making between managing and regulating.

COMMISSIONER CLARK: The distinction I'm making is that you're suggesting we should decide, we should be the ones to pick who provides the power.

MR. WRIGHT: Yes, I am suggesting that. And

if that's management, at that point in the process, then that's what I'm advocating. Frankly, I think that's the Commission's role with its authority under the Grid Bill and its overall public interest authority.

COMMISSIONER CLARK: Notwithstanding the fact that the utilities have the obligation to serve?

MR. WRIGHT: Correct.

COMMISSIONER CLARK: Okay.

MR. WRIGHT: I'm done with my summary, Mr. Chairman, and I'm happy to respond to any questions.

CHAIRMAN DEASON: Okay, questions?

CROSS EXAMINATION

BY MR. WILLINGHAM:

Q Good morning Mr. Wright. My name is Bill Willingham, represent the Municipal Electric Utilities. I have a couple questions for you.

The first one is: Does ARK believe that existing rules are adequate to ensure that they will be fairly considered in a municipally-owned utilities generation selection process?

A Yes.

Q And does ARK believe that either of the rules proposed by the Commission is necessary for ARK to be

fairly considered in a municipally-owned utilities generation selection process?

A No. ARK perceives that municipalities are going to bid anyway, that they have a compelling incentive to bid. They need to get the lowest cost power for their ratepayers, and they -- sorry.

Q Fine. That's what we believe too. Thank you. Has ARK ever had any problems obtaining information from a municipally-owned utility when they've asked for it?

A No, sir. The one instance that I'm aware of we asked for production costing input data from the city of Tallahassee, and I had fill out the form and pay them $17, or whatever it was, to cover the cost of the diskettes, but they provided it readily.

MR. WILLINGHAM: Thank you very much.

CHAIRMAN DEASON: Mr. Cresse.

CROSS EXAMINATION

BY MR. CRESSE:

Q Mr. Wright, is the role of the Commission to pick the winning bidder, or is the role of the Commission, under the law, to determine whether or not the applicant utility has chosen the most cost-effective alternative available?

A Mr. Cresse, I believe the role of the

Commission is to pick the winning bidder.

Q And is -- are they given that authority under the law?

A I believe so.

Q 403.519 gives them that authority?

A I think 403.519, together with the provisions of the Grid Bill, gives them that authority. 403.519 gives them the specific authority to review applications and assure that the winning -- and consider whether the proposed power plant is the most cost-effective alternative available to serve the need.

Q But that's different than picking a winner and saying to the utility, "You contract for that"?

A Yes, sir. And I bet you read some of the stuff I've written on this subject. The Grid Bill also gives the Commission pretty much plenary jurisdiction over the planning, development and maintenance of the power supply grid, and as you know, I think, my views and ARK's views as to the principles of comparative review as they should apply in the context of Section 403.519 would give anybody the opportunity -- give any legitimate applicant -- maybe we don't have to talk about who that is today, but would give any potential supplier the opportunity to have its determination of need granted by the Commission.

Q Commissioners, Mr. Wright and I have had some private discussions on this subject for the last five or six years and so forth, but that part of the Grid Bill that you reference is only applicable after the Commission determines their deficiencies in the grid; is it not?

A I just want to make sure that we're talking -- using the same words. The criterion in the statute is probable cause to believe that inadequacies exist with respect to the grid, but yes, you're correct.

Q So under that section of the law, if the utilities sit back and they don't do anything, and the Commission sees there's going to be brownouts and blackouts, and so forth and so on, then they can move in and tell them exactly what to do and how the costs should be shared among the various utilities and so forth and so on; is that correct?

A Yes, sir, that's true.

Q And that section of the law, the Commission has never found it necessary to use, to the best of your knowledge; is that correct?

A To the best of my knowledge, that's correct.

Q I take it that you disagree with CEPA that -- in fact you believe that it would be proper to have some negotiations after the bids were submitted; is

that correct?

A No, sir, I -- that's not correct. I may have been a little garbled in my explanation earlier.

Q On Page 2 of the ARK Energy letter dated September 17th, 1993, you say, "Once a bidder is short-listed, the finalizing of a PPA should occur rapidly since any contractual differences, if any, are known up front."

A Yes, sir.

Q Doesn't that short-listing indicate some further negotiations?

A Only to a very limited extent, as ARK intends it, Mr. Chairman. What's intended is that the bidders would have to identify, clearly highlight any changes they were suggesting in the draft power sales agreement, and that once they were selected, those -- if there were any contention as between a bidder -- and those changes that they made in the proposed power sales agreement would have to be worked out. But that's the only negotiation. We're not talking about what I believe the Staff contemplate, which is a system where you get a short list and then have potentially extensive negotiations to try to arrive at a final price.

Q But you're going to have some?

A Maybe, maybe not. It depends on whether the -- whether the bidder is willing to accept all the terms and conditions of the draft power sales agreement, and I'll give you an example. In the Cypress case it wasn't a bid context, but ARK basically put the same contract forward to Florida Power and Light Company that Florida Power and Light had executed with Cypress, with essentially three changes, as I recall: The prices were significantly lower; there were modifications to reflect the fact that -- the technical fact that ARK's project was going to be a gas-fired combined cycle unit and not a pulverized coal unit. It seems like there was one other minor change but they were that minor.

Basically I think if a bidder is willing to accept a contract as is, satisfies all the minimum requirements, has the lowest price and wins by the weighting system, then there is no further negotiation.

Q Yesterday we had some discussions with some folks about whether there are any benefits from ownership versus purchase at the end of the contract. Do you think there are any benefits for ownership at the end of the contract by the utility as opposed to the independent power producer owning the assets at the end of the contract period?

A If you assume that the asset will have real substantial economic value at the end of the contract, then there is a potential benefit to having the utility own the comparable asset that it might otherwise own.

However, I think this is something that can be addressed through contract. If your concern is to assure that the ratepayers have the opportunity to obtain benefits like -- benefits of remaining economic value at the end of the contract, you can write into the contract an option to purchase on behalf of the utility for a reasonable price. You can write into the contract an option at the utility's option, if you want, to extend the contract. The contract that I referenced proposed by ARK's affiliate, Pahokee Power Partners 2, to Florida Power and Light specifically had a provision in there that would have allowed FPL to elect, at its option, to extend the contract for another ten years beyond the 30-year initial term, and the price would have to be negotiated, but my belief is you can handle the contract.

Q My next question, I think, can be addressed by a yes or no first before the explanation. I hope I word it that way, so I can understand your answer. All right, would you object, would ARK object to a provision in the RFP and in the negotiated contract

that at the completion of the contract period all assets used in -- to perform that contract, all the power plant site emission allowances which have been granted, by whoever grants them, and the site, must be turned over to the utility and they name the price in the bid?

A Excuse me, and who names the price, Mr. Cresse?

Q The bidder.

A Unfortunately, on behalf of ARK, my answer is I don't know the answer to that. I have not had occasion to discuss that question with them. I will be happy to get everybody an answer in writing, as part of ARK's posthearing comments, if you will.

Q Thank you. No further questions.

COMMISSIONER CLARK: Let me ask -- Mr. Cresse, I think the point you're trying to make is that at the end of the contract the ratepayers have nothing, in the sense that if it belonged to the utility, it could continue to provide service to the customers, and if there was not a minimal investment in it, they're not earning on it, but it's still providing service, and you want that same -- your viewpoint or your client's viewpoint is that you don't get that benefit when you contract for power with an independent,

power producer, and you're trying to suggest a contract term that will put you, or put the ratepayers in the same position at the end of that contract; is that correct?

MR. CRESSE: That's one of the things I'm suggesting. And I'm also suggesting, Commissioner, that we're looking out 25 or 30 years. And the one thing that we know for sure is whatever vision we have of the future, it's going to be wrong. And I don't know the value of emission allowances. I know they're extremely valuable. I know that our environmental laws may get more stringent or less stringent, and so forth. I know that as they become more stringent or less stringent, they become more valuable. I know that we have prevention of significant deterioration rules and regulations in this state today, but you can only put a power plant out there, and you can't put another one if it's going to cause a significant deterioration. The person that's got the contract and got the allowances, which were granted from the state, has that at the end of that period. It could be very, very valuable. And if the utility has it, that value is passed on to the consumers without cost, without any economic cost. If you're in a bidding situation for those emission allowances, it will be passed on to the consumer with

significant economic cost.

COMMISSIONER CLARK: Let me ask Mr. Wright a question. Do you think your client would be agreeable to a contract provision that says at the end of the contract term the utility would have the option of purchasing the asset at net book value? And I guess one of those things would be that you would have to keep books that would depreciate the plant in the same way the utility would depreciate a plant and keep track of its accounts in the same way.

MR. WRIGHT: Commissioner Clark, again my answer -- my specific answer on behalf of my client is I don't know, but I would like to go ahead and tell you what I think. I think that if -- I think that if that were a term in a Commission-approved contract that was available to have a price bid against it, I think ARK would bid. If you knew what the deal was going in, you could adjust your -- you would adjust, any bidder would adjust his price accordingly. So I think that -- I can say I'm confident that ARK would bid in such a situation if that were part of the approved RFP. Whether they would have reservations or objections is something I just don't know.

CHAIRMAN DEASON: Well, isn't it a matter of -- it kind of boils down to a question of shifting some

risk. I think the utility is saying is they want the option at a certain specified price to acquire the facility and all of the permits and allowances that go along with it. And it would seem to me -- I would -- I obviously can't speak for your client -- my guess would be they would probably be willing to bid, willing to absorb some of that risk, but the bid price might not be quite as good because they're giving up something.

MR. WRIGHT: That's kind of what I think, Mr. Chairman. Like I say, I haven't had specific occasion to discuss that issue with my client. But I think that's the right analysis. You just take what's given on the back end and make your bid accordingly.

CHAIRMAN DEASON: Mr. Neiser?

COMMISSIONER JOHNSON: Let me ask one question of Mr. Cresse. Mr. Cresse, one of your first questions to Mr. Wright was what role did he think the Commission should play in the bidding process, and he stated that he thought, yes, that he thought that our role should be to pick the winning bidder. Since we're in an informal setting, I wonder what did you think? What role should the Commission play, given the status of the law?

MR. CRESSE: Commissioner, I think under the law, and I think it's the appropriate role, the

Commission is constantly reviewing the prudency and the operation of the utility and passing those judgments. They don't -- there's a fine line between regulating and managing and making decisions on behalf of the utility. When you start making decisions on behalf of the utility, you have moved, in my opinion, from the regulatory role to the management role. So you have to watch that very, very carefully, that you don't move into that role. You heard the questions yesterday that said if -- if you order a contract for a utility to enter into, which I don't think under the 403.519, you have the authority to do. I'll make that very clear. I think you have the authority to say, "Yes, you've met your burden, that we need the capacity, and that's the most cost-effective alternative." I don't think you can say, "And you got to enter into a contract with John Doe."

But you remember yesterday I asked the question: "Should the utility be held responsible for a quality of service problem if it was caused by the independent contractor? " And I thought the response was, "You can't hardly do that." I don't think you can do it if you told them to enter into that contract and pick that contractor. I would reserve judgment if they enter into that contract and manage that contract on

their own. And that's the way they have arrived at it. I think what you're about here today, in the last two days, is getting people to answer the question: What process should we use or require the utilities to follow in order that we can make a determination of the most cost-effective alternative?

That is, I think, the sole purpose of this rule. Some folks want to expand it beyond that, but I think the sole purpose is what process must be followed so you can make an intelligent decision.

That's a long answer. I hope I answered your question.

COMMISSIONER JOHNSON: The one concern that Mr. Wright raised was that in allowing the utility to be the evaluators is just inherently unfair, and that we won't get the most cost-effective analysis as an end result; that there are those subjective factors that will lend itself to skewing towards the utility, and that if we want the most cost-effective final resolution then we need to be involved and make that decision. There's some appeal to that argument.

MR. CRESSE: Yes, ma'am, let me respond to that.

Obviously, a third-party evaluator in a conflict is going to be necessary. But if you hire a

third-party evaluator up front and they make the initial decision, the utility is still going to have to evaluate that thoroughly and completely. If they disagree with the third-party evaluator, they're going to come up here and tell you they disagree with it. And you are going to be the final arbitrator of whether that utility has met its burden of proving to you that is the most cost-effective alternative.

So I view that very simple. The utility carries the burden; they do the evaluation; they're managing their own business. If you want an independent -- you are the final arbitrator, you're the third party. The question is do you want a fourth party? If you want that fourth party, then you go ahead and select an evaluator to assist you in making your final decision. That's the process that I would recommend and come into. But you cannot relieve the utility from the responsibility of doing that evaluation and coming to you. Now, you're going to ultimately make all these decisions for a while because this whole industry -- and everybody is going to be testing you. They're going to be testing the utilities to see if they can get a better deal coming to the Commission, so you all are going to get involved in this thing. You might spend as much as time on this as

you do in rate cases, which that ought to scare you to death.

COMMISSIONER JOHNSON: Thank you.

COMMISSIONER CLARK: Mr. Wright, one of the things that the whole question -- Mr. Cresse's questions to you with respect to turning the project over at the end of the contract period is based on the notion that you will have gotten a return of your investment. And that utilities, likewise, when they build a plant they depreciate it and the investment dwindles to the point that the ratepayers get a good deal because they are not having to pay on a rate base.

In your experience, has that been true? Because I remember during several rate cases where you had plant that was depreciating but, at the same time, you were continually making capital improvements to the plant, such that the rate base was not going down and, in fact, in some cases it was going up.

MR. WRIGHT: In my experience, Commissioner Clark, that's not the case, as you suggested. That is, that despite depreciation of the original cost of utility plants, the net rate base on which the utility continues to earn does not -- it may go down some. I haven't studied the exact relationship between accumulated depreciation and net additions, but it

doesn't go to zero over 30 years as you would expect it to on the front end. And that's one of the reasons that I think you ought to hold the utility to its bid price, in fact, because that hasn't been the experience. The utilities have added, and if you get a bid price with a revenue requirement stream that establishes being below the utility's avoided cost from a nonutility generator, then the ratepayers will know what their costs are going to be over the life of the project.

COMMISSIONER CLARK: The independent power producer has to make the same type of capital improvements to continue to meet his contract. He eats the cost and there's no -- you don't have the similar opportunity that utilities have to come in and say, "We had to add scrubbers and things like that to meet these requirements and, therefore, we need to add it in rate base."

MR. WRIGHT: That's right.

COMMISSIONER CLARK: But do you think that the RFP that the -- the utility ought to have the option of including that in the RFP, the option to buy, at a given price, at a given way at arriving at the price. Should they be able to put that in the RFP?

MR. WRIGHT: I personally do not see any

reason why not.

COMMISSIONER CLARK: Okay.

MR. WRIGHT: That is my personal opinion.

CHAIRMAN DEASON: Mr. Neiser.

MR. NEISER: Just by way of comment we would essentially support the position that Mr. Cresse has just stated with regard to if the utility has the duty to serve, the burden to serve, then to turn the responsibility over to anyone else to evaluate bids where there is some discretion, some judgment, it assumes that third party would have better judgment than the utility. And we just see it as highly improper to suggest that someone else can do that better than the utility, recognizing always that we must be before the Commission for final approval of what the recommendation is.

I think somewhat analogous is the fact that whenever someone goes out to purchase something, they usually make the judgment as to what are the best alternatives. They don't ask someone else to make that judgment for them in the final analysis.

General motors, who is looking to decide whether they are going to manufacture a part for an automobile themselves, or whether they are going to have it done by some other manufacturer in the

marketplace, they will take bids; they will evaluate those bids; they will make a determination as to whether it is better for them to have it done as an out source or done by themselves. They in turn do not take that to any agency or governmental body for review. The competitive marketplace will make the decision for them.

Here the only distinction, of course, is we do take the final result to an agency for open public inspection of the evaluation. So I find it highly unusual to suggest that when a person is going out to decide what to purchase or not to purchase, that it is required to go elsewhere for that decision, rather than for the person paying the bill, making the decision to purchase, should have that right to decide. My only comments.

CHAIRMAN DEASON: Those comments were in lieu of questions I take it.

MR. NEISER: Yes.

MR. WRIGHT: Mr. Chairman, since this is rulemaking, could I just add a responsive comment to Mr. Cresse's comments?

CHAIRMAN DEASON: Yes. Why don't we see if there are any more questions, and you kind of hold that to the end, and we'll give you that opportunity.

COMMISSIONER CLARK: When you do your redirect.

MR. WRIGHT: Okay. I just thought it fit logically here better, but that's fine.

CHAIRMAN DEASON: Mr. McGlothlin.

MR. McGLOTHLIN: I'd like to ask Mr. Wright in his capacity as an economist he would respond to the analogy using General Motors, whether that's a meaningful comparison to the bidding situation with the utility that is going to be the only provider of retail service.

CHAIRMAN DEASON: I think that's an open question. You can probably cover everything with that one there. (Laughter) (Pause)

MR. WRIGHT: My own view is that the context is so different that it's not altogether that meaningful. It does have some appeal to it, but we are in the context of regulating a public service in the public interest under a state program. And I think it's the Commission's task to assure that the best project is chosen to serve the power supply needs of the ratepayers of this state. And I think you all ought to make the decision.

And this will let me make my comment in response to Mr. Cresse. And that is, if what you wind

up with on the back end -- as you suggest, Commissioner Clark, is you all review an evaluation anyway, and if you ask the questions in that evaluation, not was it reasonable, but was it accurate, then you will essentially be replicating -- to make that evaluation you will, practically speaking, have to replicate the evaluation that was done on the front end to determine whether it was done correctly and you will be right where you were. And now you have got two evaluations. One done potentially by the utility and one done by you all or by your third-party contractor. I think if the Commission does the evaluation in the first place or a the third-party evaluator employed for the purpose by the Commission does it in the first place, you're a lot less likely to have challenges if the utility's bid is the winning bid.

Let's say you hire me --

COMMISSIONER CLARK: I think that's highly speculative.

MR. WRIGHT: Pardon?

COMMISSIONER CLARK: I think that is highly speculative, that you would have less challenges if you had a third party. Because, in fact, you really introduce another person who would challenge it, that being the utility.

MR. WRIGHT: Yes. Well, --

COMMISSIONER CLARK: I am in agreement with the analogy to General Motors is probably not quite correct, but you have a spectrum of industries sort of in this country. You have those that are not regulated at all -- not regulated very much at all and they can go and do what they want, and then you have public utilities and on the far end you have government actually providing the service. And at this end we do, in fact, manage to make those decisions when its government contracting for the service and then providing the service. But, you know, the utilities are somewhere in the middle between being a totally private unregulated entity and being a government service. And I think to some extent we ought to let them go ahead and manage and then review what they do. And I agree with you that in effect you have -- we'll be reviewing it anyway, but there's always the possibility that people will believe the review they did was correct and we won't have any challenges, and they will have made the decision. They will have fulfilled their management duties.

CHAIRMAN DEASON: I think perhaps the question is is the standard -- I hate to use the legal term -- standard of review or whatever, is a question

if it comes to the Commission, and it probably will, do we look at it with the presumption that the utility is correct and somebody has got to prove to us that they are wrong; or is it they come in and they've got to prove from the most intricate detail that what they did was right and here's all the reasons? Is that part of your problem?

MR. WRIGHT: Yes, sir. And I think it's a lot closer -- the way I think the issue ought to be framed is a lot closer to the latter. I think the issue ought to be, "Was the complete evaluation and scoring correct," not "was it reasonable."

MR. NEISER: Mr. Chairman, it's our understanding that the applicant does carry the burden of proof by law.

CHAIRMAN DEASON: Does that conclude your questions, Mr. McGlothlin?

MR. McGLOTHLIN: Yes, sir.

CHAIRMAN DEASON: Staff.

CROSS EXAMINATION

BY MS. RULE:

Q Mr. Wright, I'm Marsha Rule for the Commission Staff.

The examples that you have been given about GM, for example, are free market examples of

procurement of items, right?

A Yes, ma'am.

Q And in the free market you presuppose a willing buyer and a willing seller, is that also correct?

A Yes, that is surely one of the specific assumptions of the free-market competition model.

Q And has it been ARK's experience that there are willing buyers in this market?

A No, ma'am.

Q Why not?

A ARK's perception is that the potential buyers would rather buy from themselves. They would rather build their own plants.

Q And so what you're trying to propose is some sort of incentive to get around that natural inclination; is that correct?

A Yes, ma'am.

Q And hence the cash incentive to use the bid process.

A Correct.

MS. RULE: Thank you.

CHAIRMAN DEASON: Thank you, Mr. Wright.

MR. WRIGHT: If I could just make one more comment.

CHAIRMAN DEASON: Very briefly.

MR. WRIGHT: Very briefly. Yes, sir.

Back to the distinction between the General Motors free-market procurement context.

There's another important difference here, and this relates to the legal arguments that you all have heard me make about the nature of these proceedings. And that is, the need determination that the Commission grants for a power plant is an integral, essential component of the site certification order that any jurisdictional power plant must ultimately obtain in order to be built. It is a part of a governmentally granted license. There's no license other than a license to do business to make cars. You have to have the license, you have to get your ticket punched to build a power plant in the state of Florida.

CHAIRMAN DEASON: Thank you, Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman.

(Mr. Wright excused.)

CHAIRMAN DEASON: Mrs. Rule, are there other nonutility generators which wish to make presentations at this time?

MS. RULE: I'm not aware of any but this would be the time for them to step --

CHAIRMAN DEASON: If there are any, please

make yourself known at this time.

Mr. Neiser, I think you're finally on.

MR. NEISER: Thank you. Mr. Gaddy will put our first witness on.

MR. GADDY: Good morning, Mr. Chairman, Commissioners. I call our first witness of six.

MICHAEL ROSENZWEIG

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. GADDY:

Q Sir, would you please state your name and address for the record?

A My name is Michael Rosenzweig. I'm Vice President of National Economic Research Associates, 1800 M Street, Suite 600, Washington, D.C. 20036.

Q Mr. Rosenzweig, did you prefile comments in the form of testimony in this docket?

A I did.

Q Do you have any corrections to that testimony?

A I have two. In the initial comments, on Page 20, Line 22, there is the word "risk" separated by dashes, the first dash is an error, it should be eliminated.

Q Very well.

A Then on Page 22, Line 4, the question starts, "Are they any," and it should be, "Are there any."

Q Do you have any other corrections, sir?

A No, I do not.

Q Mr. Rosenzweig, would you please summarize your testimony?

A I will.

My testimony was requested by Florida Power Corporation in order to support their approach to this rulemaking, and that is, in brief summary, that they basically support the primary or original rule proposed in this proceeding, except that they suggest two modifications.

My testimony went to a conceptual explanation of why those two modifications are requested, and then additional witnesses who will follow me are going to take my concepts and demonstrate why in the real world they are important and necessary.

Throughout my testimony and throughout a lot of the comments that you received in writing and orally were based on the concepts surrounding risk. And in my testimony -- and now I'd like to point out some of the distinctions associated with that concept that may explain why everyone is not in complete agreement as to

how to approach this issue.

The fundamental concept which I think everybody agrees on but perhaps isn't clear as words are used in the discussion, and that is risk is, in fact, uncertainty.

If a particular event or a particular decision has no uncertainty associated with it, there's no risk. If you know you're in an airplane and it's going to crash, you don't have a risk whether you're going to crash or not or whether you're going to arrive safely or not. If you're getting on an airplane at the beginning of the trip there is some level of uncertainty of whether you will arrive, and so there's some risk. And it's important to keep that in mind, that if you have no uncertainty, if it's deterministic, then there is no risk. And if there is, on the other hand, uncertainty, there is risk.

Another important idea that I think needs to be kept in mind is that even for the same event or the same issue, risk can be different for different people. The focus of this proceeding, of course, is power projects. And if you look at the primary parties, the principal parties in a power project, they have different risks. Who are the principal parties: ratepayers, utility investors, project developers, and

project lenders. Those are the ones that everyone has spoken about in this proceeding so far, but they have different risks. What are the risks for ratepayers? Well, the risk for ratepayers is they want to make sure that -- well, not that they want to make sure -- the risk for ratepayers is uncertainty about the price of electricity. Their concern is they don't want to pay more for electricity than they need to, and events in the utility or in the development of a project and the execution of a project will have a effect on their -- the price they pay for their electricity, so there's some uncertainty.

For utility investors, utility investors are concerned about the return of and return on their investment, the dividends, their interest and repayment of debt. Things that happen that reduce the ability of the utility to make those payments increases the uncertainty or is the uncertainty associated with their investment, and that's the risk that they have.

What about the project developer? The project developer is in it for profits, and the things that go on that make his profits uncertain, those are the things that create risk for the project developer.

And finally the lender to the project, well, the lender wants to get his money back, he wants to get,

a return of and a return on his investment, his loan to the project. And the things that go on that raise questions about whether he'll be able to get that money back, the appropriate return, are the risks that the lender faces.

Now, it's important to understand that because these risks are not the same; the risks of a ratepayer are certainly not the same risks faced by the lender; that mitigation of risks, reducing risks for one party is not also the same as reducing the risk for any other party, or all other parties. In fact, it may be that if you reduce the risk for one party you increase the risk for the other.

For example, the lender to a project may be very happy to have a take-or-pay contract as opposed to a take-and-pay contract. You've heard these terms used and it has to do with whether there's performance standards in the contract.

If you have a take-or-pay contract the project has a much higher likelihood of getting all the revenues that it anticipates. And if they do, the lender has a much higher likelihood of getting all of its money. There's less uncertainty about getting its return of and return on the loan. So its risk could be reduced. But if you do that, if you have a take-or-pay

contract, then ratepayers have a much higher uncertainty about the price of their electricity because it may be that that project will be generating when it's not the most economic alternative because it's take or pay, and it may, in fact, be -- since you're already paying for it under the contract, it may be generating when it's not necessary, or you may be paying for it when it's not needed, when the capacity is not needed. So it's possible that mitigating risk for one participant in a project or an event actually reduces or increases the risk for another party.

With all this uncertainties, why are people willing to involve themselves in projects, why are they willing to take risks? Well, the answer is they want to be paid for it, and that's where the link comes to another issue that we have been talking about or lots of people have been talking about and that's the cost of capital.

For investors, the cost of capital is the payment that they receive for taking risk. The higher the risk the higher the payment that anyone wants to receive. So that as risks change, as risks increase, the cost of capital increases; risks decrease, the cost of capital required will decrease. The fundamental principle is that risks should be balanced by the

reward that's associated with those risks.

Let me see if I can make that somewhat clearer with an example or a small explanation.

Let's look at the risk for utility shareholders. What are the uncertainties for -- not shareholders, utility investors. The risks to utility investors is that when the utility calculates all of the money, gets all of the revenue that it gets from selling electricity and pays all of the expenses that it has to pay, that there won't be enough money left over to pay all of the dividends and interest and the repayment of debt that they expect. That's the uncertainty.

Now, what are the factors that affect that? Obviously, variations in revenues will affect that, but also the extent that expenses are fixed and grow means that there's less of a cushion, so that if you have here is the fixed expenses and here is the revenues, we know revenues are going to vary back and forth, and it's the difference between the two that provides the funds to satisfy investors. And as you move that up by having more fixed costs, then you increase the uncertainty or the risk that investors will get what they expect out of the investment.

This may explain some of the distinctions or

differences of opinion between some of the witnesses.

Dr. Roach, for example, said that there's only one risk for investors and that's the risk of disallowance. Well, clearly, if you have a disallowance you can affect the revenues and that does create a less available, fewer funds available to pay off investors. But as you can see from my explanation, there are lots of other things that affect that risk. If you increase fixed payments, then you also affect the cushion available, the funds available to pay investors. And when you do that -- of course, the more you increase fixed investments, the more you expose investors to variations in revenues, there's less of a cushion available. So it's more than just disallowances that results in uncertainty to ratepayers, it's also the size of fixed expenses and it's also the variability in revenues. All of those things contribute to risk to ratepayers, so it's more than just the risk of disallowance.

Now, Florida Power Corporation basically supports the initial rule proposed in this proceeding, but it has two concerns, and they relate directly to this issue of risk and risk mitigation.

The two concerns are basically that the proposal as currently worded appears to have a bias in

favor of purchasing. And that bias arises because there's a presumption in the wording that appears to favor purchasing. It says, effectively, that if you want to do anything other than purchase, you must justify that. Well, that leads to the concern that if there is a bias towards purchasing, people will purchase because it seems to be the easier way to go. It's the path of least resistance. Why are we concerned about that? Well, you heard a lot of talk and not much disagreement that when you have assets with risks, and we've talked about all the risks that are associated with assets, one way to reduce the risks for everybody concerned is to diversify. And Dr. Roach agreed that that was an intelligent way to run your business. It's an intelligent way to handle your investments. You diversify your investments among different types of stocks with different types of risks because the so-called portfolio effect reduces your overall risk. This isn't a new concept in the electric utility industry. That's the way the utilities under your jurisdiction, Florida Power Corporation in particular, that's the way they manage their business. They don't put all of their eggs in one basket. They have different types of fuels, they have even different type of fuel delivery arrangements, trying to mitigate

the risks associated with any particular asset.

But that concern extends to the difference between purchasing and building. Building certainly has risks. There are the risks that you're very familiar with, that you've discussed them in, I'm sure, in all sorts of cases before this Commission, but purchasing has some risks. I discussed those risks in my testimony, and there are four basic ones, and I think -- I call them risks associated with purchasing, but I think they are the concerns that you've heard expressed in questions of some of the witnesses before now. And, also, I think they go directly to Commissioner Lauredo's concern where he talks about the social aspects of contracts. And I think he's picked up one of, at least one of the risks that I talk about, and I think Chairman Cresse has picked up on a number of the others. And there are four distinguishing factors about dealing with projects through contracts. And they are the fact that the motivation of project developers and the people who have run independent power production projects are different than utilities. And primarily they are profit-driven. And it's true that utilities are investor-owned and they are profit driven, but they are subject to your regulation. And as a result of being subject to your regulation they

have to be sensitive to both your wants and needs but also to the political process that you have to be sensitive to, so they have to be concerned about the social aspects of your regulation also, society's needs.

We also have heard a lot of discussion about the problems of dealing with power plants through contracts. That is the method of operation, operation or coordination between utilities and between power projects, and it's just inherent in the nature of contracts that they're imperfect. No one has either the time or the scope to be able to draw up a perfect contract, particularly one that's going to extend over 20 or 30 years. It's just inherently -- it's logically impossible to think that we could know what all of the issues are, important issues that are going to arise between a project and the utility over a 20-year or a 30-year period. And even if we could, if you think about how difficult it would be and how expensive it would be to try and draft that contract, it's just not reasonable to believe that the contractural mechanism is going to be perfect. So that's another risk you don't have with building that you do have with buying.

Third, NUGs -- we've heard talk about NUGs being around since 1978 with PURPA or maybe there have

been two or three that have been around for fifty years. But reality, the market is a very new market. It's a very relatively new market. The majority of the megawatts that have come on line have really come on line in the last three to five years if you just count up the megawatts.

These contracts are for 25 -- 20, 25, 30 years. We don't know how well they're going to work. We don't have any experience. We don't have any really large number of projects for long periods of time that we can draw conclusions. So there should be some concern about how well these contracts will work over the long term. And I think that that's an issue that we've touched on before.

Finally, related to the contractural nature of the NUGs utility relationship, is that it changes the ability of utility management to control their plants. It has to. It cannot be as easy to control a generator if it's inside your company or outside your company. Clearly, the incentives of the people who operate the plant, if they are in your employ, is a lot different than the people who are controlled by contracts.

So the point of all of this is that there is a set of risks that is peculiar to purchasing versus building.

Now, don't misunderstand, we're not saying that they're great. I'm not saying that they're better or worse, that one is riskier than the other. All I'm saying is that they're different. And once you have assets with different risks, it makes good sense, good common sense to try to diversify those risks. And that's all we're asking that the rule be modified to allow.

What we're suggesting is that instead of having a presumption that all buying is proper, that is if you -- no matter how much of your resources are under contract as opposed to being within the direct control of the utility, you still must justify not buying. What we're suggesting is that at some point, there ought to be a concern that perhaps you're putting too many of your eggs in one basket. Perhaps we ought to be concerned that there's a concentration of these unique risks to buying. Not that you shouldn't buy anymore but that you should be concerned about it. And what we're suggesting is that the Commission should be concerned about it so that their rules suggest that after a certain point, and I, in my -- just a personal feeling, personal opinion, that, you know, when you have about 20% to 30% of your resources in one particular risk basket, then you ought to be saying, if you want to continue, if you think it's really best to

have more of this particular set of risks, an asset which has this sort of risk, you better be able to prove or demonstrate to us that it makes sense. That the increased concentration of risk, which has with it the prospect of increased cost, because remember we said risks were related to cost, that it's offset by whatever the benefits of continued reliance on, in this case, purchasing is and that's all. That's all we're suggesting that the rule say. There's a threshold, not a cap, contrary to what some people have been interpreting. That there's a threshold beyond which the Commission wants the utility to demonstrate that it understands that there's a portfolio of risk concentration question; that it's addressed that issue, and that if it is, in fact, in the best interest of ratepayers, that that risk be accepted because the benefits are greater, fine. If not, then don't go ahead. But the purpose is just a flag just to say, we're concerned, you be concerned. It is after all the way this Commission has historically had its utilities operate.

They don't want all of the utilities having one type of generation or one type of fuel or one type of fuel contract. There have been decisions where this Commission has supported the theory of diversification. And just suggest that you're not changing that because

there is a new way of acquiring assets.

The second issue, which is the one that's tied into the Section 712 considerations, is the issue of what to consider in evaluating bidding processes. How to evaluate bids; what should be included, what shouldn't.

What my testimony suggests is that this is part of a general consideration, and you've heard the phrase "buy versus build." Now, this is not something that's new in the world. It may be relatively new in utilities because utilities historically haven't gone out to purchase their generation assets. But it's a process that's gone on for -- ever since there have been corporations, ever since there have been corporate organizations there's been an issue as to what should be the extent of the corporate control.

That decision, and it is not one, incidently, that is a question of whether it's regulated or not regulated, whether it's a GM or in a competitive market are a utility in a regulated market. It's the same sort of considerations, and that is: how do you decide whether it's better to buy outside in the market or to have the process inside under corporate control?

The decision is an economic one. The question is an economic question. And the answer, the criterion that should be used is the same criterion,

that's used in all business decisions: What's the most economic decision?

Our concern is that in order for that decision to be done correctly, you need to know that you've got all of the costs and all of the benefits in the calculation. If you leave out some costs, you can end up with the wrong answer.

What we're suggesting is that the rule, as currently proposed, doesn't explicitly say that the Commission understands that this is an economic question and it's a comparison of costs of doing business one way versus doing business another way. And that all the costs need to be included.

Now, the concern that we have is that there are some costs which are not so obvious. They're not so obvious in the utility context because again the history hasn't been that utilities have been out buying their assets. The history has been that they have been building their assets. But there are costs that -- there are things, developments which can, in fact, have real cost effects.

And our proposal is that you, in your rule, be very explicit in saying that those costs should be included. And to the extent that you can, we would suggest you give explicit direction as to what those

costs are. Now, we're not suggesting that you say what the answer is. Those answers would change on a case-by-case basis. But we think it is important that you give direction that all of those costs be included and to the extent you can, what types of costs they are.

Now, what are they?

CHAIRMAN DEASON: Could you expand on that? When you say "all costs."

DR. ROSENZWEIG: I was about to do that.

CHAIRMAN DEASON: Do you mean "environmental externalities?"

DR. ROSENZWEIG: Well, to the extent that environmental externalities are an issue, they're probably in both the buy-versus-build situation. And, in fact, nowadays that truly seems to be the case since almost everybody is purposing the same type of assets.

CHAIRMAN DEASON: So you're testifying on behalf of Florida Power that we consider environmental externalities? Is that your testimony?

DR. ROSENZWEIG: No, I'm not testifying --

CHAIRMAN DEASON: You need to clarify it because that's what the message I'm getting.

DR. ROSENZWEIG: Well, I'll give you some examples -- I was about to give you some examples of the types of costs that I have in mind. What I'm

suggesting is --

CHAIRMAN DEASON: Now, you said all costs.

DR. ROSENZWEIG: That's right.

CHAIRMAN DEASON: Okay.

DR. ROSENZWEIG: Now, I'm not suggesting -- when you say "environmental externalities," we need to get -- go ahead. We need to get into -- you know, to be more specific, what do we mean by "environmental externalities." Are we talking about environmental externalities in the sense of a comparison between the effects of one type of asset on another type of asset? We need to be very careful on that, because how do we do that, how do we calculate that? What are you -- you know, are you going to say what you mean by environmental externalities, because if you say, any environmental effect is at an appropriate cost in a comparison between the two -- between the two alternative modes, that's a judgment for you. If you think that that's an appropriate way to judge between two assets, you know, you should suggest that.

I think you need to be very careful in deciding that issue. I'm not saying that I agree with how you would do that because I don't know how you would do that. If you want to talk about that we can talk about it, because I think you need to be very

careful how you do that.

CHAIRMAN DEASON: No, my concern is your bold statement that all costs and all benefits need to be considered. And what some people consider costs and benefits, another person may not. And there is a question of being able to quantify certain costs and certain benefits. And it gets back to the argument we've had many times over the last few days as to things that can be readily quantified and objectively reviewed, and things that are subjective.

DR. ROSENZWEIG: I think that -- again, if you believe that those are costs that should be included, they should be included in both alternatives. I think that you raised the issue that I agree with, which it may not be very easy to do these calculations. And I'm suggesting that that's a topic for a whole other discussion and it's an important topic, because if you do that incorrectly -- I'm not suggesting you throw costs in incorrectly, the bold statement of all costs is not -- anything, you know, let's throw it up on the wall and see what sticks. I mean, I'm talking about identifiable costs to the extent that they're quantifiable, you should be quantifying them. To the extent they're not, you need to find a way to appropriately and accurately reflect them in a decision

process. All businesses have to do that. And all I'm suggesting is that that same process be put in place here. And all I'm suggesting is that for your rule is that you recognize that and give guidance to that effect. I'm not suggesting that you say how to do it, because I agree with Chairman Cresse that I'm not sure that is your job. Your job is to review what others have done and decide whether it's correct or not. But that's, you know, that's my view of it. But I was going to give you a couple examples of the types of costs which typically are not thought of.

One has been a subject of debate, and has been raised in the Energy Policy Act of 1992, and that is the cost of capital effects of purchasing. And that's because it's related to risk. I mean, there are two types of costs that typically aren't thought of: One is related to risk and that's the cost of capital effect, and the other is to managerial efficiency. And I'll give an example of that.

But we've debated the cost of capital issue. The question is, does purchasing have an effect on cost of capital? I think there is -- if you look at the discussion of risks that we had, I think it's pretty clear that -- to the extent that they're fixed payments for example, in a purchasing contract, it reduces the

amount of revenue, of funds available to investors. That increases their uncertainty. That has to increase the risk. And that has to increase the cost of capital. I think even some of the nonutility generators agreed to that. Mr. Reilley, yesterday, from Enron, said yes, there's the cost of capital effect. He said, "But, you know, if you're going to do that, you should look at all the risks." We're suggesting the same thing. We're not suggesting that there be a one-sided or biased review. We're suggesting cost of capital effect from fixed payments. That's pretty clearly an issue. And how you go about analyzing it, I think that's something that's left to analysis, to the people who are going to do the evaluation. You should review it and decide whether you think it's credible.

But there are other risks, and my testimony goes and describes that yes, it's more than just the fixed payment. There are other risks that are associated with buying versus building, and those should be evaluated; to the extent that you can quantify them you should quantify them. And when all of those costs are brought into the calculation, then you can tell which is the least-cost alternative between buying and building.

As far as managerial efficiency, the one example I'd give you has also been discussed here, and that is the loss of flexibility that can occur when you contract versus doing something in-house. That's just inherent in the nature of contracting. There's less flexibility and some of the other Florida Power Corp witnesses will give you real-life examples of how losing flexibility can increase costs.

But I think it's just common sense that if you contract out for something, you're bound by the contract. And some of the witnesses have said yes but you can renegotiate the contracts. That's true, you can renegotiate contracts. It's not clear you always get what you want out of it. It's also not clear that it won't cost you something. In fact, someone mentioned the Baltimore Gas and Electric RFP that's out on the street now. Baltimore specifically asked for the ability to postpone the in-service date of the project that they're after, any project that comes in from their RFP. But there will be a cost for them. And to the extent that it's not explicitly captured in the RFP, someone should take into account what the value is of that lost flexibility, and there are ways to calculate it, and I discussed that in my testimony. And, in fact, Baltimore's putting that in their RFP I think as

a direct result of our doing an analysis for them in a dispute with a NUG about who was providing the cheaper alternative. That issue actually was litigated.

But the point is, is that when you go out on contract you do change the nature of the managerial scope of control and you reduce flexibility or change flexibility. Utilities -- you're familiar with this in all the planning reviews that you do, utilities come in and they make their planning decisions based on forecasts of sensitive parameters that go out for 20 or 30 years. Changes in the price of fuel can change the economics of a unit dramatically. And yet, if you're locked in by contract into a particular technology, into a particular in-service date, it may be very difficult to get those changed. And if you can get them changed, it may be expensive. In either case, there are costs associated with either having the wrong unit at the wrong time with the wrong fuel, or having to pay a nonutility generator to modify his contract. And all we're suggesting is those costs should be reflected in the buy-versus-build decision.

Let me just summarize. What we're suggesting is that there are two changes that the proposed rule could benefit from. One is that there be explicit recognition that there is a portfolio concern between

purchasing and all other resources, and that you should make your utility alert to that fact and that you expect them to address that issue. And then in the evaluation of purchase-versus-build decisions, or any other resource alternative, you should make it very clear that you expect all costs, all legitimate costs, to be accurately and properly reflected. And to the extent that you can be explicit in your guidance, for example, I think you should suggest that the cost of capital effects be evaluated, or that loss of flexibility or loss of managerial control should be evaluated. And any others that you can identify. I think you should explicitly put that in the rule.

Now, there were exceptions taken to our position, and I would just like to briefly run through. I think I address most of what the disagreement is between basically CEPA and our position, and I think the problem we have with their position is that they seem not to understand the risk/reward relationship.

I mean, Dr. Roach argued that there's no financial effect unless there is a disallowance. And that just misses the whole point. If there is a disallowance there is no risk. I mean it's a certainty. There will be an adjustment because of that disallowance, but there's no more risk. The risk comes about with the

threat or uncertainty of the disallowance.

And I think that's important when you evaluate his analysis, that's a fundamental element to his argument. And he defended it yesterday, that there is no cost of capital effect, no financial effect, unless there is an actual disallowance. And that's -- or he uses the phrase "a predicted" -- and I'm not sure what that means, but there's a sense that there's a certainty, unless there is a certainty of a disallowance, some sense of certainty, there's no financial risk. That clearly can't be right, because a risk is about uncertainty, not about certainty. And we're saying there are all these risks associated both with building and with buying.

There was a theme through much of CEPA's testimony that what you really should look at is the fact that there are no credit rating effects; that credit rating agencies don't change or haven't changed the ratings of utilities because they purchase. That really misses the point.

If you remember back to the discussion on what causes cost of capital, it's changes in risk, not changes in ratings. It's investors that determine what the cost of capital is. It is not credit rating agencies. They do provide information, they do provide analysis, but as was discussed yesterday, you can have

wide variations in the cost of capital within one class of -- rating class of utilities. There can be differences of 100, 200, 300, 400 basis point in double A and single A utilities, between -- that is, in a class of single A utilities there can be differences of two or three or four percentage points in cost of capital. So it's not debt ratings, it's perception of risk.

I guess the last thing I'll bring up was that Mr. Howard made a -- I think, a major point of saying that you don't need to be concerned about NUG risks very much because there are all sorts of ways that they're mitigated. In particular, he said that lenders really look very hard at projects, after all their money is involved. And I would just caution you, that that's true. But if you recall back to our discussion of risk, lenders are looking at it from their perspective. They're looking at it from the perspective that they want to ensure their return and their getting their principal back. And if that means mitigating risk that increases ratepayer risk, they're going to do that. And so, the fact that they mitigate their risk doesn't mean that ratepayer risk and ratepayer costs are being considered. But I think that is the important consideration in all

CHAIRMAN DEASON: Call the hearing back to order, please. Questions? Mr. Willingham. No questions? Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Dr. Rosenzweig, I'm Joe McGlothlin. I represent Falcon Seaboard Power Corporation, participating as a member of the CEPA organization.

For starters, I think based on your prefiled testimony and your comments this morning, you agree that the comparison of the build option to the buy option should be made from the perspective of what is best for ratepayers, do you not?

A I do.

Q And one of the central points of your comments is your proposal that all costs of one approach, build or buy, be compared with all costs of the other approach; is that right?

A One of my proposals, yes.

Q All right. Would you agree that a competitive procurement procedure, such as a bidding mechanism would ensure that all costs of one are compared with all costs of the other?

A No, I -- if it were done properly, I wouldn't say that just because it's a bidding procedure that it

automatically would include all costs. It depends on how the RFP was designed and how the bidding evaluation process was handled.

Q All right. If done carefully and properly, a competitive procurement mechanism can do a good job of ensuring that all costs of one are compared with all costs of the other?

A If it's done in that way. I mean, you could envision a bidding system which had nothing to do whatever with a build decision. You could just decide going in, "I'm not going to be building," and there are utilities that have done that, so there's no comparison of building versus buying in that situation. You're just going out to get the best bid that you could get.

Q All right. I'll grant you that my question assumes that there's some interest on the part of the utility to build an unit. Under that hypothesis, would you agree that a competitive procurement mechanism, if done right, it's a good way to ensure that all costs of one are compared with all costs of the other?

A If done properly, it's one way of doing it. I think, yes, I think that is right. But it has to be done properly and by "properly," it's exactly the point we're trying to raise here, all costs should be included in that evaluation.

Q I want to talk to you about your recommendation that a utility that has in its mix of resources something like 30% of purchased power be required to justify any additional purchases before proceeding.

Let's assume that a utility -- let's assume that that principle is embedded in whatever procurement mechanism comes out of a rule proceeding for purposes of my question. And let's assume there's a utility that has the 30% purchased power in its mix presently. And let's assume that it wants to build its next unit. Under that scenario, would there be any obligation of the utility to consider at all the option of purchase?

A I think there's always an obligation to consider all alternatives.

Q Well, let's say that the utility has the 30% portion of purchased power in its mix, and it simply announces, "I'm going to build my next unit." And there's a requirement that it justify purchasing if it's at that level. What opportunity does an independent who is poised and ready to offer an alternative to request that consideration be made?

A I guess I'm not going to answer your question directly at first because I don't understand the relevance of it. You have a hypothetical, a hypothesis

and then a conclusion, and they don't seem to be related. That is, the fact that a utility is required by this Commission in a rule to justify purchasing, once they had more than a certain threshold level of purchased resources, as far as I can tell logically, has nothing do with that utility saying, "Hey, I'm just going to build and I'm not going to give anybody the opportunity to purchase." I didn't see the nexus, the connection between those two. One certainly doesn't give -- you know, having that requirement to be concerned about portfolio considerations doesn't give anybody any right to not consider all alternatives. So I'm having trouble with your question, I guess.

Q Well, how do you envision it working? There's that requirement in the procurement mechanism, and you have a utility that has no interest in entertaining a purchase option, it wants to build. What happens?

A Well, again, I'm having trouble because I don't see that they are related. I mean, I think you're trying to set up a hypothetical that doesn't -- I'm trying to be gentle, doesn't make sense, because the way it would work is if the utility doesn't want to purchase, whether it has this requirement to be concerned about portfolio diversification or not, he

has to convince the Commission that that's the appropriate answer, independent of whether there's a -- the threshold has nothing to do with the decision of the utility to not consider purchasing or to consider purchasing. What it says is if you're going to purchase beyond a certain point, you should be concerned about concentration of particular kinds of risks. Not that you shouldn't purchase. It's not a cap. I mean, I know it's been characterized as a cap but it's not. All it says is you should be concerned about concentration of particular types of risks. And if you can still want to buy -- my view is not that they would use it as an excuse not to buy, but that they would not be alert to the concentration of risk by continuing to buy, because I think purchasing frequently offers a very attractive alternative to building. And I'm not concerned that they won't want to build. I'm concerned that they'll want to buy too much without being alert to portfolio considerations. If they are alert to portfolio considerations I don't think there's a problem.

Q Do you envision a procurement mechanism under which this 30% criterion would be a part, but the utility would, nevertheless, have a obligation to issue a RFP and entertain proposals?

A All right. Again, I don't think there's a connection between the 30% portfolio consideration threshold with what's the appropriate mechanism. And I think you're trying to make a connection there.

I think that the utility is obligated to consider all alternatives, and I think it's then obligated under the proposed rule to make it clear to the Commission that it's done that. So if it has to do that by putting out an RFP, I would think the utility would want to put out an RFP in order to know that it is worth buying more, even though -- in the hypothetical you've set up it's got a considerable reliance on purchased power. In order to know that it's worth concentrating risk beyond the level that it is now, it needs to put out an RFP so it can say, "Hey, I've got a purchase here that's really good, and it's worth taking these extra risks because the benefits outweigh the risk." So I don't know how I would answer that question.

Q All right. Perhaps I'm beginning to understand you. You propose, then, not that this 30% criterion or consideration be codified by rule, but that it be a consideration that the utility take into account as it evaluates the alternatives, is that how you perceive it?

A Well, I think the Commission should be concerned about this problem. I think the Commission should put it in its rule that says, "If you're going to use more than 20 or 30% purchased power in your resource mix, we want you to come in and convince us that you've considered the concentration of risk problem." And if you have, fine. I mean, we're not saying that that means you don't buy. It's not a cap. It's just saying we want you to be alert, we want utility purchasers to be alert to this diversification issue. And that's all we're saying. Be alert to it.

Q If that is codified in the rule, and if a particular utility is at the 30% level, would you agree that that combination of factors would make it more difficult for a purchase option to be the winner in the RFP?

A Well, I hope not, because if you're saying it's more difficult, then you're suggesting that without the codification people are going to ignore the portfolio aspect of this and I think that would be very unfortunate. In fact, the way you state that just makes it more imperative to have it codified so that people don't ignore that risk. Because if that risk isn't being ignored, it will make absolutely no difference in the evaluation because it will be part of

the evaluation. So I think your concern is what I'm sharing, is that it should be put in the rule so nobody has a reason or an excuse not to consider these risk aspects.

Q Your concern about one of the earlier proposals was that it appeared to be biased in favor of a purchase option. Would you agree that the result of this proceeding should be to have no bias against either the purchase or the build option?

A Yes.

Q You described several reasons why you believe the purchase option or independents are fundamentally different than the utility in terms of the interest as support for the portfolio consideration, I believe. And I've heard you list four in your summary.

First, you said the motivation is different. Secondly, you said that there's a problem dealing with the operation of a unit through the contract. Third, you said that the reality is that the independent source is a new and untested market. And fourth, you say that the contract changed the ability of the utility to control plants.

Just as an initial question, aren't two and four the same consideration?

A Well, I think you've -- and I understand I

was speaking quickly because of our -- everybody's time concern, but I think you've slightly missed the point of two and four.

The point about two is that it's not a matter of control, it's just that it's inherently impossible, I believe, to have a perfect contract. And, therefore, because of imperfections in the contract, not just control of plants, but all terms and conditions, you know, raise the possibility that you haven't considered and haven't provided a mechanism for dealing with all - possible eventualities. So I think you narrowed it down, so when you did I think you made two and four the same.

Q Would you agree that the degree of success of dealing with those considerations is dependent upon the sophistication of the contracting process?

A I would agree with that, but I think fundamentally -- you're an attorney, so I hope you would agree that it's impossible. It would be impossible to believe that you could draft a perfect contract to control the relationships over something as complicated as power delivery, power supply for 25 or 30 years with a contract. I mean I think --

Q On the motivation item, you said independents are different because they are profit-driven. Would

you agree that a utility has an obligation to deliver least cost service to its ratepayers?

A I think that's the statutory requirement in Florida. I think it's true -- I think it -- conceptually it's true everywhere but I think it's even statutorily required in --

Q Would you agree that an independent would have no opportunity to even do business unless it demonstrates that it is the best deal for the ratepayers?

A That an independent would not have any ability to do business?

Q Won't have the opportunity to do business unless it convinces -- unless it demonstrates it is the better deal for the ratepayers?

A By "doing business," do you mean putting in RFP responses or do you mean --

Q No, selling capacity and energy.

A I would like to believe that's true. Unfortunately, I think there's human frailties in all activities. And I think, as some experiences have shown, you can have an independent and a contract signed and it turns out not to be the best result, which is not an argument against bidding at all. It's just a reality of life.

Q And both the utility and the independent try to make a profit for their shareholders by providing least cost service; is that right?

A I think -- when you say that the -- that was a complicated question. I don't know if they try to maximize return to their shareholders directly by offering least cost. I believe they both try to have economical, to be economical and competitive, and they both do try to provide profits to their shareholders. I guess I'd have to think about the connection that you made that that's the only way or perhaps the best way that they try to do that.

Q Well, I'm suggesting that both have similar motivations both in being low cost and in making a profit. Let me refer you to --

A That's what I just said. I agree that they both do have those two motivations. I thought you were trying to connect them. The only point I was making is that I think those are the primary motivations for nonutility generators, and I think there are additional motivations for regulated utilities that the nonutility generator isn't subject to.

Q I refer you to Page 7, Lines 1 and 2 of your first comments where you say, "Perhaps a single common objective of a nonutility generating utility,

therefore, is to see after the well-being of their shareholders." So they really don't differ in that respect, do they Dr. Rosenzweig?

A I think that's what I just said. I said they both share that particular common goal. Let me clarify that that's not the only goal for either and that there are differences in goals between utilities who are regulated and nonutility generators who are not.

Q One of the other concerns that you think justifies the portfolio consideration is the fact that the independents represent a new and untested market; is that right?

A Yes, subject to what I think I said, which is new and untested in the long term. That is, there are very few, I believe, nonutility generators, particularly independent, that is non-QF utilities -- excuse me, non-QF generators that have been in business a significantly long period of time that we would have enough information to judge that the method of relationship, the mechanism between the utility and the nonutility generator works without concern.

Q If you'll look on Page 19 of your first comments, beginning at Line 15, you make this statement: "Historically, NUGs have been highly reliable and, moreover, a NUG has a strong profit

motive to make sure its unit is available. This information is available to investors. Given NUGs' high availability statistics and incentives to be available, investors will most likely expect a NUG to meet contract performance conditions and that the utility will make the full capacity payment throughout the contract term."

Isn't it true that one reason why you believe there is -- increased financial risk is because investors perceive the NUGs as motivated and able to perform according to their contracts, and, therefore, entitled to payment of the capacity payments?

A With respect to the specific issue of the performance standards, that's what my testimony said, yes. But, obviously, these contracts, as you are aware, are very thick documents that have many, many terms and conditions, and so it's not just -- it's not just that one term that I was referring to when I talked about the unproven nature of the relationship between NUGs and utilities.

Q At one point in your testimony you described several ways that a utility might want to make sure its portfolio of resources is diversified. You listed type of technology, fuel prices, sizing and modularity among others.

Would you agree that it would be possible through the RFP and bidding process for a utility to specify or give priority in its RFP to technology type, fuel, the size of the unit, or the modularity of the unit, and achieve diversification through a purchase scenario?

A The answer to that question is yes, but there are other considerations. And the comments of your witnesses, CEPA's witness, continue to focus on only operational and short-term considerations. The four distinction -- the four NUG-specific concerns that I raised are different than the fact that you can have technology diversification, you can have fuel diversification, you can have all of these other diversifications. Yes, you can, but there's more to it than that and I'm suggesting that you just don't ignore these other considerations.

Q I want to talk to you a minute about the subject of the possibility of increased financial risk associated with the capacity payments of a purchased power contract.

At Page 20, beginning at Line 1, you pose this question: "Is it always the case that NUG contracts which require a utility to make fixed capacity payments increase financial risk to the

utility?" And you say, "Not necessarily. If such payments are automatically flowed through to ratepayers, financial risk may not increase."

Do you acknowledge, then, that it is possible to fashion a regulatory mechanism that would ameliorate the possibility of perceived financial risk?

A Ameliorate but not eliminate.

Q Okay. You don't think it's -- did you not intend by that statement to say it could be eliminated?

A No, because if you continue on, I say it's essential, however, to consider investors' perceptions regarding the risk of the Commission revisiting the prudence of power purchased agreements or changing the mechanism by which the utility passes through capacity payments to ratepayers.

Q Okay.

A As long as investors perceive that it is not absolutely ironclad, and I think we can discuss for hours how that that's not the case. I'd be very skeptical of someone claiming that there's a mechanism that absolutely insulates investors from risk. Then there will be some remaining risk. Yes, you can certainly mitigate it and is it useful to mitigate risk? Yes, it's useful to mitigate risk. Does it eliminate the risk? No, I don't believe it eliminates

risk.

Q In your summary when you were addressing that you mentioned that there is uncertainty with building and buying. That would be true with respect to the possible perception of increased financial risk also, would it not?

A It would.

Q And would you agree that that is one of the costs that occur on both sides of the build versus buy options that would have to be factored into the overall comparison of the total cost?

A That and all other costs, yes.

MR. McGLOTHLIN: Those are all the questions that I have.

CHAIRMAN DEASON: Any questions?

COMMISSIONER JOHNSON: I had a couple of questions.

I need to better understand your threshold level of purchased power argument. First, how did you come up with the 20 to 30%?

DR. ROSENZWEIG: Basically, I decided what I would feel comfortable with if I were trying to evaluate the portfolio mix of just about anything. And, basically, I decided that since it's not a rule that says you should or should not have any more or any

less, I was trying to figure out when should a regulatory body be concerned about that level. And from my experience on a regulatory body, I would want to know when you get to, you know, a quarter to a third that, you know, somebody is paying attention, that if there are these unique risks and that diversifying those risks away is a benefit to ratepayers, I'd want to know that somebody is actually thinking about that issue when they make a decision to continue to increase their reliance on whatever resource, but in this case purchased power.

COMMISSIONER JOHNSON: And what would happen at that point in time? Say they've reached that 30% threshold, would you then shift the burden? Because before 30 we really shouldn't worry about it or we wouldn't question the particular utility, and after that point the burden would sort of shift.

DR. ROSENZWEIG: Yeah, I think that's essentially what would happen, is that you would want to make sure you would want to have the utility purchaser demonstrate to you that they had considered all of these -- all of these aspects of it; that it's not just, "We went out for a bid and we got the lowest cost." You would want to know, yes, but there are things that are not embedded in that cost, these other

risk factors, and we want to make sure that you considered that in deciding that it was worth continuing the -- increasing your reliance on purchases.

COMMISSIONER JOHNSON: And would the converse of that argument apply if the utility does not have at least 30%, then should we then require or have them justify to us why they don't have that diversity?

DR. ROSENZWEIG: I think that's true -- yes, and I think the rule as it is stated now says that. So we're not suggesting that that be dropped.

COMMISSIONER JOHNSON: Right. Okay.

CHAIRMAN DEASON: Staff.

MR. MOYLE: Mr. Chairman?

CHAIRMAN DEASON: Yes.

MR. MOYLE: May I be permitted just to ask one or two questions of those witness, please?

CHAIRMAN DEASON: Surely.

MR. MOYLE: Thank you.

CROSS EXAMINATION

BY MR. MOYLE:

Q Mr. Rosenzweig, my name is John Moyle, and I'm participating on behalf of J. Makowski and CEPA. And perhaps you can help me understand a part of your testimony.

Am I correct in saying that you're recommending to the Commission not a cap, but a threshold concept that if purchased power reaches a certain level, it should be looked at and evaluated for an investor-owned utility?

A Let me make sure I understand, because I sort of missed at the end of it. Are you asking me whether I'm saying that once they reach 30% they should then being to consider purchases?

Q No.

A No.

Q At any point along the way that they should look at this idea of diversification or concentration.

A Yes, I think that they should be doing that all along.

Q As it relates to purchased power?

A Well, I think as it relates to all of their resources; but, yeah, that includes purchased power.

Q Okay. And my question would be does that

also include power derived from plants that are built by the utility itself?

A Yes, I think they should be concerned about -- if there are risks that are unique to building, they should be concerned about overconcentration. I think we've seen 15 years of the kinds of risks that can accrue from --

Q Okay. Let me ask you this hypothetical question: Assume a utility in Florida that had, say, 15,000 megawatts serving the people of Florida and less than 1% or less than 2% of that were purchased power, would that be a problem the Commission should look at in terms of diversification?

A I think it's a problem that the utility should look at, and the utility -- the Commission should be alert to it, but if, in fact -- I guess the short answer is it should be looked at. That is, they should look and see whether they have considered the risks associated with whatever mix of resources they have, 1% purchased plus 99% diversified among other resources, and see whether there is a concentration of risk. And whether that concentration of risk is -- the potential costs associated with that concentration of risk is overcome by the benefits associated with those resources.

Q But you told me earlier that you were recommending to this Commission that they should look at this in terms of purchased power. You're not saying that they shouldn't look at it in terms of power produced by the utility, are you?

A No. This is a purchased power -- my understanding is this is a purchased power rule.

Q And my last question to you is, in your opinion, if it is a problem, if that 2% of 15,000 megawatts is not -- that's all there is of purchased power, would you have a opinion as to whether competitive bidding might help in solving that unhealthy concentration or lack of diversification problem?

A Well, you slipped in some pejorative words in there. I don't know, and you wouldn't know without looking at the specifics, whether it was an unhealthy or a healthy concentration of risk. But I think competitive bidding helps. I think it's -- that's the favored way. It's the preferred way. It's the way I would recommend acquiring any purchased resources is with competitive bidding.

MR. MOYLE: Thank you, sir.

MS. RULE: I'm Marsha Rule with the Commission Staff.

CROSS EXAMINATION

BY MS. RULE:

Q You had said that the proposed rule is biased toward the buy option; is that correct?

A Well, I'm afraid it may create a bias toward the buy option, yes.

Q And you agreed with Mr. McGlothlin that the rule shouldn't have any bias in that fashion; is that also correct?

A Correct.

Q Utilities, though, tend to be biased toward the build option, right?

A There are utilities that are not. There are utilities that are, in fact, biased against the build option.

Q Is there an inherent incentive for utilities to build as opposed to buy in terms of the return they will earn?

A Barring any friction in the system, there shouldn't be.

Q Is there?

A I guess I can't answer. You're asking me a general question, and I don't think I can answer for each and every utility is there a bias. The fact of the matter is that their purchases are supported by

debt and equity, and they earn a return on -- an allowed rate of return, or an earned rate of return that's controlled by the Commission as an allowed rate of return on whatever their investments are. So whether they have huge investments or not huge investments, they are earning their allowed rate of return or have an opportunity to earn their allowed rate of return on their investments. There are some questions about whether if you have a concentration of purchased power, whether there is some financial risk that is associated with the variability of earnings, whether, in fact, you increase -- decrease the stability of earnings, and that's an issue that should be looked at. But other than that, I can think of no reason why a utility should want to build rather than buy.

Q You can't?

A No. Because it earns no more money on a per share basis, whether it has 10 plants or whether it has 100 plants, because for each plant it has to raise new equity and it has to raise new debt. So it doesn't earn more money for each shareholder. When you say "the utility," I'm thinking of the owners of the utility, the shareholders.

Now, if you're suggesting that the managers

of the utility have a inherent bias towards building, I guess I don't feel that I'm qualified to address what is in the minds of managers. One can make an argument that people like to manage bigger operations than smaller operations, but other than that, there is no -- there should be no financial incentive to choose between buying or building because you don't -- as a shareholder you don't earn any more than what your allowed rate of return is because you have more plants, because you have to have more equity to support that.

Q As you depreciate a plant does the amount upon which you earn go down? Decrease?

A Sure. Yes, that's a true statement, you said that as though there was a connection there and maybe there's a connection in your mind. I didn't understand the connection.

If you weren't continuing to build, as you depreciate your plant, the depreciation also provides funds which allow for the repayment of debt and equity. So that you reduce the amount of debt and equity that are outstanding, so what you're earning on your remaining rate base is, you know, presumably the allowed rate of return. So no one is earning any more or earning any less.

Q Is there a problem in Florida that you know

of with utilities buying too much power?

A When you say "a problem," you mean that there are some -- I've heard that there are difficulties that are associated with purchased power.

Q That wasn't the question. Do you know whether or not utilities are purchasing an unsafe level of power, let's say beyond your 20%5 or 30% mix that you suggest?

A I don't know whether there are people -- first of all, I'm not suggesting that 20% or 30% is an unsafe level. I've never suggested that.

Q An amount beyond which you would suggest justification.

A I don't know as a fact. I know that Florida Power Corporation, at least on an energy basis, is close to that level. They are certainly above 20% on an energy basis. And if you pick the 20% level then I would think there should be some concern about concentration of risk associated with purchasing.

Q That wasn't the question.

A I thought it was the question. I'm sorry.

Q No. Are you aware of whether or not there are utilities in Florida that are approaching that level?

A I thought I answered that explicitly:

Florida Power Corporation, which is a Florida --

Q On an energy basis, right?

A Yes.

Q Capacity basis?

A Florida Power Corporation is not above 20% on a capacity basis. I don't know whether there are any other utilities that purchase more than that.

Q How about other utilities, are you aware of their mix?

A I'm sorry, in Florida?

Q Yes.

A As I just said, I'm not aware of the utilities in Florida, their mix.

Q Well, accept for a moment the hypothetical that some utilities don't have 20% and, in fact, have a very low percentage. And let's also assume for a moment that some utilities will only purchase power if they have to. How can a rule correct for that bias, assuming for the moment that it does exist?

A Well, the rule, I would suggest, already does because if they are below the threshold that I'm recommending, the bias that I'm concerned about still exists. The rule hasn't been changed, they have to come in and justify why they are not purchasing when they acquire new resources. So there is that bias and

the rule gives them, you know, prompts them to go in the direction of purchasing, and it says if you don't purchase, you need to explain to the Commission why you're not.

Q But it only prompts them to that extent of 20% or 30%, correct?

A The rule as stated now, my understanding, you know --

Q I'm sorry. With your suggested change, it would only prompt utilities to move in that direction --

A Right.

Q -- to the extent of 20% over 30% right?

A That's correct. But your concern, the hypothetical you stated --

Q Okay let me continue with this just a minute.

A Can I just answer what you asked me?

Q Well, I think you did, thank you.

A I didn't complete my answer.

Q You're suggestion --

CHAIRMAN DEASON: Listen, my patience is growing a little bit thin.

Let's give the witness an opportunity to answer. I wish he would be more direct in his answer and these are not trick questions. It seems like you

tried to discover every little detail of the question and try to find a way to be disagreeable. That's my own interpretation.

DR. ROSENZWEIG: Well, I apologize.

CHAIRMAN DEASON: I know you're a professional witness and that's what you get paid to do.

This is a rulemaking. We're just trying to get to -- what we think is a good policy here. I would just appreciate, and this is a request from the bench, just try to be cooperative and answer the questions. The same direction to the attorney, don't try to be so antagonistic, just ask the question politely and perhaps you'll get a polite answer.

MS. RULE: Let me be very direct then.

Q (By Ms. Rule) I am concerned that your 20% to 30% justification level, let's call it, would, in effect, act as a cap for some utilities in Florida. How could can we correct for that?

A I guess -- how do I correct for -- it seems to me that all I'm suggesting is that they come in and justify any further purchasing. I'm not trying to be uncooperative, but I'm confused. Your concern was if they had very little purchasing and they have no incentive to purchase, but now if they are at the

threshold, they have -- 30% of their resources are purchases. It seems to me your concern goes away. All I'm suggesting, at that level there shouldn't be a concern about not having enough purchasing; perhaps there should be a concern about too much purchasing, not that there shouldn't be any more purchasing. So I guess I'm having trouble and that's --I wasn't be uncooperative; I was confused by your concern.

Q It seems to me, then, that you're agreeing that it may, in effect, in the end, cap the amount of purchased power that -- please follow along with me for a moment -- that an unwilling utility might have. Please, I'm just asking you to assume that a utility might not be willing to purchase power, because that's an allegation that's been made before the Commission several times and the Commission has had to deal with that. So without adjudicating that right now, let's assume an unwilling utility.

A I think an unwilling utility could say that it's concerned about these risks and not purchase any more. What we've proposed is they have to come in and justify all of their resources that they have, if I understand the rule, that they are going to purchase. And, you know, if nonutility generators, in my experience, they will come in and participate in those

proceedings and they will make their case.

I guess I would say, yes, it could act -- if someone wanted it to act as cap, it could act as a cap. I would be concerned -- I wouldn't understand what your concern would be. If they were capped at a third of their resources purchased, why is that a problem? What is the downside of that from your perspective? Suppose that they were recalcitrant, they want to build, you know, but if they have got 30% of their resources, unless what you're suggesting is they are not getting the least cost resource, in which case you should take them to task, and they should be appropriately dealt with, you know, if they are not getting the least cost resources. You know, I guess I don't understand what your concern is.

Q Would you suggest to the Commission a set-aside for utilities to build?

A No, I wouldn't.

Q On Page 5 of your September 10th comments, where you discuss the 20% to 30% threshold, do you distinguish in that between power purchased from utilities and power purchased from nonutility generators?

A No.

Q Should the Commission make that distinction

at all?

A Yeah, I think the utility should -- the Commission and the utility should look at the relative risk profiles, and if they are different, then there should be a distinction.

Q So perhaps a utility that was making a higher amount of its purchase from another utility, assuming a good risk profile, might in the end be able to justify more than 30% power purchased?

A They might be, yes.

MS. RULE: Thank you.

CHAIRMAN DEASON: Questions, Commissioners?

COMMISSIONER JOHNSON: Let me make sure I understand you. I know we've asked you a lot of questions about the threshold level of purchased power, but let me tell you how I've interpreted everything you have said; is that up to 20% or 30% it would be your opinion that the utility would have to justify why it is not purchasing power. And after that 30%, it would have to justify why it is purchasing power.

A Correct.

Q Okay.

COMMISSIONER JOHNSON: Thank you.

CHAIRMAN DEASON: That's all the questions. Thank you, Doctor.

MR. NEISER: I call Terran Miller.

TERRAN A. MILLER

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. NEISER:

Q Mr. Miller, would you please give your name and your business address and your affiliation, please?

A Yes. My name is Terran A. Miller. My business address is Merrill Lynch & Company, World Financial Center, North Tower, 21st Floor, New York, New York 10218-1321.

Q Have you filed some comments in this proceeding?

A Yes, I did.

Q And do you have any corrections or additions to make to your prepared statement?

A I have two minor corrections and there was one omission of a -- that should be added. On Page 18 of my testimony, Line 12, the fourth word "either" should be stricken. And at the end of that sentence it should say "or both."

On Page 20 of my comments, Line 13, after the word "obligation," the words "to serve" should be insert.

And finally, on Page 25 of my testimony it refers to an Appendix 2, which in the transposition process was omitted and that should be added. I would make one comment that there is no Appendix 1, so all of those that try to find it won't be able to.

So it's Appendix 1 and that is being circulated at this time, so that all the parties have access to it.

Q Mr. Miller, would you please give the Commission kind of a summary of what your written comments are all about?

A Yes. Thank you, and good morning.

The purpose of my testimony has really been broken down into four parts. The first part that I have is the conditional support of the proposed rulemaking. My support is conditional because the rulemaking only calls for a discussion of potential costs rather than a methodology to quantify the costs.

Second, what I plan to talk about is the rating agencies' approaches to quantifying purchased power risk concentrating on Standard & Poor's approach because based on both my work experience and my opinion, the S&P approach is the most widely accepted and, therefore, utilized approach by the marketplace.

Third, I plan to briefly discuss the risks

specifically concentrating on financial risk.

And fourth, I'm going to talk about the market's assessment of the obligations associated with purchased power and the role it has established in determining cost of capital.

First, conditional support.

I believe that the Commission must go beyond the discussion stage and develop a methodology which measures the cost of capital effects, including the debt-like equivalents of the purchase option of both the purchase and build options before determining the least-cost option.

From the rating agencies' standpoint, I'd make the following comments: Not all the rating agencies agree on either the methodology which should be used in calculating debt equivalents or which threshold purchased power crosses the point of materiality. However, all the rating agencies agree that the signing of a purchased power contract is not a risk-free transaction.

The agencies, unlike Mr. Roach's comments, do not selectively apply this methodology. They apply it throughout all the companies and all of the situations in the electric utility universe.

The measure of risk will be a function of the,

terms and conditions of the PPA and the regulatory treatment accorded recovery of the obligations. However, these are risk mitigating factors, and not risk elimination factors, again as Mr. Roach and others have implied.

From the S&P standpoint, what they do is take a qualitative and quantitative approach. They calculate the net present value of the capacity payments discounted at 10%, at 10% over of the life of the contract. They take the debt-like nature of the capacity payment measured over and apply it to a risk spectrum, which accounts for both the type of contract, "take or pay," and/or "take and pay," and the regulatory treatment accorded the payment.

For take-or-pay obligations, the risk spectrum weighting would be 40% to 80%; for take and pay the risk spectrum weighting ranges between 10% and 50%. The more favorable regulatory treatment, the lower the risk factor chosen from the range.

Once the debt equivalent is calculated, S&P uses a 10% interest rate to calculate the equivalent interest expense to be factored into their adjusted coverage ratios.

In terms of the risk that the market and the rating agencies attempt to quantify, let me say -- make

the following points: Again, these risks can be mitigated, they can be shared, but they cannot be eliminated.

These risks are operating, regulatory and financial risks. These risks can only be borne by three parties, the company, the ratepayer, or the developer.

In terms of operating risks, there's been a lot of comments made about those risks. I'm not going to go on and make a lot more, except to say that the market seems to concentrate on operation reliability, economic operational risk, and demand risk.

From the regulatory standpoint, clearly preapproval and competitive bids can reduce risk, which is factored into the models, but, again, I would stress does not eliminate the risk.

A lot has been also said about construction risk, and let me just make a couple of comments about that.

A lot of people at this point in the argument are choosing to compare the construction risk associated with the last construction cycle and the construction risk now associated with -- the buy option associated with IPP construction, and I think that really is a misguided comparison. And part of the

factors that have to be taken into account is now going forward, most company-build options will be done as a result of either least cost planning or integrated resource planning. Second, most new construction will be much smaller in its nature, modular in size, in its configuration, and in that regard we will not see the acid concentration risk that we had in the construction cycles of the '70s or the '80s. And, also, more than likely we will avoid the rate shock associated with those large construction programs.

From the financial risk standpoint, I believe the market has come to the conclusion the financial risk starts with the signing of a purchased power contract. With the signing the seller gains a potential claim. IPPs do not state that they would not make a claim against the purchaser if it ever stopped paying under the contract.

With the contract the developer then has a potentially financiable asset. Several electric utilities have had to spend millions of dollars to buy back contracts, even though the plants have never been constructed. Clearly, an indication of the financial responsibility associated with just signing the contract.

Another financial risk is tied to the

volatility of financial performance. The greater the percentage of revenues tied to pass-throughs the greater the volatility because of sales changes. The market will assess risk to that -- uncertainty to that and assign a risk factor.

Lastly --

CHAIRMAN DEASON: I'm sorry, you lost me on that very last one. Could you explain that a little bit further?

MR. MILLER: Certainly. It goes back to what Mr. Rosenzweig was talking about earlier. And that is, the greater percentage of your expenses are tied to a one-time past-through of an expense, or a higher fixed cost component, the less ability your revenues have to adjust if you have a downturn in sales.

Lastly, a lot has been said about the disallowance risk, and the fact that the debt equivalency is only tied to disallowances.

Let me make a couple of other points in regard to that, and that is disallowances are the manifestation of the risk. The risk does not all of a sudden appear and occur at the time of the disallowance. All that we have at that point is a quantification of the risk that always existed.

From the market's perception and perspective,

as I stated earlier, S&P's approach is generally the most accepted. The market has been forced to deal with the realities of purchased power because of a number of reasons.

One, is public financings for IPPs where the developers are asking the market to provide financing based on the purchasing utility's purchased power agreement. And in that regard the market is forced to look for the reciprocal obligation and quantify the reciprocal risk: The money paid by GSU to satisfy the Southern Company after it stopped making payments on their purchase of power agreements between the two parties. The satisfaction paid by Tucson Electric in its restructuring because of the Century Power contract.

Also the market has been forced to deal with a growing number of downgradings and watch listings which have cited purchased power among the reasons for the downward revisions or the credit watchings. The most recent was earlier this week when Moody's put Atlantic City Electric on their respective watch list based on a growing percentage of purchased power obligations in their resource mix.

Over the last three years -- and we did a study on this by contacting the rating agencies -- and

we have quantified for S&P, Duff & Phelps and Fitch, that in 1990 five out of the 55 downgrades cited purchased power. In 1991 five out of 20 downgrades cited purchased power. In 1992 nine of 22 downgrades cited purchased power.

Companies which have been downgraded do not trade differently than companies with similarly lower rated -- that are similarly lower rated after the downgrade. Downgrades come at both a cost of higher borrowing costs and reduced financing flexibility. Reduced financing flexibility does not come without a cost.

To concluded, what I'd like to say is that you have the opportunity to craft a mechanism which will measure and quantify the risk associated with purchased power. If that mechanism does not accurately assess those risks, the market will assess those risks, and those risks will probably come at the cost of higher cost of capital. And that concludes my summary.

Q (By Mr. Neiser) Mr. Miller, just before you conclude your comments, would you just give a word or two as to why Florida Power came to Merrill Lynch to give some comments here, perhaps distinguishing the real world versus what might happen in theory?

A Florida Power approached Merrill Lynch to the,

extent that a lot has been talked about here in the theoretical attempt to measure the risk associated with purchased power. In talking to potential lenders to electric utilities on a daily basis, I can tell you that those lenders are concerned about this fact, do take it into account and do listen to the rating agencies in terms of when they downgrade because of purchased power obligations, that that does result in a higher cost of capital to those companies which have been downgraded.

MR. NEISER: Thank you. And he's available for questioning.

CHAIRMAN DEASON: Questions? Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Good afternoon, sir.

Mr. Miller, I'll begin with a point that you make at least five times and once in large size print. Would it be fair to say that perhaps the central point of your prefiled testimony is that purchased power is not risk free?

A That is among one of the points, yes.

Q You do agree in your prefiled comments, though, that any risk associated with purchased power can be reduced by the terms of a well-crafted purchased

power contract; is that right?

A Again we're talking about risk mitigation and not risk elimination.

Q Yes, that was my question.

A Yes.

Q And you also say in your prefiled comments that any risk attendant to a purchased power arrangement can be reduced by particular regulatory treatments; is that right?

A That is right.

Q One of those is the preapproval of contracts?

A That would -- yes.

Q Another regulatory function that could reduce the risk of purchased power would be ensuring that any selection is based on the results of competitive procurement; is that right? I refer you to Page 21, Lines 9 to 11.

A Yes.

Q And, in fact, in your comments you acknowledge that in a given situation the purchase option could present the utility with the least risky alternative; isn't that right? Page 18, Line 21.

A Yes.

Q And you make that comment -- in making that comment you recognize, do you not, that the build

option is not risk free, either?

A I don't think anybody would say that the build option is risk free.

Q You also state on Page 18 that where the purchase option presents the least risky alternative when compared to the build option, purchasing power would serve to enhance or improve the overall risk profile of the purchasing utility; is that right?

A You can create a scenario that in a given point in time it is a better option for a company to purchase at that point than build, yes. But, again, there are times when it is more appropriate for a company to build in order to mitigate its long-term risk than it is to buy. It's on a case-by-case basis.

Q All right, sir. And would agree that a competitive procurement mechanism, such as a bidding requirement, would serve to make sure that that comparison is made so that the least risky and better alternative is available to the utility?

A If in crafting the competitive bidding process that will be followed, those considerations are taken into account in how it is crafted, the answer is yes.

Q Would you agree that in your comments, both prefiled and today, you have described those risks that

attend, in your opinion, the purchased power option?

A I'm sorry, I'm not sure I understood you.

Q You're comments focus on those risk that attend to the purchased power option; is that correct?

A Yes.

Q And you have not related that to a consideration of the risks attendant to the build option in your prefiled comments?

A I believe in my prefiled comments I do make some comment about, again, the point I pointed out today that the construction -- risk associated with construction, which is a fluid consideration, is likely to change over time, and that, again, the -- those that want to argue that the risk associated with construction only relates to the nuclear building scenario -- history that we have seen are overstating, or potentially overstating the risk associated with construction in the future. And I think that has to be taken into account.

Q You're referring to the point that the desirability of smaller, more modular units reduces construction risk to the utility?

A It can, yes.

Q Okay. If smaller more modular units make sense for the utility, are they likely to make sense

for independent providers as well?

A Absolutely.

MR. McGLOTHLIN: No further questions.

MR. MAY: Mr. Chairman, just a couple of questions.

CROSS EXAMINATION

BY MR. MAY:

Q Mr. Miller, Bruce May on behalf of Enron Power Corporation. Good morning.

A Good morning.

Q On Page 17 of your direct testimony you make reference to certain power purchase contract agreements that have raised difficulties; specifically you refer to a power purchase agreement between Tucson Electric and Century Power.

A Uh-huh.

Q Are you familiar with that contract?

A All of the terms, no.

Q Are you familiar with some of the background in that contract?

A The history, yes.

Q Mr. Miller, are you familiar with the term "self-dealing" in the context of regulatory policies?

A Yes, I am.

Q And Century Power was formally Alemita

Company; wasn't that right?

A It was.

Q And Alémita was formed by Tucson Electric Power, correct?

A It was.

Q It was a wholly-owned subsidiary?

A At one point in time.

Q So the power purchase agreement that you're referring to in your testimony was a product of an affiliated transaction?

A That is correct.

Q Now, the Tucson Electric Power contract that you referred to was not approved by the Arizona Corporation Commission, was it?

A By the ACC?

Q Right.

A Subject to check, my recollection is it was not approved by the ACC but by the FERC.

Q Now, the contract has been subsequently sharply criticized by the ACC, hasn't it?

A Yes.

Q In fact, the Arizona Corporation Commission has characterized that contract with Century as an abusive, self-dealing relationship, right?

A I don't know if those were their exact words.

Q Subject to check would you --

A Sure.

Q Now, the Florida Public Service Commission has regulatory policies in place to address affiliated transactions. Are you aware of that?

A That is my understanding, yeah.

Q Okay. Now, do you believe that competitive negotiations, arm's-length negotiations between utility power suppliers and purchasers could alleviate the risk of abusive self-dealing?

A I think the nature of a competitive bid is if the Commission is the final arbiter, that that will be their obligation to -- if the electric utility is the winning bid, to make sure that that is the real least-cost option.

Q Fair enough. Finally, I need to be clear on this, Mr. Miller. Tucson's purchases from Century Power, they were not the product of any sort of competitive solicitation, were they?

A They were not. But let me make one point here, and that is, this is an illustration of what the market has been forced to factor into its evaluation of electric utilities to the extent that when Tucson had a restructure, there were $715 million of additional obligations that had to be carved out of what ended up

being the enterprise value of that company, above what certain parts of the market assumed were going to be those claims. And in that regard, those risks are now being factored into the marketplace when other people sign contracts. You know, the nature of how they got there, I don't know if from the market's perspective is as important as the dollars associated with how much had to be carved out of the estate and how much had to be satisfied and what that has illuminated to the market.

Q The marketplace -- does marketplace analyze a particular regulatory environment in assessing risk?

A Absolutely.

MR. MAY: Thank you. No further questions.

CHAIRMAN DEASON: Staff.

CROSS EXAMINATION

BY MS. RULE:

Q I'm Marsha Rule representing the Staff.

A Good morning.

Q I don't know if you have one, but I'm looking at ARK Energy's -- a copy of ARK Energy's September 17th, 1993, comments. Have you had an opportunity to review those?

A I have not seen those and I do not have a copy of them.

Q What I'd like to do is, since you haven't seen it, just briefly tell you about an example here and ask you to comment on it.

The comments include -- looks like a paper written by Mark La Fratta.

A I'm sorry, before you go on, since I've now gotten a copy, can you tell me what page you are on?

Q I can't tell you what page of the whole thing. What I'm looking at is on Page 5 of the paper presented at the 8th Annual Cogeneration and Independent Power Market Conference, "The New Utility Offensive, The Credit Rating Weapon."

A Okay.

Q And on Page 5 of that paper --

A Uh-huh.

Q The author talks about in late 1991 an example in which Virginia Power had its credit rating lowered.

A Uh-huh

Q Are you familiar with that?

A Yes.

Q He talks about a 4,000 megawatt or a purchase of an additional 4,000 megawatts, I assume from various sources, being cited as the reason for downgrading. Do you recollect that?

A In general terms.

Q But the author also says that -- it's at the end of the fifth page, it says, "I believe if you ask financial officials at Virginia Power or at the rating agencies whether Virginia Power's credit rating would have been even lower had Virginia Power proceeded with plans to construct an additional 4,000 megawatts of capacity in the mid-90s, you'd get a very predictable affirmative response." What's your comment -- would you give an affirmative response?

A I believe in my prefiled testimony I said there are certain circumstances where purchasing can reduce the overall business risk of the Company going forward. I believe that is an example of that situation at that point in time for Virginia Electric Power. And, again, what I think you get into is that all these analyses have to be done on a case-by-case incremental basis.

Q I think the author is trying to make the point that -- well, in the middle of Page 5 it says, "If Virginia Power borrowed the billions necessary to construct those facilities it would surely do so under the traditional method of financing, i.e. half debt and half equity. What would that amount of debt do to Virginia Power's credit rating?" So your comment is

that's a question you would have to ask in every single case, what would that amount of debt do to Virginia Power's credit rating or FPL's credit rating or Florida Power Corporation's credit rating?

A I think that in addressing the cost of capital issue, you have to look at, again on an fluid basis, what the incremental decision does to that cost of capital, whether that be the build option at that point in time, or the buy option.

Q Well, I think the author's point is that that's not -- it's being done -- let me see. Back on Page 4, he says, "Press reports say that Virginia Power received a lower credit rating -- it entirely misses the point -- it's inappropriate to compare the credit rating of a utility before and after the purchase from the QF or IPP."

How can we get an around that? How can the Commissioners get around that in the process of approving or looking at generation capacity additions? (Pause)

A Well, I don't know that I agree with the author that it's inappropriate to compare credit ratings before and after the purchase decision. I think that is one of the things that you have to take into account. Because if credit ratings are going to

decline because of the results -- because the results of your competitive bid result in them making a purchase option, and, therefore, their cost of borrowing goes up and you did not take that into account, then you did not effectively -- you did not effectively come up with necessarily the least-cost option.

MS. RULE: Thank you.

CHAIRMAN DEASON: Let me ask a question, and it's kind of a general question, one I've always wanted to ask someone who works at a rating agency.

MR. MILLER: Used to. Used to.

CHAIRMAN DEASON: Used to. You still have that perspective

You were with Standard & Poor's and now you're with Merrill Lynch.

MR. MILLER: Right.

CHAIRMAN DEASON: Okay. I understand that risk and uncertainty go hand in hand, and certainly investors are concerned with risk, as they well should be.

What I get from this discussion and others is that there's uncertainty associated with meeting increased demand for electricity, and that there's uncertainty whether you purchase additional capacity or,

whether you build additional capacity. Would you agree with that or is that --

A You are assuming that you have to -- assuming that you have to then build to meet that demand rather than doing it out of existing facilities, yes.

CHAIRMAN DEASON: Okay. So that's a more risky situation than if a utility already had adequate facilities in place to meet increased demand?

MR. MILLER: Everything else being the same, I would agree with that, yes.

CHAIRMAN DEASON: Okay. Now, does that mean, then, that utilities in Florida then are more risky than others since this is a growing state?

MR. MILLER: It will be taken -- again, it's a balance between the higher growth, okay, can result in higher revenues over time, and, therefore, enhance credit quality. But the other side of that is it depends on how much of that higher growth, (a), causes for increased construction risk or the potential for construction risk going forward. So it's a balancing.

CHAIRMAN DEASON: Well, I guess the reason I asked the question is it seems to me that when we look at different utilities and -- because every utility is different, certainly they have different service territories, that a positive for some utilities is that

it is in a growing territory, the economy is strong, new customers are moving in, there is a possibility for increased revenues; that's good. But then at the same time it's kind of like the joke, "Well, that's good; no, that's bad; no, that's good; that's bad, but that's good" Is it, Well, yes, growth is good, but then there's -- you have to build capacity and that creates risk.

Is a utility serving in a dormant service territory less risky that one that serves in a growing territory?

MR. MILLER: Not necessarily. Again, it is a two-edged sword, and you are talking about something that is paradoxical, and that's why when you look at a rating agency and generally when they give you a list of factors they consider, one of the factors will be service territory, okay.

Another factor will be construction requirements, new money requirements, how much their cash flow will satisfy those new money requirements, so it is taken into account as two separate items that are somewhat opposite edge of the same sword. So you do get the benefit on the one hand, and you do get some additional risk on the other. Yes.

CHAIRMAN DEASON: And what we need to do as

regulators is to make sure that we make the decisions which are in the best interest of the customer, which supposedly are least cost, which -- and those costs need to consider the risk involved.

MR. MILLER: That is correct. And also as regulators, depending upon if a company chooses to build or chooses to purchase, how you deal with those additional costs. You can mitigate some of the risk of that future spending, and that is one of the things that when they talk about supportive or nonsupportive regulation, that the kind of buzzword that goes into a lot of credit agency write-ups, what they are talking about is that exact content.

CHAIRMAN DEASON: And how does Florida fit into that?

MR. MILLER: I think traditionally Florida has been considered one of the more supportive regulatory environments.

CHAIRMAN DEASON: If you want to expand, go ahead.

MR. MILLER: No, I'll just stop there.

CHAIRMAN DEASON: You don't want to get in trouble, right?

Any further questions?

COMMISSIONER CLARK: No.

CHAIRMAN DEASON: Thank you, Mr. Miller.

MR. MILLER: Thank you.

MR. NEISER: Thank you, Mr. Miller.

CHAIRMAN DEASON: Just a moment. We only have one court reporter today. We're going to take five and come back again.

(Brief recess.)

(Transcript continues in sequence in Volume VI.)

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of: Proposed Amendment of Rule 25-22.081, F.A.C., Contents of Petition; and Proposed New Rule 25-22.082, F.A.C., Selection of Generating Capacity.	DOCKET NO. 921288-EU

THIRD DAY - AFTERNOON SESSION

VOLUME VI

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN J. TERRY DEASON COMMISSIONER SUSAN F. CLARK COMMISSIONER LUIS J. LAUREDO COMMISSIONER JULIA L. JOHNSON
DATE:	Friday, October 1, 1993
TIME:	Commenced at 8:30 a.m. Concluded at 4:45 p.m.
LOCATION:	FPSC Hearing Room 106 Fletcher Building 101 East Gaines Street Tallahassee, Florida 32301
REPORTED BY:	JOY KELLY, CSR, RPR Bureau Chief SYDNEY C. SILVA, CSR, RPR PAMELA A. CANELL Official Commission Reporters -and- LISA GIROD JONES, RPR, CM

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APPEARANCES:

(As heretofore noted.)

ADDITIONAL APPEARANCES:

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PROCEEDINGS

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CHAIRMAN DEASON: Call the hearing back to order.

This may be an appropriate time to try to discuss some plans for the remainder of today.

We will work through lunch today so please feel free to order in a lunch and to eat it here in the hearing room or whatever you like. The Commissioners I'm sure will be eating here at the bench.

As far as the evening plans are concerned, it's my anticipation that if there is any way reasonably possible that we can conclude the hearing today, that certainly would be desirous. And if it could be done without working terribly late, I will try to pursue that. And when I say terribly late I'm speaking of 6:30, 7:00 this evening but not past that time.

If it appears that there is no way possible, I see no need for even working that late. If we're going to have to have another day we'll just conclude it at around 5:00, which is normal time. I can't predict what that's going to be until we get into the proceeding if concluding by 6:30 or 7:00 is even possible.

There's been a question as to whether some

type of closing arguments are going to be allowed.

If there's time, that's fine with me, but you know what the time is as well as I do.

If anyone has anything to add, that's pretty much where we stand, and if anyone has any comments or suggestions, we'll welcome to hear from you.

MR. WILLIS: I just spoken with Mr. Neiser over the break -- with Mr. Hadaway, we would request that, to be able to put him on this afternoon and to take a read about 3:00 of where we are, and to work him in around that time.

CHAIRMAN DEASON: Okay. Now, I've also had a request from Ms. Swim and I've indicated to her that I would try to accommodate her, and that is if it appears that we're going to work late tonight and conclude the hearing today, that she'd like some consideration to be taken a little bit earlier. Unless there's strong objections by others, I will try to accommodate her in that request. But that's only if we feel like we're going to work late and conclude today. If it appears there's going to be another day required, she's certainly willing to wait until the next day.

MR. NEISER: Mr. Chairman, my only suggestion would be to try to get a straw vote as to how many witnesses are still wanting to get on to the stand at

this point.

I think some may have gone home, just maybe checking right now here in the hearing room as to the people who still would like to get on the stand will give us some feel of how good we're doing.

CHAIRMAN DEASON: That's a very good suggestion. Could we just have a simple show of hands of all those individuals who wish to come forward at some point during this proceeding and to give testimony.

MR. WILLIS: I think Tampa Electric has one that's not in the room.

CHAIRMAN DEASON: I count at least eight, and if there are individuals not presently in the room, that would be more.

MR. HOFFMAN: Mr. Chairman, Tallahassee may have Mr. Brinkworth provide some brief comments as well. He's not here right now.

CHAIRMAN DEASON: So we still have a considerable number of people. Of course, the pace could quicken as the day proceeds.

MR. NEISER: You've seen that happen before on a Friday afternoon, haven't you?

CHAIRMAN DEASON: I have seen that happen before. We'll go ahead, but my immediate announcement

right now is, so that everyone will be on notice, that we do plan to work through lunch. So whatever arrangements you need to make, please do so.

Mr. Neiser?

MR. NEISER: Thank you, Mr. Chairman.

At this time we are calling Mr. Gower, who is in the witness chair.

HUGH A. GOWER

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. NEISER:

Q Mr. Gower, I'd ask you if you would state your full name, your current status of employment, your address, if you would.

A My name is Hugh Gower. I'm self employed. My address is 195 Edgemere Way South, Naples, Florida 33999.

Q And by whom have you been previously employed most recently?

A Most recently I spent the last 33 years with Arthur Andersen and Company in the practice of public accounting.

Q Do you have any corrections to make to your prefiled testimony?

A I do not.

Q All right. Mr. Gower, would you please

summarize what you have presented to the Commission in written form?

A I'd be happy to and I know it will please the Commission to know that my testimony is short and my summary will be even shorter. Although it will present a contrary point of view to some of the views expressed on the previous two days.

My testimony covers the financial accounting and reporting requirements relating to purchased power contracts which cover the output of specific generating units or groups of units requiring the utility to purchase a large percentage of the output, if not all. Contracts which are long-term in nature, sometimes covering the entire useful life of the plant, and which impose the requirement on the utility to make fixed capacity payments over a long period of time. For financial accounting purposes, these are either executory contracts or considered to be an outright liability of the utility.

The accounting and reporting requirements include disclosure of the nature and terms of the contract, percentage of the plant being purchased, the aggregate remaining fixed payments, the nature and amount of variable payments, and in addition, if those are deemed to be an outright liability of the utility,

the contract is capitalized on the balance sheet of the utility as a contractual right to the plant and a related long-term debt.

These are the disclosure and accounting requirements contained in generally accepted accounting principles and the regulations of the Securities and Exchange Commission. And the notion is to make the facts, whatever they are, completely and fully visible to users of financial statements who frequently use those statements to make informed investment decisions. These requirements are not applicable only to purchased power contracts, but to any type of long-term contract or significant financial commitment.

The notion is very simple: These contracts which require the utilities to pay fixed amounts over a long period of time have some attributes of liabilities. They are either outright liabilities or they're major commitments. The larger, the major commitment or reliability in relationship to the company's financial resources, the greater the risk. And the risk is not just disallowance. It's the use of the companies financial flexibility, plus the potential risk that whatever those costs are, even if the Commission is willing to allow the Company to charge those costs, the market may not accept, and there are

examples of that.

The issue is not whether purchased power has a higher cost or a lower cost than utility ownership of a generating unit, but merely accounting for those cost, whatever they are. And towards that end and towards the interest of good accounting, cost accounting, and good economic analysis, my suggestion is that the Commission require that to be considered. That is, if higher capital costs to the utility are attributable to purchased power contracts, and we've heard testimony that that does take place and I agree with that, Then those should be assigned to the purchased power option in evaluating. Again, that doesn't mean that purchased power would be more expensive than utility ownership, it just means that the cost accounting ought to be good and accurate and economically correct.

Q (By Mr. Neiser) Mr. Gower, I believe it was Dr. Roach yesterday on the stand that was commenting about the structure of independent power producers and that frequently they are structured with the use of a partnership arrangement. From the accounting perspective, can you give any insight as to any concerns there?

A Yes. Well, the reason why they are

structured as partnerships is to further the financial strategy of the investors. And that financial strategy -- and it's a good one, I'm not being critical of it at all. The financial strategy of an investor in high risk projects, a venture capitalist as an example, their strategy is to at all times reduce the amount of capital they have invested. That is one of the ways in which they increase their return beyond that which might be available to a utility owning a project.

The reason why a partnership is used is because through a partnership, the benefits of the tax losses which will occur in the early years of the project pass through to the investors as contrasted to utility ownership, tax deductions occur through accelerated depreciation. If the utility owns the power plant, those are retained in the deferred tax reserves of the utility and reduce its rate base. That's not so with a partnership. Those pass through to the partners, they use those tax benefits to offset their other income, which presumably would be substantial, and that way they reduce their investment.

I'm not being critical of that in any way, that's good financial strategy and that is how they are able to craft a contract which may, in some circumstances and does in many circumstances, offer a

purchased power price to a utility which is cheaper than if the utility owns the project itself.

The risk is and I'm sure investors in these projects account for it is that, Congress in its infinite wisdom, might again change the tax law, as they did in 1986 and 1993, to retroactively change the ability to use tax deductions. I think that's a horrible thing. It's un-American, it's unfair, and it shouldn't happen. But it has happened and it is a risk, and that's one of the reasons why the suggestion of Florida Power to use a diversified portfolio strategy to mitigate risk is a good idea.

Q Mr. Gower, while you were offering your comments, I believe it was Commissioner Clark who was asking Mr. Wright when he was on the stand as to whether there are any financial implications of an option for a utility to purchase the generating unit at the end of the contract. And are there any concerns there, again from the accounting perspective?

A Well, it would have an implication, most certainly if the utility had an option to purchase the generating unit at the end of the contract or at some point in the contract, at net book value as Commissioner Clark suggested, that contract would be required to be capitalized on the utility's balance

sheet and shown as an outright liability. It would also show the asset.

That's as contrasted to merely having a disclosure in the footnote of how much money the Company owes on the remaining fixed payments of the contract.

From my point of view it makes no difference whatsoever what the accounting is, whether it's actually put on the utility's books or merely reported in its footnotes, doesn't affect the economics of the contract the costs are whatever the costs are and it's either a better deal or not as good a deal as utility ownership. There are some examples of purchased power contracts which are, in fact, capitalized on the utility's books, because of factors such as the option to purchase. But it doesn't change the economics, it just changes how it's shown on the company's books. So there's no bias as a result of that against a purchased power contract.

Q So there would be no competitive advantage then resulting from this -- and that a purchased power contract could still compete with the utility?

A Absolutely. Absolutely. It's whatever the facts are and whatever all the costs are. As Mr. Wright suggested, if the venture capital investors gave

up the right to whatever residuals there were, then their price to the utility would change. And I think that would be right. We've seen that in real estate contracts, lease transactions; a lot of that goes on in the cable TV industry as well.

Q Mr. Gower, is it fair to say then the reason Florida Power came to you for your testimony here is that from the perspective and an outside independent financial auditor of the financial statements of Florida Power, if they require the recognition and accounting of costs resulting from purchased power, that in turn the Company ought to acknowledge those costs in the evaluation of its bids for purchased power?

A Yes, that's true. And, of course, it's not the outside auditors who require the accounting recognition, it's the rules of generally accepted accounting principles, and currently the SE -- excuse me, the Security and Exchange Commission has a high degree of interest in the treatment of purchased power contracts, and they may impose requirements beyond generally accepted accounting principles. And the financial managers of any company, and utilities as well, have to comply with those in preparing their financial statements and reporting to the public.

As I say, the whole object of these required

disclosures is merely to lay out the facts, whatever they are, so that anyone who uses the company's financial statements will understand them.

MR. NEISER: He's available for questioning.

CHAIRMAN DEASON: Mr. Cresse?

MR. CRESSE: Mr. Chairman, I have had the opportunity to learn from Mr. Gower for about 14 years and I hate to pass it up today to learn some more, but in the interest of time, I'm going to do that. But I want you to know I think it's a sacrifice on my part. (Laughter)

CHAIRMAN DEASON: We appreciate your sacrifice.

CHAIRMAN DEASON: Mr. McGlothlin?

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Gower, only a couple of questions.

You've described, I believe, from an accounting standpoint to recognize any costs associated with the purchased power option. Would you agree with those other witnesses who have acknowledged that from the standpoint of comparing purchased power to the build option, it's important to identify, compare all costs of both options for the benefit of the ratepayers?

A I certainly do agree with that.

Q Now, you've talked some about the particular

capital structure that some independents may avail themselves of. Would you agree that in order to be competitive, either the independent or the utility has to do a lot of things well and capital structure is only one consideration?

A Certainly. The project has to be well constructed and operated well to be competitive.

MR. McGLOTHLIN: I don't have any further questions.

CHAIRMAN DEASON: Staff. Commissioners? Thank you, Mr. Gower.

MR. GOWER: Thank you.

MR. NEISER: Mr. Gower, you dodged some bullets today. Congratulations.

Thank you for being with us.

MR. GOWER: Thank you.

(Mr. Gower excused.)

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MR. NEISER: Next witness is Mr. Wieland.

KARL H. WIELAND

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. NEISER:

Q Mr. Wieland, good afternoon. I'd appreciate it if you would state your name and address for the record, and who you are affiliated with.

A I'm Karl H. Wieland. My business address is 3201 34th Street South, St. Petersburg, Florida 33711 I'm employed by Florida Power as director of business planning.

Q Have you prepared some comments for the benefit of the Commission on this rulemaking docket?

A Yes, I have.

Q Do you have any corrections to make?

A No.

MR. NEISER: All right. Before we proceed, Commissioner Johnson, can you see the witness from where that sign is? Let's do something about that. Let's try it over here if we can.

Q (By Mr. Neiser) Mr. Wieland, would you please summarize your prepared comments?

A Certainly. At the risk of maybe beating a horse that's been beaten a lot today, namely, on the

cost of capital issue and the impact on the purchased power, I'd like to contribute a little bit additional to that.

We've had a lot of discussions about the impact of purchased power today and the fact that it should be taken into account when they do a build-versus-buy decision. I agree up front that the same considerations need to be taken account into the build decision.

What I'd like to do today really, is to give the Commission a little bit of comfort in the fact that there are ways to actually make that calculation. That it's not as difficult and involve as many factors as, for example, the consideration of externalities. And to do that I'd like to just very briefly walk you through the way we would propose to treat those.

I'm not -- we're not here today to ask you to accept this methodology or the numbers they are for illustration to give you some comfort that this can actually be done. I'd like to do that for the purchase option and then I'd like to make a couple of comments about how risk of construction and other things are taken into account when you do the build option.

The final point I'd like to make is as the other witnesses have stated, we believe that the rule needs to be modified, that rather than just discussing

these impacts, that they actually be -- that there's a requirement to take them into account when the utility comes to you with a build or buy proposal and a selection.

With that, let me put up a couple of charts if I could. If I had a pointer I could do my Ross Perot imitation today but -- okay, here we go.

Let me begin by saying, Commissioners, that evaluating a decision as to build something or purchase something and buying something, something we've been doing for the last couple of decades, so what I'm showing you is not anything that's been newly invented. I certainly didn't invent it so I don't take credit for that. I may take some credit of saying this ought to be applied. But we routinely do the same analysis I'm going to show you in-house. For example, to make the decision that we just did recently as to whether to buy a computer system and own it, in other words, or whether we ought to go lease it from some third party. We make the same decision for office buildings; some of our buildings in district office are leased, some of them we own. We make the same decisions that some utilities do on cars. Sometimes you lease a fleet, sometimes you own it. So the kind of decision-making process and the kind of analysis is consistent with that, and there's nothing new about it.

Let me begin, the first thing that you do -- and this is sort of the same thing that a company like S&P does, is identify the total liability that you have when you start entering into a contract where you have to make fixed payments, and calculate the present value of that. In Florida Power's case, I think you've been told that we have approximately 1500 megawatts; some of it from utilities, about a third of it -- the other two-thirds from QFs. I make no distinction between those two.

What you do is you look, you take a look at all of the payments, the fixed payments, not the energy cost, that you've obligated yourself to and you do a present value calculation. In our case, that's about $3 billion over the next 20 or 30 years. The reason it's so large is because our capacity payments alone are going to be reaching 300 million a year within two years and escalating to as high as $500 million, so we are talking about very large numbers.

Now, where of the analysis differs is that in most lease-purchase analysis, that obligation is viewed as 100% debt. When you do a purchase of a power supply, that is generally not true. In fact, it ranges -- and this again is something that is strictly taken from S&P's methodology, it ranges all over the map from

virtually nothing to 100%. These would be some of the sale lease-back transactions that people have engaged in in the years past with nuclear plants. Those S&P would consider virtually debt equivalents.

On the extreme other end of the scale, you're going to say, is there ever anything at zero? Yes. Anything that does not have a fixed payment stream? The broker system. We have contracts with other utilities to buy on a broker system or with other arrangements on sort of a daily basis with no commitment, that has absolutely no risk.

What we're talking about here today for the most part are performance-based contracts with qualifying facilities that basically say, "It doesn't really matter whether we need the capacity or not as the purchaser, as long as the owner of the facility produces it, it gets paid." It only does not get paid if the facility doesn't perform to certain standards. And those contracts typically will be in the 10% to 50% range.

Now, how do you -- I don't want to spend a whole lot of time going up on all of the factors that S&P takes into account when they decide where that falls. But three of them are very important because they have been talked about a lot here today. One of them is preapproval. One of them is a capacity cost recovery

clause, and the other one is a regulatory out clause.

What S&P says, very specifically, that those are three things out of many others that you have to have, that you have to have in order to get down to the minimum 10% level. Others include things like dispatchability and a number of other factors. The main point here is that -- because the point has been made by a number of witnesses, if you have a capacity cost recovery, and if you have preapproval, and if you have a reg-out clause, then the risk goes away.

That may be their opinion, but it's not S&P's opinion, and it's S&P's opinion is the one that counts because they basically are the referee and the judge. What they're saying, is very specifically, that in order to get down to the minimum risk level, you have to have all of those. What I'm doing here, and quite frankly, I have spent a lot of my time speaking with people like Curtis Moulton and Debbie Goldsmith at S&P, convincing them that we should be right here at the minimum. So we have told them all the great things that we have. We have not gotten a final ruling of it but I'm quite confident that they're going to look at our arrangements as being very favorable, and at the low end of the risk spectrum. But the risk again that they're going to assign is not zero.

Let me then just briefly say well, given that what do you do with that? The methodology that we will propose is very simple. It says that without a purchase here is Florida Power's current debt/equity structure, approximately 1.3 billion of debt and 1.7 billion of equity, which is about 43% debt and 57% equity, including nonpreferred stock and things of that nature. Our purchased power equivalent, using the 10% risk factor and it's 10% of that $3 billion is $300 million. When you add that debt equivalent to your regular debt, which is exactly what S&P does, And that is strictly by their methodology, you distort the two ratios. All of us now have 48% debt and 52% debt. And all we're saying is that we have to rectify that. Not only am I saying that, but S&P says that. It says, "If you want to retain the same credit quality that you have absent a purchase, you've got to get back to the same debt structure that we would expect you to have for that rating."

And to do that, you have to put additional equity into the business. You can also do it by getting higher ROEs, but my proposal is that it would make more sense to put additional equity into your capital structure in order to get back to the same point where we were. In this example, to get back to

43% debt and 57% equity, you need to add 175 million of equity, not 300 because some of this equity is actually used to pay down some debts, some roughly speaking, if you have a 50/50 debt/equity structure then you only have to put in 50 cents of new equity for every dollar of purchased power obligation.

Another point I'd like to make here briefly is you say, "Well, how do we know that that $300 million is the right number? What I would propose is that we use the number that S&P calculates, not the one I calculate, but the one that S&P calculates and uses it. If you look at their latest ratings, it's a document that's been talked about a little bit, the June credit review, they are beginning to publish that number. It's not in there for all of them yet, but it's specifically for companies like San Diego Gas and Electric and Southern California Edison, this book actually contains what this number is. In other cases they've told you what the recomputed ratios are, but there's no problem obtaining that information. Once S&P has finished with our analysis, which they're in the process of going through, we can call them, you can call them and they can say, "What is FPC's debt equivalent?" And it will be -- you know, it may not be exactly 300 million to begin with because it does change

from year-to-year. But it's not a number that we make up. So it's a number that's readily available and it's done even if you went by an independent third party.

To summarize, how does this restructuring of your capital structure affect your cost, and that's really what the bottom line is. That $175 million has a revenue requirement associated with it, 12% return plus whatever income taxes that are associated with that. And that, just in round numbers, is $34 million.

There's a benefit to it because you use that money to pay down your debt. If you're using just 8% for illustrative purposes, that will give you a net effect, a net cost of about $20 million a year.

Now, when you put that in relationship to capacity payments that are 300 million to 500 million a year, you get a cost or an additional cost that's in the neighborhood of 5% to 10%.

And the reason I bring that up is because, you know, we've heard a lot about -- that there is a cost, and at least I wanted to give you some idea as to how big that cost is. And I don't think we're talking about anything gigantic. 5% or 10% in my opinion is something that easily can be overcome by any IPP just from the cost of capital advantage that they have. The fact they're going to purchase with 80% or 90% debt,

rather than 50%.

Let me then make just a couple of other comments about the build side.

You've heard a lot of discussion about yes, we buy this argument, fine. But building is so much worse. I don't necessarily agree with that. Clearly, there is a risk associated with building. But to a large degree the cost structure of the utility already reflects that risk. When you folks give us 12% ROE, the reason it's 12% and not 7% or 8% or 9% is because of the risk premium. You know that we, as equityholders, are going to be taking some risks. Now, what are those? The risk of building a power plant and getting it disallowed is one of them. The risk of our expenses getting out of hand is another, the risk of our revenues showing up is another.

And that -- so our cost, not that there is not a risk to construction, but I think the point to remember is that our cost already reflects that risk. And only to the extent that the riskiness of what we take on as new construction is out of line or exceeds the risks that are part of our normal ongoing business if there is some extra cost. And clearly, if we were to go out tomorrow and announce that we were going to build another nuclear plant, the perception in the

financial community is that that risk is significantly greater than what the 12% ROE allows for and what our 50/50 cap structure allows for. And it would immediately trash our ratings, unless we did two things: One is to convince them that we could mitigate it, and two, that we decided that we're going to try to finance all of that with equity and not float any debt. Not that that could be reasonably done.

There's a second aspect to it and it's important to remember that.

Another reason that the -- that construction may carry risk but not necessarily an extra cost, is because we build typically any project with the same 50% to 55% equity. So we put a lot of owner capital in there to begin with which shields the amount of debt that has to be borrowed. So again, that's already accounted for. And finally, I think something that also needs to be ignored and again when we present our case to you sometime down the road when that decision comes up, we intend to factor that in, is that the risk with construction, and the risk with ownership, need to be considered over the entire life cycle. The risks are predominantly during the construction phase. I mean, what people are worried about, and those are the people that lend us money, are is it really going to

cost what you think it's going to cost? And are the regulators going to disallow some of those costs?

Now once that project is in rate base and allowed, then the benefits of ownership become huge, because now you've got cash flow generation, you have a return on investment, and so there's sort of a turnaround. The risks tend to be during the construction period. And in order to properly analyze the benefits and the risks and the costs associated with the build option, you need to look at it over the entire life cycle.

Those are the comments I have. And again as I mentioned, we don't expect you as part of the rule to say, "Yes, here's how to do it." The only thing we ask is that the rule become specific enough to where this kind of analysis goes beyond just a discussion stage, but actually becomes part of the analysis that's required in front of this Commission.

MR. NEISER: Thank you, Mr. Wieland. He's available for questions.

CHAIRMAN DEASON: Mr. McGlothlin? Mr. Watson?

CROSS EXAMINATION

BY MR. WATSON:

Q Mr. Wieland, I'm Ansley Watson.

Would the method you have proposed here and

in your testimony be used only for the purpose of comparing the net present value revenue requirements of a purchase option with those of a build option, or would you suggest that they be used for other regulatory purposes as well?

A Well, it's to do the build-versus-buy option. It may be applicable to other things but you'd have to get more specific.

Q For example, you wouldn't expect the Commission, in a revenue requirements proceeding, to use this imputed or reconstructed capital structure for ratemaking purposes?

A Yes. I think I am saying that. What I'm suggesting is that to the extent that the utility has to maintain its financial integrity with purchased power, that the utility has to revise its capital structure exactly in the same manner that I'm proposing here, so that when there is a rate case and a rate issue, those costs actually get incorporated into the decisions. Yes, I think --

Q But that would be true only if the purchase option were selected by the utility as the least-cost option at any given point in time.

A Yes.

Q All right. So the real purpose, then, would

be to add on to the costs associated with the purchase option for the purposes of comparing it with the build option. If those additional costs that are identified by your proposed method result in a choice by the utility of the build option, because it turns out to be cheaper, then the Commission would not need to make these capital structure changes, because you wouldn't have to issue additional equity that you say you should issue.

A Well, I think there is still the issue that when the utility builds, when it comes in for a rate case and determines the revenue requirements for that, the capital structure that the utility has at that time for whatever reason, in this case a building, will still be at issue, so it's there indirectly.

Q I understand that. But that's a function of what the utility has done in terms of making an investment in new plant.

A Yes.

Q And that investment would be supported by whatever the capital structure of the utility was at the time the investment was made, or after the making of the investment?

A Yes, I think so, other than -- one of the things I'm saying is that your capital structure may be

affected by the fact that you made the investment.

Q Correct. I understand that.

A Sure.

Q So you either get the cap structure that reflects the investment made by the utility in order to pursue the build option, or after having pursued the build option, versus a capital structure such as that you have suggested if despite the add-on to the IPP cost for purchase, if you select the buy option?

A If I understood you right, I think it's yes.

Q Mr. Wieland, in your direct testimony on Page 7, Lines 24 to 25, and then continuing over on to Page 8, Lines 1 to 3, you state, "The Company's credit rating has been sustained despite the fact that the financial community is aware of the Company's plans to construct generation capacity. There is no question that FPC has the financial strength to finance Polk County 1 and 2, as well as additional generation capacity, without endangering its credit quality."

In making this statement do you rely fairly heavily on the fact that Florida Power Corporation's credit rating has not been disturbed by your construction plans?

A Well, I think I rely on it more than that. That's one factor. But the credit rating agencies know

of our construction plans; they see our capital outlays; they see the kinds of financial ratios that we will be maintaining. So they look at it, but part of my job is to look at that too. Part of my job as a company, when I do financial planning, is to go out and look to make sure that what we have in terms of a construction project does the same thing, namely, not endanger our financial well-being.

Q Right. And very clearly it might help out a little bit. Very clearly, if I see that happening, then what you look at is, (a), is there some other way of getting there, and certainly, the purchase option is one that we have looked at in the past and will continue to.

Q Yes, sir. And you, being prudent, as do the rating agencies, look out into the future in making judgments about most of these matters, do you not?

A Well, I don't know if we look out in the future because I'm being prudent. We don't have much choice in the matter.

Q Correct. But I'm saying you look into the future as a matter of course?

A Yes.

Q I'd like to show you your form 10K filed with the Securities and Exchange Commission. And I assume

you've seen this document?

A I know they are around. Frankly, I haven't read them.

Q Well, I'd like to call your attention to two matters in the 10K.

A Okay.

Q I have an excerpt here, rather than using the whole book. (Hands document to witness.)

Mr. Wieland, in the excerpts from Florida Power Corporation's 10K that I've given to you, on Page 30, I guess the second portion under -- about the middle of the page that's headed "Utility Revenues, Fuel and Purchased Power Expenses," the second paragraph basically spells out the fact that "revenues in these categories include amounts resulting from fuel, purchased purchase and conservation adjustment clauses which are designed to permit full recovery of these costs." And then it goes on to explain how those cost recovery mechanisms work.

And you have indicated that the full recovery of costs is contemplated by these adjustment clauses that are in place?

A Yes.

Q Would you agree that Florida Power Corporation has fully informed the financial community

regarding its purchased power obligations?

A The purchased power obligations, from what I recall, are disclosed in the management discussion sections of the various documents that we file.

Q Correct. And you would find that on Pages 42 and 43 of the excerpt that I've given you, would you not? For example, on -- after discussing the purchased power agreements and the capacity payments and the present value thereof that's shown on Page 43, the second paragraph below that states "the Company does not plan to vary materially the level of purchased power it currently has under contract. The Company believes that its current contracts allow for system reliability and help reduce construction expenditures. However, without a change in regulatory policy, these contracts could weaken its overall credit ratings."

Now, despite this disclosure and the fact that S&P is fully informed also about what it is Florida Power Corporation has done and is doing, the market, and in particular S&P has not downgraded Florida Power Corporation's credit rating, has it?

A That's correct. Although I'll be very frank with you, that is probably the single biggest concern that we have at this stage.

We are pleased that we have not been

downgraded. We are concerned a great deal that it is just a matter of time. Because, clearly, when you look at what our restated ratios look like, when you take that into account and we've done that calculation --

Q And you've graphically depicted them in some of the charts --

A Exactly.

Q -- attached to your testimony?

A It tells you that you're not really a double A anymore because as you may know, we're double A-minus to begin with. So it's not like we have a tremendous amount of cushion.

I can tell you that we have told S&P that we will do what is within our power to try to remain there. If you read their latest credit review of us, it mentions purchased power. It also mentioned specifically a very strong dedication to credit quality. What we have, in essence, asked them to do and will continue to do, is that this is a relatively new issue, and it's something that has been defined and come up with over the last couple of years. Don't hammer us right out of the box. Give us a chance to first of all, you know, have you tell us what your expectations are, and give us a chance to respond.

And we hope to be able to do what we can in

order to maintain the rating, but there's certainly no guarantee at this stage. Just the fact it hasn't happened does not give me a great deal of comfort.

Q I see. Now back to Page 43 of your 10K, the last sentence that I quoted off of there, says, "However, without a change in regulatory policy, these contracts could weaken its," Florida Power's Corporation's, "overall credit ratings."

You have cost recovery clauses in place; you have contract preapproval. What other or additional regulatory policies does Florida Power Corporation feel are appropriate to prevent purchased power from weakening its credit rating?

A The recognition that a change in capital structure is necessary to compensate for that. I did not write this so I can't tell you everything it had in mind. That would be my interpretation, is that the Commission has to recognize that yes, there is some liability, and it does change and affect your ratios, and they feed to be fixed, which is very much, from what I've understood, is what Southern California asked their Commission to do. I'm not totally familiar with that but it's the same concept.

Q So you would construe the sentence that I quoted out of here to mean take corrective actions in

terms of changing the capital structure to the extent you do decide to make purchases rather than build?

A Yes. And it may not be that we will ask the Commission to change it for us because the Commission doesn't dictate the capital structure as it is.

What we envision is that when we come to the Commission during the rate case, and we have a capital structure which may have been adjusted for that, you know, from our own perspective, is that the Commission doesn't say, "No. Wait a minute. If you have too much equity without giving us a chance to explain, well, here is why we have this additional equity."

Q Correct. (Pause) On Page 5 of your testimony, and this is related to the questions I just asked you: At Lines 11 and 12 you indicate that "FPC will continue to monitor its credit measures and take corrective actions necessary to preserve its credit standing." What corrective actions might these be?

A Primarily, making sure that our debt/equity structure and our coverage ratios for interest are sufficient to maintain the credit standing. And to some degree that's going to be some give-and-take between us and the credit agencies, because, you know, it's one of those things where they have not told us exactly what their expectations are down to the nearest

detail. But that discussion will continue, and we will just do what we can.

Now, what I cannot guarantee clearly is that if the cost of that is too much or if we simply feel we can't issue the equity, somewhere along the line we also have to make a decision is it even feasible to keep the rating. At this stage we think it is but I can't make those guarantees down the road.

Q I see. And, likewise, you cannot guarantee that if you are not able to maintain the various financial indicators that are required by S&P to maintain the rating, you can't guarantee that S&P will downgrade you?

A No. In fact, I hope they don't.

Q Have your lenders recognized what is shown in your charts, or have they recognized the purchases that Florida Power Corporation is making now, and will be making in the not too distant future?

A Well, I'm not sure that I've got the expertise to say that. I almost have to go back and reach back to Mr. Miller's testimony, who is a lender basically, he represents them. And when he tells me that, "Yes, we look at what S&Ps are doing and we are aware of those," then that tells me, yes, they are very much aware of that and take that into consideration:

What I have not had is any direct contact with the lenders because that's not part of my job.

Q Okay. You're not here today saying that because of the purchases you've made, that your cost of debt has increased?

A No.

Q At Pages 9 and 10 of your testimony you talk about purchasing power providing no cash flow for the utility to use in financing future generation projects. And over on Page 10, at Lines 2 through 5, you state "Those investors receive all of the benefits of the cash from depreciation and their return on investment, but have absolutely no obligation to use those funds in order to build future facilities for the purchasing utility."

Here you're making a statement with respect to the investors in an independent power project from whom you might purchase?

A Yes.

Q Does a utility have a obligation to use cash flows from depreciation and return on investment to build future facilities?

A I would go back and say that a utility has an obligation to provide service to customers. Exactly how it chooses to do that, I'm not sure is that

relevant. The way it finances new construction, typically is from the funds, the internal funds as they are sometimes called; come from depreciation, come from deferred taxes and come from a return on the investment.

Q Correct. And to the extent you -- well, you make a statement on Page 9 that purchased power provides no cash flow whatever for the utility.

A That's right.

Q Now, is that really correct?

A Yes. Simply because every dollar of purchased power capacity is recovered through the capacity cost recovery clause, dollar for dollar. We pay a dollar, we recover a dollar; there's nothing that goes to the company.

Q But your rates are not comprised only of fuel or purchased power cost. When you turn around and sell the product basically that you have purchased from the IPP or from Southern Company or from some other utility, do you not receive at least some return on your investment in your distribution facilities, for example. Because of the fact that when the price to your customer, who is buying from you, includes not only a portion to recover your fuel and purchased power cost, but it also includes a base rate for your

service, does it not?

A Right.

Q Is there not a -- isn't that where you basically recover your cost of service as a utility?

A Not for capacity. Simply because you have a separate clause.

I think your argument might be valid if you had that as part of base rates but it's not. The purchased power and fuel are strictly on their own regulatory mechanism, so its revenues flow exactly with the expense. So there really is nothing that in any way, shape or form, stays with the utility.

Q To recover those costs, in other words, the -- if you recover what you would have normally recovered through base rates for your investment in the plant that generated the capacity and energy?

A Right.

Q Do you recover through the clause your transmission cost?

A No. Those are all in base rates.

Q Correct. That's what I'm saying. When you send your bill to the customer who ultimately consumes the electricity you sell, that bill is in several parts.

A Right.

Q It has a base rate for whatever class of service the customer is taking.

A Uh-huh.

Q And that base rate includes a return to the utility, does it not?

A It includes a return on its investment along with all of the other expenses that are not under a separate clause.

Q Correct.

A And the problem is that with purchased power there is no investment.

Q Okay.

A So, therefore, there is no indirect benefit from that.

Q Could we say that you're receiving a return through your base rate on the generating plant that is in your rate base but which was not used to produce the particular electricity being purchased by the customer?

A I'm not sure I know how to answer that, because we don't color code our electrons as to where they come from.

Q You can't.

A The intent of base rates is to make the utility whole for its investment, a return on that investment, and other expenses that it has.

Q Correct. I guess my point is that when you purchase power from an IPP, you pay a capacity payment and you pay an energy payment.

A Right.

Q When you turn around and sell the energy that you have purchased, you don't just charge your purchaser for the energy at cost?

A Yes, we do.

Q Do you not charge a base rate in connection with that sale as well?

A No. No. Everything we buy, whether it's from another utility or from a NUG, is recovered purely through the capacity cost recovery mechanism.

Q There's no charge for distribution, transmission?

A Well, but that's --

Q Meter reading?

A Sure. Sure. But that's a charge to take care of those investments and those expenses.

Q I understand that. But you make that charge in addition to the charge for the energy you have sold?

A The entire cost of purchased power and the revenues that it would get from that are treated in the fuel or purchased power cost recovery clause, and there's no mixing of that with base rates. They are

two completely separate items.

Maybe it would be easier, because I'm really having a problem with that. Either I'm not understanding your question or maybe you don't understand the mechanism. But, you see what I'm saying? All of the expenses, every dollar that we spend for fuel and capacity costs, and energy conservation is in that same category, every dollar we spend is matched with a dollar of revenue; not base revenues, but a dollar of revenue that comes from those recovery factors.

Q I understand that completely. Let me see if I can get the pot right here. (Pause)

You buy one kW from an IPP.

A Okay.

Q Okay. Forget the capacity side. What do you pay the IPP for that kW? Whatever you contracted to pay; is that right?

A Sure.

Q Okay. You sell 1 kW to a residential customer, okay?

A Okay.

Q Are there charges on the residential customer's bill for that one kW in addition to whatever your fuel adjustment charge is at the time?

A For that purchase?

Q Yes.

A Yes. It's under an item called "capacity cost recovery."

Q Okay. There is no base rate residential charge for that?

A No.

Q How do you know when to leave the base rate off of the 1 kW that your residential customer is billed for when you don't color code the energy and capacity?

A I'm sorry. I don't understand that.

COMMISSIONER CLARK: Mr. Watson, I'm having a hard time understanding the point you're trying to make. And since this is rulemaking, why don't you just state it --

MR. WATSON: I'm trying to understand how a utility, which charges its tariff rates, does not charge its tariff rate when it turns around and sells purchased power.

MR. WIELAND: Well, it does charge a tariff rate.

Q (By Mr. Watson) But you said it's not on the bill.

A No, I didn't say that; it is on the bill.

It's on the bill as a separate item. In other words, the recovery for fuel and purchased power is on the bill.

Q I understand that.

A Okay. But it's not part of base rates.

Q I understand that. But there is also, when the residential customer gets the bill for that kW, is there a customer charge on the bill for that month?

A Sure.

Q Is there an energy charge for the 1 kW on that bill? Right out of your tariff.

A An energy charge.

Q Yes.

A When you say that 1 kW, a kilowatt hour maybe might be better for residential.

Are you talking about the purchased power kilowatt hour or just --

Q I'm talking about you sell electricity to your customer.

A Uh-huh. He gets billed, like 8.00, 8.50, or something, for a customer charge and so many cents per kilowatt hour for energy --

Q Right.

A -- so many cents per kilowatt hour for fuel and so many cents per kilowatt hour for capacity.

Okay?

Q Correct. Now, he gets the customer charge, the energy charge, the fuel adjustment charge, the capacity charge.

A Right.

Q Whether or not the kWh that he is purchasing that month was generated by one of your plants or by an IPP with whom you have a contract?

A No. The base rate would include whatever plant investments we have.

Q I understand.

A If you purchase something, then, in essence, his purchased power cost would go up. I'm really trying to be responsive but I'm having a hard time understanding.

MR. NEISER: Mr. Chairman, let me just --

MR. WATSON: I thought that this was fairly clear.

COMMISSIONER CLARK: Not to me.

MR. NEISER: And I understand. It's not a matter of being recalcitrant, it's a matter of communication. Let me just try this.

What I think Mr. Wieland is trying to say, is yes, there is a base rate charge to the customer when there is purchased power that is going to them. But

those revenues that are received through that base rate charge pay for nothing other than what the company has invested in and/or has in the way of operation and maintenance expenses. None of those dollars go towards the cost of the purchased power.

MR. WATSON: I understand that completely. What do those dollars go to?

MR. NEISER: To the investments of the company, such as the transmission lines and the distribution lines, and for the salaries of people and maintenance expenses.

MR. WATSON: Are those cash flows to the utility?

MR. NEISER: Clearly, but to reimburse it for its investment and its operating and maintenance expenses. None of those cash flows go to help pay for purchased power.

MR. WATSON: I agree with that 100%.

MR. NEISER: Then I think both of us don't understand your question.

MR. WATSON: I just asked if there were cash flows to the utility and you said "Yes, but." I understand "yes"; he's already given me the "but" in his testimony.

Now, they may go for investment in plant to

the extent that the return portion of the base rate is not paid out as a dividend.

Do you understand that? I mean there's a return to the utility in your base rate.

MR. NEISER: No, we have a problem, because I think Mr. Wieland is clearly stating, and I would agree totally with what he's saying, there is no markup, not one dollar markup to the customer for purchased power.

MR. WATSON: Listen, I'm --

MR. WIELAND: Let me --

MR. WATSON: Basically, we recover our purchased gas cost the same way you recover your fuel adjustment cost. However, to the extent you are charging a base rate on your resale of power purchased from a nonutility generator, there is a return on your equity investment in your entire company included in that rate, or else your rates aren't very well designed.

CHAIRMAN DEASON: Maybe I can simplify this. I'll give it a shot anyway.

There may be a problem talking about cash flow and profit or markup. I think what Mr. Neiser is saying is that when that kilowatt hour from the NUG goes through the system, that that kilowatt hour that registers on the metering is billed and that goes to

pay for costs that have already been incurred by the utility in providing that service.

So there's really no additional profit -- but there is cash flow, and I think that's what Mr. Watson is getting at is the question is about cash flow. So, yes, the kilowatt hour comes from a NUG and goes through the system and registers on the meter, it generates cash flow. Now, whether that cash flow results in any additional profit or not is a whole different question but I don't think that's his question. It's strictly cash flow.

Now, am I understanding the question?

MR. WATSON: That's correct, but to take it just -- and I'd love to get off of this.

Q (By Mr. Watson) To take it just a little bit further, to the extent that the utility's base rates were set properly to recover its cost of service, and to the extent that that cost of service includes a return on the utility's investment; which the utility is not obligated to spend for a new plant; which it is not obligated to pay out as a dividend; which it is permitted to use in any way that is prudent, there is some -- a portion of the cash flow is also returned, which can be used, albeit small an amount, it is some return for future investment for the utility. Do you

disagree with that?

A Well, I don't think so but I'm not really sure I fully --

Let's see if this is right: Clearly, the cash flow that we collect from base rates is in excess of the cash flows we have to meet bills. Because one of the expenses, one of the major ones is depreciation which is not a cash expense. And my whole point of my testimony is that that's cash flow that we use to build new power plants.

And, you know, if I got the gist of your question right, you're asking me, isn't there some cash flow from the fuel or from purchased power. And my response is that no, that -- yes, we have cash coming in, but, then, it's only enough to pay the bills, and --

CHAIRMAN DEASON: Let me ask a question, Mr. Watson. I hate to interrupt, but we need to get through this.

If you had no purchased power and you generate a kilowatt hour of electricity from your own plant, it goes through the meter and you bill for it, there is a small portion of that kilowatt hour which is recovery of depreciation expense.

MR. WIELAND: Yes, sir.

CHAIRMAN DEASON: It's a small portion which is return on equity investment.

MR. WIELAND: Right.

CHAIRMAN DEASON: And both of those are cash flow above the normal requirements of cash outflow. In other words, depreciation expense is normally considered a source of funds.

MR. WIELAND: Exactly.

CHAIRMAN DEASON: And to the extent you have return on equity, that's funds available to pay dividends or to reinvest in the business.

MR. WIELAND: Exactly.

CHAIRMAN DEASON: Now, if you replace that 1 kilowatt hour, do nothing else except just buy it from a NUG, it still goes through the same transmission lines and distribution and it registers on the meter. And you bill it and you get the same dollar of revenue from the customer for that. And to the extent that there is a small portion of that which is a return on equity, that's cash flow to the company. And to the extent there's a small portion of that which is depreciation expense, that's cash flow to the company.

Now, is that right or wrong?

MR. WIELAND: Well, no, I think that's right. What you're saying, Commissioner, is that if we decide

to buy it from somewhere else rather than generating it ourselves, the cash flow from base rates does not change.

What happens, though, is there may be an additional expense for the purchased power which may be offset by fuel savings. But that cash flow gets washed out in the fuel recovery clause.

CHAIRMAN DEASON: It may be the same cash flow and maybe not additional dollars coming to you, but the sale of that kilowatt hour from the NUG does generate the same revenue as if you had generated it yourself. And whatever cash flow your kilowatt hour would have generated, theirs generates the same cash flow.

MR. WIELAND: That's exactly right, Commissioner. But the difference is that we don't get any additional cash flows. Our cash flows are what they are. If we buy more purchased power, there is no additional cash flow, and I think that's really the basic issue.

CHAIRMAN DEASON: Right. There's maybe nothing additional. I don't know if Mr. Watson assumes there is. I'm not assuming there is in my question. There may be nothing additional, but there is cash flow generated.

MR. WIELAND: Because what I'm struggling with, Commission, and, you know, you know that I'm very involved with fuel adjustment, purchased power cost recovery. And one of the basic premises that we all work with is that there is no earnings, there is no return; it's a flow-through.

CHAIRMAN DEASON: And I don't think the question relates to earnings; it's a question of cash flow, and the two may be related but they are certainly not the same.

MR. WIELAND: No. So that's why I'm struggling, you know, trying to understand.

What I'm hearing is that it really isn't a flow-through, and I'm saying, well, unless we're doing something wrong that I'm not aware of, that where we keep something. And the only place where I can see a little bit of extra cash flow is this 80/20 split on economy. But beyond that, I'm lost --

CHAIRMAN DEASON: Well, you could argue, and it's probably too small to even measure, but to the extent that there are some variable operating and maintenance expense at a plant you don't have to incur because you buy, there may be some small fraction of a fraction.

MR. WIELAND: Yes, but I'm almost assuming

that's too small to -- yes. That's absolutely right.

MR. WATSON: I'm looking primarily at the return on equity, and I think I have gotten clear, with help from the Chairman, what I wanted to make clear.

And, Mr. Wieland, I have no further questions. Thank you very much.

MR. WIELAND: Thank you.

CHAIRMAN DEASON: Thank you, Mr. Watson. Staff.

CROSS EXAMINATION

BY MS. RULE:

Q Mr. Wieland, I'm Marsha Rule from the Commission Staff.

In one of your examples earlier you mentioned that the example didn't distinguish between purchases of power from utilities or from nonutility generators. Is that correct?

A I'm sorry. Did you say "distinguish"? I mean, I'm basically treating them the same.

Q Exactly.

A Okay.

Q There is a difference in a lot of contracts between utilities and utility generators. So, aren't those contracts typically a lot shorter?

A Contracts between utilities?

Q Uh-huh.

A They vary all over the map. Typically, they are shorter. But the contract we have with Southern Company, for example, goes, I think, all the way to the year 2010, if I recall. So it's fairly lengthy, but most of them tend to be shorter. And when we do this credit analysis, the net present value is going to be lower the shorter amount or the shorter the contract term is.

Q From a risk standpoint, does the term of the contract make any difference?

A Yes. I would think so, simply because the longer you lock in on something, the more things can change, the more uncertainty there is.

MS. RULE: Thank you.

CHAIRMAN DEASON: Thank you.

Thank you, Mr. Wieland.

I want to apologize to the court reporter. I said everybody could have lunch and we worked through lunch. Obviously, she can't eat while she works like the rest of us can.

We're going to take a break, give Joy an opportunity to get some lunch, and as soon as she's finished with lunch, we'll get started back. And I don't know exactly how long that's going to be. But

I'll leave that up to Joy to do as quickly as she can.

(Recess was taken at 3:00 p.m.)

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CHAIRMAN DEASON: We need to call the hearing back to order so I can eat my lunch.

Mr. Neiser.

MICHAEL B. FOLEY, JR.

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. GADDY:

Q Good morning, sir. Would you please state your name and business address for the record?

A Yes, my name is Mike Foley. My business address is 3201 34th Street South, St. Pete, Florida.

Q And your employer?

A Florida Power Corporation.

Q What is your position with Florida Power?

A Director of System Planning.

Q Did you prefile testimony in this docket?

A Yes, I did.

Q Do you have any corrections to that?

A No, I do not.

Q Mr. Foley, will you please summarize your testimony?

A I will briefly.

As Director of System Planning for Florida Power, my job is to identify the resources needed to supply our customers with a continuous supply of reliable, economic electricity.

I cannot see the future; no one can. Therefore, in the supply of generating capacity we've used the portfolio approach rather than depending on any one type of resource.

Our planned Year 2000 capacity mix is nuclear 7%, coal 20%, oil and gas 17%, demand-side management 20%, and purchased power 14%.

Even though there is diversity among the suppliers of purchased power, there are several typical characteristics they tend to have in common. One is the majority are natural gas-fired combined cycles, at least in Florida; they are highly leveraged and their only obligation is to their stockholders.

NUG owners don't have a obligation to serve and no contract can make them continue to operate if they are losing money.

Thus, due to their similarities, there is a chance that they could be vulnerable to some common-mode failure. Therefore, the portfolio approach would urge that caution be observed before abandoning

the traditional utility ownership mode to total reliance on purchased power.

It is with this in mind that I recommended in my testimony in addition to the Commission's proposed rule to require that once a utility's purchased power reliance exceeds its capacity reserve margin, that's 15% in the case of Florida Power, that the utility show why an additional purchase will be beneficial to its ratepayers. This is tying on to what Mr. Rosenzweig proposed when he proposed 20% to 30%. And as a planner, I would feel more comfortable with an even lower margin at the point at which this presumption reverses.

And the purpose of this is to make it clear for those that follow this hearing, the ones that aren't here are and that read the rule, that the Commission intended for all factors to be considered, not just the price and the determination of what capacity to add.

With this addition, I generally endorse the Commission's proposed rule. And with respect to the Staff's alternate rule, I agree with Mr. Woodbury, who was the next-to-the-last witness yesterday, that the utility's bid price shouldn't be required to be published in the RFP.

And finally, if the Staff's alternate rule is adopted, I think it would be very beneficial to include many of the clarifying intentions explained by Mr. Ballinger in the first day of this hearing.

That concludes the summary of my testimony.

Q Thank you Mr. Foley. He's available for questioning, Mr. Chairman.

CHAIRMAN DEASON: Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Foley, one of the other witnesses, I think it was Mr. Rosenzweig, referred to your 15% criterion. Do I understand correctly that your proposal has to do with a perceived reliability function as opposed to anything about the cost of capital impacts, as some of the other witnesses have been testifying to?

A Yes.

Q I'm going to refer you to Page 8 of your comments. You state at Line 8, "Florida Power's current reserve margin criterion is 15%. Limiting the reliance on purchased power to 15% ensures that there will be adequate resources available in the event of a disruption in the purchased power supply." So your concept there is that the resources that you own will

be back-stopping the resources that you buy in case they are not available to you; is that right?

A Yes.

Q And in terms of referring to the reserve margin, the 15%, there is implicit in that a contemplation that all of the purchased power resources will be unavailable at one time; is that right?

A Yes.

Q Now, I want to pose a very simple scenario to you, a very simple hypothetical. If I have two units -- let me preface that. You've heard references to the ability of independents to establish a track record of availabilities of 90% and better?

A Yes.

Q Okay. If I have two units, each of which has an availability of 90%, it follows, doesn't it, that the probability that one might be out or unavailable at any one time is 10%?

A I agree to that.

Q And would you agree that to calculate the probability that both of those units will be out at the same time, the calculation would be .10 times .10, which is a 1% probability?

A I agree to that.

Q Now, would you agree that if I have three

units, each having an availability of 90%, the calculation is .10 times .10 times .10, which one-tenth of 1%?

A I would agree with that, too.

Q Now, I don't want to go step by step, but I went up to seven units, Mr. Foley, and I calculated the probability that seven units, having availability of 90%, would be out at one time to be one-one-hundred-thousandth of 1%. Would you accept that, subject to check?

A Yeah, and before we get to No. 7 could I add a statement?

Q One more question. Is it true that you have presently some 30 or more contracts with different power supplies that you purchase?

A I think that's correct.

Q So the probability that all of your purchased power resource would be unavailable at any one time is pretty small, isn't it?

A Calculated in the way that you're calculating, assuming that the availability, the actual operating availability is the determining factor, I agree with the whole premise of what you've done.

My concern is not with that, not that the nonutility generators are not good operators. You are.

I take no quarrel with that. My only concern as a planner is that there are common-mode failures lurking out there, potentially -- I'm not going to say they are going to happen even -- that could result in the continued operation to cease of a source of capacity that has no obligation to serve. And I outline some of the things that I could think of.

I'm way out of my field, but Mr. Gower this morning talked about something about the tax law changing that is apparently pretty important to the profitability or the high return on nonutility generation. That's a common mode that happens to be common to all of the nonutility generation. If that law changed and you could no longer continue to make money, as Commissioner Lauredo said, the rule of the whole, or something like that -- "if you're in a hole, stop digging."

The concern is that a prudent planner looks for these common-mode failures, and if there are some, then you start getting more cautious and you start trying to factor these things into your decision process. And it's these common-mode failures that I'm urging that the Commission recognize the potential for, and urge utilities to not go headlong into this thing.

Q Would you also take into account the

contractual rights that have been established and the contractual provisions for those occurrences and make some estimate as to how real or how speculative that probability is?

A You can, yes, but to the extent that you can force someone to continue with a contract, operate when they are in that hole to make them keep digging, I don't think a contract can do it.

Q All right. I want to pose one more question to you and to simplify things, rather than pass out a document, I'm going to reduce just a few items on it to something on the easel.

What I've provided you is a one-page excerpt for a recent ten-year site plan of Florida Power Corporation. And I will be referring to the entry for the summer of 1993 on the top left.

Is it true that when Florida Power Corporation calculates its reserve margin, the calculation is to take total capacity resources, subtract the firm peak demand, and the difference is the reserve margin in megawatts. That's, basically, the calculation for reserve margin, is it not?

A I guess so.

Q Well, if you'll look below the calculation of the firm peak demand to the items that go into the

calculation of total capacity resources, would you agree that to arrive at that number you would take generating capacity, plus QF capacity purchase, plus firm purchased power plus the interchange power, which is intrastate. Are those four items added to arrive at the total capacity resources?

A This is your exhibit, I guess so.

Q Well, it's taken from your annual report.

COMMISSIONER CLARK: I mean, that sounds right to me. What's wrong it with it?

MR. FOLEY: Well, there's nothing wrong with it. I don't know where he's going. I don't know why he doesn't put this on himself rather than trying to lead me into something I don't where he's going.

Q (By Mr. McGlothlin) It's a very simple point and I'm not trying to be mysterious. My final question to you is isn't it true, then, that in calculating reserve margin you include your purchased power resources in calculating the reserve margin for Florida Power Corporation?

A I would agree to that, absolutely.

Q So, in essence, all of your resources are backing up all of your other resources?

A I agree to that, yes, sir.

Q And it's not true that your company-owned

resources are backstopping purchased power?

A That's correct. All of them. They depend on each other to be there for the total amount because we need to have not just 100% of the customer's demand available, but that amount plus a reserve margin.

Q In your last determination of need case, Florida Power Corporation proposed to receive a determination of need for Polk County Units 1, 2, 3 and 4; is that correct?

A That's right.

Q And part of the rationale for asking for a determination of need for all of those units was Florida Power Corporation's contention that increased purchased power would be a threat to its capital rating; is that right?

A I think a more fair characterization was that we believe that no more purchased power could compete with the Polk County capacity given all the factors that were presented in the need case; and that there was no reason to submit that capacity to a further bid. If there is a distinction there --

Q Your position was not that you shouldn't buy more purchased power because of the impacts on Florida Power, but because nobody else could compete with you?

A Yes. When you factored in all of the things

we've talked about here today.

Q In any event, the Commission denied your total request. And is it your understanding that part of the rationale for not certifying 3 and 4 was that the time available would give competitive alternatives the opportunity to present their proposal to you?

A That's correct. And we've subsequently agreed with the Commission and the wisdom of not going ahead and granting the need for that capacity because our load growth has decreased significantly. And had we gone forward with purchased power agreements. We might be faced with a situation, should they have competed effectively with the Polk capacity, to be in a situation where we had obligations to go forward with a contract and not have a need.

That's one of the costs that we're urging be factored into this process, that it's not always without risk to go forward with a purchased power contract in light of the lost flexibility associated sometimes.

Q You're referring to the slippage in the in-service date of 3 and 4?

A Yes.

Q Polk County 3 and 4 remain your next proposed planned units, do they not?

A The ten-year site plan covers a time period in which there is nothing else beyond Polk 3 and 4 other than the potential for a third 500 kV line, which being studied very, very closely.

Q But in your construction plan Polk County 3 and 4 remained the next unit identified; is that right?

A Well, we don't have a plan after ten years, I guess is what I'm trying to say.

Q Well, at Page 8, Line 14, you make this statement. "Purchase of power exceeding 15% of our megawatt capacity would not be advisable." Well, that sounds to me not that you're proposing that the effects be considered, but it's your position that you ought not buy any more.

My question to you is: Does Florida Power propose to utilize this 15% reliability consideration that's identified as a reason why it should build Polk County 3 and 4 and should not be required to competitively procure that capacity?

A No. That decision has not been made, and I concede to you that that language does read, or could be concluded to read, that we don't intend to purchase above 15%. That is not the intent of our proposal, but rather as Mr. Rosenzweig suggested that when a utility gets up in this range, that the reversal of the

presumption be made; that the utility should look very cautiously and carefully, and this Commission should expect the utility to do so when it exceeds a certain level. He proposed 20% to 30%, as a planner I'm a lot more conservative than he is, and the thing that gives me greater comfort is something less than that and a reserve margin is a nice target. There's nothing magic about it. I'll grant you that right up front.

Q Would you agree that the Commission should consider all of the evidence bearing on the reliability of independent power in determining whether your proposal is reasonable or not?

A Yes.

MR. McGLOTHLIN: No more questions.

CHAIRMAN DEASON: Mr. Moyle, Staff, Commissioners? Thank you, Mr. Foley.

(Mr. Foley excused.)

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MR. NEISER: Our final witness is Robert Dolan.

ROBERT D. DOLAN

appeared before the Commission as testified as follows:

DIRECT EXAMINATION

BY MR. NEISER:

Q Good afternoon, Mr. Dolan. Would you please state your name, address and business affiliation, please, for the record?

A Yes. My name is Robert D. Dolan. My business address is 3201 34th Street South, St. Petersburg, Florida 33711, and I am employed by Florida Power Corp.

Q Mr. Dolan, have you prefiled some rebuttal testimony in this proceeding?

A Yes, sir, I have.

Q Do you have any corrections to make in it?

A I have one correction on Page 4, Line 11. The typing created a new type of generation. It should have been "intermediate" instead of "immediate" generation.

Q Okay. And recognizing that your total testimony is only about five pages long, can you give us a brief summary?

A Yes, I could. Florida Power is suggesting that the Commission consider the portfolio approach to utility resources in order to ensure cost effective and

reliable generation for the ratepayers. We are also suggesting some language additions to the Commission rules that all costs should be included in the evaluation for increases or decreases in cost to capital rather than just a discussion of these costs. This is necessary for all resources to compete on the same basis.

Also Florida Power has had probably as much experience as any utility in the state of Florida in contracting for NUG capacity. These contracts, our oldest firm contract, was executed in December of 1984. We have 1100 megawatts worth of NUG capacity under contract, and we have found that contracting does not have all the benefits that direct ownership has.

The reasons for this is that when a contract is executed both parties presumably assume they have a well-crafted document. I don't think we sign a contract that we thought was bad when we signed it. But neither party at the time of the execution of the contract has a perfect knowledge of what may happen in the future and circumstances can change radically in just a couple of years.

Also contracts have numerous disputes and, in fact, we've had probably slight disputes with every one of our contracts. We've had other disputes which have

been litigated before this Commission, or will be litigated soon. And there are a couple that you'll probably see very soon. One we've already discussed with you all at the Dade County need petition a few months ago where the fluctuations and the output are causing costs to be incurred by ratepayers in excess of our avoided cost.

Other problems that we're having is that we've had two gas-fired combined cycles that do not have any fuel -- No. 2 oil is the fuel backup. Destec -- Barry Huddleston, I guess, yesterday said he believed that Destec, being a prudent developer, always has No. 2 oil as a backup fuel for a natural gas-fired facility. I believe Barry, after checking with his management yesterday, realized that the Tiger Bay facility does not have No. 2 oil backup also we do not -- the air products facility or Orlando Cogen does not have No. 2 oil backup. These are things or costs that may come up that if we owned that generation, we would have No. 2 oil backup. We thought when we wrote the contracts that it was required in the language we interrupted; obviously, they're interrupting the language differently.

Also one other thing that we do not want, as Mike Foley mentioned, is for us to publish our avoided

cost in the RFP process.

Florida Power in January of '91 issued an RFP where we published our avoided cost. It's obvious when you look at those -- the bid submittals that they were tied to avoided cost. Several of them are at 100% of avoided cost, so if we hadn't have published it, most likely the cost would have been lower. It couldn't have been exactly 100% of avoided cost.

And the Commission here heard from several NUG developers about the well-crafted contract. And dealing with contracts on a full-time basis at Florida Power, I would like to see that well-crafted contract, because a well-crafted contract is in the eyes of the beholder, whether that be the bank, whether that be the developer or whether that be the utility. And they may all have different views of what they think is a well-crafted contract.

Other problems we've had with some of our contracts, and it just happened this week during this hearing, is we had to cycle off several of our big fired oil plants due to the contracts we have not having dispatchability. Now, when Florida Power executed those contracts, we felt like, for one, that we could achieve dispatchability through the economics. Well, it's gotten obvious, we've got 480 megawatts

on-line today. We didn't get that. We also thought our load growth, both peak load growth and minimum load growth, were going to be at a greater rate than we've experienced in the last few years. That's another example of where if we had had direct control, we would be lowering the output of these units.

Also in the permitting of several of the facilities, the NUGs, in trying to get their permits as speedily as they could, put burdens on themselves that probably a utility wouldn't.

Tiger Bay's facility, due to air permits -- or Destec's due to air permits can only dispatch to 80% of their full load capacity. It has nothing to do with the technology; but when it goes to lower levels, it exceeds the emissions allowed by the state air permit.

And, again, as Chairman Cresse pointed out, the utility has an obligation to serve to its ratepayer. It has a social obligation that is enforced by either the state governor or this Commission. The NUG only has an obligation to its investors, and it may deliver under a social obligation but only if it will not incur increased cost to its investors or stockholders.

I think that concludes my summary.

MR. NEISER: Mr. Dolan is available for

questioning.

CHAIRMAN DEASON: Ms. Brownless.

CROSS EXAMINATION

BY MS. BROWNLESS:

Q Good afternoon, Mr. Dolan. I want to look at Page 4 of your testimony. If I look at Page 4 up here on Lines 4 and 5 you say that you're opposed to the revelation of your own avoided cost; is that correct?

A Yes.

Q What exactly do you mean when you say "avoided cost"? Is that the number that is used to develop your generation expansion plan?

A Well, this avoided cost was used in our generation expansion plan and also used -- it was being developed for NUG purchases.

Q Well, I can make this real brief. After you identified whatever your next avoided unit was, did you use a generic cost for that avoided unit or did you use some combination of generic cost, for example, an EPRI TAG cost and Florida Power-specific cost?

A When we develop the generation expansion plan and the cost associated with the units, we use a combination of things including EPRI information, constructor's information and FPC's experience.

Q Okay. But the cost that you used was not a

sharp-pencil cost tied down to a particular site where FPC would build that unit, was it?

A The cost was a more generic cost. We did not have EPC contracts or any contracts for vendors of the equipment, so it was an estimate using our best knowledge at the time.

Q And much of that information was basically industry-wide known, generic information?

A That's true.

Q When you say also on Page 5 here that you think the utility should be able to submit a confidential bid when you're talking about Staff's alternative rule. When you say "a confidential bid," what you're talking about there is your actual sharp-pencil price, is it not?

A That's correct.

Q Which wouldn't necessarily be the information that Staff was requiring be provided on the front end of its rules; is that correct? Wouldn't necessarily be the same?

A That's correct, but it may influence the bidders by showing the avoided cost. It may influence their price.

Q And I just want to add one point. Your fuel projections are already made known to the general

public through the fuel purchased power cost recovery clause proceedings that happen every six months, are they not?

A That's correct.

Q Okay. So that information is public knowledge also, right?

A I believe it is.

Q In the CEPA rule we've suggested that when a utility bids, it be allowed to recover its cost exactly as any other bidder. Do you disagree with that recovery mechanism?

A Well, I think Florida Power would prefer to keep traditional ratemaking going on in our generation expansions and have the prudence reviewed by this Commission. I believe Florida Power's track record in the past, and this Commission may correct me if I'm wrong, we have come in at below cost for all of our generation, except for one that I can think of which was our nuclear plant built in the mid '70s. So that the ratepayers in the past, and in the construction of CR4 and 5, the Intercession City peakers, Debary peakers have incurred lower costs by allowing the traditional regulatory prudence and revenue requirements of actual utility construction cost.

Q But let me just ask you a question. So you

prefer to rate base your plant rather than have a dollar-for-dollar immediate cost recovery through the fuel adjustment clause?

A Yes, ma'am.

Q Do you understand that the CEPA's rule would allow you, based upon whatever bid price you have, to let your ROE float?

A That's the way I understand it.

Q And your utility doesn't think that's an advantage to the utility?

A It could be an advantage to the utility but it also could be a disadvantage to the utility because we're getting into more and more competitive ties with the price of your product. If it was artificially higher, or higher than it has to be, it could affect your ability to compete. It's a short-term gain for a long-term loss.

Q So you would rather protect your ROE. I mean, instead of taking -- instead of developing a bid price which has an ROE in it of whatever it has, you would rather have a guaranteed return?

A A guarantee? I don't think the Commission here guarantees a return for us, but an allowed utility rate of return considering prudence, yes.

Q That's interesting. You've mentioned some

problems you've had with your cogeneration contract?

A That's correct.

Q And most of the examples you used, I believe, are affiliated or associated with the seven contracts that were all negotiated at one time; is that correct?

A Well, it was eight. But out of the RFP, although the contract with Destec or the old general Peat, EcoPeat contracts, which are much older -- the bulk of them are of the '88 vintage, negotiated in 1988.

Q Well, setting aside for a minute what you refer to as the Tiger Bay project or the Destec project, I think the Air Products contract is one of the seven or the eight that came through as a piece.

Didn't Florida Power Corporation, essentially, write a contract and tell the people who participated in that RFP, "Here's the contract; this is what we want. You do this; give your best price to do this"?

A That's correct. In that RFP we published a contract. It was for several reasons.

One, we actually needed that fourth type of generation. We needed immediate generation in the '91, '95 time frame. We did the bid in that year. We felt like needing those resources in such a quick time that

showing the base contract would speed up the RFP process because we didn't have time to waste. And the first --

Q Did it?

A Obviously, it did because we issued the RFP I believe January 11th. The last contract was executed, I believe, March 17th.

Q Those contracts are all virtually identical, I mean, with regard to all major aspects of the contract, are they not?

A They had some slight changes. One of them could either be a small power producer or a cogen, another one had two sites. They all had different prices, but materially they were, essentially, the same.

Q Was it one of Power Corp's rationale for doing this that the NUG community could provide that power faster than Power Corp could, bring it on line quicker?

A That was one of the things we were looking -- a lot of those projects that bid, one us already on line, the Dade County facilities, several others were in fairly late stages of development, maybe had submitted air permits already. So several of those projects had probably been in the development stages

for a year.

Q Have, in fact, those projects, to your knowledge, all the eight contracts involved, proceeded a pace? I mean, do you think there is anybody that is not actually going to deliver the contracted for capacity that you all wanted?

A All of the contracts are under construction, although ownership changed several times and some contracts have consolidated. There were two, a phosphate and orimulsion contract became a natural gas contract at one facility, but all of them are under construction or are already in operation.

Q Do you have any reason to believe that all of that capacity that was committed will not be built and come on line in a timely fashion?

A Like I said, four of them are already under commercial -- under operation and four are coming on line at their schedule or maybe slightly ahead.

Q Would you have had the ability when you put that model contract together to require complete dispatchability and also to specifically require a backup fuel if it was a gas facility diesel or if it was a coal facility gas? Could you have done that in your contract? Was there any reason why you couldn't have done that?

A The first one on dispatchability, obviously, we could have done that. At the time we did not, and this is the problem I pointed out with contracts. We thought we could get the dispatchability through economics and maybe didn't need as much dispatchability as we're finding we need.

On the backup fuel issue, we thought we handled that in the contract. We stated in the contract that deliveries of energy could not be interrupted except for events of force majeure by the fuel transporter or supplier.

Q Uh-huh.

A Looking back we should have just said, "Why don't you have 72 hours of fuel on site?" These are some of the problems that I mentioned in contracting for capacity rather than ownership because we thought we had done what we were talking about, that we -- now if we did a contract again, there's numerous things we would change about that contract, including regulation specs to prevent the Dade County problem, complete dispatchability as we did later in the CFR contract. Just specify and you'll have so many hours of backup fuel --

Q But it wasn't the question of the NUGs not doing what you wanted, it was a question of you not

telling them to do those specific things; is that correct?

A There's two things. One is we didn't tell them to do certain specific things, like dispatchability, which we're trying to negotiate with some of them at this time, which is difficult. But the other we thought, as I mentioned, we felt we had taken care of the problem. Then upon reading the language, got a different interpretation. And we're not through with the interpretation of that language on the No. 2 oil backup, I can guarantee that.

Q Thank you, Mr. Dolan. To my own financial interest, I'm glad to hear that.

Had the seven units been built by Florida Power Corporation and not been purchased power, would those units still be in rate base, assuming that they were constructed? You wouldn't take units out of rate base because you were not going to run them at the capacity factor that you originally anticipated they would be run at, would you?

A I'm not sure I understand the question. We're not talking about -- by these guys creating dispatchability problems, we're trying to fix the dispatchability problem and we're not talking about changing their capacity.

Q But I guess here's my point. If you had built these plants yourself --

A Yes.

Q -- you would have put them in rate base, would you not?

A Hopefully, if this Commission would have allowed us to.

Q God willing, right?

A Yes.

Q And if the operation of those particular units was different than you originally anticipated, because they were going to be used more of the time or less of a time or instead of on peak they were going to be used at some other time. Would you take them out of rate base?

A No, not if they were used and utilized equipment. If they were put in extended cold shutdown as we have done units, they would have been taken out of the rate base but not if they were being utilized.

Q Because what one would look at was how prudent it was at the time that you constructed that facility, would you not? That would be the analysis to see whether they should be subsequently removed from rate base?

A That's right.

Q So then why should not the analysis, when one looks at purchased power in the kind of instances which you describe, also focus on what was reasonable and prudent at the time, and what your own best judgment was at the time when you entered into those agreements?

A I think we agree with that. We're not talking about just because we don't -- we've been negotiating with the people to try to solve the minimum load issue because it's not specified in the contract specifically; it is specified in some Commission's language. But we're not talking about taking them out of the rate base. We're just talking about maybe having them help us that which may, in fact, help themselves to solve this problem.

If we had had direct ownership of the plants rather than through a contract, there wouldn't be an issue of, you know, interpretation of the contract. We'll just pick up the phone and call the plant manager and tell him to shut down or back off to a certain level.

Q But your ratepayers would still be paying for that capacity, would they not?

A They would pay for it whether it was under the cogen contract or as if we had built it ourselves.

MS. BROWNLESS: Thank you, Mr. Dolan. That's

all I have.

CHAIRMAN DEASON: Staff?

CROSS EXAMINATION

BY MS. RULE:

Q Mr. Dolan, I'm Marsha Rule of the Commission Staff.

In ARK Energy's September 20th comments they included a draft rule, and one of the provisions in their draft rule was that upon request by a potential bidder, the utility issuing the RFP or the utility with whose transmission system the bidder intends to interconnect, if different, would verify the adequacy and feasibility of the bidders proposed transmission interconnection, and there's provision for a nonrefundable fee of $2,000 for the service.

How have you handled interconnection in these contracts in the past? Do you have a procedure for an advanced feasibility study?

A Well, I guess I have two points on that. One, I guess, they talked about a $2,000 nonrefundable cost. In the past, and I don't have one of the contracts with me but my memory says that we were using a $10,000 refundable deposit on the interconnection cost.

Most of the studies may only take $2,000, $3,000; we've refunded all of the interconnection

studies but I think we would prefer to have a higher amount refundable.

But the other problem I have with ARK's proposal is I'm not sure how we would ever do the interconnection study. Say we put out an RFP, and just make it 500-megawatts as the RFP, and people have been stating earlier that people are getting responses maybe 10 to 1 megawatts, so we get 5,000 megawatts to study, which may be located everywhere. How would we ever figure out the interconnection cost without doing a complete permutation of every, project because an interconnection in Leon County affects our transmission system also in Jefferson County. I mean, it isn't just a local interconnection. These projects are getting bigger and they overload transmission lines everywhere, so I'm not sure that we would ever get the study done because you would almost have to plug all of them into the system at one time and evaluate the interconnections.

It would be much better, and this is how we did our other RFP, is you pick the winners; you maybe give them preliminary information about where -- you know, don't locate here, do locate here, or, you know, all ten of you can't locate on the same industrial park. And do the interconnection cost estimates after

either the short list is chosen or some smaller list because, you know, the developers, obviously if they ride out and they see big wire, they probably -- we could do some kind of cost estimates very preliminarily, but they may change drastically according to which ones get picked.

As I said before, do we do their cost estimate as if nobody else existed? And then we come up with a cost estimate and then it ends up you pick -- and a lot of these RFPs, you don't have just one winner, you have multiple winners -- when we plug all -- and let's just make it like our RFP -- all eight of the contracts together, they dramatically affected each other's interconnections. Maybe in our RFP, all of them located in Polk County, the bulk of them located in Polk County utilizes a lot of the common pieces of the same transmission grid.

To shorten my answer, I'm not sure -- the costs I don't agree with and I'm not sure the process they propose is workable or of any benefit to have the interconnection cost up front because there's no way we could do good interconnection costs not knowing how many of the projects get selected.

MS. RULE: Thank you.

COMMISSIONER CLARK: Mr. Dolan, you

apparently support Enron's view that there should be competitive negotiations between the parties at the conclusion of the RFP process.

MR. DOLAN: That's correct.

COMMISSIONER CLARK: Did you hear Mr. Wright's suggestion this morning that you really just negotiate with the winner?

MR. DOLAN: Well, you know, when I said Enron's proposal to do competitive negotiations, you could either do that with just the winner or with one or two or three other -- with a small group or just with the winner. But there's no reason to not negotiate terms and conditions that may benefit every party involved, the ratepayer, the utility and the nonutility generator, because you just happen to submit a contract in the RFP. And the next thing I have about the CEPA rule about not being able to negotiate, this contract may live for 30 years. Does that mean you could never renegotiate a term, such as we're trying to do with some of our NUGs, to get some sort of dispatchability, that you would just be -- you've got to live with that forever regardless of whether circumstances may change where renegotiation would benefit all the parties.

COMMISSIONER CLARK: Well, the one thing that

concerns me about having a negotiation after the RFP process is you can -- I can envision a situation where you have a winner, and you negotiate on some things that you feel need to be fine-tuned, if you will, and the person that comes in second says, "Hey, wait a minute. You know, if you had offered -- if that had been part of the deal I could have offered you a better price and been the low bidder." Don't we invite more litigation that way?

A You potentially could invite more litigation. But in this process, as we find in our standard offer, the losing NUGs have a tendency to litigate and it's just a matter of them trying to find their issue. Because there's a lot of money involved.

COMMISSIONER CLARK: Well, do you think under your thought that there should be a competitive negotiation, should you have to first -- you determine the winner of the RFP process and then you begin negotiations with them. If you can't reach a satisfactory contract between that particular NUG and the utility, then you could go to the next one. Do you think that's the way it should work, or should you be able to negotiate simultaneously with, say, the top three?

A I would perceive if we did this that we would negotiate with the winner first and try to come to a

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A I would perceive if we did this that we would negotiate with the winner first and try to come to a

conclusion. At that point, according to how long it took, you may negotiate with number two or reissue your RFP. According to what your needs were, because if it took a long time they -- their submittal may be stale also.

COMMISSIONER CLARK: Okay.

CHAIRMAN DEASON: Thank you, Mr. Dolan.

MR. NEISER: One or two questions.

MS. RULE: Excuse me -- oh, I'm sorry. I wanted to let you know Staff has another question at some point in time.

CHAIRMAN DEASON: You want to go ahead and ask your question now and then Mr. Neiser can wrap it up.

Q (By Ms. Rule) Mr. Dolan, in your testimony -- I'm sorry, in your comments you express some concern about Staff's alternative rule needing clarification to ensure that utilities can submit a confidential or sealed bid. And the question is would Power Corp be willing to be held to the bid price if it were a sealed bid?

A I guess Florida Power preferred Mr. Ballinger's interpretation on Wednesday where we would not be held to the sealed bid if we could prove prudency. That the overruns were prudent.

If it's the -- but I may, you know, add to that that if the only way we were allowed to compete was to live by our bid, I think we probably would.

Q Thank you.

REDIRECT EXAMINATION

BY MR. NEISER:

Q Mr. Dolan, in response to a couple of questions from Ms. Brownless, I think the question related to would we take units out of rate base if we found ourselves in a position of not needing at a time some generation.

Has the Company in the past ever taken some units out of rate base and put them in extended cold standby at a time when there was excess generation related to demand?

A Yes. I thought I added that in my response to Ms. Brownless, that, you know, if we were not using the units or were not used and useful for whatever reason, and they were put into extended cold shutdown, we would take them out of the rate base. Although, if we just changed their dispatch order or arrangement, as had we done with many of our units, we would not take them out of the rate base.

Q And is that flexibility with regard to taking a unit out of rate base, putting it into extended cold shutdown, is that flexibility lost with the purchased power contract?

A It's my belief that it is. I think people

have mentioned, you can write in a lot of flexibility in contracts, such as delaying in-service dates or other things, but they come at huge costs to the ratepayer to get that flexibility, that with utility ownership they get more naturally.

Q And with response to the question about how much litigation would this process develop, do you foresee the amount of litigation being in direct proportion to the number of rights that are created by a bidding rule?

A I think I concur with that. From just looking at CEPA's rule, it took about a year and a half if the RFP went -- if there were no blips in the whole RFP process, I could envision numerous hearings, including going to the Supreme Court at several different stops along the way. Where if you did a one-stop process, as we did in our RFP in January of '91, selected eight winners, 559-megawatts of capacity, had numerous losers, it was adopted, the RFP was approved at the Commission at a PAA in July and had no intervenors in the process.

MR. NEISER: That's all I have.

CHAIRMAN DEASON: Thank you, Mr. Dolan. Are we ready now to proceed with TECO's presentation?

MR. WILLIS: Yes, we are. I'd like to call

Dr. Hadaway.

DR. SAMUEL C. HADAWAY

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. WILLIS:

Q Could you please state your name, occupation and business address?

A My name is Sam Hadaway. I am president of FINANCO, INC., a utility consulting firm in Austin, Texas. My address is 3445 Executive Center Drive, Austin, 78731.

Q Could you please give a brief summary of your educational background and training, as well as a summary of your testimony, please?

A I have a Ph.D. in finance. I've served as a college professor early in my career. I went from that to the Public Utility Commission in Texas, where I was the chief economist and chief financial witness. And for the past ten years I have been involved with FINANCO, I've been president of the Company for the past five years.

I can go into more detail than that if you'd like, but that's basically what I do.

Commissioners, I'm pleased to be here. I was retained by Tampa Electric to discuss the financial

issues that are involved in Paragraph 7 of your proposed rule. I'm always nervous or concerned, or at least apprehensive about coming into a room with this many attorneys involved in it. And I was getting more and more that way as I was thinking about coming up to get to testify today, but then I remembered that John Rowe was going to follow me in a few minutes and that he is from Georgia Tech. And I got to thinking about young men that are from his school that are coming over here to do battle tomorrow. And I thought more and more about the Chairman's comments that all risks are relative. And so I'm feeling better about being here instead of somewhere else. That's really what we're here about.

Specifically, my testimony addresses the effects on the cost of capital that may occur from the utilities entering into a long-term purchased power contract. I have some comments about that that I will summarize.

I will also briefly touch on the areas of the fairness issue; is it unfair or are there potential situations of unfairness that may arise if a nonutility generator can lever up its capital structure; if it can use to its advantage financial leverage.

And then also, very, very brief, and I don't

know that I'll say anything about this unless someone wants to ask me a question about it, but in my testimony there is also a brief section about the reliability issue as it relates to the capital structure of the nonutility generator.

But basically what it amounts to is you have seen many, many comments from the Wall Street community, particularly from the rating agencies, about the various kinds of risks that are associated with the alternative ways of doing things. And Moody's is listed, and then you've seen these things before, but they've listed six different categories of risk that come about and they say, right up front, that these risks apply to one degree or another to either a purchase situation or to the build situation. And I've also got some brief notes at the end of my outline here that I've prepared for the past couple of days, where I want to comment specifically on some of the things that Dr. Roach said about some of these issues.

But basically Moody's list of six risk elements start out with demand, risk, as you heard Dr. Brown speak about on the first day we were here; Supply risk, which has to do with whether the particular resource will be there when you need it; operating risk; construction risk; rate base risk, which is

something we haven't had a lot of discussion about in the past couple of days, And then also regulatory risk. Well, all of these things are sort of put together, but what we all know is that there is really no way to have a free lunch. Risk exists. And it doesn't go away just because we package a project slightly differently, or if we slice the pie up in different ways.

So a question that I think, that we've all been grappling with in these proceedings, and in proceedings elsewhere around the country, has to do with how can it be a lower priced situation if you do it through a nonutility generator than if you had the same kind of situation done by the utility itself. And I guess I'm still puzzled by that to some extent myself. Particularly some of the extreme statements about -- well, particularly that Dr. Roach made, I guess. I'll come back to those.

But I was also taken by the comments that Mr. Reilley gave to you yesterday, late in the afternoon, and I guess I do agree with what he had to say.

There are indeed risks, either way you go about it. And you need to look at these things almost in each situation on a case-by-case basis.

The demand risk to me, having been involved with the Texas Commission for a good portion of my

career, the thing that has struck me about that discussion, it's not just whether the regulator might disallow a particular item that has been included in the cost of service or not disallow it. Certainly, Florida is looked at and your purchased power adjustment clause is viewed as one of the most constructive ways of dealing with this kind of thing. But to me the demand risk issue is much more than that. You've heard witnesses today, and I believe yesterday as well, and also Moody's quote some of these in their write-ups about Gulf States' situation with its purchased power contract with the Southern Company.

Well, from the time I was with the Texas Commission, and later on working in other forums related to that purchased power contract, I know that Gulf States entered into that purchased power contract when they were about to lose a gas contract that was very, very favorable at a time when gas prices were expected to go out the roof and they needed the capacity. By the time it was all said and done, the transmission line was built by the thousand megawatts of capacity. They had lost a major position of their industrial load in Louisiana. The world changed. The situation that faced them when they finally started to receive that power and needed to recover for it really

didn't provide any good way of doing it. The rates were already pretty high and they couldn't recover. And according to the Moody's review, and based on some other information I've seen elsewhere, Gulf States ended up paying $300 million to buy out of that contract with Southern Company and as you know, they're in the process of no longer being an independent utility company, they've been bought by another interest.

On the other hand, I have also been involved in another case that was mentioned by one of the witnesses about Texas -- New Mexico Power Company. They had been basically a distribution kind of company, had no generation in Texas of their own, but decided to build two state-of-the-art, fluidized bed combustors to burn on site lignite, and various other kinds of fuels, if necessary. And they went into that to produce about 30% of their own power. By the time they had built those units -- again the world had changed, gas had not gone up in price like they thought it would. The difficulty that they faced in the courts and elsewhere, have left that company because of the build decision in a very, very serious situation.

So that it amounts to in my mind is that the build versus buy can go either way. But to make

comparisons, as you've heard some people do, about the risk of building when you're talking about a nuclear power plant, versus the risk that we're talking about in some of these purchase contracts, is not a good comparison. That's not the right focus, because there's not much risk for a utility, a major utility to build 100-megawatt combined cycle facility for itself. It could do that and from my experience with the rating agencies, it shouldn't cause a blip in the rates. At the same time, up to a certain point, small amounts of purchased power obviously are not going to cause a major concern by the rating agencies. They say that in their rating reports.

So to look at the situation ahead of time, and try to set down this is the way we're always going to it is very, very hard. Sometimes it will be better to negotiate purchased power contracts. Sometimes it will be better to build a facility.

I heard some comments -- operationally I don't know too much about these, I'm not engineer, but where if a utility is building a facility, particularly a small one, and they see that there is a slight change, they may have the flexibility to move it around a little bit. Whereas, if they had said, "We're going to start funding your nonutility generator fixed

charges," they have to take up the contract on the time period when it's set. So there are all those kind of tradeoffs that I don't know how you make a rule ahead of time that can cover all of those things.

That's probably the main point of my testimony. Also, though, I do have a section that talks about this debt equivalence issue. Having been an old college professor at one time, it's hard for me to sort of leave lay Dr. Roach's comments that the fixed costs associated with additional purchased power contracts don't cause risk unless they're defaulted upon.

Any time that you have fixed charges on the income statement ahead of the equity shareholders returns, their risk has changed. Clearly the question is: Do those risks change more if you build or buy? And those are the kinds of things that you have to trade off. But the examples that you have seen, and I won't go through one, there is one in my testimony -- where if you take on additional fixed charges ahead of your equity payments, that you must offset that with additional equity is just plain common sense economics. It's in every textbook that you see anywhere. And it doesn't matter whether the accounting profession absolutely requires that the contracts be capitalized and put on the balance sheet or not. That's simply the

way things work. The risk is increased depending on where the fixed charges are. And again, those things are very hard to predetermine.

Okay. Those are the principle things that I wanted to talk about. I don't think that I have a strong feeling about the reliability issue relative to the amount of equity that's in a nonutility generator's situation, but we all have many, many things, and maybe that's where Commissioner Lauredo was coming from. We've seen situations where large amounts of debt worked just fine as long as fuel prices are stable and the situation is as it has been for the past four, five years, it all works great. But when the situation changes, we've seen the S&L industry, we've seen the real estate industry, we've seen the effects that large amounts of debt can have. So those things should be considered. They shouldn't necessarily be thrown out, because that's the way that kind of business is done. But they are important. And they should be considered and they are there as a risk.

In terms of whether that creates a situation that's not fair, again, there's no reason not to take advantage of an opportunity that exists to lower costs. But at the same time in comparing two proposals, one beside the other, it is simply not an adequate

comparison to ignore the differences in risk and other factors that are caused by different capital structures. That's the extent of my comments. If I have any -- if someone has any questions I'll be happy to answer.

CHAIRMAN DEASON: Mr. Watson?

CROSS EXAMINATION

BY MR. WATSON:

Q Dr. Hadaway, I'm Ansley Watson, and I appear today for CEPA.

Would I be correct in giving your testimony the following overall characterization, let me ask you this: Would it be that both the buy and build options of a utility have risks just as would a utility's decision to do neither when faced with the need for additional generating capacity?

A Yes.

Q And doesn't your testimony really say that the Commission should look at the cost associated with each of the two options on a case-by-case basis?

A That's the principle thrust of it. I think that the main thing, the main point that I would want to make, though, is that I do not believe that the build option in the same size and the same kind of technology is more risky than the purchase option.

Q And you are aware that there are those who have testified here who would disagree with that feeling?

A That's right. I think reasonable people can disagree on that point.

Q Absolutely. Thank you.

CHAIRMAN DEASON: Mr. Palecki.

MR. PALECKI: Yes. Mike Palecki for the Commission Staff. I haven't made an appearance yet, so I guess I should do that now.

CROSS EXAMINATION

BY MR. PALECKI:

I just have a couple of questions. We heard Florida Power Corporation testify that the risk reaches the area of concern when you achieve 20% to 30% of purchased power, would you agree with that?

A I don't have a specific level in mind. It's sort of a continuum to me.

Q Are you aware of the percentage of purchased power on TECO's system?

A No, I'm not.

Q Are you aware at all whether TECO is at that 20% to 30% purchased power level?

A I don't know. I haven't investigated that at all.

Q Do you have any input that you could provide

to the Commission on how it should handle a utility that avoids having purchased power on its system? As you're aware, the Commission is required by statute to encourage cogeneration. Do you have any ideas in -- if the Commission had to deal with a utility with very little purchased power that was not amenable -- or seemingly not amenable to going after more purchased power?

A We've heard other people testify, I believe today and certainly in previous days, that if those options are out there, and if the utility chooses a different resource, then the utility has a burden to show that the reasons for choosing that other resource were good. And others have the opportunity, and certainly do in rate case settings, to say, "These other things were there when you decided to build this power plant. We don't think it was prudent for you to do this, this and this." Fortunately, in the state of Florida you have not had the kinds of desperate situations that I have seen, not just in Texas but in other states as well, where major, major disallowances came about over these kinds of issues. But that's the appropriate forum.

The utility has to make its own choices. It has to be managed the way its management believes that

it should. But at the time they bring those choices to the regulator, then the regulator has the last call on that. And then that's where your job is to look at the situation and say, "Is this the prudent thing to do?"

Q Do you think it's reasonable for a rule to be implemented that would require a utility to place or to go after purchased power when it has very little percentagewise on its system?

A Again, I view this as -- I said continuum before about the 20% to 30%, But it depends on the circumstances. I know of utilities that have some sort of avoided cost, energy-based standard offers that if someone wants to sell them energy at that price, they'll buy it. But they don't need capacity, or in their view they don't, and at least to date many of them have not. Therefore, they have not had any capacity charges that they would even pay to QFs.

So not knowing exactly the situation you're asking me about, I may be way off base on your example, but you have to look at the situation, and if it's not prudent for that utility to not take advantage of other opportunities that are out there, then this Commission has every opportunity to look at what the utility brings in and offers to them, you know, when they try to rate base a plant.

MR. PALECKI: Thank you. We have no further questions.

COMMISSIONER CLARK: I would like to ask Tom Ballinger something just to make sure I understand things.

The capacity cost recovery factor, it's our intention to move all purchased power into that clause and out of rate base as companies come in for a rate case?

MR. BALLINGER: I don't think so.

COMMISSIONER CLARK: All right. Refresh my memory as to what --

MR. BALLINGER: I think the intent of it is to treat purchased power, nonutility purchased power, to allocate it based on cost of service methodology. So we're allocating it much like base rates, instead of on a per kilowatt hour charge. It's also in my understanding used as kind of a interim basis for purchases before you have a rate case.

COMMISSIONER CLARK: Then I've gotten it exactly opposite when you would go to the next rate case.

MR. BALLINGER: A utility-built plant would go into rate base.

COMMISSIONER CLARK: All right. What about

purchased power?

MR. BALLINGER: That would stay in the cost recovery clause.

COMMISSIONER CLARK: Do we currently have purchased power in base rates now?

MR. BALLINGER: If we do, there is very little, and it would only be long-term purchases. Over the last few years, we've moved from having both economy purchases and unit power sales or capacity purchases from base rates into the capacity recovery clauses, and for a variety of reasons, mainly because of the problems of forecasting what those sales would be
and trying to guess those revenues in setting rates.

COMMISSIONER CLARK: Okay.

MR. PALECKI: Commissioner, at a very early stage, one of the very early iterations of a draft rule for this particular docket, the Staff had drafted a proposal that would have put all purchased power, as well as utility-built plant, through the clause, but we withdrew from that position, and we no longer advocate that particular avenue. But that was one of the early drafts that we probably submitted to the various Commissioners.

CHAIRMAN DEASON: Any further questions?

Thank you, Dr. Hadaway.

MR. WILLIS: Can Dr. Hadaway be excused?

CHAIRMAN DEASON: Yes.

(Dr. Hadaway excused.)

MR. WILLIS: Call Mr. Rowe

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JOHN ROWE

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. WILLIS:

Q Please give your name, address and business affiliation?

A My name is John Rowe. I'm Vice President of Regulatory Affairs for Tampa Electric Company, P.O. Box 111, Tampa, Florida 33601.

Q Would you please summarize your testimony?

A Yes. Commissioners, good afternoon.

Our company was the first utility in Florida to go through the power plant need process after it became effective, and we've been a party to three determinations of need before this Commission.

I've been deeply concerned about much of what I've heard so far in this hearing and about what I've read in some of the comments that have been filed.

It's pretty clear from the number of parties represented, particularly those hanging on late on Friday afternoon, that a great deal of money must be at stake.

What I believe is being examined here is whether the regulated model is broken or whether it can be materially improved so that consumers can realize any additional benefits. And my remarks address a few policy issues which you're now facing. Mr. Mestas and, of course, Mr. Hadaway that you heard just have spoken to other aspects of the rule consideration, which we ask you to examine as well.

I would like to reiterate a few points that I would suggest that you understand, keep in mind and use as guidelines as you weigh the comments.

The first of these is that after all the procedures have been decided and all the rules have been followed and all the results have been known, regardless of what you decide to do, only the regulated utilities in the Commission are left to be responsible to the public. Only the utilities in the Commission have a statutory obligation to do that.

Secondly, I believe that the consumer's number one concern is that they will be able to get electric service when they need it and where they want

it. The price the consumer pays is certainly important, but the price only becomes primary when they're assured of reliability. And we're not talking about how long a single plant may run. All machinery breaks eventually, and it's usually at an unplanned or inconvenient time. As far as the consumer is concerned, they want to know about their service at their given point in time and whether they can get it. 1989 Christmastime is probably the best and most recent evidence that we have of that.

The third point is that if utilities are not held responsible for their decisions about how to meet their statutory obligations and some other approach fails, the Commission may be blamed for preempting the process that worked previously.

And I think we've been talking about an approach that we've had for a number of years that has worked pretty well and it continually needs tuning up, and all of us ought to look for that, but it hasn't been irretrievably broken.

Providing a detailed specific set of procedures in selection criteria may well be in the best interest of the nonutility generators. But, I believe that it's unnecessary to provide all that detail and all of those selection criteria, all of the

utility's plans for generation in order to bid on a project. The fact that many companies have been able to bid on projects and many utilities have been able to buy nonutility generation is pretty good evidence of that. It hasn't been done in the past and I don't believe it needs to be done in the future.

But, in any I event, the real question is whether the selection process will be in the consumer's best interest. Again, the primary purpose of this process is not to promote competition. The primary objective is to adopt the process which best serves and protects the consumers of this state.

The present process of selecting generation can be tuned up, as I mentioned, but there's no evidence that it has been broken. And the benefits of competition, in large part, can be realized for consumers without encouraging nonutility ownership of the generation. We've kind of spoken to it in terms of economic risks here and there. But, in fact, if you were to require a utility to bid out the cost of constructing the plant, but then the utility owns the plant, the utility continues to own it and we have a pretty well-regulated model. But the consumer has been protected largely from the construction risk that goes on.

When ownership is shifted to other parties, there are some real problems with assigning the responsibilities for failures. A certain amount of that can certainly be taken into account by contract, but as many have mentioned, we're still looking for that well-crafted contract. And when there are disputes, as there inevitably will be over the long term, there is a cost of litigating those problems.

If you decide to make material changes in the selection process, we believe you need a rule to reflect those changes. There's just too much at stake here for the consumers for you to forego making a rule altogether, so we think you ought to have some kind of rule. But I urge you to make that rule very flexible, allowing for creativity to operate for the particular circumstances that exist with respect to each of the regulated utilities at the time it makes that generation decision to be recognized and for the consumers to be protected under your oversight. I urge you not to box yourselves in to detailed procedures, which are certainly untested at this point.

We recommend that you give more serious consideration to the original Staff rule proposal, as modified very slightly by Mr. Mestas and he will speak to those particular modifications; they're minor.

We believe that anyone in Florida, with very few exceptions, who builds generation in Florida should be required to go through the need process. And that if you adopt some form of bidding as being the only way that people demonstrate that the selection they've made is cost effective, that everyone should have to go through that process. Each party should operate under the same rules and demonstrate that they're operating or generating need will be met with the most cost-effective solution.

However, I do believe that true cogeneration, and when I say "true cogeneration," I mean, the kind that comes from waste heat of industrial processes as opposed to some of the so-called PURPA machines, what we call and recognize in Florida is most of the generation -- cogeneration that we have. And cogeneration from solid waste disposal facilities, which are owned by the government, should be exempted from the bidding process. That is, there should be some set aside for that because I believe that they serve other important public policy objectives as well. And I believe, as the law says, that facilities under 75 megawatts should be exempted.

Allowing nonutility entities to own and operate a significant portion of the generating

capacity of a regulated utility is really an untested quantum change in regulation. And the Commission should proceed very carefully in experimenting with this form of deregulation. As you're well aware, the delicate balance between consumers, regulation and utilities is on the line.

So our bottom line is that we believe it would not be in the best interest of Tampa Electric's customers for you to adopt a detailed rule, which on the front end restricts your regulatory discretion to ensure on a case-by-case basis that we, the regulated parties who serve, can continue to fulfill that obligation that we have.

That concludes my summary.

MR. WILLIS: Mr. Rowe is available for questions.

CHAIRMAN DEASON: Mr. Watson.

CROSS EXAMINATION

BY MR. WATSON:

Q Good afternoon, Mr. Rowe.

A Mr. Watson.

Q Does Tampa Electric Company use various fuels in its generating plants?

A We do. We use primarily coal but we use several fuels.

Q And do you obtain that fuel by contract?

A We do.

Q If your suppliers were to fail to deliver the fuel to operate your generating plants, would that affect Tampa Electric Company's ability to provide service?

A Sure it would, assuming we couldn't get it from an alternative source.

Q You rely on that contract that you have with your supplier?

A Obviously we do rely on it. We also rely on ourselves to provide a margin of error by providing a certain amount of inventory at the plant, by looking for alternative sources of power as they may be available. Ultimately, it's not just the fuel that is the critical factor, it's whether there is power available to deliver to the customers. That's what they want.

Q Correct. And being a prudently managed utility you also have a reserve margin in your generation?

A We try to.

Q You make the statement at Page 11 of your prefiled testimony at Lines 21 to 22 that "We believe that it is impossible to assure consumers of

reliability and continuity simply by contract."

Is that consistent with Tampa Electric Company's relying on a mere contract for fuel, which is an important ingredient in your generation?

A No, sir, I don't think it is in that we don't think it's possible to assure consumers of reliability and continuity simply by relying on a single fuel contract either. You have to provide for some other means of providing the power. And the contract that we have with fuel suppliers, as well crafted as we may try to make it be, has obviously, not from past history, turned out to be as reliable as we would like it to be.

Q Immediately following that statement you say, "It should be noted at the outset that the more ironclad a contract is, the less likely it is that a nonutility generation" -- I assume you mean generator -- "will sign it at a reasonable price."

Does this reflect any attitude on your part or on the part of Tampa Electric that the power purchase agreements approved by this Commission over the past several years should be deemed imprudent?

A I'm not in the business of judging prudency. I think that -- and I'm not familiar with the contracts that the Commission has approved in that way. I was making a general statement about the relationship

between the number of terms and conditions that one puts into a contract and the willingness of a party who has a slightly different objective to sign it. The more onerous the person who's seeking to buy a particular good or service makes a contract to protect himself, the more difficult it is, generally, for the other person to provide that at perhaps the price they would like to.

Q But if the party to whom the contract is offered knows that these are the terms that are being offered; and if I want to play in this game, this is what I have to price and that is made available to all comers. Isn't that sort of what competition is all about or at least part of it?

A As a general statement, I would say competition is certainly related to that, yes, sir. I think, however, that we're not exactly in full competition here. We have considered some elements of competition and the utilities themselves are certainly not full competitors by their nature in law. We're constituted in a somewhat different way. And the question that faces us is how quickly or how slowly will we and should we move toward a less monopoly model and toward a more competitive model?

Q And I guess that's, in large measure, the

general thrust of your testimony that the Commission should be wary of changing a system that has been in place for some time?

A Not to say that change should not take place, but they should certainly be wary of it because it is a system that in the past has worked very well. And I would hate to throw out all the good aspects of what has worked well, unless it has a real promise, in fact, a good certainty that it will be better.

Q Mr. Rowe, as part of your capacity mix at Tampa Electric Company, do you rely on any purchases from other utilities or from cogenerators?

A We do.

Q Approximately what percentage of the capacity on your system or your total capacity is represented by nonutility generator purchased power?

A I really don't have the number.

Q Do you know how much you purchase from other utilities?

A No, I don't.

Q Do you have any long-term purchase contracts with either nonutility generators or other utilities?

A There is a long-term purchase contract with TECO Power Services, an affiliated producer.

Q Okay.

A Mr. Mestas will be able to tell you about our cogeneration contracts. That's his area of specialty.

Q At Page 14 of your testimony, Lines 4 through 8, you make the statement that "If an investor-owned utility or if investor-owned utilities can no longer own generating facilities, their ability to earn a return for their investors will fall dramatically. This can lead to very serious consequences for their customers."

Mr. Neiser asked Dr. Roach yesterday -- were you here when the exchange occurred -- whether the shareholders of a utility are compensated for purchased power the way they are when they invest in the utility-built generation. Do you recall that question?

A No, I don't, but I accept that.

Q Well, let me ask you this: The fact that the ability of a utility investor to earn a return -- in other words, the shareholder's ability to earn a return -- should this be a consideration if the particular utility that we're talking about cannot provide what is determined to be the best deal for its ratepayers?

A I still think it should, and let me elaborate, if I may. I think it goes back to the statement that I made about the competitive model versus the monopoly model and how quickly or how slowly

we ought to move from one to the other. If we make a move where suddenly we have decided to take the major investment that has been made by utilities over a period of time, and in order to try to get the best price for customers -- and that's another question about whether indeed it would be if we went to other kinds of generation -- we interrupted the expectations of the investors in the company materially. There are people who invest in our company who would be hurt by that. The value of their stock would drop, and I think that's a matter to be considered. There are many people that rely on utility stocks. They're teachers', unions and they're retired people, and they are people like you and me. And they're relying on an adequate return, on a fair return on investment. It's not that they won't earn a return on the remaining investment, but incrementally their growth in their investment and the growth in their stock will not be what they expected, and their stock will fall as a result. And I think that needs to be taken into effect.

Wherever there's been a quantum change in a too short a period of time, whatever that means, in a deregulated sort of industry, someone, some party, in some cases several parties, have suffered consequences that have been undesirable.

Now, the new model may turn out to work very well, but somebody had to lose something in order for the new model to work. And I would not like to see that happen in this industry. I would like to find a way that we can take on the benefits of competition in an orderly and defiant way without destroying the best of what's gone on before.

Q Well, you talk in your testimony -- I forget exactly where it is -- about the regulatory compact?

A Yes.

Q Should the consideration that you just finished discussing -- let me ask you this, should the utility be permitted to make the investment in its own plant and dedicate that investment to public service, when the service to which it is dedicated can be provided at a lower overall cost to the public? I mean, if we want to get into social considerations?

A I think that if all of the appropriate costs are measured that that won't be necessary.

Q Your comments and some of the questions that Mr. Cresse has asked other witnesses rely in substance almost solely on the utility's obligation to serve for their justification, and that's my opinion. Isn't the obligation to serve a part of the regulatory compact you described on Page 4 of your testimony?

A Yes, I think it is. Yes, sir.

Q Now, that compact assumes that the utility owns all of its distribution, transmission and generation facilities, doesn't it?

A I'm not sure that it speaks to it. That's certainly the way that it's been done in the past.

Q Well, let's assume these services were unbundled, as they are and have been in the natural gas industry for quite some time. Would the regulatory compact you describe continue to apply to generation?

A I would have to have more information than that. It kind of depends on -- well, the regulatory compact is what the regulatory compact is. I can tell you how it's worked in the past and how it's worked well. And that's exactly the question facing us. What should be the compact, I think, for the future?

If one were to define regulation as being quite different, and if I understand what you intend to mean by unbundling to mean that the generation supply portion of electric service is deregulated entirely, then it would be a quite different world. And I really haven't contemplated how far that might go and what it would be take to unwind it, but I would hope that we would avoid the problems that happen in the gas industry when that happened and just as I know you went

through them.

Q Well, let's just assume that a world in which you have a company or a number of companies that provide generation, all wholesale power producers, and you have other companies that provide transmission service. And then you have a distribution company, which basically is how the natural gas industry is structured today. In other words, your generator is your natural gas supplier or producer, your transmission company is a transmission pipeline, interstate or intrastate. And then you have folks like our local distribution companies here in Florida, Peoples Gas, West Florida Natural Gas, City Gas, and they are local distribution companies.

Local distribution companies in the gas industry rely entirely on contracts with the pipelines for transmission and the producers or gas marketers for their gas supply. In your case, let's say that your distribution electric utility, it would have to contract with Transco and Genco in order to get what it needs to distribute at the distribution company, would it not?

A It sure sounds that way.

Q If you assume that example in the electric industry, where under Chapter 366 does the obligation

to serve fall?

A I couldn't tell you. I mean, I can't say exactly how that falls. Chapter 366, I'm sure, was written again in the context of assuming the model the way that it had been, but I don't have a legal opinion as to exactly what would apply.

Q What happens when a utility fails to meet its obligation to serve?

A Typically the Commission takes action either to correct the utility or to penalize it.

Q Now, are these -- is the imposition of a penalty, either through the return on equity or a monetary fine or whatever, is that a certainty for the utility in that case?

A When the Commission decides that it's going to penalize, I think it's pretty certain that the utility is going to pay. Is that what you asked me?

Q Yes. I mean, is it certain, number one, that a penalty is going to be imposed, and if it's going to be imposed, is it certain what the amount is going to be?

A I think you'd have to ask the Commission that. Assuming that there has been something appropriate to penalize and the Commissioners decide that, as to the certainty of whether they would

consider a particular event penalizable, or whatever, I think they are the best ones to ask.

Q So you're basically saying it's uncertain?

A Yeah, in that respect I guess it's uncertain.

Q If a nonutility generator with whom you have a contract to deliver energy and capacity fails to deliver per the contract, isn't there a pretty -- isn't it fairly certain that it's not going to get paid? It's a take-and-pay situation?

A That's another if that you have. It kind of depends on that well-crafted contract that you mentioned and how well the lawyers are able to deal with it.

Q Does TECO Power Services have an obligation to serve Tampa Electric Company other than that created by contract?

A That's a good question. I would say from a legal point of view that it does not. I would say that from the view of this particular Commission, that it certainly would pierce through that corporate relationship and expect TECO Power Services to be held to, at least, if not a higher standard of performance than someone who was not affiliated.

Q Do you obtain reliable service from TECO Power Services?

A Yes, since January 1.

Q And that's a relationship that is governed only by a contract.

A Other than that that I described, except that if they are not behaving the right way, we've got a short cut to try to solve that problem without having to go to the lawyers to do it.

Q All right. Were there any penalties imposed on Florida's investor-own electric utilities as a result of their inability to meet customer's needs during the December '89 Christmas freeze?

A You mean were there fines or that sort of thing? I'm not aware of any in that respect. There was certainly an awful lot of effort put into explaining what happened, and there were a number of changes that were made as a result of it. I don't think I'd call those penalties, but there were changes made.

Q Cost of being regulated.

A Yes, sir.

Q Can you recall, Mr. Rowe, when the last time a Florida investor-owned electric utility was penalized for failure to live up to its obligation to serve?

A I can't tell you a date. If you want to call disallowance as a failure to the obligation to serve, I

could cite any number of those but I couldn't put the date on them.

COMMISSIONER CLARK: Mr. Watson, do you have an example of what constitutes their failure of the obligation to serve?

MR. WATSON: I'd love to hear one from the electrics. We've heard about it all today.

Q (By Mr. Watson) Could you give me an example of what constitutes a failure to meet the obligation to serve?

A Are you asking me have we failed?

Q No. I'm asking if you can give an example of what would constitute a failure to meet this obligation we've heard about for the last three days.

A I'll try.

Suppose that a given company failed to have adequate reserves, knowing that a reserve margin was necessary, and this Commission had found that a reserve margin was necessary, and then the Company failed to provide that sort of capacity. And then as a result of that customers were not served or they had to incur a much larger cost than expected. I would say that's a failure of the obligation to serve.

Q Wouldn't it be the failure to have the reserves, more so than it would obtaining capacity or

energy at a much higher cost that would constitute the failure?

A The bottom line result is the same. The customers weren't served.

COMMISSIONER CLARK: Have we had any situations where customers weren't served, such that you would consider it -- consider that a utility did not meet its obligation to serve? Has that ever happened?

MR. ROWE: I'm not aware of that, Commissioner. I think that the relationship, as I said, has been one where we're constantly reminded of it. And with this Commission's oversight and the responsibility of the utilities, we worked very hard so that that didn't happen. And I'm not aware of a quantum failure on the part of the compact.

COMMISSIONER CLARK: Mr. Watson, is it your view that the 1989 blackouts constituted a failure to serve, to meet that obligation?

MR. WATSON: No, I don't believe it did

COMMISSIONER CLARK: Okay.

MR. CRESSE: Mr. Chairman, I can jiggle Mr. Watson's memory just a moment. There has been a penalty imposed by this Commission on an electric utility for having too many short -- actually, it's

tree trimming. In a specific geographic area in this state, the utility neglected to keep that, and they were having these "flickers." This Commission imposed a penalty on that particular utility.

In addition, I think the guidelines which the Commission uses are the performance standards which are required under your rule for an electric company, the expectations that you have for performance under those rules.

MR. WATSON: Could I ask Mr. Cresse if he's aware of any instance other than the one he just cited where a utility has been --

MR. CRESSE: No, I left shortly after that.

MR. WATSON: Thank you. That's all the questions I have.

CHAIRMAN DEASON: Staff.

MR. PALECKI: I just have three questions.

CROSS EXAMINATION

BY MR. PALECKI:

Q What percentage of nonutility generation is on TECO's system?

A Mr. Palecki, I think Mr. Watson asked me that same question. I still don't know the answer.

Q Has TECO ever solicited bids or issued a request for proposals for nonutility generation?

A I don't know.

Q Is there any reason to believe that TECO would do so absent a Commission rule specifically requiring bidding or RFPs?

A I think it's -- with the present circumstances and the history of the need process that it would be pretty difficult for TECO to come in and justify its cost without having gone through some sort of an analysis. But it would depend upon the point in time that TECO were coming in. Certainly TECO would consider what it believes is out there and I think it would be prudent to find out what is out there. But, again, it depends upon the circumstances at the time that they are requesting generation, the kind of generation that they believe is necessary, as to whether it would be appropriate to do so at the time.

I think that the Company would have to come in and justify to the Commission why it didn't do it if it wanted to own the generation. But just as we did in the last case here, it's been cited before today with the Department of Energy grant, we would have expected had that not come along, that some sort of a bid process would have been necessary to justify our cost effectiveness. Some sort of bidding.

Now, what I had in mind at that time was that

we would be required to put out the construction cost to bid, as opposed to bidding for the power outright. That was the stage of the philosophy at that time.

But as we pointed out to the Commission and the Commission agreed, that in order to take advantage of that particular grant, there wasn't time to go through a full alternative power bidding process and still be able to secure the bid for the Department of Energy. So that was an exception to the rule that I believe has kind of existed out there without a formal rule being in place.

MR. PALECKI: Thank you. We have no further questions.

MR. WILLIS: We ask that Mr. Rowe be excused and call Mr. Mestas.

CHAIRMAN DEASON: Before we do that, there were a few things I wanted to do.

First of all, what we're going to do is we're going to take a short break. But before we do that, I'm going to make a request that all interested persons, to the extent possible, try to reach some type of consensus as to what our time requirements are going to be for the remainder of this hearing. If it is at all possible to finish today, and when I say today, that means something around the hour of 6:30, certainly

no later than 7 o'clock, and whether there's going to be the need for closing arguments, and even the possibility of whether closing arguments maybe could be substituted for some presentation we otherwise would get at this late hour, as is always a possibility.

And also be cognizant of the fact that the Chair has the right and the prerogative, as has been noticed, to put time limits on presentations. The Chair has certainly been reluctant to do that in the first two and three-fourths days of this hearing, but as the hours grow shorter and shorter that may be a requirement.

So just given all of those considerations, I would welcome any comments or suggestions from the parties as to how would be the best way to proceed for the remainder of today's activities.

We're going to take ten. Thank you.

(Brief recess.)

CHAIRMAN DEASON: I understand that in the spirit of cooperation and in the spirit of recognizing that this is Friday afternoon, that we've come to a consensus that we probably can be out of here by 5:00. And, in fact, I am tempted that come 5:00, I will just turn this little button down here by my side which turns off the microphones and declare the hearing over.

So everyone just please act accordingly.

I think Mr. Mestas is the next witness.

DON MESTAS

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. WILLIS:

Q Would you please state your name, address and business affiliation?

A Yes, my name is Don Mestas. My business address is 702 North Franklin Street, Tampa, Florida 33602. And I am employed by Tampa Electric Company.

Q Would you please give a brief summary of your testimony?

A Yes, thank you.

The purpose of my comments is to address certain issues the Commission should bear in mind as it considers the adoption of a rule pertaining to the selection of generating capacity.

I am proposing the revised rule suggestions to the Staff's alternative recommendation, which will protect the interest of Tampa Electric and its customers, while at the same time, providing both nonutility and other utility suppliers with a meaningful opportunity to participate in supplying a

portion of the generation resources required to meet the needs of the state.

The rule revisions I am proposing encourages flexibility. The rule should be permitted to evolve over time as circumstances change and as additional experience with competitive bid solicitations is gained.

We can support the Staff's revised alternative rule as proposed by Mr. Ballinger with the following modifications. And we, likewise, reject portions of Mr. Huddleston's proposed CEPA rule based on its incompatibility with these proposed modifications.

The rule should not be unduly detailed and restrictive of the Commission's regulatory discretion. The Commission should retain fail-safe stocks to ensure that it is the utility's customers' interest that are best served. The rule should not foster the pursuit of litigation. The rule should recognize the benefits of negotiations between bidders and the utility. The rule should avoid inclusion of unnecessary technical details, which could lead to multiple legal challenges based on so-called rights created by the rule. The rule should recognize that it is the electric utility's ultimate obligation to serve customers in Florida. The rule should focus on the protection of electric utility customers rather than on electric utility competitors.

The rule should result in a careful measured step toward competitive bid solicitations, rather than a giant leap into a hole. The rule should guard against any attempt or inclination to simply exclude new utility-owned generation all together. The rule should not alter the fact that it is the utility's responsibility before this Commission to establish the need for additional generating capacity to meet its obligation to serve its customers.

A utility should be able to seek a waiver from the bid rule and other supply-side opportunities should continue to remain as viable options. A utility's plan for transmission additions for deferring capacity should not be part of a supply-side competitive bid rule. Issuing an RFP bid package for capacity resources up to seven years in advance of actual need may eliminate the utility's flexibility to avoid cost.

The utility should not be required to provide proprietary computer models, databases or its cost estimates and financial assumptions in its bid solicitation package. The utility should evaluate and select bids and then commence negotiations prior to executing a purchased power agreement with a successful bidder.

The utility should be permitted to reject all bids, if not in its customers best interest. The utility must justify such action before this Commission. The utility, and not the rule should determine what is an adequate bid security deposit and total security performance deposit on the basis of each RFP it issues on a case-by-case basis. If the utility provides the additional capacity to meet its needs, it should be permitted to continue to be eligible to recover its investment so long as the utility is regulated by this Commission through proven traditional rate base procedures.

The provisions of a bid solicitation rule for capacity procurement should apply to municipal and REAs as well as IOU electric utilities. I would stress the importance of allowing flexibility in this process in permitting the rule to evolve over time, as additional experience is gained with competitive bid solicitations.

MR. WILLIS: Mr. Mestas is available for cross.

CHAIRMAN DEASON: Ms. Brownless.

CROSS EXAMINATION

BY MS. BROWNLESS:

Q Good afternoon, Mr. Mestas, I'm Suzanne Brownless.

I just want to go through your modifications to the Staff rule so I understand what modifications you've made and how your process works as opposed to what the Staff has previously described their process would be.

Am I correct that your RFP process would be initiated and it would be at that point in time, at the point where you decided not to have an RFP process, that you would get a waiver from the Public Service Commission?

A Yes. The utility company would first determine what its capacity needs are. And it would decide how it intended to meet those needs. And if it thought that the proper way to meet those needs was to build and own or to solicit competitive bids for that capacity, it would petition the Commission, identify its needed capacity and indicate at that time how it intended to fill that capacity need.

Q And I assume that that would be, for example, if you thought that you wanted to build a coal plant, that that would, in fact, be six or seven years prior to the in-service date of the coal plant that this RFP

waiver proceeding would be taking place. At the beginning of your planning process, in other words.

A To the extent it was a baseload unit with that kind of lead time and the commitment needed to be made, yes.

Q Okay. Then if you decided to go with the RFP process, you would let the RFP, which you developed yourself in-house, and then you would submit a sealed bid, if you decided to participate, to a third party who would hold all the bids?

A That's correct.

Q Okay. The third party would give all those sealed bids back to you after recording, I guess, whatever -- what everybody's price was, right?

A At the conclusion of the RFP expiration period, the bids would be returned to the utility for evaluation.

Q Okay. And then the utility would develop a short list?

A That's correct.

Q Okay. Would the criteria, by which the utility screened the bidders, be announced at any time in your process?

A Yes, we would include a selection and evaluation criteria, if you would, in the RFP process.

A weighting criteria to indicate those factors which are important to us in terms of both what's been referred to as priced and unpriced factors.

Q And could that be something as simple as a price that's going to be 60% and a nonprice that's going to be 40%?

A Whatever the evaluation process that we elected to use would be indicated in the RFP package.

Q How would subjective criteria be handled in this notification process as you envision it?

A I think to the extent that subjective criteria is necessary in the evaluation of an RFP proposal, it would be indicated to the extent we could. I don't intend to say here that subjectivity would be entirely absent the evaluation process. But we ought to be in a position to justify the decision we've made based on an evaluation of the proposal and on good solid subjectivity.

Q Okay. My understanding of your rule is that once you looked at all of the bids, you would retain the right to reject all bids; is that correct?

A That is correct.

Q And then at that time, you would proceed, if it was a plant greater than 75 megawatts, to come to the Commission and utilize the current need

determination process?

A If we rejected the bids, the option would be either how to obtain the capacity that's still required. It could be a reissue of the RFP, it could be a determination by the utility to build or it could be an opportunity to secure the capacity from some other resource.

Q Or you could rebid?

A I thought I mentioned that. We could rebid, I'm sorry.

Q Assuming you go through the bidding process and get your short list of bidders and you go to a need determination, what would be at issue in the need determination under your plan as you perceive it?

A From our perspective, there would be no issue. We would have selected at that point in time what we've considered to be the most optimum, least cost reliable alternative available to us. And we would proceed before the Commission in terms of meeting our generation needs with whatever that option selected is.

Q I guess what I'm getting at is right now in a need determination there's really two pieces to it. One piece is the megawatt need, is this capacity actually needed. And the other piece is has the utility or the QF or whoever is coming in provided the most cost-effective

alternative. Would those still be the issues that would able to be litigated in that process?

A No. What I mentioned earlier on and what I perceive to be the sequence is that we would appear before the Commission, initially, identifying the level of capacity that's required to meet our expansion requirements. In other words, we would identify the capacity and when we need it and the type and that sort of thing. And concurrent with that, we would indicate how we would proceed to obtain that capacity and why. We could either seek a waiver at that point in time, or issue or submit an RFP at that point in time and indicate a willingness to solicit bids.

Q Okay. So you really are proposing a bifurcated process where your need is identified on the front end and you get some indication at that time how you propose to fill it?

A That's exactly correct.

Q And then you would come back in a subsequent proceeding --

A With how we intend to fill that need.

Q -- and say, okay, this is how we did it?

A That's exactly right.

Q Under your proposal, does the utility have to bid to build or can it be the default builder?

A The utility could build in either of those two cases. For instance, if the utility elected to seek a waiver for cause and was able to sufficiently justify before this Commission why a waiver from the RFP or solicitation package was appropriate, then, of course, we would proceed with the construction of the facility. We may very well solicit competitive bids in terms of contract construction for the project at that point in time.

Alternatively, at the conclusion of a solicitation package in which we, for whatever reasons, found ourselves in a position to reject those bids, then the alternative at that point in time would be, of course, again, to justify before this Commission why we found it necessary to reject those bids. And it must be with cause. Having reached that conclusion, then our options are open again in terms of how to replace or obtain the capacity that we sought to obtain through the RFP package.

Q So your process could result, in fact, in a reiterative to the process because you may be back to ground zero at the end of --

A That clearly would not be the indication or our desire. But it's not to say that in some instances, based on the quality of bids, one should not

be forced to accept a bid that does not meet the criteria that are set out in the package.

Q We heard Mr. Ballinger testify earlier that the Staff does not pursue competitive bidding where the utility bids because they thought it was inherently unfair for the utility to score its own bidding in relation to other folks. That seems to be a common sense rational. How do you respond to that?

A Well, I certainly can't plow any new ground in that area. It's been discussed several times this afternoon. I believe ultimately the decision in terms of who the adequate builder of that new plant will be, will be determined in this hearing room. And if that's the case, I believe, again, if it's a utility that has the obligation of utilizing that power, seeing that it's on line when it needs it, to meet its load requirements, to serve its customers, that it's dispatched properly, that it's the right kind of technology, that it has some reliability and viability in terms of the technology, that we ought to play a very front-end role in selecting the units that will be provided to meet those capacity needs that we've identified.

Q Okay. And you don't think there would be any inherent bias in favor of your own bid.

A Clearly, if it was inherently biased, then

as it reached this location, the opportunity to point that out would be immanent amongst the participants in the proceeding.

Q Let me ask it this way: Do you believe if you participated in your own bid, the level of scrutiny would be quite intense?

A Yes, I do. But think about this, there are several options with respect to -- first of all, the utility participating in its own bid solicitation, which is a possibility, certainly. You know, the utility bid could be the lowest bid offered, at which point in time I wouldn't suspect that the list of intervenors would diminish, but, nonetheless, it could clearly be the lowest bid of the proposals accepted.

On the other hand, it could be -- way to the other extreme, heaven forbid, but it could fall off the table and be the highest one. Well, talk about subjectivity, it might be very difficult in those circumstances to use all the subjectivity, inherent subjectivity you may wish to utilize and pull that bid into the realm of other more competitively based bids.

So the other alternative would be if you have a close grouping of bids to provide that capacity, which included the utility's bid, then at that point in time, you know, we would utilize what we consider to be

the most obviously fair evaluation of what we should select to meet our needs. And then we would be prepared to stand on that recommendation in support and before this Commission and the intervenors.

Q Under your process would TECO Power Services have the ability to bid in your own service territory, in TECO Power's service's territory?

A Actually, the way we have proposed our bid package is that if the electric utility company intended to submit a bid in the RFP package, that the affiliate utility company would not.

Q Okay. So it would be an either/or kind of situation under your plan?

A Yes.

Q How does your process treat standard offered contracts as we know them today, or how would they treat the standard offered contracts?

A Yes. It's somewhat silent on that. I recognize that the Staff had intended to have the standard offered contracts for smaller QFs of 100 kW or less, in addition to having some either set asides or specific waiting criteria for cogenerators in solid waste facilities in the rule. As it relates to standard offers, I must tell that in my personal opinion, setting aside standard offers for cogenerators

of 100 kilowatts or less is, I think, meaningless.

Q Okay. But, nonetheless, required by federal law?

A Well, there is an opportunity to purchase from them. The fact that you have a so-called standard contract is necessarily a requirement.

Q Okay. Does your answer also apply to small power producers, renewables and the other categories of folks that the Staff has --

A Yes. As Mr. Rowe indicated, as well as it related to the Staff's proposed ruled, I think there ought to be some opportunity to focus on the municipal solid waste and the cogen, True cogen type facilities in the bidding procedure.

Q How would you determine Tampa Electric's avoided cost under your process? And I have a very simple question. Would it be the avoided cost number that's associated with your planning parameters, for example, something that can be developed from a ten-year site plan?

A Yes, it would be, Suzanne, similar to the question you asked earlier. It would be our best estimate based on EPRI Tag numbers, our own personal experience in what we know to be the most recent cost for that type of unit.

Q If a successful bid were completed, would you

consider avoided cost being set at your bid price, winning bid price or the next to the lowest winning price or some permutation of the bid --

A Yes, I think there would be good reason at the conclusion or subsequent to an RFP process to have identified a new avoided cost price based on actual numbers.

Q Okay. I'm curious --

A If the following unit is somewhat similar in scope and nature, if one unit is a baseload unit and the next unit in your generation expansion plan happens to be a peaking unit, for instance, you wouldn't want to use your baseload unit, although it was the most-recently executed unit as your avoided cost.

Q But if there were two combined cycles?

A If they were similar, you would, certainly.

Q Okay. I'm curious about how your short list negotiations would be conducted. Would it be conducted -- would you negotiate with the first guy and see what you can do with him; in other words, the lowest bidder assuming it's not you, of course, because we assume you're going -- if you have the lowest price then you wouldn't do any negotiations -- one at a time or would you do like four guys in four rooms and just go around?

Q Well, honestly I really haven't thought all

that through, and I don't know why it's really necessary to -- and that's some of the flexibility I think we ought to have. If you narrowed it down to one bidder and that's the only fellow you're going to negotiate with and you've eliminated an awful lot of leverage in terms of negotiations, I think that perhaps, and, again, I'm not real firm on this but from my own thought, it might be that if the utility has selected two or three bona fide competitive providers of the service, then we ought to have an opportunity to negotiate with each of them and select that ultimate proposal which ends up in the most least cost-effective proposal.

Q Let me tell you, frankly, what the IPPs are concerned about, is that you have this nice competitive bidding process and everybody is ranked and then, let's say, bidder No. 1 had built a combined cycle plant as what he proposed, and he proposed -- and its location was in Orlando, and it had certain criteria to it. And he didn't make the cut, he didn't make the short list. And his price was, let's say, a dollar a megawatt, to make this a simple thing. All right. Now, we get down to the short listed negotiations. QFs are concerned that what results from this --

A QFs or IPPs?

Q Well, IPPs. The Independents. We're going

to lump them all together in the NUG category; not you guys, the not-you-guys category. They're concerned that the project that comes out of this negotiated process, in fact, ends up being very similar to what was rejected on the front end and never made it to the short list. How would you propose to limit your negotiations on the back end so bidders on the front end would see it as fair?

A It would seem to me in that situation that the bidder with the lowest cost ought to be in the best position to conclude the negotiation process most satisfactorily. He's already got a leg up on all the competition. He comes into the negotiation process with the lowest price. The company is looking to provide that generating capacity at its lowest cost.

COMMISSIONER CLARK: But isn't it possible through your negotiations that that price will go up because you want certain things in the contract?

MR. MESTAS: Possibly, yes. It could very well.

COMMISSIONER CLARK: And I think what Suzanne is saying is that there is a very real possibility that what you finally negotiate is really what looked like the bid of an unsuccessful bidder. And that happens. It happens in construction contracts where you deal with the lowest bidder and then you begin negotiating

and lo and behold, if the other bidders had had that opportunity or known those changes were there --

MR. MESTAS: Well, again, as I preface my remarks, let me just say, again, my concept would be to select the two or three lowest bidders in the solicitation process and commence the negotiations with them in order to find that proposal which best meets our needs at the least cost. And it just seems to me it would be a logical place to start with those who'd come in with the lowest price.

COMMISSIONER CLARK: And just through that process you would have to be cognizant of the fact that you can't then negotiate up or negotiate a deal that is really what somebody else offered at a better price?

MR. MESTAS: Again, that's a problem with only looking at one way of obtaining capacity as the means for supplying -- the competitive bid rule as being the only means to supply capacity. There are opportunities to negotiate contracts for that capacity that should be and do, in fact, currently exist today where we can sit down with independent utilities or nonutility generators and meet our requirements on an individually negotiated contract basis. So that's the reality of the competitive bid solicitation.

But competitive procurement, I believe in

terms of ultimately selecting that supplier that will provide that generating capacity, must come as a result of ongoing negotiations at the conclusion of the solicitation process. There are just not enough sheets of paper to identify all the terms and conditions, as you've heard many times today, to carry that agreement over a 15- or 30-year period. It will be subsequently revisited many times otherwise.

Q I have three more questions. How much QF capacity do you have on your system right now as of 1993?

A In the neighborhood of -- well, we have approximately 400 megawatts of QF capacity in our system serving load that we previously served. And we have an additional 250 to 300 megawatts of QF capacity in our system that is under contract with other utilities.

Q Okay. Let me ask this question a different way and more briefly. I understand that you have four contracts right now with third parties, qualifying facilities or small power producers that sell electricity to Tampa Electric; is that correct?

A QFs?

Q QFs or SPPs, small power producers?

A We have currently two QF contracts in the contract with TECO Power Services that we're purchasing

power from that are in commercial operation today. We have an additional QF contract with an in-service date in 1995.

Q Okay. How many megawatts is that capacity? Let's put TECO Power Services in a different box. How many megawatts is the contract --

A We would have in the neighborhood of 440 megawatts or so of QF capacity in our system of which 40 megawatts to ultimately 60 megawatts are engaged in firm capacity contracts with Tampa Electric Company. And the other 370 to 400 megawatts of QF capacity is being utilized to offset internal load, such as to offset cost in excess of our avoided cost.

Q Would it be fair to say that that's roughly a little more than 1% of your --

A No. The way I would calculate that that's in the neighbor of 12% or 13% of QF capacity in our system, serving load that we otherwise had served.

Q Excluding self-service generators?

A Well, if you wish to exclude the self-service generators, then clearly we're talking about something in excess of 1%.

Q Okay. But not much more than 1%?

A Not much more.

MS. BROWNLESS: That's all I have. Thank

you, Mr. Mestas.

CHAIRMAN DEASON: Staff?

CROSS EXAMINATION

BY MS. RULE:

Q I'm Marsha Rule of the Commission Staff. One question.

Under your rule proposal, if the utility were to bid, would you be willing to be bound to that bid?

A Yes, if we submitted a seal bid, we would be bound by that bid.

Q For the life of the contract?

A Under the requirements that if other parties in that particular situation were also bound by that same bid, yes.

MS. RULE: Thank you.

CHAIRMAN DEASON: Thank you, Mr. Mestas. I hope you can catch your flight.

MS. MESTAS: Thank you.

(Mr. Mestas excused.)

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CHAIRMAN DEASON: That concludes TECO's witnesses; is that correct?

MR. WILLIS: That's correct.

CHAIRMAN DEASON: Okay. Next on my list is Gulf Power.

I want to make one thing clear, I have one party who has sat very patiently through this entire proceeding, it's LEAF, and whatever we do today we're going to hear from Ms. Swim before 5:00.

MS. SWIM: Thank you.

CHAIRMAN DEASON: So can you conclude your witnesses before 5:00, Mr. Stone?

MR. STONE: Mr. Chairman, in the interest of time, I have no witnesses. Our comments have already been inserted into record and we would just simply like to state that Gulf Power Company favors the Commission retaining a great deal of flexibility in its rule, so that we don't make concrete decisions today that would hamper the ability of the companies to tailor their selection process to the particular needs they face at the time of their particular selection. We very much are cognizant of our obligation to serve and we very seriously work towards fulfilling that obligation.

And that concludes our comments.

COMMISSIONER CLARK: If you had to align yourself with the other investor-owned utilities, would you align yourself with FPC or TECO?

MR. STONE: To be perfectly candid with you --

COMMISSIONER CLARK: For purposes of this proceeding. (Laughter)

MR. STONE: We've pretty much aligned ourselves with the Commission's draft rule, the original rule, the one that was in the notice of rulemaking. We have notice that there were some suggestions or refinements to that rule that FPL suggested that we reviewed those as adequate suggestions. But we believe that it's appropriate to recognize that there are differences among utilities, and there are differences within a utility over time. And we think that the Commission's rules ought to recognize that fact and allow us to be flexible, recognizing that that gives us the obligation to vary our selection procedures based on the circumstances we face at that time.

COMMISSIONER CLARK: Okay.

CHAIRMAN DEASON: Thank you, Mr. Stone. The next on my IOU list is FPL. Are there any presentations to be made by Florida Power and Light?

MR. CHILDS: We have no oral presentations.

CHAIRMAN DEASON: Thank you, Mr. Childs. That brings me to the municipals.

MR. WILLINGHAM: I have a short presentation and then Paul Elwing from Lakeland will give a few comments and also Tallahassee wants to put on a witness.

CHAIRMAN DEASON: Okay. And you -- let me

ask you, how long will it take for you to give your comments, Ms. Swim?

MS. SWIM: I think for me to just give my comments would not take more than ten minutes. I don't know whether there will be any questions on it.

CHAIRMAN DEASON: Okay. And Mr. Willingham, how long do you anticipate the entire presentation for the municipals?

MR. WILLINGHAM: Less than 20 minutes.

MR. McKENZIE: Mr. Chairman?

CHAIRMAN DEASON: Yes.

MR. McKENZIE: I think I'm the only gas utility representative, I'm Norrie McKenzie with Peninsula Pipeline. I think I'm the last or only gas utility. I would like to have five minutes for comments, please.

CHAIRMAN DEASON: Okay. I think we can get to everyone. Right now we'll proceed down the list. We won't take anyone out of order, at least for the present time. The list that I have for the municipal electrics has City of Lakeland first. Is there anyone here from the City of Lakeland?

MR. WILLINGHAM: Yes. But before we put Lakeland on I'd like to give just a few comments about where we're going with our comments to the rule.

CHAIRMAN DEASON: Please proceed.

MR. WILLINGHAM: Thank you.

My name is Bill Willingham, I represent FMEA and FMPA. We filed comments regarding our concerns and a few recommendations to the Commission's proposed rules.

One thing I would like to clarify is that we're not advocating a rule that requires the IOUs to be subject to a bidding rule. We merely suggested comments which would take municipals out, but still require the municipals to follow some sort of RFP process, not necessarily the process that applies to investor-owned utilities.

One concern that I've heard that I have from the comments during this hearing is Mr. Ballinger's comments that municipals should come in on a case-by-case basis and request a waiver of those selections that generically do not apply to municipals. We've requested today just to be eliminated from the rule as far as they apply to municipals, and we can do away with it once and for all. We generally believe that Mr. Ballinger's comments regarding the fox guarding the henhouse does not apply to municipals.

Again, the distinction between municipals are not advocating that it does apply to the IOU's or the co-ops. And, in fact, you've heard testimony from CEPA

and ARK stating that the existing rules are adequate for municipalities.

The municipals really have little or no incentive to build their own generation. We're also subject to the Sunshine laws and our evaluation of the generation alternative is to conduct it at a public hearing, which is overseen by elected officials. And this is prior to submitting our need petition to this Commission. We really just believe there's no fox in our case.

We believe that the record of the proceeding is sufficient to -- for the Commission to exclude municipalities, if not all utilities, from a predefined RFP procedure.

In addition, Mr. Sharma from KUA testified as to the problems that the proposed rule will impose upon municipal utilities.

At this time this is the end of my comments and I'd like to present Paul Elwing from Lakeland, who will describe briefly Lakeland's process and some of the concerns that Lakeland has with the rule.

CHAIRMAN DEASON: Okay.

MR. WILLINGHAM: Also we late-filed some testimony for Mr. Elwing and there's additional copies on the counter over there.

Mr Elwing?

PAUL H. ELWING

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. BRYANT:

Q Mr. Elwing, would you please state your name and your employer?

A Yes. My name is Paul H. Elwing, and my business address is 501 East Lemon Street, Lakeland, Florida 33801. And I work for the City of Lakeland, an electric municipal utility. I'm also here on behalf the Florida Municipal Power Agency and Florida Municipal Electric Association.

Q Would you briefly summarize your comments?

A Yes, sir. Lakeland, as a municipal, is respectfully requesting the Commission's consideration of excluding municipals from the proposed rules. Lakeland feels that the current rules are adequate for the Commission to regulate or oversee municipal generation additions.

The bidding rules as being proposed, we feel, will yield no better results to the municipals but will result in cost, both in dollars and in flexibility.

As we heard some earlier witnesses state,

costs as high as $300,000 have been bandied around. We're not taking issue what the exact cost is but there is a dollar cost there. And participating in a process that gives no additional benefit to our customers, our ratepayers, we do not feel is a prudent use of our ratepayers' money.

Also, as Mr. Sharma from Kissimmee Utilities stated yesterday, a formal process such as is being presented here can limit our flexibility through lost opportunities due to the inherent timings in these proposals, as well as being able to -- we would like to be able to dynamically adjust the process to meet the local and public concerns as we look to new generation sources.

Some of these issues can conflict with local city government authority. We're governed by city commission and they are elected officials. And they reserve the right to make the final decision-making processes when the municipal utility goes out for generation sources.

Supply options that we, as the utility, present to our city commissions are exhaustively reviewed by our city commissions, who are answering directly to the citizens through the public hearings. And when going through the public hearing process, the

municipal utility must have the flexibility to be able to change its criteria to meet the need and concern of the public. A specified procedure to go through, such as some of the things we've heard in this proceeding, would limit that ability.

When our city fathers then determine what is the best alternative or choice for their customers, then we, as the utility arm of the city, bring that decision before this body of the PSC for your view. We respectfully would like to retain that same process that we currently have now.

That concludes my comments.

Q Thank you. May I ask one quick question?

You generally are not opposed to employing an RFP process but you would like to stick with the RFP process you currently use; is that correct?

A That is correct. We support an RFP process, and we would just like to be able to design that process to meet our needs and for it to be flexible.

MR. BRYANT: Thank you very much.

Mr. Elwing and myself are both available for any comments and requests.

CHAIRMAN DEASON: Okay. Questions? Staff, Commissioners?

Thank you, Mr. Elwing.

MR. ELWING: Thank you.

(Mr. Elwing excused.)

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MR. CHAIRMAN: Mr. Hoffman?

MR. HOFFMAN: Thank you, Mr. Chairman.

My name is Ken Hoffman on behalf of the City of Tallahassee. We call Mr. Gary S. Brinkworth.

GARY S. BRINKWORTH

appeared before the Commission and testified as follows:

DIRECT EXAMINATION

BY MR. HOFFMAN:

Q Mr. Brinkworth, could you state your name and by whom you are employed and in what capacity?

A Yes. My name is Gary S. Brinkworth. I'm employed by the City of Tallahassee as a superintendent of System Planning. My business address is City Hall, 300 South Adams Street, Tallahassee, Florida, Zip Code 32301.

Q Mr. Brinkworth, has the City of Tallahassee filed comments addressing the original proposed rule and responsive comments addressing Staff's alternate proposed rule in this proceeding?

A Yes, we have.

Q Could you provide a brief summary of the City

of Tallahassee's comments?

A Yes, I will. (Pause)

The City of Tallahassee supports generally comments that you've previously heard from other municipal utility witnesses regarding a concern we have for the suggestion by Staff that we seek waivers for individual issues within the rule which we find to be nonapplicable to municipal utilities.

The City feels that approach is unnecessarily burdensome on us, requiring us to bring to this Commission the burden of proof, why we should be excluded. And it will increase our legal cost and the other costs that we would incur to pursue a resource solicitation.

We would suggest that the Commission consider either writing into the rule specific exclusions for municipal utilities or possibly collecting rule provisions and writing them into a separate rule directed only at municipal electric utilities.

The City has a general concern for what we perceive to be a tendency in the alternative proposed rule submitted by Mr. Ballinger to allow the Public Service Commission to encroach on the local regulatory authority of the City Commission to the City of Tallahassee. We believe that it's very important that

we preserve the right to use our local regulatory body to select the methodology and the criteria that we would utilize to select resources for the local electric utility.

We also believe that the so-called "sealed-bid approach" to capacity selection is, in fact, appropriate for municipal utilities. The City's current process contemplates a sealed-bid process. We believe, in fact, that that sealed-bid process tends to reduce the appearance of an unfair advantage on the part of the local municipal electric utility by requiring us to follow the same requirements and stipulations that any other outside bidder would have.

Our process, as it's developed right now, requires a third-party evaluator for the sealed bids, and that evaluator is engaged and managed directly by the City Commission, which is our regulatory body.

We also believe that the requirement in the Staff's proposed alternative Rule 25-22.082(5), regarding the filing of the RFP at the Public Service Commission prior to release, should be designated for us as an information filing only.

We feel this way because by the time that RFP has been developed and ready for issue, we've had extensive public involvement, a lot of public hearings,

a lot of town meetings, a lot of interaction with our customer owners. And we would be very concerned that the filing of that RFP before the PSC would imply that there is an opportunity for this regulatory body to alter the conditions of the RFP which were selected by our local regulatory authority.

Finally, the City is very concerned about the suggestion located in alternative proposed Rule 25-22.082(6), regarding the preference for special resource types, that is high-efficiency cogenerators, renewable resources and waste energy facilities.

We believe that that, again, preempts the local regulatory authority of our City Commission and may require us to give preference to generation or capacity types that, in fact, our community and our customer owners have no interest in.

That concludes my summary.

Q Thank you, Mr. Brinkworth.

MR. HOFFMAN: He's available for questions, Mr. Chairman.

CHAIRMAN DEASON: Questions? (Pause) I think there are no questions.

Thank you for your patience and for your presentation.

(Mr. Brinkworth excused.)

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CHAIRMAN DEASON: Mr. McKenzie, I believe you indicated maximum of five minutes.

MR. MCKENZIE: Yes, sir. You can cut me off.

CHAIRMAN DEASON: All right.

NORRIE McKENZIE

appeared before the Commission and testified as follows:

MR. McKENZIE: My name is Norrie McKenzie. I'm vice president of Business Development for Peninsula Pipeline Company, a proposed subsidiary of Southern Natural Gas, an interstate pipeline that serves seven southeastern states.

Southern Natural is owned by SONAT, Inc., headquartered in Birmingham, Alabama. My business address is 4 Greenway Plaza, Houston, Texas 77046. My comments are brief.

As I understand the 1993 Florida Electrical Power Coordinating Group's ten-year site plan, it projects electrical generating plants with natural gas as their primary fuel by the year 2002 to have a gas requirement of over 3 billion cubic feet per day or 3 bcf per day.

Today the natural gas capacity into Florida is approximately 1 bcf per day. Florida Gas

Transmission's current expansion will increase that capacity to 1.5 bcf per day. This projects a tremendous natural gas deficit or demand.

Peninsula Pipeline will supply natural gas transportation. Although natural gas transportation cost of electricity may seem small, it is not insignificant. For example, a 235-megawatt plant may cost $235 million using the $1,000 per kilowatt rule of thumb.

This plant would require 45,000 MMBtu per day of natural gas. At today's commodity cost of natural gas of approximately $2.25 per MMBtu, this represents $40 million per year, not including the transportation of that fuel. This commodity portion is usually market-sensitive and passed directly through to the electrical ratepayer.

Taking, for example, Florida Gas' Phase III transportation rates, including fuel of approximately 85 cents per MMBtu, the transportation of this fuel would cost approximately $14 million per year. Over a 15- to 20-year plant life, the transportation of fuel alone could approximate the original cost of the plant. In fact, if electrical generation cost 3.5 cents per kilowatt hour, this 85 cents represents approximately 20% of the cost. Therefore, the electrical ratepayer

deserves the lowest cost fuel transportation alternative.

One way to ensure that ratepayers receive that low-cost alternative is competitive bidding; without it, it may not happen. For instance, the present agreement between Florida Power Corporation and ANR Southern Pipeline Company dated April 8th, 1993, provides that Florida Power tender the natural gas transportation for approximately 470 megawatts of future gas requirements.

In other words, Florida Power has already contracted for natural gas transportation for two 235-megawatt plants that are not certificated, two units above and beyond the proposed Polk County Units 1 and 2, which are certificated. If Florida Power self-builds, for example, similar units, Polk County 3 and 4, the gas transportation is already contracted. In this case competitive bidding would at least allow transportation alternatives to be considered, ensuring that the electrical ratepayer receives the lowest cost fuel transportation alternative.

I share the Commission's concern of the social responsibility to serve. The natural gas industry also has this responsibility.

We're entering the first winter where natural

gas will flow under the Federal Energy Regulatory Commission's Order 636, which may and I hope will be the last step in deregulating the natural gas industry.

To date, I think natural gas consumers will tell you that they have benefited by deregulation and now have more choices than ever and lower cost options due to increased competition.

The natural gas industry and the electrical industry are very analogous. And I believe the ultimate electrical consumer will benefit and enjoy the benefits of increased competition in the electrical generation sector, including the inherent competition that will result in natural gas transportation.

Did I make it?

CHAIRMAN DEASON: I believe you did.

MR. MCKENZIE: I'm open for questions, if you have any.

CHAIRMAN DEASON: Questions for Mr. McKenzie? Mr. Neiser?

CROSS EXAMINATION

BY MR. NEISER:

Q Just to inquire as to whether or not you are actually aware that there has been a contract entered into for Units 3 and 4 at the Polk County site as opposed to possibly confusing that with our existing

Anclote units?

A No, sir. As I understand the precedent agreement, it is for up to -- and this includes future expansions -- for up to 300 million cubic feet, or 300,000 MMBtu per day or 300 million cubic feet per day. Anclote is 120 of that 300. Polk County Units 1 and 2 would be 90, to bring that 120 plus 90 up to 210, leaving an additional 90 out of that 300; that would be another 470 megawatts.

It doesn't necessarily say that they have to be Units 3 and 4 of Polk County, but that they are any future expansions Florida Power may have.

Q Okay. Could that possibly be options rather than the actual contract for that capacity?

A The way I read it, it states that Florida Power Corp must tender future gas transportation needs to what is considered SunShine or ANR.

MR. NEISER: I tried. Thank you.

CHAIRMAN DEASON: Mr. Cresse?

CROSS EXAMINATION

BY MR. CRESSE:

Q In your opening statement were you indicating that there's more demand for gas than there is supply?

A I indicated that the electrical site plan projects by Year 2000 that there is over 3 bcf of

electrical plants that will have natural gas as their primary fuel. Today there is 1 bcf or approximately 1 bcf of capacity into the state.

Q Are you suggesting, then, that under the certification of need process the Commission should not certify any more need that is dependent upon natural gas until the pipeline meets that deficit?

A No, sir. I think if you'll run the numbers, you'll see that there are probably 2 bcf of electrical generation capacity in the state today that has natural gas as their primary fuel. So you have 2 bcf today with 1 bcf capacity, you're going to have three in the future with more.

Q And does that mean that if natural gas is a cheaper source of fuel than the alternative, which is being used today, then we're paying more for the alternative than we should if natural gas is available?

A If what you stated is correct, I believe that would be an appropriate assumption.

Q Do you have an understanding that natural gas today in the market is cheaper than No. 6 oil?

A I take it is as a fact, if you're stating it.

Q Thank you.

A If you're stating that as a fact, I take it as a fact.

CHAIRMAN DEASON: Staff?

Thank you, Mr. McKenzie.

MR. McKENZIE: Yes, sir. Thank you for the opportunity.

(Mr. McKenzie excused.)

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CHAIRMAN DEASON: Ms. Swim.

DEBRA SWIM

appeared before the Commission and testified as follows:

MS. SWIM: Commissioners, I'm here on behalf of the Legal Environmental Assistance Foundation, and I made an appearance earlier.

We have filed comments in this case, and for today's purposes I would like to also submit the written comments that we filed on March 10th of '93, which are also part of the record but they weren't part of the record today, so I want to make sure they're included.

On the topic of generation selection, LEAF offers comments in two areas: one in terms of process and the other in terms of substance. Substance-wise, generation procurement procedures need to factor in the environmental and the associated economic costs of energy service alternatives.

Despite the best available control technology, there are pollution impacts from power plants. Coal pollutes the public's air and water, generally speaking, more than gas; and gas pollutes the public's air and water, generally speaking, more than solar or more than increased efficiency in the delivery of energy services.

The failure to factor in these environmental costs also poses significant economic impacts to ratepayers. For example, there is an effort in recent Clean Air Act amendment compliance cases that have been before you to deal with the cost of complying with increases in environmental requirement. And that means that the customers of the utilities that chose to rely on plants that pollute more are facing significant increases to fund more stringent pollution control requirements.

The Commission's cost-effectiveness assessment of generation alternatives should factor these environmental and associated economic impacts into the decision of what's the most cost-effective alternative. And LEAF has four specific recommendations in this regard.

First, we would like to see the Commission open up an environmental cost docket to attempt to

monetize these costs. In the Cypress case and in the Staff recommendation I'll read one sentence for you, "There does seem to be a consensus among the participants in this proceeding that the issue," referring to environmental externality quantification, "should receive further review and study on a generic basis, and Florida Power and Light recommends that as the appropriate next step."

We urge you to take that step and open a docket to start looking at this issue. And I would suggest probably that if you did so, you could probably get the Department of Environmental Protection to participate in that effort and provide expertise in areas where you haven't had that in the past.

But while we're discussing these issues, we also want to see you incorporate a less precise approach in the rule that's before you today. And we have some general recommendations in this regard. One approach would be to establish -- to set aside a reasonable percentage of the need for capacity that's identified for renewable resources and for highly-efficient cogenerators. And then within that set-aside percentage allow these resource providers to compete on a least-cost basis.

At the Solar and Renewables Conference we had

in Cocoa Beach a couple of weeks ago, I talked to a lot of the people who do this as their business. And it really could make a big difference if we just had a small set-aside for them, allow them to compete on the basis of least cost to allow these clean industries the place that they need in the state of Florida.

Another approach that is less precise than monetizing is to an adder or discount approach. What you would do is create an adder for some or all of the supply-side resources. For example, carbon-emitting resources or fossil fuel resources, or alternatively some form of discount or credit for renewable or efficiency resources.

You could get even less precise, if that was your choice, and just generally require utilities to factor environmental impacts and their associated economic impacts into resource planning; or create, in some fashion, a direct incentive such as a higher rate of return for utilities that emphasize these environmentally benign measures. 32 states have some kind of environmental externality requirements, and we urge Florida to join them.

And my last recommendation in the area of substance is we would like to see the Commission in this rule create an opportunity for energy service

companies, that is energy efficiency entrepreneurs, to compete with generation suppliers to meet capacity needs that are identified.

Your action in the conservation goals area where you decide how much of Florida's efficiency potential should be captured by Florida's utilities investments, could leave a lot of room open for efficiency entrepreneurs to operate, you know, in the generation selection mode. Depends on what you do, but there is a huge potential out there, and these are companies that deserve some support.

That brings me to the process comments that I referred to earlier.

LEAF agrees with Staff's witness, Tom Ballinger, that our purpose here is to avoid the eleventh-hour surprises that came up in the Cypress need determination case, although there is another surprise that we wish to avoid.

In a need determination case, there are two things at issue: One, is there a need for generation? And the other is, which option should meet that need? It's a surprise associated with the issue of whether there is a need that we want to avoid.

In recent need determination cases, the Commission made findings that the utilities'

demand-side management efforts were deficient and that they should be more aggressive. Nonetheless, the Commission found that there was a need for generation despite these acknowledged deficiencies in the utilities' DSM efforts. And, thus, at best, the evaluation that's required by Section 403.519, that is whether conservation measures are reasonably available to mitigate the need for a new plant, came too late in the process to really matter.

Now, our ideal solution to this problem would be for the Commission to require each utility to develop and implement a least-cost integrated resource plan, and we will be sponsoring testimony in this regard in the conservation goals rule docket.

In the interim, we express our support for CEPA's bifurcated process, since it would allow the Commission the opportunity to make a more timely and, thus, a more meaningful evaluation of the utility demand-side management efforts.

In this way we can avoid the eleventh-hour surprises that come up when you have a single hearing that combines both an assessment of whether there is a need and exactly how we should fill that need.

That concludes my remarks.

CHAIRMAN DEASON: Questions for Ms. Swim?

Mr. Cresse?

MR. CRESSE: Mr. Chairman.

CROSS EXAMINATION

BY MR. CRESSE:

Q In your last statement you seem to be suggesting a bifurcated hearing. Do you agree with Tampa Electric's proposal, Mr. Mestas' proposal, that there would be a determination of need, then they go out for bid?

A I haven't looked over -- I was not sent Tampa's proposal and I haven't looked it over.

Q All right. Let me clarify the question then.

Do you believe that there should first be a determination of need for capacity and then subsequently another hearing to determine whether or not that capacity has been obtained in the most cost-effective manner?

A Yes. I think that is CEPA's proposal.

Q All right. Now, would you agree that in that first hearing all of the issues of whether or not they've had adequate conservation programs and whether they can meet that need through additional conservation programs, and so forth and so on, could be the subject of the first hearing. But once that hearing has been held on that subject and the Commission has voted, that

it doesn't come up again in the second hearing?

A That's fine, just with the understanding that the first hearing is a 120.57 type of proceeding.

Q Is that -- I don't know what that means but as long as you're talking about evidentiary hearing, legal talk, so you can cross examine people and have a good time doing all that, right?

A Yes.

Q Okay. So looking at it from the utility's standpoint, then you say in the first hearing we prove up our need and we don't have to see LEAF in the second hearing. Is that a fair statement?

A Well, it depends on how much you're investing in renewables and highly-efficient cogenerators.

Q But in the second -- they would have already made that decision in the first hearing, would they not? The second hearing would be devoted to fair process and least cost?

A The second proceeding, the way I understand your question, would be devoted to selecting how to meet that need.

Q That capacity requirement?

A So, yes, that issue would be decided in the first hearing.

Q All right. You mentioned something about a

set-aside for renewal and high efficiency and so forth. Does that exist now, today, in terms of a cogenerator or a qualifying facility having available to it a price that it can sign a contract for today?

A Well, I'm not --

Q Is that a form of set-aside?

A I've looked at the comments submitted by Barney Capeheart, on behalf of the highly-efficient cogenerators, and it is their position that it's necessary to have more of a recognition for the role of highly-efficient cogenerators. And that's what we're looking for.

Q Well, you say "more of a role." Do you want highly-efficiency generators to be paid more than the lowest-cost alternative or equal to the lowest-cost alternative?

A Well, there's a range of ways to approach it: One approach is to have a set-aside for the highly-efficient cogenerators. And then within that percentage of need that's set aside, allow the competition on a least-cost basis. Another approach would be to give a modest price preference in recognition of the value of this resource in terms of environmental impact and associated economic impact.

Q Maybe my question wasn't clear.

Would you want this Commission to require a utility to pay a higher price than the least-cost unit available because that person was using renewable fuels or was a high-efficiency unit? Should they be paid a premium above what's least cost is what I'm asking you?

A Yes. That's what I answered, yes.

Q And the answer to that was "yes"?

A Yes.

Q Let me ask you this question: If they're high efficiency, why would they need a premium?

A Well, I would refer you to the testimony of Dr. Barney Capeheart to document that they're not receiving it. And the fact that they're not receiving it shows that they need it.

Q So the electric ratepayers should subsidize the highly-efficient cogenerators?

A The benefits of high-efficient cogeneration are directed by the legislature. The legislature directed the Commission to favor highly-efficient cogenerators and to favor renewable resources. And I think in terms of following the legislative directive in this regard for the policies that the legislature had in that directive, you know, yes, that's --

Q So the Commission is violating the law?

A I'm saying that the Commission has the

authority to do this and they haven't.

Q Well, then they were authorized as opposed to being directed; is that correct?

A That's right.

Q There is a distinction in that, is there not, under the law, between being authorized to do something and directed to do it?

A Yeah, sure.

Q Okay. You're asking the Commission somehow to take into consideration environmental impacts in certification of need; is that correct?

A You know we are urging the Commission to take into account environmental impacts. And, you know, one place would be in certification of need, but that's not, I mean, necessarily limited to.

Q I understand that. But for this hearing, you're asking it for that period?

A That's right. Basically, in terms of their selection of generation resource, which is the topic of this hearing.

Q Are you asking basically what, under the statute, is the economic regulation of utilities to become the environmental regulator or to participate in environmental regulation because the environmental regulation is not adequate to protect the citizens of

this state?

A No, I don't think so.

Q Why, then, should the economic regulator be requested to get involved in environmental regulation?

A Well, you know, despite the best available pollution control technology, there are environmental impacts, as I explained earlier in my testimony, from the construction and operation of power plants and the type of power plant or basically energy resource selected has varying impacts. And it's the Commission's rule to have some oversight into those varying impacts.

I'm not suggesting that they set the environmental standards but acknowledge that the pollution impacts and the associated economic impacts from the pollution impacts exist and take some accounting for that as they make decisions over which generation alternative is preferable.

MR. CRESSE: Thank you.

CHAIRMAN DEASON: Mr. Neiser? Mr. McGlothlin? Staff? Commissioners?

Thank you, Ms. Swim. (Pause)

(Ms. Swim excused.)

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According to my list, we have exhausted it

and there are no other presenters at this time. If I'm mistaken, please identify yourself, because this is your last opportunity.

Okay. I know that some interested persons have inquired about the possibility of having closing arguments. I know some parties have indicated that they think that is unnecessary or have agreed not to engage in closing arguments. But I've had an indication that at least one individual wishes to do so. And I've indicated that up until the hour of 5:00 that that would be permissible. I'm not soliciting it, but if it is coming, let's go ahead and have it.

MS. RULE: Well, I think some people have already left thinking that it was not going to happen who perhaps would have stayed around had there been an indication it would be available.

CHAIRMAN DEASON: Mr. Moyle, what's your pleasure? I've had an indication that some people thought there were not going to be closing arguments and that it may be unfair for you to engage in yours when others thought there were going to be none.

MR. MOYLE: Well, Mr. Chairman, I realize the time on a Friday afternoon, after three days of long and often exhausting testimony, but I had -- probably very presumptuous, but I had the idea in my mind,

particularly after Mr. Cresse made his closing in the middle of the proceedings. And I had a couple of points to make that might be helpful to the Commission, not as much in the nature of a closing argument, as personal observations. And since this is a Rule 120.45 rule hearing, I thought I would do it. But I don't want to do anything that's going to unfairly prejudice anybody else.

CHAIRMAN DEASON: Well, that's what my concern is at this point is, if there are other parties who felt like that there were not going to be closing arguments and have since vacated the room, I don't want to give anyone unfair advantage. But all parties have the opportunity to file further comments or responses to whatever has been said or whatever has taken place in this hearing. Is that correct?

MS. RULE: That's correct. Transcripts should be available the 15th of October, with the comment deadline October 29th.

CHAIRMAN DEASON: Mr. Moyle, I would just encourage you to do that in written form. And I will assure you that they will at least receive my attention, and I'm assure the other Commissioners will review that as well.

MR. MOYLE: Okay. May I just -- these are

not intended to be a brief, but may I do it in correspondence with copies to everyone?

CHAIRMAN DEASON: Is that permissible, Ms. Rule?

MS. RULE: Yes.

CHAIRMAN DEASON: That will be fine. Thank you for your understanding.

MR. MOYLE: Thank you.

CHAIRMAN DEASON: Thank you all for a very enjoyable three days. (Laughter)

MS. RULE: Mr. Chairman, Mr. Jenkins from the Staff had a request.

CHAIRMAN DEASON: I'm sorry. Hold on everyone.

MS. RULE: Joe Jenkins had a request. He would like people to cover something particularly in their comments if they file them.

He noted that there had been a lot of discussion about the risk of disallowance and wondered what it would take in the changes of the law or rules or statutes for you all to be comfortable that there wasn't going to be a risk of disallowance. In the interest of his question, you may wish to cover that.

CHAIRMAN DEASON: Thank you. Thank you all.

(Thereupon, the hearing concluded at 4:45 p.m.)

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FLORIDA)
: CERTIFICATE OF REPORTERS
COUNTY OF LEON)

We, JOY, KELLY, CSR, RPR; SYDNEY C. SILVA, CSR, RPR; PAMELA A. CANELL, Official Commission Reporters, and LISA GIROD JONES, RPR, CM.

DO HEREBY CERTIFY that the hearing in Docket No. 921288-EU, was heard by the Florida Public Service Commission at the time and place herein stated; it is further

CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed under our direct supervision, and that this transcript, consisting of 871 pages, Volumes I through VI, inclusive, constitutes a true transcription of our notes of said proceedings.

DATED this 12th day of October, A. D., 1993.

JOY KELLY, CSR, RPR
Chief, Bureau of Reporting

SYDNEY C. SILVA, CSR, RPR
Official Commission Reporter

PAMELA A. CANELL
Official Commission Reporter
(904)488-5981

LISA GIROD JONES, RPR, CM

STATE OF FLORIDA)
:
COUNTY OF LEON)

The foregoing certificate was acknowledged before me this 12th day of October, 1993, by JOY KELLY, SYDNEY C. SILVA, PAMELA A. CANELL and LISA GIROD JONES, who are personally known to me.

Evelyn L. Borschel
Notary Public - State of Florida

EVELYN L. BORSCHEL
MY COMMISSION # CC289265 EXPIRES
May 25, 1997
BONDED THRU TROY FAIN INSURANCE, INC.

STATE OF FLORIDA
BEFORE THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

IN RE: APPLICATION FOR POWER PLANT CERTIFICATION OF FLORIDA POWER CORPORATION POLK COUNTY SITE PA 92-33	DOAH CASE NO. 92-5308 EPP OGC CASE NO. 92-1494

FINAL ORDER APPROVING CERTIFICATION

On January 25, 1994, this matter came before the Governor and Cabinet, sitting as the Siting Board, pursuant to the Florida Electrical Power Plant Siting Act (PPSA), Section 403.501 et seq., Florida Statutes (1993), for final agency action concerning a recommended order dated December 3, 1993, attached as Exhibit 1, which recommends site certification for the Florida Power Corporation Polk County site. By order dated February 26, 1993, the Board found the Polk site to be consistent and in compliance with existing land use plans and zoning ordinances. On February 25, 19932, the Public Service Commission certified the need for 470 MW of natural gas-fired combined cycle generating capacity at the site.

No party has filed exceptions to the Recommended Order. On January 5, 1994, Florida Power Corporation (FPC) filed an uncontested Motion for Correction of Scriverner's Error. FPC's motion suggests that an inadvertent omission of the word "steam" from proposed Condition II as recommended creates an arguable ambiguity concerning when supplemental site certification must be sought for expansion of the site's generating capacity.

Upon consideration, the motion is GRANTED. The Siting Board ORDERS that, in accordance with past practice, the word "steam" be inserted at the appropriate location in Condition II to avoid any future uncertainty as to the applicability of supplemental certification proceedings under Section 403.517, Florida Statutes. FPC shall be required to utilize the supplemental site certification procedure whenever, in accordance with Section 403.519, Florida Statutes, it desires permission to expand the steam electric generating capacity of the Polk site beyond that authorized by this Order.

Having reviewed the recommended order and otherwise being fully advised, it is ORDERED:

1. Pursuant to Section 120.57 (1)(b)(10), Florida Statutes (1993), the Recommended Order dated December 3, 1993, (Exhibit 1) is APPROVED and ADOPTED by the Board.

2. The Board APPROVES certification for the location, construction and operation of 470 MW of natural gas-fired combined cycle generating capacity at the FPC Polk County Site as proposed in the Site Certification Application, subject to the Conditions of Certification contained in Appendix A to Exhibit 1, as modified by this Order.

3. The FPC Polk County Site is certified for an ultimate site capacity of 3000 MW fueled by coal gas, natural gas, and fuel oil, subject to need determination by the Florida Public Service Commission as required by law, supplemental application review and approval by the Board pursuant to Section 403. 517, Florida Statutes, and compliance with the Conditions of

Certification contained in Appendix A to Exhibit 1, as modified by this Order.

4. Condition of Certification II shall read as follows:

Any anticipated facility expansions beyond the certified initial nameplate capacity of 470 MW, production increases, or process modifications which may result in new, different, or increased discharges of pollutants, change in the type of fuel as described in XIII.A., or expansion in the steam electric generating capacity shall be reported by submissio of a supplemental application pursuant to Chapter 403, F.S.

5. The Board DELEGATES to the Department of Environmental Protection the authority to assure and enforce compliance by Florida Power Corporation and its agents with all of the Conditions of Certification imposed by this Order.

NOTICE OF RIGHTS

Any party to this certification proceeding has the right to seek judicial review of this Order under Section 120.68, Florida Statutes, by the filing of a notice of appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 2600 Blair Stone Road, Tallahassee, FL 32399-2400; and by filing a copy with the appropriate District Court of Appeal. The notice of appeal must be filed within 30 days from the date this Order is filed with the Clerk of the Siting Board.

DONE and ORDERED this 27th day of January, 1994, at Tallahassee, Florida, pursuant to a vote of the Governor and Cabinet sitting as the Siting Board, at a duly-noticed and constituted Cabinet meeting on January 25, 1994.

FILING AND ACKNOWLEDGEMENT

FILED, on this date, pursuant to S120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Clerk

1/27/94
Date

THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

BY
THE HONORABLE LAWTON CHILES

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been sent by U.S. Mail, to the following listed persons:

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Certificate of Service (continued)

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this 27th day of January, 1994.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

R T Donelan

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Sharyn L. Smith
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December 3, 1993

Honorable Lawton Chiles
Governor
State of Florida
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Tallahassee, FL 32399

Honorable Robert A. Butterworth
Attorney General
State of Florida
The Capitol
Tallahassee, FL 32399-1050

Honorable Bob Crawford
Commissioner of Agriculture
State of Florida
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Tallahassee, FL 32399-0810

Honorable Betty Castor
Commissioner of Education
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Honorable Jim Smith
Secretary of State
State of Florida
The Capitol, PL-02
Tallahassee, FL 32399-0250

Honorable Tom Gallagher
Treasurer and Insurance
Commissioner
State of Florida
The Capitol
Tallahassee, FL 32399-0300

Honorable Gerald A. Lewis
Comptroller
State of Florida
The Capitol, Plaza Level
Tallahassee, FL 32399-0350

Re: Florida Power Corporation Polk County Power Station Application PA 92-33
DOAH Case No. 92-5308EPP

Dear Siting Board:

Enclosed is my Recommended Order in the referenced case. Exhibits received in evidence and the transcript of the hearing have been delivered to Richard T. Donelan, Jr., at the Department of Environmental Regulation.

As required by Section 120.58(5), Florida Statutes, please provide the Division of Administrative Hearings a copy of your final order in this case within 15 days of rendition.

Sincerely,

DIANE K. KIESLING
Hearing Officer

DKK:smc

Enclosure as noted

Copies furnished:

Gary P. Sams
Richard W. Moore
Pamela I. Smith
Richard Donelan
Hamilton S. Oven, Jr.
Lucky T. Osho
Karen Brodeen
Michael Palecki
M. B. Adelson
Carolyn S. Holifield
Doug Leonard
Julia Greene
John J. Dingfelder
Mark Carpanini
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Richard Tschantz
James Antista
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Joseph L. Valenti
Don E. Duden

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: APPLICATION FOR POWER PLANT CERTIFICATION OF FLORIDA POWER CORPORATION POLK COUNTY SITE PA 92-33	)	DOAH CASE NO. 92-5308EPP OGC CASE NO. 92-1494

RECOMMENDED ORDER

Pursuant to notice, a certification hearing was held on October 26, 1993, in Bartow, Florida and on November 2, 1993, in Tallahassee, Florida, before the Division of Administrative Hearings, by its duly designated Hearing Officer, Diane K. Kiesling.

APPEARANCES

Florida Power Corporation:	Gary P. Sams Richard W. Moore Attorneys at Law Hopping Boyd Green & Sams 123 South Calhoun Street Tallahassee, Florida 32301 Pamela I. Smith Corporate Counsel Post Office Box 14042 St. Petersburg, Florida 33733-4042
Department of Environmental Protection:	Richard T. Donelan, Jr. Marcy LaHart Assistant General Counsels 2600 Blair Stone Road Tallahassee, Florida 32399-2400
Southwest Florida Water Management District:	Richard Tschantz Martin D. Hernandez Assistant General Counsels 2370 Broad Street Brooksville, Florida 34609-6899
Polk County, Florida:	Beth Harlan Assistant County Attorney Post Office Box 60 Bartow, Florida 33830

Parties

In addition to the parties which appeared at the hearing, the Department of Community Affairs (DCA), the Trustees of the Internal Improvement Trust Fund, the Department of Transportation (DOT), the Central Florida Regional Planning Council (CFRPC), the Florida Game and Fresh Water Fish Commission (FGFWFC), Hillsborough County, the Environmental Protection Commission of Hillsborough County, and Tampa Port Authority have party status in this proceeding but did not appear at the certification hearing.

Other parties to this certification proceeding include Estech, Incorporated and C&G Citrus L.P. (collectively, Estech), IMC Fertilizer, Inc., (IMC), and U.S. Agri-Chemical Corporation (USAC). These parties are the mining companies which currently own and/or operate mines on the proposed Polk County Site. They are admitted as parties for the limited purpose of accepting the conditions of certification which are specifically applicable to them.

STATEMENT OF THE ISSUE

In this proceeding, Florida Power Corporation (FPC) seeks approval to construct and operate 470 MW of natural gas-fired advanced design combined cycle (NGCC) generating capacity at its proposed Polk County Site. Additionally, FPC seeks a determination that the Polk County Site has the environmental resources necessary to support an ultimate capacity of 3,000 MW of combined cycle generating capacity fueled by a combination of

natural gas, coal-derived gas and distillate fuel oil. Such an ultimate site capacity certification may be granted pursuant to Section 403.517, Florida Statutes and Rule 17-17.231, Florida Administrative Code.

PRELIMINARY STATEMENT

This proceeding was held pursuant to the Florida Electrical Power Plant Siting Act, Chapter 403, Part II, Florida Statutes, and Chapter 17-17, Florida Administrative Code, to consider FPC's application for power plant site and ultimate site capacity certification of the Polk County Site. The ultimate site capacity would consist of 3,000 MW of generating capacity, including 1,000 MW of NGCC capacity and 2,000 MW of coal gas-fired combined cycle (CGCC) capacity, plus any later-identified linear facilities. The Polk County Site initially will include three linear facilities: an upgraded transmission line, a backup natural gas pipeline, and a reclaimed water pipeline from the City of Bartow.

Pursuant to Section 403.519, Florida Statutes, the PSC issued a determination of need for the first 470 MW of combined cycle generating capacity at FPC's proposed Polk County Site on February 25, 1992.

As required by subsections 403.508(1) and (2), Florida Statutes, a land use hearing was held before the undersigned hearing officer on December 7, 1992. By Order dated February 26, 1993, the Governor and Cabinet, sitting as the Siting Board, adopted the Recommended Order in toto, holding that the proposed project is consistent and in compliance with existing land use

plans and zoning ordinances of Polk County and Hillsborough County, Florida.

After proper notice, a certification hearing as required by Section 403.508(3), Florida Statutes, was held in Bartow, Florida on October 26, 1993, and in Tallahassee, Florida, on November 2, 1993.

FPC presented the oral or written testimony of 15 witnesses and its Exhibits FPC-1 through FPC-23 were received into evidence.

Testifying on behalf of FPC were Kathleen Small, Eric Major, George Fantozzi, Harold Frediani, Dale Williams, Tom Adams, Charles Gupton, Phillip Murdock, Christopher Squires, Doug Coomer, Analee Moore, Fred Shanholtzer, John Cochran, Stephen Niles, and Doug Fulle.

No other party presented witnesses during the hearing. Exhibits DEP-1 through DEP-3 of the Department of Environmental Protection (DEP) were received into evidence. Additionally, one person testified at the public hearing held on October 26, 1993, in Bartow, Florida.

The transcript of the proceedings was filed on November 29, 1993. The parties timely filed a joint proposed order. The proposed findings of fact are adopted in substance as modified in this Recommended Order.

FINDINGS OF FACT

Project Site and Vicinity

1. FPC's proposed Polk County Site is located on approximately 8,200 acres in southwest Polk County, Florida, in

an area dominated by phosphate mining activities. The Polk County Site is approximately 40 miles east of Tampa, 3 miles south of Bartow and 3.5 miles northwest of Fort Meade. Homeland, the nearest unincorporated community, lies about one mile to the northeast of the site boundary.

2. The Polk County Site is bounded on the north by County Road (CR) 640 and along the southeast and south by a U.S. Agri-Chemical Corporation (USAC) mine. CR 555 runs north-south through the site.

3. The Polk County Site is comprised of land in four different phases of mining activity: mine pits, clay settling ponds associated with phosphate mining, land which has been mined and reclaimed, and land which has yet to be mined. Approximately one-half of the Polk County Site is subject to mandatory reclamation.

4. Land uses adjacent to the Polk County Site consist almost entirely of phosphate mining activities. One mobile home is located at the intersection of CR 640 and CR 555 approximately 2 miles from the proposed location of the principal generating facilities.

General Project Description

5. The initial generating capacity at the Polk County Site will be NGCC units. Under what has been designated as the Case A' scenario, ultimate site development will consist of 1,000 MW of NGCC and 2,000 MW of CGCC generating capacity, for a total of 3,000 MW. Under the alternative Case C scenario, the ultimate site capacity would consist of 3,000 MW of all NGCC

capacity. The Case C scenario was initially developed as the worst case scenario for the socioeconomic impact analysis (i.e., the one that would produce the least amount of economic benefit.) The combined cycle units which initially burn natural gas can be modified to burn coal gas if necessary to meet changes in fuel supply or pricing. However, under the proposed ultimate site capacity, CGCC generating capacity will be limited to a maximum of 2,000 MW out of the total of 3,000 MW.

6. At ultimate buildout the major facilities at the Polk County Site will include the plant island, cooling pond, solid waste disposal areas, and brine pond.

7. The plant island will be located on mining parcels SA-11, SA-13 and the northerly portion of SA-12. The plant island ultimately will contain the combined cycle power block, oil storage tanks, water and sewage treatment facilities, coal gasification facilities, coal pile and rail loop, and coal handling facilities. The cooling pond at ultimate buildout will be located in mining parcels N-16, N-15 and N-11B, with a channel through N-11C. Mining parcels N-11C, P-3, Phosphoria, Triangle Lakes and P-2, if not used as a solid waste disposal area, will be used as water crop areas to collect rainfall for supplying the cooling pond. The brine pond will receive wastewater reject from the reverse osmosis (RO) water treatment system and will be located on mining parcel SA-9. Two solid waste disposal areas (SWDA) are planned for ultimate development of the Polk County Site. The SWDAs will be mining parcel SA-8 initially and mining parcel P-2 in later phases, if necessary.

Coal gasification slag will be the predominant solid waste to be disposed of in the SWDAs.

8. Other areas included within the Polk County Site are mine parcels N-11A, N-13, N-9B, Tiger Bay East, Tiger Bay, the northerly 80 acres of N-9, SA-10 and the southerly 225 acres of SA-12. Along with providing a buffer for the Polk County Site facilities, these parcels also will provide drainage to Camp Branch and McCullough Creek.

9. Linear facilities associated with the initial 470 MW of generating capacity at the Polk County Site will include a 230 kilovolt (kV) transmission line upgrade, a reclaimed water pipeline, and a backup natural gas pipeline.

Site Selection

10. A comprehensive process was used to select the Polk County Site. The goal of that process was to identify a site which could accommodate 3,000 MW of generating capacity and offer characteristics including: (1) multi-unit and clean coal capability; (2) technology and fuel flexibility; (3) cost effectiveness; (4) compatibility with FPC's commitment to environmental protection; (5) ability to comply with all government regulations; and (6) consistency with state land use objectives.

11. The site selection process included the entire State of Florida. Participants in the site selection process included a variety of FPC departments, environmental and engineering consultants, and an eight-member Environmental Advisory Group (EAG) composed of environmental, educational, and community

leaders. In October, 1990, with the concurrence of the EAG, the Polk County Site was selected.

12. The ultimate basis for the selection of the Polk County Site was the disturbed nature of the site as a result of extensive phosphate mining activities. The Polk County Site also is compatible with FPC's load center and transmission line network, and is accessible to rail and highway transportation systems.

PSC Need Determination

13. On February 25, 1992, the PSC issued Order No. 25805 determining the need for the first 470 MW of generating capacity at the Polk County Site. The PSC concluded in its order that the first two combined cycle units (470 MW) at the Polk County Site will contribute to FPC's electric system reliability and integrity. It also concluded that the first two units would enable FPC to meet winter reserve margin criteria and to withstand an outage of its largest unit at the time of system peak demand. The PSC stated that it was important for FPC to secure a site to meet future needs and that the first two units would contribute toward this goal.

Basis for Ultimate Site Capacity

14. The Site Certification Application (SCA), including the Sufficiency Responses, addressed the impacts associated with 3,000 to 3,200 MW of generating capacity under several scenarios. FPC eliminated or modified several of the scenarios by filing a Notice of Limitations which addressed the capacity and environmental effects of 1,000 MW of NGCC and 2,000 MW of

CGCC generating capacity at the Polk County Site. Throughout the SCA, Sufficiency Responses and Notice of Limitations, the capacity constraints and environmental effects were analyzed under a worst case scenario, i.e., the maximum environmental effects that could be expected at ultimate site capacity.

15. An ultimate site capacity determination will significantly reduce the time and expense associated with processing supplemental applications for future units at the Polk County Site under the expedited statutory procedures of the Power Plant Siting Act. This will allow FPC to respond more quickly to changes in growth and demand. An ultimate site capacity determination also provides FPC the assurance that the Polk County Site has the land, air and water resources to support future coal gas-fired generating capacity.

Project Schedule and Costs

16. Construction of the initial 470 MW of NGCC generating capacity is scheduled to begin in 1994. These units will go into operation in 1998 and 1999. Based on current load forecasts, it is expected that approximately one 250 MW unit will be added every other year to the Polk County Site. Under this schedule, ultimate site development of 3,000 MW would occur about 2018.

17. Capital investment for the Polk County Site is expected to be approximately $3.4 billion for the 1,000 MW NGCC/2000 MW CGCC Case A' scenario and approximately $1.7 billion for the all NGCC Case C scenario.

Project Design

18. Generating units for the Polk County Site will be advanced design combined cycle units firing natural gas and/or coal gas, with low sulfur fuel oil as backup. Each combined cycle unit will consist of one or two combustion turbines (CT), a heat recovery steam generator (HRSG) for each CT and one or two steam turbines (ST). The first 470 MW of generating capacity will consist of two CTs firing natural gas, two HRSGs and one or two STs. At ultimate site capacity, the Polk County Site will consist of 12 CTs, 12 HRSGs, and 6 to 12 STs.

19. A combined cycle unit is a generating system that consists of two sequential generating stages. In the first stage, the natural gas, coal gas or fuel oil is burned to operate the CT. Hot exhaust gas from the CT is passed through the HRSG to produce steam to operate the ST. The CT and steam from the HRSG can be arranged to drive individual generators or a single generator.

20. In later phases of the Polk County Site, up to 2,000 MW of combined cycle generation may be fired on coal gas. The combined cycle units that were initially constructed to operate on natural gas can be modified to operate on coal gas. Under the Case A' scenario, two coal gasification plants would be built to produce coal gas for the combined cycle units.

21. Associated with the coal gasification phase of the project will be the expansion of the plant island to accommodate the storage and handling of coal. Coal will be transported onsite by railroad. A rail loop for coal trains will be

constructed on the plant island. It will be sized to accommodate a 100-car coal train. The coal storage area and limestone stockout will be located within the coal loop. Limestone is used in the coal gasification process as a fluxing agent to improve the viscosity of the coal slag, a by-product of the coal gasification process. The coal storage area, including the coal piles and emergency coal stockout system, will be lined with an impervious liner, and runoff from the coal storage area will be recycled to the coal gasification plants.

22. The cooling pond for the Polk County Site will be located north and east of the plant island. Water from the cooling pond will be used for producing steam and condenser cooling. The cooling pond will be constructed initially in mining parcel N-16 and then in parcels N-15 and N-11B for later phases. These areas are mined-out pits which are surrounded by earthen dams. These dams will be upgraded where required to provide stability equivalent to the requirements of Chapter 17-672, Florida Administrative Code, for phosphate dams.

Soil and Foundation Stability

23. To evaluate the existing soil conditions at the Polk County Site, more than 165 test borings were made. The plant island is an existing mine pit which has been partially filled with sand tailings from phosphate mining operations. Underlying the sand is the Hawthorn formation which is often used as the base for deep load bearing foundations. Foundations for the heavier loads of power plant facilities will require pile foundations or similar types of deep foundations that will extend into the Hawthorn formation.

24. The potential for sinkhole development at the Polk County Site was investigated by reviewing historic sinkhole records, aerial photographs, well drillers' logs, and by drilling three deep borings at the site. The investigation demonstrated that the potential for sinkhole development at the Polk County Site is low and acceptable for this type of construction.

Construction Activities

25. Construction of the Polk County Site will be phased over an approximately 25-year period beginning in 1994. The development of the Polk County Site is expected to take place in seven phases. Changes in the scope or sequence of the individual phases may occur depending on capacity needs over time.

26. During Phase I, the initial earthwork and dewatering activities required for the construction of the plant island and cooling pond will take place. The initial cooling pond and plant island area will be dewatered and fill will be placed in SA-11 and SA-13 for the initial power plant construction. Water from the dewatering activities will be conserved by storage in mining parcels SA-8, SA-9, SA-10, N-15 and the northerly part of SA-12, except for quantities used in IMC's recirculation system. Clay consolidation will commence for other parcels, such as N-11A, N-11B, N-11C, N-13 and N-9B. Phosphate mining and related operations will still function in parcels P-2, P-3, Phosphoria, Triangle Lakes, and N-9.

27. The initial vertical power plant construction for the first 470 MW of generating capacity will take place in Phase II.

Water stored in Phase I, along with reclaimed water from the City of Bartow, will be used to fill the cooling pond in parcel N-16. Any excess reclaimed water from the City of Bartow, if necessary, will be stored in the eastern portion of N-16. Mining parcels SA-10, the southerly part of SA-12, and a portion of the offsite Estech Silver City plant site will be configured for drainage enhancement to McCullough Creek. Mining parcel SA-8 will be prepared to receive solid waste and parcel SA-9 will be prepared to receive wastewater from the RO system and neutralization basin. Wildlife habitat creation and enhancement will begin in parcels N-9B and N-13.

28. Phase III of the Polk County Site represents the operation of the power plant from 235 MW to 1,500 MW, currently projected as NGCC capacity. The plant island, which will contain the generating units, will be located on mining parcels SA-11 and SA-13. The cooling pond will be located in N-16 and will receive reclaimed water from the City of Bartow and water crop from mining parcels P-3, Phosphoria, P-2, Triangle Lakes, N-15, N-11B, N-11C, the northerly end of SA-12 and the east end of N-16.

29. Phase IV will encompass the development of the Polk County Site from 1,500 MW to 2,000 MW, currently projected as NGCC capacity. In conjunction with the additional generating units onsite, the cooling pond in N-16 will be enlarged to 1,219 acres. Other portions of the Polk County Site would remain the same as in Phase III.

30. During Phase V, coal gasification is projected to be introduced to the Polk County Site. Generating capacity will be

increased to 2,250 MW of which 1,000 MW are projected to be NGCC and the remaining 1,250 MW will be CGCC. To accommodate the coal gasification facilities, the northerly portion of SA-12 would be filled. The balance of the site would remain as described in Phase IV.

31. During Phase VI, the generating capacity at the Polk County Site is projected to increase from 2,250 MW to 3,000 MW. This generating capacity will be a combination of 1,000 MW on NGCC and 2,000 MW on CGCC. During this phase, the cooling pond will be enlarged to 2,260 acres and will include parcels N-16, N-15 and N-11B, and a channel through N-11C. Earthwork will be required in N-15 and N-11B to repair and improve dams, and add slope protection on the dam inner faces and seeding on the exterior faces.

32. Phase VII will be the final phase of the Polk County Site. During this phase, if the solid waste disposal area in mining parcel SA-8 were to become full it would be closed and mining parcel P-2 would be prepared to receive solid waste from the power plant operations. Parcels P-3 and Phosphoria will be available for mitigation, if necessary, as a result of activities in parcel P-2. This phase might not occur if coal slag is successfully recycled.

Fuel Supply

33. Fuel for the initial 470 MW of combined cycle generation will consist primarily of natural gas, with light distillate fuel oil as backup. Natural gas will be delivered by pipeline to the Polk County Site at a rate of 3.75 million cubic

feet per hour. FPC currently plans to receive natural gas from the proposed Sunshine Pipeline for which certification is being sought in a separate proceeding. The Application for the Sunshine Pipeline was filed with DEP in August 1993. The other source for natural gas will be the backup natural gas pipeline which is being certified in this proceeding as an associated linear facility.

34. Fuel oil will be delivered to the site by tanker truck, and enough fuel oil will be stored onsite for three days of operation for each combined cycle unit. At ultimate development, three 4-million gallon oil tanks will be located on the Polk County Site. All fuel handling and storage facilities, including unloading areas, pump areas, piping system, storage tanks, and tank containment areas will meet the requirements of DEP Chapter 17-762, Florida Administrative Code, and applicable National Fire Prevention Association Codes.

35. At ultimate site development, the combined cycle units would use both natural gas and coal gas as primary fuels, and fuel oil as a backup fuel. As with the initial phase of operation, natural gas will be supplied by pipeline. At 1,000 MW of NGCC capacity, six to eight million cubic feet per hour of natural gas will be required. Coal for the coal gasification units will be delivered by railroad. For 2,000 MW of CGCC generating capacity, approximately 15,000 to 20,000 tons of coal a day will be required.

Linear Facilities

36. The initial 470 MW of NGCC generation includes three associated linear facilities: a 230-kV transmission line

upgrade, a reclaimed water pipeline, and a backup natural gas pipeline.

230-kV Transmission Line

37. The 230-kV transmission line will be routed from the existing FPC Barcola Substation within the Polk County Site to the FPC Ft. Meade Substation adjacent to CR 630. The transmission line corridor is approximately 1,000 feet wide within the Polk County Site boundary and narrows to 500 feet as the corridor leaves the site. The transmission line corridor follows several linear facilities including an existing transmission line right-of-way, CR 555 and CR 630. Land uses along the corridor are primarily phosphate mining, agricultural and industrial. Wetlands within the transmission line corridor are minimal and are associated primarily with roadside ditches. Where the transmission line crosses McCullough Creek, the creek will be spanned.

38. The 230-kV transmission line will be constructed using single shaft tubular steel poles with a double circuit configuration for two 230-kV circuits. The transmission line structures will range in height from 110 feet to 145 feet. The conductor for the transmission line is a 1590 ACSR conductor that is approximately 1.54 inches in diameter. Conductor span lengths between structures will range from 500 to 900 feet.

39. The transmission line will be constructed in six phases. During the first phase, the right-of-way will be cleared. Clearing in upland areas will be done using mowers and other power equipment. Clearing in wetlands, if necessary, will

be accomplished by restrictive clearing techniques. After the right-of-way has been cleared, existing structures which will be replaced with new transmission line structures will be removed by unbolting them from their foundations and removing the structures with a crane. Foundations for new transmission line structures will be vibrated into the ground using a vibratory hammer or placed into an augured hole and backfilled. After the foundations are in place, new structures will be assembled on the foundations using a crane. Insulation and pole hardware will be mounted on the structures after erection. In the fifth phase of construction, conductors will be placed on a structure by pulling the conductors through a stringing block attached to the structure. During the final phase of construction, the structures will be grounded and any construction debris will be removed from the right-of-way. The construction of the 230-kV transmission line is estimated to require approximately 17 weeks. Construction of the transmission line will meet or exceed standards of the National Electrical Safety Code; FPC transmission design standards; Chapter 17-814, Florida Administrative Code; and the Florida Department of Transportation Utility Accommodation Guide, where applicable.

40. Electric and magnetic fields from the 230-kV transmission line will comply with the standards set forth in Chapter 17-814, Florida Administrative Code. Audible noise from the transmission line should occur only during rainy weather and will not exceed 39.1 dBA at the edge of the right-of-way. Since the transmission line is not located near many residences,

interference to television and AM radio reception should be minimal. If interference does occur, it can be identified easily and corrected on an individual basis.

Backup Natural Gas Pipeline

41. The backup natural gas pipeline will originate at the Florida Gas Transmission pipeline in Hillsborough County at CR 39. The backup pipeline corridor runs generally east for 18 miles until it enters the Polk County Site at the western boundary of the plant island. The pipeline corridor is 1,000 feet wide and it generally follows linear facilities such as Jameson Road, a Tampa Electric Company transmission line, the CSX Railroad, Durrance Road, and Agricola Road. Several subalternate corridors are proposed in Polk County where the backup natural gas pipeline crosses phosphate mining land. The subalternate corridors, all of which are proposed for certification, are necessary to maintain flexibility in routing the backup natural gas pipeline around active mining operations.

42. The uses of land crossed by the backup natural gas pipeline corridor consist primarily of phosphate mining and some agriculture. There are only two areas of residential land use along the corridor, one along Jameson Road in Hillsborough County, and the other near Bradley Junction along Old Highway 37 in Polk County. Ecological areas crossed by the natural gas pipeline corridor include a portion of Hookers Prairie in Polk County, some isolated wetlands associated with phosphate mining activities, and the South Prong Alafia River near CR 39 in Hillsborough County.

43. The backup natural gas pipeline will consist of a metering facility, a scraper trap for pipeline cleaning, a maximum 30-inch buried pipeline made of high strength steel, a pressure regulating station, a cathodic protection system for corrosion control, and a Supervisory Control and Data Acquisition (SCADA) system to monitor and operate the pipeline. The pipe to be used for the natural gas pipeline will be manufactured in accordance with standards specified in 49 CFR 192 and the industrial standards referenced therein. Pipe thickness will vary depending on the population of the area crossed. External corrosion control for the pipe will be provided by an external coating around the pipe and a cathodic protection system designed to prevent electrochemical corrosion of the pipe. Pipeline sections will be hydrostatically tested before leaving the factory to 125 percent of the design pressure.

44. Activities associated with the construction of the backup natural gas pipeline will include survey and staking of the right-of-way, right-of-way preparation, stringing of the pipe, bending, lineup welding and nondestructive testing, ditching, lowering in of pipeline sections, backfilling, tying in pipeline sections, testing and right-of-way restoration. Construction of the pipeline will take place typically within a 75 foot-wide right-of-way. A wider right-of-way may be required where specialized construction activities, such as jack and bore methods, are used. After construction, the natural gas pipeline will have a permanent 50-foot right-of-way. Where the pipeline

crosses federal and state highways or water courses, directional drilling or jack and bore construction methods will be used to minimize disturbance. Where the pipeline crosses the South Prong Alafia River, directional drilling will be used to locate the pipeline underneath the river bed.

45. Pipeline welding will be done by highly skilled personnel who have been qualified in accordance with 49 CFR 192. Pipeline welds will be visually inspected and a percentage of the welds will be x-rayed for analysis.

46. Once the pipeline is constructed, buried and tie-in welds completed, the pipeline will be hydrostatically tested. Hydrostatic testing will use water with a minimum test pressure of 125 percent of maximum operating pressure. Water for hydrostatic testing will be pumped from and returned to the Polk County Site cooling pond.

47. Construction of the pipeline will comply with Title 49 CFR Part 192, Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards; Chapter 25-12, Florida Administrative Code; Safety of Gas Transportation by Pipeline; and the FDOT Utility Accommodation Guide.

48. After construction of the backup natural gas pipeline, the right-of-way will be restored and a 50-foot-wide permanent right-of-way will be maintained. Line markers will be located along the pipeline at regular intervals and warning signs will be posted where the pipeline crosses roads, railroads, or stream crossings.

49. The estimated cost for the pipeline construction is $611,100 per mile, or $11.2 million for the 18.2 mile pipeline route.

Reclaimed Water Pipeline

50. The reclaimed water pipeline will run from the City of Bartow to the cooling pond near the eastern side of the Polk County Site. The reclaimed water pipeline corridor follows the CSX Railroad and U.S. Highway 17/98 south from the southerly Bartow city limit turning west toward the Polk County Site just south of Homeland. Land uses along the corridor include phosphate mining, commercial sites, rural residences and recreation. The corridor does not cross any environmentally sensitive habitats.

51. The reclaimed water pipeline consists of a buried pipe, 24 to 36 inches in diameter, butterfly valves about every mile along the pipeline, and a flow meter. Pumping of reclaimed water will be provided by the Bartow Sewage Treatment Plant. Construction of the reclaimed water pipeline is similar to that of the natural gas pipeline and includes the following activities: survey and staking of the right-of-way, right-of-way preparation, ditching or trenching construction, stringing of the pipe and pipe installation, back filling, hydrostatic testing, and right-of-way restoration. Where the pipeline crosses state or federal highways or railroads, the pipe will be installed by using jack and bore construction. Construction of the reclaimed water pipeline is estimated to cost $500,000 per mile or $5,000,000 for the total length of the pipeline.

52. Construction of the reclaimed water pipeline will comply with the standards in Chapter 17-610, Florida Administrative Code, the Florida Department of Transportation Utility Accommodation Guide, and the EPA Guidelines for Water Reuse Manual. The pipeline will be hydrostatically tested prior to operation. Corrosion control of the pipeline will depend on the material used for the pipeline and the soil conditions. If a polyethylene or a polyvinylchloride material is used, no corrosion control will be necessary. If ductile iron is used, the soil will be tested for corrosive properties and, if necessary, the pipeline will be protected from corrosion with a poly wrap material.

Solid Waste Disposal

53. Various types of solid waste will be generated by the operation of the Polk County Site. Depending upon the type of solid waste, disposal may be made in the onsite solid waste disposal areas or it may be disposed of offsite.

54. Waste inlet air filters from the combustion turbines and general waste, such as office waste, yard waste and circulating water system screenings, will be recycled or disposed of offsite at the Polk County North Central Landfill. Solid waste from the well water pretreatment and blowdown pretreatment will be disposed of onsite in the solid waste disposal area to be constructed in mining parcel SA-8. Sulfur, a by-product of coal gasification, will be of marketable grade and will be stored in a molten state onsite and delivered to buyers by rail car or tanker truck. Slag, a by-product of coal

gasification, will be the largest volume of solid waste generated at the Polk County Site. Slag is potentially marketable and FPC will make efforts to recycle this by-product as construction aggregate. If slag is not marketable, it will be disposed of in the onsite solid waste disposal areas initially in mining parcel SA-8 and later, if necessary, in parcel P-2. Low volume spent acidic and basic solutions produced in the regeneration of demineralizer resin bed ion exchanges during operation of the facility will be treated in an elementary neutralization unit to render them non-hazardous. Other potentially hazardous waste will be tested and if determined hazardous will be disposed of in accordance with all applicable federal and state laws.

55. Onsite disposal of slag, and well water and blowdown pretreatment solids will be made in the solid waste disposal areas to be constructed in parcels SA-8 and later, if necessary, P-2. These parcels are clay lined impoundments that have clays generally 20 to 40 feet thick. Prior to disposal of any solid waste in a clay settling area, that area will be drained and the clays consolidated. The clays will be probed and if the clay thickness is less than 10 feet it will be refurbished or patched with a synthetic liner. Additionally, a geotextile net will be installed to provide tensile strength to the upper layer of clay. Perimeter leachate collection piping will be installed. Leachate in the interior of the solid waste disposal areas will be monitored and collected by the use of well points to maintain the leachate head at no greater than 4 feet. The solid waste

disposal area in parcel SA-8 will be closed by installing a two-foot thick soil cover which will be seeded and graded to provide water crop to parcel N-16. At closure, the leachate level will be pumped down to minimize the residual leachate head.

56. The clay which lines the base of the solid waste disposal areas decreases in permeability as it consolidates and the solids content of the clay increases. In the first 20 to 50 years of consolidation, the hydraulic gradient of the clay is reversed and water will drain upward. Analysis of the clay shows that it would take 60 to 100 years for leachate to seep through the clay liner. After closure and capping of the solid waste disposal area occurs and the leachate residual head is pumped out, leachate is not expected to break through the liner. Based on the design of the solid waste disposal areas and the analysis of the clay, the solid waste disposal areas in parcels SA-8, and later P-2, should provide equivalent or superior protection to that of a Class I landfill under Chapter 17-7.01, Florida Administrative Code.

Industrial Wastewater

57. The Polk County Site is designed to be a zero discharge facility. There will be no offsite surface water discharge of contaminated stormwater or cooling pond blowdown. Cooling pond blowdown will be treated first by a lime/soda ash softening pretreatment system. A portion of the softened effluent will be routed to the cooling pond and a portion will be treated further by reverse osmosis (RO). High quality water from the RO system will be reused in the power plant as process

water. The reject wastewater from the RO system will be sent to the brine pond for evaporation. In later stages of the Polk County Site operation, the RO reject wastewater will be concentrated prior to disposal in the brine pond.

58. The brine pond will be constructed in parcel SA-9, a waste clay settling pond. Parcel SA-9 has thick waste clay deposits which will act as a liner. A synthetic liner will be placed along the interior perimeter of the brine pond out to a point where the clay is at least 10 feet thick. The synthetic liner will prevent seepage of the brine through the embankment of the brine pond and will provide added protection near the perimeter of the brine pond where the clay liner is thinner.

Groundwater Impacts/Zone of Discharge

59. The brine pond and solid waste disposal areas will be located in waste clay settling ponds with thick clay liners. They will be constructed to minimize, if not eliminate, seepage of brine and leachate to groundwater. If brine or leachate should seep through the clay liner, dispersion and dilution will reduce chemical concentrations so that neither primary nor secondary groundwater quality standards will be exceeded at the boundary of the zone of discharge.

60. A zone of discharge has been established for the solid waste disposal area in parcel SA-8, the brine pond in parcel SA-9, and the cooling pond in parcels N-11B, N-15 and N-16. The zone of discharge will extend horizontally 100 feet out from the outside toe of the earthen dam along a consolidated boundary surrounding these facilities and vertically downward to

the top of the Tampa member of the Hawthorn Group. A groundwater monitoring plan will be implemented to monitor compliance with groundwater standards at the boundary of the zone of discharge.

Surficial Hydrology and Water Quality Impacts

61. The Polk County Site is located along the divide between the Peace River Drainage Basin and the Alafia River Drainage Basin. Water bodies near the site include McCullough Creek, Camp Branch, Six Mile Creek, Barber Branch, and South Prong Alafia River. Mining has disrupted or eliminated natural drainage patterns from the Polk County Site to these water bodies. Currently the only drainage from the Polk County Site to these water bodies is through federally permitted National Pollutant Discharge Elimination System (NPDES) outfalls to McCullough Creek and Camp Branch.

62. To assess the impact to the surficial hydrology of the Polk County Site and surrounding water bodies, the baseline condition was assumed to be the surficial hydrology which would be present under current mandatory reclamation plans for the mining parcels onsite and offsite. The baseline for non-mandatory parcels was assumed to be the minimum reclamation standards under the DEP/Bureau of Mine Reclamation (BOMR) (formerly within the Department of Natural Resources) Old Lands Program and the baseline for non-mandatory offsite parcels was considered to be the existing condition. The one water body onsite for which the baseline condition presently exists is Tiger Bay, which has been reclaimed and released. The baseline

condition for the Polk County Site ultimately would include elimination of seepage from N-16 to Tiger Bay and removal of the NPDES outfall weir from Tiger Bay to Camp Branch. These conditions will result in a lowering of the water table in Tiger Bay and the drying out of wetlands in that area. Under current reclamation plans, water bodies also will be created in parcels SA-12 and SA-11. Other than the reclaimed Tiger Bay and Tiger Bay East, DEP, Southwest Florida Water Management District (SWFWMD) and Polk County have not claimed jurisdiction over any of the water bodies onsite within areas in which phosphate mining activities have been or will be conducted.

63. The major construction activities which may impact offsite surface water bodies are the dewatering activities associated with the initial phase of construction. During this period, parcels SA-11, SA-13 and N-16 will be dewatered to allow earth-moving activities to take place. Dewatering effluent will be stored onsite, reused in IMC's recirculation system, or discharged in the event of above-average rainfall. After the earthwork is complete, the water will be returned to N-16. Based on this construction scenario, no adverse impact to offsite surface water bodies is expected from the construction activities associated with the Polk County Site.

64. The Polk County Site has been designed to function as a "zero discharge" facility. No surface water will be withdrawn from or discharged to any offsite surface water body as a result of plant operations. Certain non-industrial areas within the Polk County Site will be designed, however, to provide offsite

consumption is estimated to average 19,000 gallons per day, with a peak consumption of 36,000 gallons per day. As an alternative, FPC may connect with the City of Bartow or the City of Fort Meade potable water system.

69. The subsurface hydrology of the Polk County Site consists of three aquifer systems. The uppermost system is the surficial aquifer which is located in the upper 20 to 30 feet of soil. Due to mining operations, the surficial aquifer has been removed from the site except beneath highway rights-of-way and portions of some dams. Below the surficial aquifer lies the intermediate aquifer which is comprised of an upper confining layer approximately 120 feet thick, a middle water bearing unit about 60 feet thick, and a lower confining unit about 80 to 100 feet thick. This aquifer system provides potable water to some small quantity users in the area. Below the intermediate aquifer is the Floridan Aquifer, which consists of the Upper Floridan Aquifer, a discontinuous intermediate confining unit, and the Lower Floridan Aquifer. The Upper Floridan Aquifer provides a larger source of potable water for the area. The Lower Floridan Aquifer is characterized by poorer quality water and has not been used generally for water supply.

70. The principal impact to groundwater from construction of the Polk County Site will be from the dewatering activities in parcels N-16, SA-11 and SA-13. This impact, if not mitigated, could result in the lowering of groundwater levels in the surficial aquifer in adjacent wetlands. During construction, recharge trenches will be constructed in certain

locations near wetlands. Modeling analysis demonstrates that the recharge trenches will adequately mitigate any offsite groundwater impacts that otherwise would be caused by construction dewatering.

71. The principal groundwater impact from the operation of the Polk County Site will be the withdrawal of water from the Upper Floridan Aquifer for process water and cooling pond makeup. Water from the Upper Floridan Aquifer is the lowest quality of groundwater that can be used for the Polk County Site while maintaining the cooling pond as a zero discharge facility. The withdrawal of 17.5 mgd from the Upper Floridan Aquifer at ultimate site development will not adversely impact offsite legal users of groundwater and will comply with the SWFWMD consumptive use criteria for groundwater withdrawal.

Ecological Resources

72. The baseline for the ecological resources at the Polk County Site was established as the site condition that would exist following (i) mandatory reclamation under reclamation plans approved by the DEP/BOMR, and (ii) non-mandatory reclamation normally carried out by the mining companies. In the cases of Tiger Bay, which has been reclaimed and released by DEP/BOMR, and Tiger Bay East, which has revegetated naturally without reclamation, the ecological baseline was represented by the current condition of these parcels. This baseline methodology was proposed by FPC in a Plan of Study which was accepted by DEP in a Binding Written Agreement.

73. The predominant land cover that would occur under the baseline condition at the Polk County Site would be agriculture.

Approximately 70 percent of the Polk County Site, or approximately 5,678 acres, would be developed as crop land, citrus or pasture. The remaining 30 percent of the site would be reclaimed as non-agricultural uplands, wetlands and open water bodies. Tiger Bay already has been reclaimed and released by DEP/BOMR and Tiger Bay East has revegetated naturally. These two parcels represent one-fourth (524 acres) of the natural habitat under the ecological baseline condition. The quality of the baseline land cover and vegetation was established by surveying several onsite and offsite areas which have been reclaimed and released.

74. Baseline aquatic resources at the Polk County Site consist of Tiger Bay and the aquatic resources which would have been developed under existing reclamation plans. This baseline would include open water bodies and forested wetlands in parcels SA- 11 and SA-12, and forested and herbaceous wetlands in parcel N-16. Both Estech and IMC have exceeded their mine-wide wetlands mitigation obligations even without those wetlands. The quality of the baseline open water bodies on the Polk County Site was evaluated by surveying parcel N-16, which currently consists of open water habitat. The quality of wetlands was determined by surveying Tiger Bay, which contains wetlands that have been reclaimed and released. The baseline aquatic resources were found to have significant fluctuations of dissolved oxygen, and were characterized by encroachment of cattail, water hyacinth and other nuisance species. All of the aquatic areas sampled as representative of baseline conditions

showed significant eutrophication. No DEP or SWFWMD jurisdictional wetlands currently exist onsite, within areas in which phosphate mining activities have been or will be conducted, except in the reclaimed Tiger Bay and Tiger Bay East.

75. Baseline evaluation of threatened and endangered species, and species of special concern (listed species) was conducted by collecting information regarding regional habitat descriptions; plant species lists and ecological reports for the area; lists and ecological reports of birds, mammals, reptiles and amphibians common to the area; species checklists; reports of sightings or abundance estimates; interspecific relationships and food chains of important species; location of rare, threatened or endangered species or critical habitat for these species in the region; and occurrence of potential preexisting stresses. Information from the Florida Natural Areas Inventory and approved mine reclamation plans was reviewed. Visits were made to nearby reclaimed sites by land and low-flying helicopters. No listed plant species were found at the site or offsite study areas. Existing reclamation plans, and consequently the ecological baseline condition, do not require the planting of such species. Listed animal species which were observed at the Polk County Site and are expected under the baseline conditions include the American alligator, woodstork, southeastern kestrel, osprey, little blue heron, snowy egret and tricolored heron. The baseline conditions would provide suitable feeding habitat for these species, but only limited areas of suitable nesting habitat. Both the current condition

of the site and baseline condition provide feeding habitat for the American bald eagle, however, the nesting potential for this species will be greater after the implementation of the baseline condition.

76. Impacts to the baseline ecological resources from the construction and operation of the Polk County Site will be more than compensated by habitat creation and enhancement programs proposed by FPC. The primary impacts to the baseline ecological resources will occur when power plant facilities, such as the plant island, cooling pond, brine pond and solid waste disposal area are constructed, eliminating these parcels from the baseline ecological resources. Without development of the Polk County Site, these parcels would represent approximately 2,268 acres of viable lakes and upland and wetland habitats. FPC has proposed a total of 3,713 acres of viable wildlife habitat as part of the ultimate development of the Polk County Site. Accordingly, the available wildlife habitat after construction of the Polk County Site represents a net increase of 1,445 acres over the baseline ecological resource conditions. This increase in habitat, particularly in the buffer area, will be a net benefit for protected species.

77. In providing more wildlife habitat than baseline conditions, FPC has agreed to certain enhancement activities that will specifically offset any impact to baseline ecological resources. These enhancement programs include habitat and wetland creation in parcels N-9B and N-13; habitat creation and offsite drainage enhancement in parcel SA-10; implementation of

a wildlife habitat management plan and exotic vegetation control in parcels SA-10, N-9B and N-13; drainage enhancement to McCullough Creek and Camp Branch; and funding the acquisition of a 425 acre offsite area to serve as part of a wildlife corridor.

Air Pollution Control

78. Polk County has been designated by the U.S. Environmental Protection Agency (EPA) and DEP as an attainment area for all six criteria air pollutants.

79. Federal and state Prevention of Significant Deterioration (PSD) regulations provide that the project will be subject to "new source review." This review generally requires that the project comply with all applicable state and federal emission limiting standards, including New Source Performance Standards (NSPS), and that Best Available Control Technology (BACT) be applied to control emissions of PSD pollutants emitted in excess of applicable PSD significant emission rates. The project will limit emission rates to levels far below NSPS requirements. For the initial 470 MW phase of the Project, BACT must be applied for the following pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulates (PM and PM_{10}), volatile organic compounds (VOCs), carbon monoxide (CO), beryllium, inorganic arsenic, and benzene. For the ultimate site capacity, BACT is required for each of these pollutants, and sulfuric acid mist (H_2SO_4), mercury, and lead as well.

80. BACT is defined in DEP Rule 17-212.200(16), Florida Administrative Code, as:

> An emission limitation, including a visible emission standard, based on the maximum

> degree of reduction of each pollutant emitted which the Department, on a case-by-case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

The primary purpose of a BACT analysis is to minimize the allowable increases in air pollutants and thereby increase the potential for future economic growth without significantly degrading air quality. Such an analysis is intended to insure that the air emissions control systems for the project reflect the latest control technologies used in a particular industry and is to take into consideration existing and future air quality in the vicinity of the project. The BACT analysis for the project therefore evaluated technical, economic, and environmental considerations of available control technologies and examined BACT determinations for other similar facilities across the United States.

81. For the first 470 MW of NGCC units, BACT for SO_2 emissions from the CTs is the use of natural gas as the primary fuel and the use of low sulfur oil for a limited number of hours per year.

82. For the first 470 MW of NGCC units, BACT for CO, VOCs, PM, beryllium, arsenic, and benzene emissions from the CTs is efficient design and operation of the CTs, the inherent quality of natural gas (the primary fuel), and a limitation on the annual use of fuel oil.

83. For the first 470 MW of combined cycle units, BACT for NO_x emissions from the CTs is the use of advanced dry low NO_x combustors capable of achieving emissions of 12 parts per million by volume dry (ppmvd) at 15 percent oxygen when burning natural gas, water/steam injection to achieve 42 ppmvd at 15 percent oxygen when burning fuel oil, and limited annual fuel oil use.

84. For the first 470 MW of NGCC units, the DEP staff initially proposed BACT for NO_x emissions from the CTs as 9 ppmvd at 15 percent oxygen when burning natural gas, using dry low NO_x combustor technology. However, after careful consideration, it was determined that, because of the lack of proven technology to achieve such emission rate, it would be more appropriate to establish BACT at 73 lb/hour/CT (24-hour average, based on 12 ppmvd at 15 percent oxygen and 59° F) using dry low NO_x combustor technology and to require FPC to make every practicable effort to achieve the lowest possible NO_x emission rate with those CTs when firing natural gas. FPC also is required to conduct an engineering study to determine the lowest emission rate consistently achievable with a reasonable operating margin taking into account long-term performance expectations and assuming good operating and maintenance practices. Based on the results of that study, DEP may adjust the NO_x emission limit downward, but not lower than 55 lb/hour/CT (24-hour average, based on 9 ppmvd at 15 percent oxygen and 59° F.).

85. For the 99 MBtu/hour auxiliary boiler that is part of the initial phase of the project, BACT for NO_x emissions is low

NO_x burners, limited annual fuel oil use, and limited hours of annual operation. BACT for NO_x emissions from the 1300 kW diesel generator is combustion timing retardation with limited hours of annual operation.

86. For the 99 MBtu/hour auxiliary boiler and the diesel generator as part of the initial phase of the project, BACT for CO, VOC, SO_2, PM, benzene, beryllium, and arsenic emissions consists of good combustion controls, the inherent quality of the fuels burned, the use of low-sulfur fuel oil, and limited hours of operation.

87. For the fuel oil storage tank as part of the initial phase of the project, BACT is submerged filling of the tank.

88. For the coal gasification and other facilities to be built during later phases of the project, a preliminary BACT review was undertaken by FPC to support the demonstration that the Polk County Site has the ultimate capacity and resources available to support the full phased project.

Air Quality Impact Analysis

89. Air emissions from the project also must comply with Ambient Air Quality Standards for six criteria pollutants and Prevention of Significant Deterioration increments for three pollutants. Polk County and the contiguous counties are classified as Class II areas for PSD purposes; the nearest Class I area is the Chassahowitzka National Wilderness Area, located approximately 120 km. from the Site. An air quality analysis, undertaken in accordance with monitoring and computer modeling procedures approved in advance by EPA and DEP, demonstrated that

the project at ultimate capacity utilizing worst-case assumptions will comply with all state and federal ambient air quality standards as well as PSD Class I and II increments. For nitrogen dioxide, sulfur dioxide and particulate matter, air quality modeling was based on conservative assumptions, including background concentrations based upon the highest long-term and second highest short-term measured values (established through an onsite one-year air quality monitoring program and regional data), existing major sources at their maximum emissions, the estimated maximum emissions from certain other proposed projects, and the impacts of the proposed FPC project at ultimate site capacity. For other pollutants, detailed analyses were not performed because offsite impacts were predicted to be insignificant.

90. Impacts of the project's estimated emissions of certain hazardous air pollutants (antimony, arsenic, barium, beryllium, benzene, boron, cadmium, calcium, chromium, cobalt, copper, formaldehyde, magnesium, manganese, nickel, selenium, vanadium, and zinc) at ultimate capacity were compared to the DEP draft no-threat levels under DEP's draft "Air Toxics Permitting Strategy." All pollutants except arsenic were projected to be below the corresponding draft no-threat level. Because of the conservatism of DEP's draft no-threat levels, it was concluded that arsenic impacts would not pose a significant health risk to the population in the surrounding area.

91. Impacts on vegetation, soils, and wildlife in both the site area and the vicinity of the Chassahowitzka National

Wilderness Area, the nearest PSD Class I area, will be minimal. Visibility in the vicinity of the Chassahowitzka National Wilderness Area will not be impaired significantly by the project's emissions. Air quality impacts from commercial, industrial, and residential growth induced by the project are expected to be small and well-distributed throughout the area.

92. Impacts from the initial phase of the Project (470 MW) will comply with all State and federal ambient air quality standards as well as PSD Class I and II increments. The impacts from the initial phase of the Project are also well below the draft no-threat levels. The initial phase of the Project will not significantly impair visibility in the vicinity of the Chassahowitzka National Wilderness Area, and the impact on vegetation, soils, and wildlife in both the site area and the vicinity of the Chassahowitzka National Wilderness Area will be minimal. The air quality impacts due to commercial, industrial, and residential growth from the initial phase of the Project will be small, and are not expected to impact air quality.

Land Use Planning/Socioeconomic Impacts of Construction and Operation

93. The proposed site is an appropriate location for the Polk County Site project. The Polk County Site has adequate access to highway and rail networks, including CR 555, a major collector road, and the CSX railroad. The Polk County Site is located away from major residential areas in a location already heavily disturbed by mining activity. The site is located in reasonable proximity to major metropolitan areas that can supply an adequate work force for construction. Development of the

Polk County Site in a mined-out phosphate area is a beneficial use of land and will provide an economic benefit for Polk County. The Polk County Site also is close to existing facilities, such as existing transmission line corridors and reclaimed water facilities, which will benefit the operation of the site while minimizing the impact of the project.

94. The linear facilities associated with the Polk County Site are sited in appropriate locations. The 230-kV transmission line upgrade, reclaimed water pipeline and backup natural gas pipeline corridors: (i) are located adjacent to other linear facilities, such as existing roads and transmission lines, (ii) avoid major residential areas, and (iii) minimally disrupt existing land uses.

95. The Polk County Site is compatible with the State Comprehensive Plan, the CFRPC Regional Policy Plan, and will meet the requirements of the Polk County Conditional Use Permit. The portion of the backup natural gas pipeline located in Hillsborough County is consistent with the Hillsborough County Comprehensive Plan and the policies of the TBRPC Regional Policy Plan.

96. Construction of the Polk County Site will occur over an approximately 25-year period beginning in 1994. If the Polk County Site is developed only for NGCC capacity, construction employment will average 153 jobs per year with a peak employment of 350. The average annual payroll for construction of the Polk County Site on all NGCC is expected to be $7.1 million per year. If 1,000 MW of NGCC and 2,000 MW of CGCC units are built at the

Polk County Site, peak construction employment will be 1,000 with an average annual construction employment of 315 over the approximate 25-year period. Average annual payroll under this scenario would be $14.6 million per year. Indirect jobs created as a result of buildout of the Polk County Site will average 231 jobs for all NGCC and 477 jobs if 2,000 MW of CGCC is added to the Polk County Site.

97. After completion of the construction of the Polk County Site at ultimate capacity, 110 permanent direct jobs will be created if the site uses all NGCC and 410 jobs will be created if coal gasification is added to the Polk County Site. The operation of the Polk County Site will have a multiplier effect on the Polk County economy. The all NGCC scenario will create 272 indirect jobs and the Case A' scenario with CGCC will create 1,013 indirect jobs. After buildout, property taxes generated by the Polk County Site are estimated to be $24.3 million per year for the all NGCC scenario and $37.4 million per year if CGCC capacity is constructed at the site.

Noise Impacts

98. The ambient noise, or baseline noise condition at the Polk County Site was measured in five locations. These measurements show that the baseline noise condition for the site ranges between 30 dBA and 65 dBA at the nearest residential location. The higher noise levels are caused by truck traffic associated with the phosphate mining industry.

99. Noise impacts from construction will be loudest during initial site preparation and steel erection stages.

Earth moving equipment will produce noise levels of 45 to 50 dBA at the nearest residence in Homeland. During final phases of construction, steam blowout activity to clean steam lines will produce short duration noise levels of 69 dBA at the nearest residence. This activity will take place only during daylight hours.

100. Noise levels from the operation of the Polk County Site were calculated using a computer program specifically designed for assessing noise impacts associated with power plant operation. The highest predicted continuous noise level will be 41 dBA at several houses 2.9 miles south of the site and 47 dBA at the nearest church. Noise impacts from fuel delivery trucks and coal trains will not significantly increase the noise levels over existing conditions. The continuous noise level from the operation of the Polk County Site at the nearest residence or church will be below the 55 dBA level recommended by the U.S. Environmental Protection Agency.

Traffic

101. Traffic analyses were made for impacts to highway traffic which will result from the construction and operation of the Polk County Site. These analyses included impacts at rail crossings caused by the delivery of coal to the Polk County Site under the Case A' scenario.

102. A highway traffic analysis was made to determine if the existing roadway network in the vicinity of the Polk County Site would operate at acceptable levels of service based upon increased volumes of traffic associated with the construction

and operation employment at the Polk County Site. Methodologies for evaluating traffic impact complied with Polk County, FDOT and CFRPC criteria. County roads were evaluated using Polk County criteria and state roads were evaluated using both Polk County and FDOT criteria. Traffic volumes were evaluated for peak construction traffic in 2010 and full plant operations, estimated in 2018. The traffic evaluation included analysis of existing traffic conditions, increased traffic volume associated with growth in the area not associated with the Polk County Site, and increased traffic associated with construction and operation employment at the Polk County Site.

103. During peak construction employment under the Case A' scenario, 1,000 employees are expected at the Polk County Site. Under this scenario, the expected trip generation of the Polk County Site is expected to be 1,792 trips per day, with a morning peak of 717 trips and an afternoon peak of 717 trips. Based on this analysis, all roadways are expected to operate at acceptable levels of service with currently planned improvements to the roadways. Intersection levels of service were found acceptable for 7 out of 11 intersections. FPC has recommended improvements to four intersections at U.S. 98 and SR 60A, SR 60 and CR 555, SR 37 and CR 640, and CR 555 and CR 640 at specified traffic levels.

104. Peak operation employment under the Case A' scenario is expected to be 410 employees in 2018. Based upon this employment figure, the expected trip generation of the Polk County Site is 964 trips per day with a morning peak of 195

significant delay and the rail crossing intersections will maintain level of service A.

Archaeological and Historic Sites

108. The Florida Department of State, Division of Historical Resources, has stated that because of the location of the Polk County Site, it is unlikely that any significant archaeological or historical sites will be affected.

Mandatory Reclamation of Mining Parcels

109. The Polk County Site is comprised of phosphate mining parcels, portions of which are subject to mandatory reclamation under the jurisdiction of DEP/BOMR. The mandatory mining parcels are currently owned by Estech, IMC, and USAC. FPC has entered into stipulations with each mining company agreeing to reclamation of the mandatory mining parcels in accordance with the conditions of certification proposed by DEP/BOMR. In those conditions, DEP has proposed to incorporate the reclamation conceptual plan modifications included in Appendix 10.9 of the SCA into the certification proceeding for the Polk County Site and has redesignated those conceptual plan modifications as EST-SC-CPH and IMC-NP-FPC. The portions of the site which will be developed by FPC will be released from mandatory reclamation requirements when FPC purchases the Polk County Site.

Variances

110. FPC has requested variances from certain reclamation standards set forth in Rule 16C-16.0051, Florida Administrative Code, which will be necessary until the affected mining parcels

trips and an afternoon peak of 154 trips. At peak operation employment, all roadways evaluated were found to operate at acceptable levels of service. All intersections, except the intersection at SR 60 and CR 555, were found to operate at acceptable levels. FPC has recommended a protected/permissive westbound left turn lane at this intersection.

105. With FPC's recommended improvements, which have been incorporated as conditions of certification, and those improvements currently planned by FDOT, the existing roadway network will meet Polk County and FDOT approved levels of service at peak employment during the construction and operation of the Polk County Site to its ultimate capacity.

106. In addition to the highway traffic impact analysis, FPC evaluated the impact on rail/highway crossings from the transportation of coal by rail under the Case A' scenario. It was assumed that all coal for the Polk County Site will be delivered by rail over existing CSX transportation lines. It is expected that at full operation two 90-car trains per day will be required for the delivery of coal, resulting in four train trips per day. It was also assumed that trains will travel at speeds averaging 35 to 45 miles per hour.

107. Evaluation of the impacts at rail crossings found an increase of .5 second per vehicle per day at urban rail crossings and .3 second per vehicle per day at rural rail crossings. Based on the 1985 Highway Capacity Manual, the total delay at rail crossing intersections caused by the increased train traffic to and from the Polk County Site will not cause a

on the Polk County Site are released from reclamation. FPC has requested a variance from Rule 16C-16.0051(5)(a), which requires artificial water bodies to have an annual zone of fluctuation, and Rule 16C-16.0051(5)(b), which requires submerged vegetation and fish bedding in artificially-created water bodies. The criteria in these rules are inappropriate for a cooling pond, because it is an industrial wastewater treatment facility which cannot be efficiently or safely operated with fluctuating water levels and aquatic vegetation zones. With regard to the construction of dams for the cooling pond, brine pond and solid waste disposal areas, FPC will need a variance from Rule 16C-16.0051(2)(a), which requires a 4:1 slope for dam embankments and Rule 16C-16.0051(9)(b) and (c), which requires vegetation of upland areas, which may include dam embankments. Dams for the cooling pond, brine pond and solid waste disposal areas will have steeper slopes and the interiors of the dams will be concrete blanket revetments, synthetic liners or solid waste consistent with the industrial purposes for which these facilities have been constructed. Access to these areas will be controlled to prevent any potential safety hazard. Finally, FPC will need a variance from Rule 16C-16.0051(11)(b)(4), which requires reclamation to be completed within two years after mining operations are completed. Construction of the Polk County Site requires extensive dewatering and earthwork which cannot be completed within this timeframe.

111. Applications for variances from mining reclamation criteria were included in Appendix 10.9 of the SCA and have been

incorporated into the certification proceeding for the Polk County Site. DEP has redesignated these variance applications as EST-SC-FPC-V and IMC-NP-FPC-V. These variances are appropriate and should be granted.

Agency Positions and Stipulations

112. The Department of Environmental Protection, Southwest Florida Water Management District, and Polk County have recommended certification for the construction and operation of the initial 470 MW of natural gas combined cycle generating capacity and have recommended the determination that the Polk County Site has the ultimate capacity for 3,000 MW of natural gas and coal gas combined cycle generating capacity, subject to appropriate conditions of certification. No other state, regional or local agency that is a party to the certification proceeding has recommended denial of the certification for the construction of the initial 470 MW of generating capacity or determination of ultimate site capacity. Several agencies which expressed initial concern regarding certification of the Polk County Site have resolved those concerns with FPC and have entered into stipulations with FPC as discussed below.

113. The Florida Department of Transportation, the Game and Fresh Water Fish Commission, and the Department of Community Affairs have entered into stipulations with FPC recommending certification of the Polk County Site and a determination that the Polk County Site has the ultimate site capacity to support 3,000 MW of NGCC and CGCC generating capacity subject to

proposed conditions of certification. Hillsborough County, the Environmental Protection Commission of Hillsborough County, and the Tampa Port Authority have entered into a stipulation and agreement with FPC recommending certification of the backup natural gas pipeline corridor subject to proposed conditions of certification.

114. FPC and the agency parties have agreed on a set of conditions of certification for the Polk County Site. Those conditions are attached as Appendix A to this Recommended Order.

CONCLUSIONS OF LAW

115. The Division of Administrative Hearings has jurisdiction over the parties and subject matter of this proceeding. Section 403.508 (3), Florida Statutes (1991).

116. This proceeding was held pursuant to the Florida Electrical Power Plant Siting Act, Chapter 403, Part II, Florida Statutes.

117. In accordance with Chapter 403 and 120, Florida Statutes, and Chapter 17-17, Florida Administrative Code, proper notice was given to all persons and parties entitled thereto as well as to the general public. All necessary and required governmental agencies were parties to this proceeding, and required reports and studies were completed and presented.

118. The State of Florida Department of Environment Protection and other participating agencies either have recommended, or do not object to, certification of the construction and operation for the first 470 MW of generating capacity and certification of the FPC Polk County Site as having

the capacity to accommodate 3,000 MW of natural gas and coal gas-fired combined cycle generating capacity, subject to this Order and the attached Conditions of Certification.

119. The Applicant (FPC) has met its burden of proving that the Polk County Site project is entitled to certification, subject to the Conditions of Certification attached as Appendix A. The construction and operational safeguards for the Polk County Site are technically sufficient for the welfare and protection of the citizens of Florida, and are reasonable and available methods to achieve that protection. The proposed Polk County Site, if constructed, maintained, and operated in accordance with this Order and the attached Conditions of Certification, will produce minimal adverse affects on human health, the environment, the ecology of the land and its wildlife, and the ecology of State waters and their aquatic wildlife. Certification for the construction and operation of the first 470 MW of generating capacity is consistent with the goal of abundant, low cost electrical energy and will effect a reasonable balance between those minimal environmental impacts which will occur and the PSC-determined need for the first 470 MW of generating capacity at the Polk County Site.

120. The FPC Polk County Site, if constructed and operated in accordance with this Order and the attached Conditions of Certification, is compatible with the State Comprehensive Plan, Chapter 187, Florida Statutes, the Central Florida Regional Planning Council Comprehensive Regional Policy Plan, the Tampa Bay Regional Planning Council Regional Policy

Plan, the Hillsborough County Comprehensive Plan and the Polk County Comprehensive Plan.

121. The FPC Polk County Site, if constructed and operated in accordance with this Order and the attached Conditions of Certification, will comply with the applicable nonprocedural requirements of all agencies with jurisdiction over the Polk County Site.

122. A zone of discharge for discharges into groundwater is necessary for the operation of the Polk County Site and should be granted in accordance with the recommended Conditions of Certification.

123. The conceptual plan modifications for the mandatory phosphate mining reclamation plans and the variances from phosphate mining reclamation standards are necessary and appropriate based on the construction plans for the Polk County Site and should be granted subject to the attached Conditions of Certification.

RECOMMENDATION

Based on the foregoing Findings of Facts and Conclusions of Law, it is RECOMMENDED that:

1. Florida Power Corporation be granted certification pursuant to Chapter 403, Part II, Florida Statutes, for the location, construction and operation of 470 MW of combined cycle generating capacity as proposed in the Site Certification Application and in accordance with the attached Conditions of Certification.

2. Florida Power Corporation's Polk County Site be certified for an ultimate site capacity of 3,000 MW fueled by

coal gas, natural gas, and fuel oil subject to supplemental application review pursuant to 403.517, Florida Statutes, and Rule 17-17.231, Florida Administrative Code, and the attached Conditions of Certification.

3. A zone of discharge be granted in accordance with the attached Conditions of Certification.

4. The conceptual plan modifications (EST-SC-CPH and IMC-NP-FPC) for the mandatory phosphate mining reclamation plans be granted subject to the attached Conditions of Certification.

5. The variances from reclamation standards (EST-SC-FPC-V and IMC-NP-FPC-V) as described herein be granted subject to the attached Conditions of Certification.

DONE AND ENTERED this 3rd day of December, 1993, in Tallahassee, Florida.

DIANE K. KIESLING, Hearing Officer
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Filed with the Clerk of the Division of Administrative Hearings this 3rd day of December, 1993.

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NOTICE OF RIGHT TO SUBMIT EXCEPTIONS

All parties have the right to submit written exceptions to this Recommended Order. All agencies allow each party at least 10 days in which to submit written exceptions. Some agencies allow a larger period within which to submit written exceptions. You should contact the agency that will issue the final order in this case concerning agency rules on the deadline for filing exceptions to this Recommended Order. Any exceptions to this Recommended Order should be filed with the agency that will issue the final order in this case.

Case No. 92-5308EPP

APPENDIX A TO THE RECOMMENDED ORDER
IN CASE NO. 92-5308EPP

RECOMMENDED CONDITIONS OF CERTIFICATION