BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	DOCKET NO. 941101-EQ
Petition for determination that plan for curtailing purchases from qualifying facilities in minimum load conditions is consistent with Rule 25-17.086, F.A.C., by FLORIDA POWER CORPORATION.	

SECOND DAY - MORNING SESSION

VOLUME 3

Pages 277 through 479

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN SUSAN F. CLARK COMMISSIONER J. TERRY DEASON COMMISSIONER JULIA F. JOHNSON COMMISSIONER DIANE K. KIESLING COMMISSIONER JOE GARCIA
DATE:	Tuesday, May 9, 1995
TIME:	Commenced at 9:00 a.m.
PLACE:	FPSC Hearing Room 106 Fletcher Building 101 East Gaines Street Tallahassee, Florida
REPORTED BY:	JOY KELLY, CSR, RPR Chief, Bureau of Reporting Official Commission Reporter

APPEARANCES:

(As heretofore noted.)

I N D E X

MISCELLANEOUS - VOLUME 3

WITNESSES - VOLUME 3

EXHIBITS - VOLUME 3

P R O C E E D I N G S

(Hearing reconvened at 9:00 a.m.)

(Transcript continues in sequence from Volume 2.)

COMMISSIONER DEASON: Call the hearing to order. I believe the next scheduled witness is Mr. Lefton; is that correct?

MR. TENPAS: Yes, it is.

COMMISSIONER DEASON: Was Mr. Lefton sworn yesterday?

MR. TENPAS: Yes, he was.

COMMISSIONER DEASON: Okay. Please call your witness.

MR. TENPAS: Florida Power would call Mr. Steve Lefton.

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STEVEN A. LEFTON.

was called as a witness on behalf of Florida Power Corporation and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. TENPAS:

Q Mr. Lefton, could you please state your name, employer and position for the record?

A Good morning. My name is Steven A. Lefton. I'm vice-president of Special Projects for Aptech Engineering.

Q Are you the same Steve Lefton who sponsored prefiled

direct testimony and exhibits in this proceeding?

A Yes, I am.

Q Are there any corrections to your prefiled testimony that you need to make?

A No, there's not.

Q If I were to ask you today the questions that appear in your testimony would you give the same answers?

A Yes, sir, I would.

MR. TENPAS: I would move to have the prefiled testimony inserted into the record as though read.

COMMISSIONER DEASON: Without objection it will be so inserted.

Q (By Mr. Tenpas) Mr. Lefton, are you sponsoring prefiled exhibit SAL-1 through SAL-4?

A Yes, sir. I am.

MR. TENPAS: I would like to request that Mr. Lefton's exhibits SAL-1 through 4 be marked as a composite exhibit.

COMMISSIONER DEASON: They will be so marked as Composite Exhibit No. 6.

(Exhibit No. 6 marked for identification.)

FLORIDA POWER CORPORATION

DOCKET NO. 941101-EQ

DIRECT TESTIMONY OF STEVEN A. LEFTON

Q. Please state your name and business address.

A My name is Steven A. Lefton. My business address is 1282 Reamwood Avenue, Sunnyvale, California 94089.

Q. By whom are you employed and in what capacity.

A. I am employed by Aptech Engineering Services, Inc. ("Aptech") as Vice President, Special Projects.

Q. Please describe your education and power plant experience.

A. I have a Bachelor of Science Degree in Chemical Engineering from the University of Kansas. I have 25 years of experience involving power plant design, start-up, operation, testing, life assessment, reliability analysis, and cost analysis. In 1969, I was employed as a start-up and test engineer for the Babcock and Wilcox Company ("B&W"). B&W supplied the boilers for Florida Power's Crystal River Units 4 and 5 and Bartow Unit 1. They also supplied the Nuclear Steam Supply System ("NSSS")for the Florida Power Crystal River 3 nuclear plant. As a start-up engineer, I was involved in over 50 power plant start-up and test operations including Jacksonville Electric Authority's Northside 300 MW Unit 1 and Kansas City Power and Light Company's 880 MW LaCygne Unit 1, and outage repairs for Tampa Electric Company at Gannon

Station. I specialized in optimizing boiler and turbine control systems and led a group for B&W that tuned power plant controls in order to minimize cycling damage during unit start-up. I traveled to Canada, North America, and South America as a boiler and power plant controls engineer and as a problem solver performing work on over 50 power plants.

In 1974 for B&W, I was involved with the design and sale of two 550 MW coal-fired boilers for Basin Electric Company, a 400 MW boiler for the City of Austin, Texas, and approximately 10 other large utility boilers.

In 1974, I joined NUS Corporation as Manager of West Coast Operations in Palo Alto, California. I consulted on fossil and nuclear power plant projects including assessing safety and environmental risks of fossil power plants and nuclear power plants. I also dealt with the coal conversion of U.S. power plants for the Federal Energy Administration and storage of spent nuclear fuel and waste.

In 1979, I joined Aptech as a Vice President. One of the first major projects was a review of the operations of the Rancho Seco Nuclear Power Plant. This nuclear unit supplied by B&W is very similar to Florida Power's Crystal River Unit 3. This review involved a dispute over reliability problems and the power sales agreement between Pacific Gas & Electric Company and Sacramento Municipal Utility District.

Aptech's investigation involved aspects of plant reliability, water chemistry, nuclear steam generators, turbine failures, generator failures, and power generation at the Rancho Seco Nuclear Power Plant. I was the Aptech project manager for this investigation.

In 1982 through 1989, I served as an expert in an arbitration proceeding between Cajun Electric Power Cooperative and Riley Stoker. This case involved boilers, pulverizers, plant auxiliaries, fires, explosions, availability/reliability modeling, plant life extension, plant life assessment, and the analysis of plant logs to calculate the impacts of plant unavailability on power production costs and revenue requirements.

I provided expert services for Puerto Rico Electric Power Authority in a heat recovery steam generator lawsuit against General Electric Company. I have provided expert services for Hawaiian Electric Light Company on gas turbines and on the cost of cycling fossil power plants.

I have provided expert testimony to the Illinois Commerce Commission on the effect of operational changes on Illinois Power Company's fossil plant reliability.

In 1994, I was an expert for Pacific Gas & Electric Company in a proceeding involving Copes Vulcan, a valve manufacturer. I provided expert testimony in San Jose Federal Court regarding power plant

operations and failure analysis.

I have performed life assessment and failure analysis for numerous industrial and utility clients. Selected reports are listed in my resume attached as my Exhibit No. 5 (SAL-1). During my career, I have worked on or visited at least 500 United States and foreign power plants.

I am a member of the American Society of Mechanical Engineers and the American Nuclear Society and have been a past president of the San Francisco Bay Area American Nuclear Society.

Q. What publications have you authored on the subject of power plant cycling?

A. I have published three papers as follows (see copies attached at Exhibit No. 6 (SAL-2)):

1. "A Methodology to Measure the Impact of Cycling Operations and Power Derations on Plant Life and Reliability"

2. "Managing Utility Power Plant Assets to Economically Optimize Power Plant Cycling Costs, Life, and Reliability"

3. "Cycling Cost Assessment Project"

In addition, I have authored many other reports to clients on the subject of power plant cycling.

Q. Please summarize your experience in evaluating utility cycling of power plants in the United States.

A. I have been active in surveying utility cycling procedures and in obtaining cycling cost information at numerous power plants across the continental United States and in Hawaii.

I have been involved in cycling cost assessments for a number of utilities including the Hawaiian Electric Light Company, Los Angeles Department of Water and Power, Florida Power & Light Company, Tennessee Valley Authority, and Florida Power Corporation.

In addition, I served on a panel of experts at the recent 1994 Electric Power Research Institute ("EPRI") conference on power plant cycling. I am currently the principle investigator on an EPRI program to investigate the cost of cycling at the Los Angeles Department of Water and Power. This study involves some nine units and was designed to be a 3-year 2.3 million dollar research program. The program is entering its second year of research.

Q. What is the purpose of your testimony?

A. I will demonstrate that increased cycling of coal-fired baseload power units causes plant component damage which results in significant increases in steam plant operational costs and decreases in unit reliability. I will describe the type of materials degradation that occurs due to cycling and the type of damage it inflicts upon power plant equipment. I will give a range of the cost of cycling for units similar to Florida Power's Crystal River Units 1 and 2. In addition, I will explain that cycling of the Company's nuclear power plant similarly would result in adverse reliability and cost impacts.

Q. What is meant by the term "cycling" in connection with an electric generating unit?

A. Unit cycling refers to the operation of electric generating units at varying load levels, including on/off and low load cycling in response to changes in system load requirements. There are three distinct types of cycles. These include (1) hot starts, (2) cold starts (both of which are on/off cycles), and (3) transient load following during which unit output drops from 100 percent capacity to approximately 35 percent to help cope with system demand changes.

Generally, a hot start is one in which the unit is shutdown less than 12 hours. A cold start has a prior down time at least six times longer than a hot start (greater than 72 hours). In a typical weekday load-following type of plant transient, there is no start involved and all load swings and

peak ramp rates are smaller and less damaging than for the start-type on/off transients.

Q. How does cycling physically affect a generating unit?

A. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure cycles. The boiler and turbine components and especially the superheater and reheater tubes normally operate at about 1000°F. Removal from service results in a rapid decrease in the superheater and reheater tubing temperatures as a result of the loss of flame in the furnace and a required air purge of the furnace for safety reasons. The temperature and pressure of superheater and reheater tubing rapidly decreases resulting in cyclic thermal fatigue. Restart of the boiler also contributes to the cyclic thermal fatigue of the superheater and reheater tubing. In addition, the boiler waterwall tubing is adversely affected by the rapid shut-down pressure decreases and restart pressure increases as well as chemistry transients resulting from cycling. The boiler waterwall tubes tend to fail from cyclic fatigue and cyclic corrosion fatigue. All of these cyclic-related phenomenon increase unit maintenance costs, and lower power plant reliability.

Q. Please describe the typical degradation effects of unit cycling.

A. There are several materials degradation phenomena that are accelerated by increased cycling. These include creep, fatigue, creep-fatigue interaction, corrosion fatigue, corrosion (especially during out-of-service

periods), erosion, wear, vibration, and other interrelated phenomena that promote accelerated component aging.

Q. What do you mean by the terms "creep,""fatigue" and "creep-fatigue interaction"?

A. These are terms commonly used in engineering mechanics. Creep is the time dependent change in the size or shape of a material due to constant stress (or force) on that material. In fossil power plants, creep-related failures result from the constant stress attributable to the high temperature and pressure in a pipe or tube occurring during constant steady-state baseload operation. Fatigue is a phenomenon leading to fracture (failure) when a material is subjected to repeated, fluctuating stresses. In a fossil power plant, such fluctuating stresses result from large transients in both pressures and temperatures, that typically occur during cyclic operation.

Because baseload fossil units are designed to operate in the creep range, they experience increased outages when they are additionally subjected to cycling-related fatigue. The term creep-fatigue interaction suggests that the two phenomena (creep and fatigue) are not entirely independent, but act in a synergistic manner to cause premature failure. In fact, materials behave in a complex manner when both types of stresses occur. Creep-fatigue interaction is one of the most important phenomena contributing to component failures and can have a detrimental effect on the performance of metal parts or components

operating at elevated temperatures. It has been found that creep strains (mechanical deformation as a result of stress) can reduce fatigue life and that fatigue strains can reduce creep life.

A set of American Society of Mechanical Engineers "ASME" creep-fatigue interaction curves is shown on Exhibit No. 6 (SAL-3). The curve reveals how creep-fatigue interaction affects the life expectancies (i.e., life fraction) of three types of materials labelled 1, 2, and 3. For each of these materials, the relevant ASME creep-fatigue curve shown in Exhibit No. 6 (SAL-3) depicts the percent of the total component life fraction which can withstand creep damage and fatigue damage before failure occurs. Curve 1, which is for nickel-iron-chromium Alloy 800H ("Inconel"), shows a linear creep-fatigue interaction. This means that after 50 percent of life creep damage, it still takes 50 percent fatigue damage to cause the material to fail. Most power plants were not built with any Inconel. Instead, most power plants are constructed with ferritic steels like two-and-one-quarter percent chrome/one percent molybdenum steel. This ferritic steel is plotted as Curve 3 on Exhibit No. 6 (SAL-3). I would like to highlight the implication of the non-linear relationship of this curve. A brand new power plant component can withstand a lot of fatigue damage before it fails. However, a material that has gone through 50 percent of its life-cycle creep damage (e.g., baseload operation), as shown by Point A in the exhibit, reaches end of life (failure) with only about 10 to 20 percent fatigue damage. What this means is that older units that were designed

for and used for baseload operation over a number of years, are very susceptible to component failure when they are forced to cycle on a regular basis. In general, when this type of material experiences both creep and fatigue, it will fail much faster than if it just experienced creep.

The two stainless steel alloys 303 and 316 depicted as Curve 2 on Exhibit No. 6 (SAL-3) are between the two extremes; however, little stainless steel is used in power plants. The failure characteristics of most power plant components can be bounded by the data shown as Curve 3 on Exhibit No. 6 (SAL-3).

Q. How does your discussion of creep and fatigue relate to power plant costs and reliability?

A. Cycling-related increases in failure rates due to creep and fatigue may not be noted immediately, but inevitably, critical components will eventually start to fail. For example, if an older, baseload plant, that has typically operated with three to six starts per year and has sustained 40 to 80 percent of its design life-cycle creep damage, is now dispatched to operate at 50 starts per year, it may take only 2 to 6 years to accumulate the 10 to 20 percent total fatigue damage needed to cause component failures.

Shorter component life expectancies will result in higher plant equivalent forced outage rates ("EFOR") and/or higher capital and maintenance

costs will be required to replace components at or near the end of their service lives. In addition, cycling may result in reduced overall plant life. How soon these detrimental effects will occur will depend on the amount of creep damage already present and the specific types and frequency of the cycling. But it is unquestionably true that cycling exacerbates damage in components that are already creep-damaged due to past baseload operation. The combined effect of baseload operations that produce creep damage and cyclic operations that produce fatigue damage can be expected to significantly reduce the remaining life of power plant components compared to the life expectancy with no such interaction. In fact, I have seen many examples of these effects.

Q. What specific generation unit components are susceptible to such degradation, and what specifically happens?

A. The basic types of component damage resulting from cycling and their causative effects can be categorized into four areas: (1) accelerated boiler failures; (2) turbine damage; (3) chemistry effects; and 4) electrical and control system damage. Cycling influences each damage area as detailed below:

1. <u>Accelerated Boiler Failures</u>

- Fatigue cracking of:
  - — Boiler tubes in furnace corners
  - — Tube to buckstay/tension bar
  - — Tube to windbox attachment

- — Tube to header
- — Tube to burner
- — Membrane to tube
- — Economizer inlet header
- — Header ligament

- Boiler seals degradation
- Boiler hot spots
- Drum humping/bowing
- Fatigue cracking due to differential cooling of integrated furnace components otherwise known as downcomer to furnace subcooling
- Expansion joint failures
- Superheater/reheater dissimilar metal weld failures
- Start-up-related tube failures in waterwall, superheater, and reheater tubing
- Burner refractory failure leading to flame impingement and short-term tube overheating
- Reduced life

2. Turbine Damage

- Increased thermal fatigue due to steam temperature mismatch
- Turbine water induction
- Steam chest fatigue cracking
- Steam chest distortion
- Bolting fatigue distortion/cracking
- Blade, nozzle block, solid particle erosion

- Rotor stress increase
- Rotor defects (flaws) growth
- Seals/packing wear/destruction
- Blade attachment fatigue
- Disk bore and blade fatigue/cracking
- Silica and copper deposits
- Lube oil/control oil contamination
- Shell/case cracking
- Wilson line movement (the point where condensation occurs in low pressure turbines moves as a function of unit load)
- Bearing damage
- Reduced life

3. Chemistry Effects

- Corrosion fatigue
- Oxygen pitting
- Corrosion transport to boiler and condenser
- Air, carbon dioxide, oxygen inleakage (requiring ammonia (NH_3) countermeasures)
- NH_3-Oxygen attack on admiralty brass
- Grooving of condenser/feedwater heater tubes at support plates
- Increased need for chemical cleaning
- Phosphate hideout leading to acid and caustic attack
- Silica, iron, and copper deposits
- Out of service corrosion

4. Electrical and Control System Damage

- Increased controls wear and tear
- Increased hysterisis effects that lead to excessive pressure, temperature, and flow
- Controls not responsive
- Motor control fatigue
- Motor insulation failure due to increased accumulation
- Motor insulation fatigue
- Motor mechanical fatigue due to increased starts/stops
- Breaker fatigue
- Wiring fatigue
- Insulation fatigue degradation
- Increased hydrogen leakage in generator
- Fatigue of generator leads
- Generator retaining ring failures
- Generator end turn fatigue and arching
- Bus corrosion when cool (i.e., Low amps)
- Transformer fatigue degradation

These effects eventually increase the frequency of forced outages, and the utility's required capital and maintenance spending, while reducing component life and plant efficiency.

Q. **Are there also increased operational risks due to cycling power plants?**

A. Yes. In addition to the direct equipment damage and component

failures which I outlined, one often neglected effect of cycling is the increase in operator errors due to the increased personnel involvement that is necessary for cycling activities. Since increased cycling leads to increased opportunities for personnel and equipment malfunction, it follows that there is a higher risk of major damage to the equipment. Such errors can have additional adverse impacts such as:

- Implosion
- Explosion
- Low water in the boiler
- Water induction into the turbine and major resulting damage
- Low load instability
- Improper valve alignment

Such personnel errors typically result in major equipment damage, higher forced outage rates and higher capital and maintenance costs.

Q. Please summarize the long-term life shortening adverse effects of cycling.

A. Cycling causes faster degradation of many unit components, which in turn causes increased component failures, higher capital and maintenance expenditures, lower unit availability, and lower unit efficiency. As these effects increase over time, the production costs of the unit become so high that the unit becomes uneconomical. Premature retirement of the unit then becomes inevitable in order for a utility to minimize its overall costs. Particularly in older units that

have served a baseload function and thereby experienced much of their life-cycle creep-fatigue, the incremental cost impact of each additional cycling event is quite large.

Q. How do you categorize cycling impacts from a cost perspective?

A. Utilities historically have not specifically quantified all of their cycling-related costs. However, the kinds of impacts which I have described fall generally into at least seven cost categories. They are:

1. Change in maintenance and plant-related capital costs
2. Auxiliary power costs during start-up
3. Start-up fuel costs
4. Long-term plant efficiency loss
5. Heat rate impact due to low load operation
6. Replacement energy and capacity due to higher EFORs
7. Shortening of unit life

Aptech computes the total cost of cycling by estimating the expected values of each of these seven cost components, based upon specific unit characteristics, historic cost and outage experience, and general industry data. The first component - - the change in maintenance and plant-related capital costs - - has the largest individual impact of the various cycling costs.

We have examined the costs of cycling baseload power plants for utilities across the nation and we have found that it is possible to

estimate within reliable bandwidths both the life-cycle costs of unit cycling and the incremental cost to the utility of each new cycling event. Obviously, the incremental costs increase later in a unit's normal life cycle as the stresses of cycling begin to impact outage rates and capital costs to a greater extent. What we find routinely in our analysis is that increased cycling activity correlates very closely with increases in capital and maintenance expenditures, outage rates, efficiency losses, heat rate degradation and an overall shortening of a unit's life.

Q. Based on your evaluation of cycling costs for Florida Power and other utilities, are you able to estimate a total range of cycling-related costs for each hot and cold start of a coal-fired unit such as Florida Power's Crystal River 1 and 2 units?

A. Yes. Our studies for other companies and our evaluation of Florida Power's own operating cost history shows that a unit such as Crystal River Unit 2 can be expected to incur costs ranging between about $30,000 and $110,000 for each individual hot start. The corresponding range for a cold start is between about $70,000 and $240,000.

In addition, there are still other Florida Power costs that have not been captured by these cost ranges. For example, the costs associated with the engineering time and engineering/operations analysis of cycling impacts, cycling modifications, and plant modifications for

increased cycling, have not been included in my estimates of the cost of cycling. Furthermore, I have not included the costs of replacement power to follow increasing system loads each time that an individual baseload unit is cycled off. This additional cost can be quite significant as stated in Mr. Southwick's testimony.

Q. Describe how Florida Power's units compare with other similar utility units in terms of cycling effects.

A. Aptech did a comparative analysis of similar fossil units using extensive industry data from NERC. Exhibit 6 (SAL-4) shows the results of a comparative analysis of the impact of varying numbers of equivalent hot starts (a measure of overall cycling amounts) on equivalent forced outage rates. Each dot on the graph represents a comparable unit in the database. Crystal River Unit 2 is noted on the graph.

The lines on this graph show least squares fits for units of varying operating hours per year. In all cases, the Equivalent Force Outage Rates ("EFORs") tend to increase with increasing numbers of equivalent hot starts. The scatter of the individual data points is exaggerated by this type of plot. This graph indicates that the Florida Power unit is very similar to the other industry fossil units in their responses to the effects of cycling.

Q. From your analysis, is it fair to conclude that if Florida Power were required to shut down a Crystal River coal unit for several hours during a minimum load condition in order to continue purchasing energy from non-utility generators, that costs in the range you have described would be directly attributable to that cycling event?

A. Yes, that conclusion is correct. If a Crystal River coal unit was shut down for several hours and it would be required for generation the next day, it would have to be restarted. This is an off/on hot start cycle as I have described in this testimony. The cost of the hot start cycle for that event (in the range of $30,000 to $110,000) would be directly attributable to that event.

Q. Are you familiar with Florida Power's Crystal River Unit 3 nuclear power plant?

A. Yes, I am generally familiar with that unit and its nuclear steam supply system ("NSSS") made by Babcock & Wilcox Co. I have visited the plant, met with operating personnel and visited the nuclear simulation and training center. In addition, Crystal River 3 is nearly identical to the Rancho Seco nuclear plant in Sacramento, California on which I have performed extensive analysis.

Q. Do you know of any Babcock and Wilcox units like Florida Power Corporation's Crystal River Unit 3 nuclear plant that are dispatched by their owners/operators to follow load?

A. No.

Q. Have you considered the types of costs that Florida Power would incur if it were to cycle its Crystal River 3 nuclear unit?

A. Yes, although I have not performed any extensive cost analysis, cycling a unit like Crystal River 3 would require investigative and design measures and would have cost impacts such as the following:

1. A new and larger boron dilution letdown and charging system would be required to permit boron dilution during load increases.

2. Increased costs would be incurred to process and dispose of water letdown from the reactor coolant system following power increases. The increased costs would be associated with the need for new and larger water cleanup systems, storage facilities, water evaporation systems, disposal costs, increased resin and water usage, and increased chemistry department staff.

3. Reduced power output would be likely due to the inability to accurately calibrate the Incore Monitoring and Nuclear Instrumentation Systems following load changes. The inability to accurately calibrate these systems might result in inabilities to define power distributions accurately enough in order to return to operation at full rated power. New Incore Monitoring and Nuclear Instrumentation Systems procedures would be

required. Implementation of these procedures could result in additional labor costs.

4. Increased fuel cost would be incurred per unit of power generated. The current fuel loads have been optimized for noncycling operation. Maintaining an outage schedule that coincides with minimum system power requirements would require premature removal and disposal of fuel rods and, therefore, higher fuel costs.

5. The feedwater heater level control systems would require replacement.

6. There is a potential for increased steam generator damage because of fatigue.

7. There may be an increased fuel rod failure rate due to fuel temperature changes and potential fuel/clad interaction.

8. The ASME III, Class 1 fatigue analyses would have to be reperformed to account for the increased thermal cycles.

9. There is a potential for increased secondary system check valve wear and erosion due to increased operation at lower power levels.

10. A Complete analysis of the safety implications of any proposed operation would be required in order to ensure that there would be no detrimental impact on safety.

Q. Is this an exhaustive list of the cycling considerations and costs relating to the Crystal River 3 nuclear unit?

A. By no means is it intended as such. Because there is limited, if any, experience with the use of nuclear units for load following purposes in the United States, there is no database that can be readily used for this purpose. However, the potential costs, reliability and safety impacts can be significant, and I would not recommend that any significant nuclear cycling activity be considered in the absence of a thorough feasibility and cost analysis.

Q. Does this conclude your testimony?

A. Yes it does.

Q (By Mr. Tenpas) Are there any corrections to those exhibits that you need to make?

A No, there's not.

Q Mr. Lefton, would you please summarize your prefiled direct testimony?

A Yes, I will.

Aptech Engineering Services has completed a nine month independent study of the cost of on/off cycling of Florida Power's fossil power plants.

I was the project manager on this extensive analysis of the true cost of the impact cycling on these plants. I've also been project manager on about four other major projects and involved with some research with the Electric Power Research Institute.

The purpose of this work was to provide an independent analysis of the next incremental on/off cycle of FPC's fossil power plants. These costs were based primarily on analysis of past wear and tear cost, current production cost and current damage due to cycling.

My testimony extensively describes the affect of cycle-related fatigue, creep-fatigue interaction, and corrosion in power plant equipment. All of the cycling phenomena increased unit maintenance cost, lower power plant reliability, lower plant efficiency and reduced power plant life.

The analysis refers to hot starts, which is when the unit is shut down less than 12 hours, and cold starts, and that's costs that are accrued when the unit is shut down 72 hours or more. I think the applicable situation here is hot starts.

Our extensive experience in analyzing the effects of cycling on generating units has shown that cycling costs can be broken down into the following seven categories: Number one, which is the largest cost element is cycling related increases in maintenance and capital costs. For FPC this was typically 90% related to maintenance costs, and less than 10% related to capital costs.

Two is auxiliary power costs during start-up; simply a matter of record.

Start-up fuel cost is Item No. 3.

Item No. 4 is long-term efficiency losses, such as seal wear on a turbine, heat exchanger fouling, corrosion product transport in the power plant system.

Item 5 is heat rate impacts due to low load operation at higher than the optimum heat rate for these units. This is due to the lower heat rates at very low loads.

Item 6 is replacement energy and capacity costs due to higher equivalent forced outage rates despite FPC's best maintenance efforts to keep those rates down.

Item 7 is unavoidable shortening of life despite

Florida Power Corporation's best-effort maintenance to minimize that.

The results of this study of Florida Power Corporation's fossil plants calculated the incremental cost; in other words, the next additional cycle of a hot start at Crystal River 1 or 2 to be $65,000 as our best estimate.

It had a lower bound of about 30,000 and an upper bound of 110,000. We put broad ranges on it to cover all amount of statistical probability. Aptech believes that there's a 98% probability that the true cost is above the $30,000 conservative lower bound.

In Mr. Southwick's testimony, one of the analysis of negative avoided costs without curtailment utilized a cycling impact cost of only $30,000 per cycling event. I think this is extremely conservative.

It's important to note that the largest cost, Item No. 1, of the cycling caused maintenance and capital costs were calculated by three different and independent methods. Those methods include a top/down regression analysis that correlated past cycles with past total cost; it yielded $46,000 per start.

A bottoms-up analysis, which was an audit, was the second method of specific cycling related maintenance costs by Aptech, and that was calculated by an independent team. That cost resulted in $41,000 per incremental hot start.

The third method was a comparison using a model of other industry-related power plant cost, where we've compared Florida Power Corporation to other power plants in the industry. This resulted in a $36,500 per incremental start.

We believe that the correct capital maintenance wear and tear costs to be between 36.5 and the and $46,000 per start. We used a conservatively low 36,500 in our analysis, and that really reflects the conservative nature of that work. This item only contributed $11,600 to the lower bound estimates. Remember, the lower bound was approximately 30,000.

The fact that these three complementary but independent analysis of the largest cost item are in excellent agreement gives Aptech, Florida Power Corporation, and should give the Commission high confidence in the results of our work.

What we routinely find in our analysis of the impact of cycling at other utilities and FPC is that increased cycling activity correlates very closely with increases in capital and maintenance expenditures, outage rates, efficiency losses, heat rate degradation and an overall shortening of the unit's life.

I will conclude by stating that Aptech has independently found very substantial and verifiable incremental costs directly related to cycling FPC's baseload

and fossil plants.

Just to highlight what I've said I made a little graphic, and it really shows --

COMMISSIONER DEASON: Mr. Lefton, if you could turn off that mike, and then move it over towards you and then turn it back on that may be helpful. Thank you.

A Okay. I plotted costs, the 30,000 and 110,000 as I've stated, and the probability of distribution. Our best estimate again was at $65,000. This is a probability distribution of a correct answer. This is the cost per cycle, hot start cost essentially, and this is our number.

We think that the lower bound, 30,000, is a very, very low bound, and that the probability of the correct answer, it's 98% above that number. Thank you.

MR. TENPAS: I would tender the witness for cross examination.

COMMISSIONER DEASON: Very well. Ms. Walker.

MS. WALKER: No questions.

COMMISSIONER DEASON: Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Lefton, your work is in the area of materials degradation; is that correct?

A That's one of the areas that I've worked in.

Q And you believe there's a correlation between the

amount of cycling of a power plant on one hand and the future impacts on maintenance and capital costs on the other; is that correct?

A I somewhat agree with your statement. Let me just correct it.

In this particular study we have looked at the past cost and the current cost of cycling and we haven't really looked very far into the future. We've just looked at the very next cycle based on past cost.

Q Well, if five years from now a power plant component fails and has to be replaced, and the utility at that point incurs a capital cost and begins incurring the depreciation associated with that prospectively, is that an example of the kind of impact that you believe is associated with the cycling of power plants?

A Well, it may be in that calculation five years from now. It hasn't been in our costs to date because we didn't look out five years in the future. You've got to realize that we only looked at past cost. So if you essentially fit the cost data to cycles and look at the next cycle, I didn't look five years out in the future.

If we complete our future work of looking into the units and assessing the condition, we may see that there's damage and potentially future costs like that, but that was not included in our analysis to date.

Q As I understand it, according to your testimony, a power plant incurs the requirement for maintenance costs if it operates in a steady state and a different amount of maintenance costs if it operates in a way that fluctuates its operation; is that correct?

A That's correct, yes, sir.

Q Would you agree that the customers of Florida Power Corporation impose different kinds of loads on the system?

A Yes, I would.

Q Some customers may impose a steady high load factor constant load?

A I think you have to look at all of the customers as a whole. What's the load? Florida Power Corp has a varying load.

Q Well, a moment ago you agreed with me, did you not, sir, that customers impose different kinds of loads on the system?

A That's correct.

Q Would you agree that some customers may impose a high load factor constant load on the system?

A I could envision that case.

Q Would you agree that other classes may impose a strongly fluctuating kind of load on the system?

A I could agree that that could be the case.

Q Is part of your recommendation that Florida Power

Corporation start charging those customers more for their service now in view of the costs you believe are incurred, are imposed by way of cycling?

A Let me say I think that's a policy decision. It's outside of my purview, but certainly what I have done is calculated the cost of cycling for whatever reason, and it could be applied to any distribution of clients as Florida Power Corp or the Commission wished.

MR. McGLOTHLIN: Those are all the questions I have.

COMMISSIONER DEASON: Mr. Presnell.

MR. PRESNELL: No questions.

COMMISSIONER DEASON: Mr. Watson.

CROSS EXAMINATION

BY MR. WATSON:

Q I have just one.

Do you understand the issues in this proceeding?

A I think I understand the issues to a great extent; maybe not fully or legally.

Q But you do understand that we're talking about under what circumstances may Florida Power basically cycle off the cogenerators, the QFs, under this Commission's and the FERC's rules?

A Yes, I do.

Q Do you also understand that the contracts with the QFs that Florida Power entered into were entered into in lieu

of Florida Power's constructing its own coal unit?

A I do understand that.

Q If Florida Power had constructed that coal unit rather than entering into these QF contracts, wouldn't Florida Power Corporation have been required to cycle one or more of its fossil units when it experienced minimum load conditions?

MR. TENPAS: Commissioner, I think this is outside the scope of his direct. He's been tendered on Issue 6: Has Florida Power adequately demonstrated that the curtailments that have occurred from October 1, 1994, through January 31, 1995, were necessary to avoid negative avoided costs. I'm not sure how the inquiry into what the prior avoided unit -- how that would bear on this.

MR. WATSON: I think the inquiry is relevant. I mean, this witness is talking about costs that would be incurred due to cycling a coal plant. And I'm asking him had Florida Power not entered into these agreements, would they not have had to cycle a coal plant anyway.

COMMISSIONER DEASON: Objection is overruled. I'll allow the question.

WITNESS LEFTON: Am I to answer the question?

COMMISSIONER DEASON: You may answer the question, if you can.

WITNESS LEFTON: Let me say that I have looked at the specification for a coal-fired cycling unit and my

experience in the industry is that they are specific units that are designed for cycling, that can cycle very cost-effectively. I think if Florida Power was to build that next unit, Crystal River 6, it would have been designed for cycling and optimized such it would have had a very low cost to cycle. If, in fact, they had to cycle a unit, they probably would have cycled that unit.

Q Do you think that would have been the unit that they would have built in 1991, and I guess, really, your last statement, is that an assumption that Florida Power would have built a unit that could be cost-effectively cycled, or do you know that for a fact?

A Let me say that they'd certainly have that option. And I have seen designs and actually visited power plants that were specifically designed for cycling. My experience in that regard goes to an unit of Anna 6 at Illinois Power that I think it's cycled 4,000 times since it was built ten years ago.

Q Are those coal cycling units generally more expensive than an unit which cannot be cost-effectively cycled?

A Yes, sir, they are.

MR. WATSON: That's all. Thank you.

COMMISSIONER DEASON: Ms. Rule? Mr. Wright?

MR. WRIGHT: Thank you, Commissioner Deason.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good morning, Mr. Lefton.

A Good morning.

Q We're talking a lot about cycling. My recollection from your deposition is that you used the word "cycling" to include both cycling units on and off and cycling units up and down; is that correct?

A That's correct. And my terminology -- and we're trying to get the industry to realize that cycling includes all aspects, load following as well as on and off, but here we have differentiated start/stop versus load dispatch type cycling.

Q So your testimony goes to the cost associated with shutdowns and hot restarts?

A That's correct.

Q I noted from Mr. Harper's exhibit, which summarize the operation of Florida Power's coal-fired units during the curtailment of events that have occurred so far that during both the January 1st and 2nd curtailment events, and during the January 14th curtailment event Crystal River Unit 2, a coal-fired unit, was cycled off. Are you familiar with that or would you like to look at the exhibits to verify that?

A I'll take your word, if they were cycled off.

Q It's right in Mr. Harper's exhibit. That's fine.

A Okay.

Q Did they incur any out-of-pocket cost associated with cycling those units off at the time?

A Yes, they did.

Q Did they write anybody a check?

A Excuse me?

Q Did they write anybody a check for those out-of-pocket costs?

A I'm sure that they didn't write a check for that, but I really don't know.

Q Okay.

A I wouldn't expect that would be normal utility practice.

Q Well, did they send somebody some money for those out-of-pocket costs? (Pause)

A Certainly the cost of the auxiliary power and the fuel were accrued in some account. The maintenance in some other account. You know, they were accrued in some way.

Q On Pages 11 through 14 you talk about all of the wear and tear cost-type items and other cost-type items that accrue from cycling events. You conclude by making the statement that, "These effects eventually increase the frequency of forced outages and the utility's required capital and maintenance spending while reducing component life and plant efficiency." Are you familiar with that statement?

A Yes, I am.

Q My question is you make the statement that they eventually increased these things. When?

A Well, these things happen over time, from Day One to now. In our analysis we calculated each cycle of the unit by looking at the hourly megavatts and looked only at past costs. So if it hadn't already occurred, we didn't include it in our analysis, but typically those failures occur, if not on this cycle, perhaps the next, and it really depends on age, a number of other factors as to exactly when. We have simply looked at the past cost and calculated the additional incremental cycle due to that.

Q Have you prepared any analyses of the effects of cycling off any of Florida Power's coal-fired units in the future?

A Yes, we have.

Q Could you tell us about that a little bit, please?

A In our costs of cycling report we simply took today's cost and escalated it into the future based on past costs and their future cost of replacement power.

Q Have you prepared any specific analyses of the costs that would be associated with cycling Crystal River Unit 1 over the next five years?

A I think that was in the report. I think Crystal River 1 and 2 were the typical units that we looked at.

Q Okay. But again that was an escalated or projected estimate based on past --

A Right. Simply taking the past cost per cycle and escalated it into the future based on a number of parameters that we looked at.

Q Was that estimate just an estimate of the predicted cost per cycle over that next five years?

A Yes, it was.

Q Was it an estimate of the costs that would be associated with actual predicted cycling events over the next five years?

A No, it wasn't on actual predicted cycling. We had no way of knowing what the future-predicted cycles were, so we simply took the scenario is, if you are operating today as you are in the past, and you had a cost of $65,000 best estimate per hot start, what would it look like if you continue that similar operation in the future? So if their operations changed, costs may fluctuate.

Q So do you know how many times Crystal River 1, 2, 4, 5 are predicted to cycle off over the next five years?

A I don't know exactly. I could only infer that by the previous five years, which is a pretty good indication.

Q How many times did they cycle off over the last five years?

A If I could refer to my report.

Q Please do. (Pause)

A Do you want to pick any specific unit, 1 or 2?

Q How about 1 and 2. If you could tell us the precise time to which your answer applies I'd appreciate it.

A Well, I think give you year-by-year blow on equivalent hot starts. It's a calculation that we made. Actually in '94, on Crystal River 1, it looks to be about some 80 equivalent hot starts.

Q 80; 8-0?

A I'd say the average over the last -- well, it ranges from about 80 to some hundred equivalent hot starts.

Q Per year?

A Per year.

Q Forgive me, there's a lot of paper in this docket. Is that something that's included in your exhibits to your testimony?

A No, it is not.

Q Is that something you could furnish as a late-filed exhibit?

A It's a specially restricted document.

Q Then I think the answer is no.

How about for Crystal River 2, could you give us the range of equivalent hot starts per year for the last five years, please?

A It ranged from approximately 100 to maybe 150, 160

over the last five years.

Q Do you have the comparable information for Crystal River 4 and 5?

A 4 and 5 range from 50 to approximately 110 on 4, and 5, 60 to 110.

Q Thank you. And just so I'm completely clear, when you say over the last five years, would that be calendar years 1990 through 1994?

A I'm looking at '94 as far back as '87. We took the hourly megawatts every hour of every year net generation and calculated the number of on/off and load cycles and calculated an equivalent hot start.

Q Thank you.

You were present during my cross examination of Mr. Harper yesterday afternoon, were you not?

A Yes, I was.

Q You may recall -- if you don't I'll refresh your memory -- that I asked Mr. Harper whether there were any technical reason of which he was aware that Crystal River Unit 3 could not be ramped down at a reasonable rate to accommodate a low load event and then ramp back up at a reasonable rate to restore load. Do you recall that question?

A Yes, I do.

Q And he indicated that assuming no Nuclear Regulatory Commission prohibition, that as far as he knew that was

technically possible but it was a policy decision of Florida Power Corporation's management to operate Crystal River 3 at full operating capacity whenever it's available. Do you remember that?

A Yes, I do.

Q My question is have you performed any analyses of the cycling costs that FPC would incur or avoid if it were able to cycle Crystal River 3 down, thereby keeping its coal-fired units on line during low load events?

A We have not calculated any specific cost. However, we have looked at some of the technical reasons why it would be difficult to do that.

Q Okay. I want to propose to you an analogy between what I understand your explanation of the costs of cycling of a power plant on and off are, and the cost of operating a car.

It seems to me that you're saying -- and feel free to jump in and say this is not a good analogy.

It seems to me that what you're saying is that running a power plant is sort of like running a car. You know, we have this belief in our minds that highway miles are good miles. You get that car up to full speed and you run it down the highway, and everything is okay, and the wear and tear is minimal and you run it lots and lots of miles.

And then the analogy to the power plant would be you get it up to full load and you run it and things are generally

good. Is that okay so far?

A I generally agree with that because when you run highway miles you're more efficient, get better gas milage. The same is with the power plant baseloaded operation, you're more efficient and you have better heat rates.

Q Now, is the maintenance on a power plant that you're talking about kind of analgous maybe like to an engine overhaul, a ring and valve job or something like that on a car that you'd have to undertake at some point?

A It's more immediate. There are more -- there's more things you have to do to a hospital, especially when you operate it in a cycling mode than a car that is, you know -- you can start it up and run it and shut it down many times before you have problems, and power plants virtually every time you shut down one of these large furnaces, which could easily be the size of this room in its width and depth and height of hundred feet, it tends to thermally distort, tear them up and cause failures. So that's a little bit off the analogy, but go ahead.

Q You know you made the remark in your previous response that the effects are immediate. And what I'm trying to understand is if you're looking at a relatively very small number, what could be a very small number, of on/off cycling events over the next five years to avoid curtailing QPs, how you would be confident that that would have any effect in

light of what I consider to be fairly large numbers of cycling events that have occurred without cycling QFs on and off.

To be more specific, we have just come through what has been characterized as probably the worst curtailment period that we ever expected to experience from either side of the table. We have had seven events. And I think there's some testimony in this case to show that these seven events could have been -- curtailments of QF purchases during these seven events could have been avoided by cycling one of Florida Power's coal-fired units off for several hours during the event.

If we extrapolate that out, even without allowing for diminishment of the number of curtailments over time, we're looking at maybe 30, 35 or 40 cycles to avoid curtailments over the next five years, where based on -- and that's from any unit that might be affected -- and we're looking at on the order of 50 to 150 cycles per unit per year that have taken place historically anyway, and that I think you anticipate would take place as well.

And my question is how is an extra five or six or seven cycling events a year going to show up, you know, when it's 5% of the number of cycles that are taking place anyway?

A Let me respond by saying that that's one of the specific reasons we took the conservative methodology that we did to calculate the incremental or the next cycle cost. I

don't really care whether it is from a QF or from the indigenous load of FPC, it's simply the incremental next cycle cost.

And if you talk about seven cycles, my response would be you take seven times that $65,000, and you get some $450,000-plus number, and that's not insignificant. That's real money. For whatever reason it is caused, those are real cycle costs and I think should be recovered.

Q Well, my question, again, is how can you be confident that an extra five or six cycling events on a base of 80 or 100 is going to show up?

Your study was an extrapolation of total costs and total cycling events. How can you be confident that there's a discernible measurable effect of five or six starts a year when that represents 5%, 6%, 7% of the number of starts that's going to occur anyway?

A Well, I can be confident because I know each past cost, each past cycle has cost a certain amount due to whatever reason. And if you simply add five or six more on to that, I'd say, you know, based on our bounding analysis here, that the way to do that would be to take whatever the cost was per cycle on the past and, say, if it's now allocated to a QF or to the load or whatever, to accrue those costs on that basis. And we've been very careful to bound this analysis so that we're -- you know, if you look at our minimum cost, and

those are the cost numbers that FPC has used, I'm extremely confident that that would be the expected outcome.

Q When we started out we talked about the costs that they incur on a specific event and you mentioned start-up costs and then some accrued maintenance costs. Was that based on the presumption that there was some maintenance activity conducted during the outage?

A It was based on looking at the past maintenance, and, you know, that was the No. 1 cost item, past wear and tear. And we looked at it as past maintenance that's actually happened.

It's interesting to note that if I'd actually go out there and do a detailed inspection, actually shut the unit down and crawl through all the headers and inspect those units, I expect to find a lot more problems than I've seen already and a lot more costs. So I think those numbers are low. So based on only what's happened in the past, I've got those bounds.

If the future is typical with these kind of plants and every indication I have I compared it to Crystal River 1 and 2 to some 360 other units -- actually, 266 other units in my exhibit -- it's very typical that you'd expect more damage.

So am I confident? Absolutely. I would see maintenance costs that have occurred due to those cycles in the past. I'd expect to see more in the future.

MR. WRIGHT: Thank you.

CHAIRMAN CLARK: Any other intervenors? Staff?

MS. BROWN: Staff has no questions.

CHAIRMAN CLARK: Commissioners? Redirect.

MR. TENPAS: Florida Power has no redirect. Chairman Clark, do you want us to move the exhibits now?

CHAIRMAN CLARK: Yes.

MR. TENPAS: We'd move what has been, I believe, been marked Composite Exhibit 6 which are Mr. Lefton's exhibits SAL-1 through 4 into the record at this time.

CHAIRMAN CLARK: Without objection Exhibit 6 is admitted into the record. Thank you, Mr. Lefton. Mr. Southwick.

CHAIRMAN CLARK: Thank you, Mr. Lefton.

(Exhibit No. 6 received in evidence.)

MR. TENPAS: Commissioner Clark, if we could take a moment on one housekeeping matter, I think I have some news that may be of assistance to you in scheduling, and be of interest to the Commission, while Mr. Southwick is getting to the stand.

CHAIRMAN CLARK: Go ahead.

MR. TENPAS: I have the happy task of announcing that Florida Power and OCL have reached an agreement that will result in OCL providing some output reductions, and as a result they will qualify for Group A status.

As a result of this agreement, OCL will be -- will release its claim that the plan improperly discriminates against them. And will also be no longer pursuing their claim that the plan should include a banking arrangement.

As a result of that agreement, Mr. Yott will withdraw his prefiled testimony; a portion of Mr. Southwick's rebuttal that responds specifically to Mr. Yott will also be withdrawn.

That agreement is being typed right now and we will give you the exact pages from Mr. Southwick's rebuttal that are to be struck as soon as we have that back.

CHAIRMAN CLARK: Very good. Thank you very much. Are you ready to proceed now with Mr. Southwick?

MR. McGEE: Yes, ma'am.

CHAIRMAN CLARK: Go ahead.

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HENRY I. SOUTHWICK, III.

was called as a witness on behalf of Florida Power Corporation and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. McGEE:

Q Mr. Southwick, you were previously sworn yesterday?

A Yes, I was.

Q Would you state your name and business address for the record, please?

A My name is Henry Southwick. My address as Box 14042, St. Petersburg.

Q And what's your capacity with Florida Power?

A I'm the Director of Energy Control.

Q Mr. Southwick, do you have before you a document entitled, "Direct Testimony of Henry I. Southwick, III, that's a document consisting of 51 pages of prepared testimony and four attached exhibits designated HIS-1 through HIS-4?

A Yes.

Q Was that testimony prepared by you as your direct testimony for this proceeding today?

A Yes, it was.

Q Do you have any additions or corrections you'd like to make to that prepared testimony?

A No, I do not.

MR. McGEE: Madam Chairman, we'd request that Mr. Southwick's prepared direct testimony be inserted in the record as though read.

CHAIRMAN CLARK: The prefiled direct testimony of Mr. Henry Southwick will be entered into the record as though read.

Q (By Mr. McGee) Mr. Southwick, with respect to the four exhibits attached to your direct testimony, were those prepared by you or under your direct supervision and control?

A Yes, they were.

Q Do you have any additions or corrections that need to be made to those exhibits?

A Yes, I do.

Q Would you describe those, please?

A On Exhibit 3. We had earlier submitted to the Commission --

CHAIRMAN CLARK: Mr. Southwick, we need to have the opportunity to get to Exhibit 3.

WITNESS SOUTHWICK: Yes, ma'am.

MR. McGEE: Madam Chairman, Exhibit 3 is a three-page exhibit. It's closer to the back than the front of the exhibits.

CHAIRMAN CLARK: Let me ask a question. Whatever happened to consecutively numbering pages? I don't want to pick on you, Mr. Southwick, but, you know, there used to be some sort of informal rule if you didn't do it, you know, you were in serious trouble for not consecutively numbering. I suppose if we have to, we can get Cresse back here to terrorize everybody on that point. But just for everyone's information, if you would, for your exhibits, consecutively number the pages. It would be helpful.

MS. BROWN: Or use tabs, too.

CHAIRMAN CLARK: Okay. I'm on HIS-3. What page?

WITNESS SOUTHWICK: On Page 1 of 3 we had previously submitted a change to that page that was sent to the

Commission back on March 13th.

MR. McGEE: I have extra copies if anyone --

CHAIRMAN CLARK: I don't have a copy.

WITNESS SOUTHWICK: In addition to that revision that was sent in on March 13, I have some small revisions to Pages 2 and 3 also. They are not significant, but there are some typographical changes that I can read in.

Q (By Mr. McGee) Please do so?

A On Page 2, within that matrix of numbers there's one number that needs to be changed. It's in the column that's headed "By January 7th, 1995." The second number down in that column is 26,626, it should have been 25,626. That's the only one on that page. And then on Page 3 of 3, the first column says "October 19th, 1995," it should have been "1994". And then the bottom row, the row that says "Unit Start-up Costs," all of those numbers are wrong. Unfortunately, they were picked up from a earlier edition and they were not changed.

The first number in that row, instead of 29,137 should have been 25,626. The second number should have been 12,813. The third number should have been 25,626. The fourth number is 25,626. The fifth number is 12,813. The next number again is 12,813, and the last number should have been 12,813. Those are all of the corrections.

MR. McGEE: Madam Chairman, we'd ask that Mr. Southwick's exhibits HIS-1 through 4 be marked for

identification as Composite Exhibit 7.

CHAIRMAN CLARK: They'll be marked as Composite Exhibit 7.

(Composite Exhibit No. 7 marked for identification.)

FLORIDA POWER CORPORATION
DOCKET NO. 941101-EQ

330

DIRECT TESTIMONY OF HENRY I. SOUTHWICK, III

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Henry I. Southwick, III. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity.

A. I am employed by Florida Power Corporation ("Florida Power" or "the Company") as the Director of Energy Control.

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Electrical Engineering from Clemson University and a Masters Degree in Engineering from the University of South Florida. I am a registered Professional Engineer in the State of Florida. I have held various positions at Florida Power Corporation in Industrial Development, Division Operations, and Economic Research. In 1983, I was promoted to Manager of System Planning with the responsibility for Florida Power's generation, transmission and distribution planning. In 1990, I was named Director

of Engineering and Technical Services for the Fossil Operations area of Florida Power. I became Director of Energy Control in July, 1992.

Q. What are your responsibilities in your current position?

A. As Director of Energy Control I am responsible for the day-to-day operation of the Florida Power electric system. This includes the scheduling and dispatching of all power resources available to Florida Power to serve customer demand and the operation of the electric transmission system. I am also responsible for interchange operations between Florida Power and other utilities in Florida and the Southeast.

Q. Have you ever testified before the Florida Public Service Commission?

A. Yes, I have testified in several previous Florida Power rate and fuel cost recovery proceedings and in connection with Florida Power's acquisition of assets from Sebring Utilities Commission.

II. PURPOSES AND ORGANIZATION OF TESTIMONY

Q. What is the purpose of your testimony?

A. I will explain what is meant by the terms "minimum load conditions" and "minimum load emergency." I will show why those system conditions can create reliability and cost consequences that need to be addressed by any utility in a prudent and predictable manner. I will also outline the extent and nature of Florida Power's minimum load problem by reference to the Company's loads and resources. Having laid out the

problem, I will then describe Florida Power's efforts to deal responsibly with the minimum load problem first by using all reasonable measures to reduce its own generation levels and ultimately by developing the October 12, 1994 Generation Curtailment Plan For Minimum Load Conditions ("the Curtailment Plan"). I will explain the basic principles incorporated into the Curtailment Plan in order to achieve equitable procedures that can be readily implemented by the Company's system operating personnel. Finally, I will discuss the Company's continuing desire to respond to legitimate Qualifying Facility ("QF") operating concerns if this can be done consistent with the objectives of the Curtailment Plan.

Q. Are you the Company's principal policy witness in this proceeding?

A. Yes. To the extent that the Curtailment Plan reflects judgment calls or Company policy decisions, I will be available to testify on those matters.

Q. Are you sponsoring any exhibits in this docket?

A. Yes. I am sponsoring Exhibit No. ___(HIS-1) which contains excerpts from several relevant publications of the North American Electric Reliability Council ("NERC"), the Southeastern Electric Reliability Council ("SERC") and the Florida Electric Power Coordinating Group, Inc. ("FCG"); Exhibit No. ___(HIS-2) which reproduces the Unit Power Sales Agreement between Florida Power and the Southern Companies; Exhibit No. _____ (HIS-3) which shows how QF purchases during minimum load conditions create negative avoided costs; and Exhibit No. ___(HIS-4)

which includes examples of correspondence sent by Florida Power to its QF suppliers soliciting their involvement in dealing with the minimum load problem.

III. THE NATURE OF A MINIMUM LOAD EMERGENCY

Q. What is meant by the term "minimum load emergency"?

A. A minimum load emergency can be defined as a situation in which a utility's total system demand (or "load") falls to such a low level that the minimum generating input into the system exceeds that load level. In other words, such an emergency condition occurs when the utility can no longer match its generation and load levels because there is too much generation in relation to the system load.

Q. Please describe the components of a utility's load.

A. A utility's total system load consists of all purchases of electricity from the utility at a given point in time plus losses and station service. The load includes the electricity requirements of the utility's wholesale and retail customers as well as its off-system sales to other utilities. Typically, a distinction is drawn between "firm" loads (which include requirements services and assured capacity sales to others) and "non-firm" loads (which are interruptible either by rate schedule or contract). However, when measuring a utility's "minimum load" at any moment, one would normally include all of the demands being placed on the system at that moment.

Q. What are the components of a utility's available power supply?

A. Generally speaking, a utility's resources consist of (i) its own generating units; (ii) its purchases from QFs or other non-utility generators; (iii) its power purchases from other utilities; and (iv) its dispatchable demand-side management capability. A utility's generating units can have substantially different operating profiles, with some running virtually continuously as "baseload" units, some running intermittently as "intermediate" units, and still others operating only to satisfy "peak" demand periods. Likewise power purchase contracts -- with other utilities and with QFs -- may call for varying amounts of capacity availability.

When measuring a utility's minimum generation, one must consider the lowest levels to which the utility's resources can be reduced. The minimum generation usually will equal the sum of (i) the lowest prudent and economic operating levels for the utility's own units (typically baseload operation); (ii) the minimum purchases required under QF contracts or rate schedules; and (iii) the minimum purchase obligations under firm capacity purchase contracts with other utilities.

Q. Is it important for a utility to match its resources and loads at all times?

A. Yes, it is. In fact, this is a fundamental objective of any prudent utility. During peak load periods, it is imperative to have enough generation available to satisfy rising demands on the system, plus a reasonable margin of reserves to account for contingencies. It is equally important

to have the capability during off-peak periods to dispatch or cycle off generating resources as the load drops. Both daily and seasonally, most utilities experience wide disparities between their minimum and maximum loads. Given the resources available to the utility, its system operating personnel strive to dispatch those resources in the most economically efficient and operationally reliable manner possible so as to follow the system's fluctuating loads. Obviously, careful attention must be given to how this is accomplished. For example, it would be inappropriate from both a reliability and a cost perspective to shut down a baseload resource to meet a temporary trough in the system load, where doing so prevents the unit from serving the load as it begins to rise again.

Q. It is easy to understand why a utility must have enough generation to meet its peak demands, but why do you conclude that it is equally important to be able to reduce generation in order to match minimum load levels?

A. I base this conclusion on both reliability and economic considerations. From a reliability standpoint, keeping loads and resources in balance is a fundamental matter of system integrity and reliability. Accepted industry-wide standards require that loads and resources be kept in balance to reliably serve customers and to protect the equipment of the utility, other interconnected systems, and the customers. A utility cannot maintain a practice of intentionally dumping excess generation onto the systems of other neighboring utilities. This unscheduled

energy, commonly called "inadvertent interchange," must be held to a minimum in order to satisfy industry standards and the terms of inter-utility interchange contracts.

Given the heavily interconnected nature of the nation's electrical grid, generation excesses, like generation deficiencies, can create cascading adverse effects that place unacceptable burdens on other parties. Electricity must be used instantly, and excess generation creates frequency imbalances that can severely damage utility and customer equipment. In layman's terms, too much generation will cause motors to burn out. If neighboring utilities were to isolate Florida Power's system to avoid such impacts on their facilities, then the excess generation on Florida Power's own system would be even more detrimental.

Q. What are the economic considerations on which you base your conclusion?

A. The incurrence of uneconomic power supply costs during minimum load periods has an adverse impact on the utility and its ratepayers. Moreover, as the system is ramping-up to follow the rising load after a minimum load period, the utility will incur additional uneconomic costs if it has previously been required to operate its resources at levels less than normal minimums or to shut off units to balance generation and load. When the Company is compelled to make uneconomic purchases of energy from third parties, then in the words of this Commission's

Rule 25-17.086, those purchases "will result in costs greater than those which the utility would incur if it did not make such purchases" and will "otherwise place an undue burden on the utility."

The Federal Energy Regulatory Commission ("FERC") provided an excellent example of this problem when it issued its QF regulations in 1980. This example is cited in Mr. Robert D. Dolan's testimony. The FERC correctly observed that if a utility operating only its baseload units in minimum load conditions were forced to cut back output from those units in order to continue making a QF purchase, then the baseload units might not be able to ramp-up their output when needed again to follow the next increase in load. As a consequence, it would be necessary for the utility to meet that rising load by running less efficient, higher cost, intermediate or peaking units. As noted by the FERC, this would result in a negative avoided cost for the utility. The adverse cost impacts also are exacerbated by the fact that cycling of generating units causes a variety of other start-up and unit-related costs. I will briefly describe these impacts later in my testimony and I refer to the testimony of Mr. Steven A. Lefton for more detail.

Q. You have testified that it is necessary for a utility to keep its loads and resources in balance in order to satisfy accepted industry-wide standards. Please explain.

A. This basic operating tenet finds solid support in the industry standards published by NERC. The NERC standards, in turn, are endorsed and

followed both by SERC and the FCG. Florida Power subscribes to the operating criteria published by each of these industry organizations. Following are representative statements from the NERC Operating Guides. I hasten to add, however, that the requirement for balancing resources and loads is such a basic concept that it literally permeates those Operating Guides. The text of the applicable NERC Operating Guides is reproduced for the Commission's reference in my Exhibit No. 7 (HIS-1). In addition, that exhibit includes excerpts from the SERC and FCG manuals which confirm the intention of those organizations to carry out the objectives of the NERC Operating Guides.

1. Representative excerpts from NERC Operating Guides:

> Each control area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules to its load.
>
> * * * * * *
>
> All generating units of consequential size, including jointly owned units capable of regulating, should be equipped with AGC to ensure that the control area can continuously balance its generation with its demand plus net scheduled interchange.

2. Excerpt from SERC Agreement:

> Membership in SERC is voluntary, but members recognize a commitment to comply with NERC and SERC guidelines for the planning and operating of the interconnected electric power system.

3. Excerpt from FCG October 1994 Operating Committee Handbook:

> The FCG Operating Committee accepts the NERC Operating Guides as a basis for operations. The Florida Specific Procedures contained in this Handbook were written to either clarify or enhance a

specific NERC Operating Guide for use within the Florida Subregion. The NERC Operating Guides are not included in this Handbook, but the Guides are referenced to the applicable Florida Specific Procedure in the Table of Contents. In cases where there is no Florida Specific Procedure associated with a NERC Guide, the Guide title and number is referenced in the Table of Contents to direct the reader to the NERC manual.

IV. FLORIDA POWER's LOADS

Q. Do Florida Power's system loads fluctuate significantly?

A. Yes, the Company's total system demand can vary by as much as 1,000 MW per hour and can range from a low of about 1,850 MW up to almost 8,000 MW. It is crucial to match generation with these quickly fluctuating loads as they rise and as they fall.

Q. Please describe the fluctuation patterns in the Company's loads.

A. Florida Power's loads vary both daily and seasonally based primarily on prevailing weather conditions. This is because the Company's largest loads are related to heating and cooling requirements. The Company generally experiences its lowest customer demands late at night and early in the morning -- between 11:00 p.m. and 7:00 a.m. on weekdays, and between 11:00 p.m. and 8:00 a.m. on weekends and holidays.

Florida Power is a winter peaking utility because its service area occasionally experiences winter cold snaps which temporarily drive up

demand to very high levels. However, the Company's lowest load periods also tend to occur during the fall, winter and spring months, when the weather is often very mild.

Loads lower than 2,500 MW are considered to be the Company's "minimum load" conditions. The minimum load conditions typically occur during the October through May time frame, although the load may fall below 2,500 MW during other months as well. The example provided on page 3 of the Curtailment Plan (Exhibit No. 1 (RDD-1)) provides a good illustration of the lowest load conditions experienced in the fall-winter-spring of 1993-1994. That example shows that the lowest load day per month for the eight-month period (October, 1993 - May, 1994) and the corresponding minimum gross loads for each day were as follows:

October 31, 1993	2,009 MW
November 26, 1993	1,859 MW
December 5, 1993	1,954 MW
January 3, 1994	1,917 MW
February 7, 1994	1,893 MW
March 14, 1994	1,931 MW
April 4, 1994	1,963 MW
May 22, 1994	1,902 MW

Q. What are the comparable data for the period between October 1, 1994 and January 31, 1995.

A. The comparable data for that period are as follows:

October 16, 1994	2,015 MW
November 27, 1994	1,926 MW
December 30, 1994	2,041 MW
January 2, 1995	1,935 MW

V. FLORIDA POWER's RESOURCES

Q. Turning now to the Company's available resources, how many generating units does Florida Power own and operate?

A. Florida Power has 56 generating units located at 14 stations, and one combustion turbine cogeneration unit. The total installed net winter generating capability is about 7,335 MW.

Q. Please describe the Company's baseload generation.

A. Florida Power owns five baseload units representing 3,031 MW of net winter generating capability. This consists of (i) Crystal River Units 1, 2, 4 and 5, which are fueled by coal; and (ii) Crystal River No. 3 (755 MW net) which is a nuclear unit.

Q. Next, please describe Florida Power's intermediate units.

A. Florida Power owns eight oil- and gas-fired steam intermediate units as follows: Anclote Units 1 and 2; Bartow Units 1, 2 and 3; and Suwannee Units 1, 2 and 3. The intermediate units account for a total of 1,630 MW of net winter generating capability.

Q. How many peaking units does the Company own?

A. The Company owns 43 peakers totaling 2,634 MW of net winter generating capability. These are: DeBary Units P1-P10; Intercession City Units P1-P10; Suwannee River Units P1-P3; Bartow Units P1-P4;

Turner Units P1-P4; Bayboro Units P1-P4; Higgins Units P1-P4; Avon Park Units P1-P2; Rio Pinar; and Port St. Joe.

Q. Where is the Company's cogeneration unit located?

A. Florida Power owns a 40 MW cogeneration unit at the University of Florida in Gainesville.

Q. Does the Company have other capacity resources?

A. Yes. In addition to its substantial demand-side management activities, the Company purchases capacity from two other utilities and from a number of QFs. Mr. Dolan's testimony describes the QF purchases, which accounted for roughly 1,000 MW as of January 1, 1995 and will exceed 1,100 MW later this year. The utility purchases are from (i) the Southern Companies (approximately 400 MW); and (ii) Tampa Electric Company (50 MW).

Q. Please summarize Florida Power's total net generating capability, including purchases.

A. Chart 1 at page 6 of the Curtailment Plan which is Mr. Dolan's Exhibit No. __1__(RDD-1) showed a total system net generating capability of approximately 8,707 MW. As explained in Mr. Dolan's testimony, that figure should now be increased to 8,817 MW to reflect additional QF capacity and energy available to the Company.

Q. Does the Company require all of this generation for peak load purposes?

A. Yes. The Company requires this generating capability to meet its peak load needs, when taking into account unit outages, reserve requirements and other contingencies.

Q. Does the Company need all of this generation under minimum load conditions?

A. Obviously not. The 8,817 MW total far exceeds the minimum load levels of 2,500 MW and below. Indeed, for the reasons I explained previously, the Company must reduce a significant amount of its total available generation to match its minimum load levels.

VI. FLORIDA POWER's ABILITY TO RESPOND TO FALLING CUSTOMER LOADS

Q. What measures can the Company take with respect to its own resources to follow the load as it declines toward minimum load conditions?

A. First, I should note that the Company's system operating personnel plan ahead, to the maximum extent practicable, to have resources available when needed and off-line when not needed. For example, plant maintenance typically is scheduled during anticipated low load periods. Similarly, power purchases and sales may be scheduled so as to minimize capacity resources when they are not required. In other words, there are long-term and intermediate-term measures which are routinely taken in anticipation of the need to reduce generation when loads are low.

The system operators also have the ability, as shorter-term measures, to take the following steps aimed at matching generation and load: (i) reducing inter-utility capacity purchases to minimum levels permitted by the applicable purchase contracts; (ii) maximizing economic off-system sales to other utilities; (iii) reducing the Company's generating units to their minimum generation levels consistent with reliability constraints and operating conditions at the time; and (iv) exercising voluntary unit output reductions agreed to by certain of the Company's QF suppliers. The QF output reductions are discussed in Mr. Dolan's testimony. I will describe the other three measures available to the system operating personnel.

Q. Would you please elaborate on the first of these measures -- reducing inter-utility capacity purchases?

A. As I noted previously, Florida Power currently is buying 50 MW of capacity from Tampa Electric and about 400 MW from the Southern Companies. The contract with Tampa Electric permits Florida Power to reduce the 50 MW purchase to zero each day. This is a measure which the system operating personnel routinely take under minimum load conditions.

Q. What about the 400 MW purchase from the Southern Companies?

A. Through 1994, half of the 400 MW from the Southern Companies was purchased under Schedule E of an Interchange Agreement between the parties, and the other half was purchased under a separate Unit Power

Sales Agreement. Under those arrangements, Florida Power could be required to purchase a minimum of 84 MW depending upon conditions on the Southern Companies' system. Since the beginning of 1995, all of the 400 MW purchase is occurring under the Unit Power Sales Agreement. The minimum that the Southern Companies can now require the Company to buy and take is 168 MW

Q. What provisions in the Unit Power Sales Agreement impose this minimum take requirement?

A. The minimum purchase obligation is set forth in Section 3.6 of the Unit Power Sales Agreement which is entitled "Minimum Operation Capacity Obligation." For the Commission's convenience, I am including a copy of the entire Unit Power Sales Agreement as Exhibit No. 7 (HIS-2).

Section 3.6 requires Florida Power to take a proportionate share of the energy produced by the Southern Companies' Miller generating units and Scherer Unit No. 3 whenever those units are operating at "Minimum Operating Conditions." It is possible that the Minimum Operating Conditions at one or more of the Southern Companies' units will not coincide with Florida Power's minimum load conditions. In that case, the minimum purchases associated with that unit would not apply.

Q. Does the Curtailment Plan assume that the Southern Companies' system conditions will be such as to compel the Company to take the minimum 168 MW?

A. The background discussion in the Curtailment Plan states that Florida Power may be compelled to take the full 168 MW under the Unit Power Sales Agreement, and the minimum generation levels shown, for example, on Chart 2 at page 16 of the Plan (Exhibit No. __1__ (RDD-1) assume that the minimum take requirement will be applicable. However, I want to emphasize that this minimum take will affect the actual implementation of the Curtailment Plan only if Minimum Operating Conditions on the Southern Companies' units coincide with Florida Power's minimum load conditions so that Florida Power is compelled to accept the minimum takes during its minimum load period. The instructions to the system operating personnel (Appendix C to Exhibit No. __1__ (RDD-1)) make clear that the purchases from the Southern Companies are to be reduced as much as possible before any curtailments take place.

Q. Is there reason to believe that the minimum take requirement will not always be applicable?

A. As noted, the minimum takes depend upon conditions on the Southern Companies' system. The purchases are not always required. In fact, the minimum take requirement was not applicable on October 19, 1994, when the Company first implemented the Curtailment Plan. Therefore, the need for QF curtailments was reduced on that occasion by 84 MW (recall that the 1994 minimum was only 84 MW, as compared to the current 168 MW). Similarly, during later curtailment experiences: no purchases were made from the Southern Companies on January 1,

1995; only 23 MW from Scherer Unit No. 3 was purchased on January 2, 1995; the amounts purchased on January 7 and 8, 1995 ranged from 109 MW to 132 MW; the amounts purchased on January 14, 1995 were 96 MW or less; and the purchase amounts ranged from 8 MW to 95 MW during the curtailments on January 30, 1995.

Q. You stated that, in response to an impending minimum load condition, the Company's operating personnel also can reduce the likelihood of having excess generation by maximizing economic off-system sales. Please explain.

A. An increase in off-system sales to third parties has the same net effect as a corresponding increase in load. The Company often makes inter-utility sales under its various interchange contracts for long and intermediate time frames. In addition, the system operating personnel also engage in short-term sales when the system has available generation. Many such energy sales are made on the Florida Energy Broker System. Florida Power has direct electrical interconnections with 13 other generating utilities and makes every reasonable effort to sell economy energy to others.

Q. Are there limitations on the Company's ability to sell power off-system in anticipation of or during a minimum load condition?

A. Yes, there are. For example, the off-system sales must be made at a price that at least recovers the incremental cost of producing the energy. It is my understanding that the governing FERC pricing policies

mandate that the price for off-system opportunity sales be no lower than the seller's incremental cost.

Another factor limiting the Company's ability to market energy during minimum load conditions is the relative state of its neighboring utilities' power supply needs at the time. Florida Power cannot sell power unless it has a willing buyer, and it is quite likely that other interconnected utilities, whose loads also are weather-related, will be facing low load conditions coincident with Florida Power's incurrence of minimum load conditions. In other words, when Florida Power's loads are very low, it may have difficulty finding a willing purchaser for its available generation.

Q. How does the ability to sell power off-system affect the Company's implementation of the Curtailment Plan?

A. Just as the Plan instructs the Company's system operating personnel to minimize the power purchases, it also instructs them to maximize off-system sales as a means of mitigating the need for QF curtailments. In fact, the Plan directs that this will be done, not once, but throughout the minimum load period. The more successful the Company is in making these sales on a given occasion, the less impact QFs will feel from the Curtailment Plan.

Q. You previously mentioned a third step that the system operations personnel can take as the system load declines -- reducing the output from Florida Power's own units. Please explain how this occurs.

A. Actually, managing the generation levels of the Company's units is not a single "step," but rather a series of "steps" which is ongoing as a normal part of the system operating and dispatch functions. Each of the Company's units has distinctive operating characteristics. As a class and under normal conditions, peaking units are capable of being cycled on and off regularly to meet peak energy needs. Intermediate units likewise are capable of being cycled on and off, but generally are operated more constantly than peakers because of their lower running costs. Baseload units, which are the least expensive units to run, typically operate more or less on a must-run basis as the system's work-horses to meet the lower end of the load curve.

In addition to the general operational limits of the types of units, individual units also have their own individual operating profiles. The Company's system dispatchers routinely interact with the plant operators when evaluating the most reliable and economic mix of resources to use to meet the system's changing conditions.

Q. Can you be more specific about Florida Power's intentions for running its own units in anticipation of and during minimum load periods?

A. The Company's objective, whenever possible given the current condition of its various units and other system constraints, is to minimize the

need for QF curtailments by maximizing its own unit output reductions in a manner that is consistent with sound operating practices. Florida Power has been engaged in efforts since at least 1993 to investigate the true minimum operating levels of its various generating units because we envisioned that potential minimum load problems would occur in the fall of 1994 with the addition of large new increments of QF capacity. As a consequence of these efforts, the Company is running its own units today at much lower levels of output than it did several years ago. I should note that the Curtailment Plan anticipates that Florida Power will substantially curtail its own generating units before asking any QF to reduce its output. Given these commitments by the Company, I believe that the Curtailment Plan represents a conservative, rather than an aggressive, approach to QF curtailment.

Q. Please describe the sequence in which Florida Power will dispatch its own units in a minimum load condition.

A. To the extent we can do so in light of unit and system conditions at the time, the Company will first respond to minimum load conditions by cycling off its peaking and intermediate units.

Next, the Company will reduce its coal-fired baseload units to their normal minimum operating levels while maintaining enough margin for load control and system security. Again, this assumes that such reductions are practical at the time. Florida Power has determined that it would incur unacceptable operational risk and costs if it cycled these

units off entirely. These units are needed on the system for Automatic Generation Control ("AGC") and load following purposes. Finally, the Company will cycle off its University of Florida combustion turbine. It is worth noting that, under normal operating conditions, this treats the Company's own cogeneration plant as fully curtailable before any curtailments are required for unaffiliated QFs.

Q. What do you mean when you refer to "normal minimum operating levels" for the coal units?

A. As I have noted, baseload units normally are operated at a high capacity factor to satisfy the low end of the utility's load curve. Nonetheless, preliminary evaluation of the Crystal River 1, 2, 4 and 5 units suggests that under normal operating conditions, they can be dispatched down to lower operating levels in order to respond to minimum load conditions. Specifically, the Company is estimating that these units generally will be able to achieve the following normal minimum gross operating levels consistent with emissions restrictions, AGC requirements and other system conditions:

	MINIMUM GENERATION	ADDITIONAL AGC/SYSTEM SECURITY REQUIREMENT
Crystal River 1	120 MW	0 MW
Crystal River 2	140 MW	0 MW
Crystal River 4	150 MW	150 MW
Crystal River 5	150 MW	150 MW
SUBTOTALS	560 MW	300 MW
TOTAL	860 MW	

Let me briefly explain the column showing the AGC/system security requirements for Crystal River Units 4 and 5. Generally, those units are not operated below the normal 250 MW lower limit of their control range (i.e., the normal level at which they can remain on AGC). The additional 50 MW represents a system security requirement which is maintained in order to provide necessary load following capability. Unit 5 also provides an additional system security function whenever Florida Power's Crystal River 3 nuclear unit also is on-line. Because of constraints on the 500 kV transmission system, Unit 5 must maintain an optimal output level of between 300 and 350 MW to supply needed transmission voltage stabilization in case Unit 3 should trip off-line.

Q. Is it possible that the Crystal River coal units could achieve greater than normal output reductions without creating unreasonable risk and costs?

A. It is possible that they may not achieve as much reduction as anticipated and it is conceivable that they could achieve slightly more. I emphasize that these are estimates only. Again, in the interest of minimizing QF curtailments, the Curtailment Plan contemplates that the system operating personnel will communicate with the Crystal River plant operators and reduce the coal-fired units even more than the amounts noted above (*i.e.*, to temporary "emergency minimum operating levels") if the circumstances permit at the time.

Q. Will the Crystal River 3 nuclear unit be cycled in response to minimum load conditions?

A. No. The Company has determined that safety, reliability and cost considerations all make it impractical to dispatch the Crystal River 3 unit for load following purposes. In addition to the adverse impacts on Crystal River 3 itself and the impacts on system reliability if Crystal River 3 cannot be returned immediately to full power, it is my understanding that running the unit at reduced capacity levels also can have undesirable side effects such as producing xenon imbalances, excessive amounts of radioactive waste water and unused fuel at the end of an operating cycle. Mr. Lefton elaborates on these concerns in his testimony.

Q. Assuming that all units are available for reduced operation in the manner you have described, please summarize the Company's normal minimum gross generation levels.

A. In 1995, the normal minimum gross generation level (before QF purchases) is about 1,823 MW. This is made up of 860 MW from coal units, 795 MW from Crystal River 3, and 168 MW from the Southern Companies.

Q. Based on these minimum generation levels, can you provide some indication of the magnitude of the need for QF curtailments under minimum load conditions?

A. The actual extent of any curtailments will depend upon numerous factors which are difficult to predict. For example: QF units or Company units may happen to be out of service in a low load period; some units

may have to remain on-line for AGC or other reliability reasons; some units may elect to cycle off entirely rather than reduce their output; the minimum take requirements from the Southern Companies may or may not be applicable; off-system sales may be at relatively high levels or relatively light; and the list goes on. All that I can say with any real confidence is that the extent of required QF curtailments will be measured by the difference between (i) total system generation after all available measures have been taken short of curtailments; and (ii) the system load at the time.

The Curtailment Plan offered an example of a minimum load curtailment (Exhibit No. __1__ (RDD-1) at page 15). Perhaps it would be useful for me to update that example now that the Company has negotiated several additional voluntary output reduction plans with QFs. The example included in the Curtailment Plan assumed 792 MW of total available QF generation after the negotiated QF reductions. As Mr. Dolan explains in his testimony, two additional QFs have since negotiated output reduction plans. When these additional reductions are realized, the total QF generation is reduced from 792 MW to about 745 MW, yielding a corresponding reduction in the amount of required QF curtailments. Thus, the example in the Curtailment Plan should be modified as follows:

EXAMPLE OF MINIMUM LOAD CURTAILMENT:

Coal	860 MW	
Nuclear	795 MW	
Southern	168 MW	
	1,823 MW	FPC generation and firm purchases
plus	~~782~~ 745 MW	QF generation after negotiated reductions
	~~2,615~~ 2,568 MW	
minus	2,400 MW	Assumed minimum load
	~~215~~ 168 MW	Additional QF generation to curtail

Q. Can you provide an estimate of the likely frequency of QF curtailments under the Curtailment Plan?

A. For the reasons I have just given, any estimate would be highly speculative. Moreover, it would likely be misleading since a "curtailment" event might mean that only 1 MW was curtailed from only the as-available suppliers, or alternatively, it might mean that many more megawatts were curtailed from all categories of QF suppliers.

It bears emphasizing, however, that the initial fear of very frequent curtailments expressed to the Company by several QFs has not proven to be justified. I am pleased to say that Florida Power was forced to implement involuntary curtailments only once during 1994. Thus far, only a handful of curtailments have been required in 1995. In all other cases where system loads were below the 2,500 MW threshold and the potential need for curtailments was imminent, circumstances within and outside the Company's control came together in such a way as to

forestall that need. It is significant to note that there were 2,952 hours in the low load months of October 1994 through January 1995, while curtailments occurred in a total of only 31.25 hours, or one percent of the time. Moreover, for those QFs who have entered into voluntary output reduction plans, the impact of curtailments was even less frequent, since these QFs were able to avoid more than half of the involuntary curtailments. I refer to Mr. Harper's testimony for more information on this subject. Granted, we would prefer to have no curtailments, but the experience to date should help to alleviate any concern that the Company is attempting to trigger frequent curtailments in an irresponsible or haphazard way.

Q. You have testified that the decision to operate Florida Power's baseload coal units at minimum operating levels, rather than cycling them off, is based upon both reliability and economic considerations. Please elaborate on the economic considerations.

A. Even if reliability coniderations allow turning coal units off, this is not desirable on an economic basis. So long as the total cost to take a unit off-line ("cycling cost") exceeds the fuel savings that result from not running the unit, the net economic effect of cycling the unit off must be an increase in net system cost, or a negative avoided cost. Cycling off a baseload coal unit in order to continue purchasing QF energy can be expected to cause a negative avoided cost. As I have noted, when system load declines prior to a minimum load period, Florida Power maintains a balance of generation and load by first cycling off its

peaking units, then reducing generation from all of its steam units and finally cycling off its oil-fired units. At this point, only the largest, most economical units remain on-line (coal and nuclear units). The only remaining operational option to further reduce generation from Florida Power's own facilities would be to cycle off one or more of these baseload units. However, there is a substantial cost incurred if any of these units is cycled off.

Q. What types of costs are incurred when the baseload units are cycled off?

A. Mr. Lefton explains that a wide variety of cycling costs occur each time a baseload unit is cycled off. For convenience, I will refer to the costs described by Mr. Lefton as "unit impact costs" since they all are related directly to the specific unit being cycled. In addition to the unit impact costs, there is another significant cost component of cycling activity that relates to the replacement power costs incurred whenever more expensive energy must be generated or purchased in lieu of energy that otherwise would be available from the cycled unit.

Q. Please summarize the kinds of cycling costs that you have referred to as unit impact costs.

A. Simply stated, cycling a unit on and off makes the unit and its components wear out faster and cost more to operate than in the case of steady state operation. Related unit impact costs include, among other things: higher periodic maintenance and capital expenses as

components require repair and replacement earlier than they otherwise would; higher forced outage costs; and a reduction in the operating life expectancy of the unit. Each time a unit is cycled off and on, transients in temperatures, pressures and flow rates result in significantly increased stress and wear on many of its component parts.

In addition, unit impact costs of cycling include the effect of increasing the frequency of unit start-ups. A coal-fired unit includes many large mechanical components and systems that operate at high temperatures. When the unit is turned off, these components and systems begin to cool and will eventually reach ambient temperatures. When the unit is restarted, critical components must be slowly and evenly reheated to operating temperatures before the unit can resume operation. For example, if the turbine rotor (a very large, very expensive, integral component of the generating unit) is heated unevenly or too rapidly, it will warp, resulting in severe damage to the turbine and extended unit unavailability. Upon restart, supplemental firing is required until the unit reaches a stable operating level. The start-up fuel required to preheat and supplemental fire the unit to achieve stable operation is a primary component of the unit start-up cost. In addition, cycling and transient operation of the unit disrupts the chemical balance of the water in the boiler and cooling system, resulting in an increase in water treatment costs and related equipment problems.

Mr. Lefton discusses such unit impacts in his testimony and concludes that these costs should be expected to range from at least $30,000 to well over $100,000 each time an older unit like Florida Power's Crystal River Unit 2 is cycled. The start-up fuel cost alone accounts for roughly $13,000 per start.

Q. Please describe your second general category of cycling costs -- replacement power costs.

A. The $30,000-$100,000+ range provided by Mr. Lefton does not include the short-term replacement power costs which are incurred during the period immediately after a minimum load condition whenever it becomes necessary to replace the power that would have been available from the cycled-off baseload unit with other, more expensive power. Generally, because the baseload units supply the Company's lowest cost energy, these units are dispatched at full capacity as the system load rapidly increases each day. Cycling off a baseload unit during the overnight minimum load period creates a substantial risk that the unit will not be available as needed for this load following purpose. This is true for at least three reasons.

First, under normal operating conditions, each unit has a "minimum down time" that limits how soon it can be restarted after being turned off. For planning purposes, the minimum down time for each of Florida Power's coal units is at least six hours. This period often is longer than six hours, as for example, in the situation where Crystal River Units 1

and 2 or Units 4 and 5 are returned to service simultaneously. In that case, it is more common for one unit to return to service approximately two hours prior to the return of the second unit.

Second, once a unit is cycled off-line, that unit can only be returned to full capacity gradually. The normal ramp periods can extend for several hours during which time the on-line units may be unable to meet the rising system demand, thus requiring that alternative resources be utilized for this purpose.

Third, there is always a significant risk that a critical component may not operate properly or may fail during the shut-down/start-up sequence, resulting in a forced outage. The maintenance and repairs required by the component failure can make the unit unavailable for hours or even weeks. Although it is difficult to predict when any particular unit will trip off-line, it is reasonable to expect that this will happen from time to time.

During each period when the baseload unit is unavailable to follow load, its generation must be replaced with other, more expensive resources -- typically the capacity and energy would be provided from oil-fired intermediate units or peaking units. The differential in power supply costs to the system is a direct result of the cycling event and is the major component of the short-term replacement power cost. Another

significant, but smaller, impact is the potential start-up cost associated with the replacement power resource.

Q. In what circumstances would these short-term replacement power costs result in a negative avoided cost for a block of energy?

A. As I have already noted, the replacement power expenses are only a component of the total cost of cycling a baseload generating unit. Nonetheless, short-term replacement power costs alone will result in a negative avoided cost whenever they exceed the Company's avoided fuel cost from not generating that block of energy. Using plausible assumptions, it is reasonable to expect that replacement power costs incurred as a result of cycling a Crystal River unit would make a csignificant contribution to negative avoided cost.

Q. Can you provide an example of the impact of replacement power on the avoided cost of a block of energy?

A. Yes. It is impossible to precisely quantify this cost in advance of its incurrence. However, a simple example should serve to illustrate that this cost impact can be substantial. First, note that there is an upper limit to the benefit that can be derived from cycling off a unit during any minimum load period. If a unit such as Crystal River 2 is cycled off, it will provide at most 140 MW of relief, assuming that it has been previously operated at its normal minimum generation level of 140 MW. Assuming further that the duration of the minimum load emergency lasted for six hours, then cycling off Crystal River 2 could enable Florida

Power to accept a maximum of 840 MWH of QF energy (140 MW for six hours). If Crystal River 2 thereby became unavailable at its full capacity of 500 MW for a single hour and this power were replaced by peakers at an average cost of $60/MWH, the resulting cost differential would be $21,000 (500 MW for one hour at $42/MWH, which is the difference between the Crystal River 2 fuel cost of approximately $18/MWH and the $60/MWH replacement cost). The resulting avoided cost of the 840 MWH block of energy not generated by Crystal River 2 is equal to the avoided cost of generation ($15,120 based on 840 MWH at $18/MWH) less the replacement power cost of $21,000 -- in other words, a negative avoided cost component of $5,880 or $7.00/MWH. Of course, where a unit is cycled-off and remains off-line for longer than one hour after it was scheduled to return to service the magnitude of this negative cost will be far greater than shown in my example.

Q. Can you supply a similar example showing the effect of the unit impact costs on the calculation of avoided cost?

A. Yes. First, let me repeat that the unit impact costs also are only a subset of the total cost of cycling. And, like the replacement power costs, they will produce negative avoided costs whenever, separately or in combination with other cycling costs, they exceed the fuel savings from not generating the avoided block of energy. To illustrate the effect of these costs, I have used assumptions similar to those described earlier. The resulting avoided cost is as follows:

	CR #2
Minimum capacity - MW	140
Hours off	6
Block size - MWH	840
Fuel cost - $/MWH	18.00
Avoided Fuel Cost - $	15,120
Unit Impact Cost - $	(65,000)
Net Avoided Cost - $	(49,880)
Net Avoided Cost - $/MWH	($59.38)

For convenience, I have used a per-event unit-impact cycling cost half-way between the low and high ends of the cost-estimate range offered by Mr. Lefton. I would, however, draw the same conclusion even using the low-end estimate. My conclusion is that the unit-related costs of cycling are material and of sufficient magnitude to create a negative avoided cost (separate and apart from the short-term replacement power costs) whenever a Crystal River coal unit has to be cycled off in order to continue purchasing QF power.

Q. Do you have significant confidence in your conclusion?

A. Yes, this example clearly shows that, using plausible assumptions, the cycling cost of a coal unit results in a negative avoided cost even without considering the replacement power subset of costs. Again, the exact magnitude may be difficult to predict, but the direction of the impact necessarily will be negative. In this example, the cycling cost

for Crystal River 2 exceeds the avoided fuel cost by a factor of five. It would be necessary for that unit to be cycled off for more than 30 hours in order for the avoided energy cost to approach the cycling costs attributable to a coal unit hot-start, but it is obviously not plausible to expect the minimum load conditions to persist for such an extended period of time.

Q. Can you demonstrate the negative avoided cost impacts of cycling a coal unit in lieu of curtailments by looking at actual minimum load experience?

A. Yes. For each of the days on which curtailments have been required, we performed system operating simulations using the Unit Commit computer model which is utilized routinely to plan the daily dispatch of Florida Power's system. In each instance, we find that negative avoided costs would have been incurred if we had not called for curtailments.

Q. Please describe these simulations.

A. First, we selected as a "Base Case" the Company's after-the-fact avoided cost billing runs for each of the days in question. This case shows actual loads and costs as they were incurred <u>with</u> the required QF curtailments. Next, we developed a "Change Case" which varied the Base Case in one discrete way to simulate what reasonably might have happened if Florida Power had not curtailed the QFs, but instead cycled off one or more of the Crystal River coal units. The discrete change

was to add back the curtailed QF volumes thereby reducing the amount of load served by the Company's own generation. In other words, the Change Case simulates Florida Power's system operation without curtailments.

Q. What did the Unit Commit simulations show?

A. The results of the simulations are summarized on page 1 of my Exhibit No. 7 (HIS-3). For every curtailment event, the Change Case shows that Florida Power would have incurred negative avoided costs had it not curtailed the QFs in accordance with the Curtailment Plan. The negative impacts ranged from over $2,000 to more than $40,000.

Q. Do the Unit Commit simulations include all of the cycling costs you described earlier?

A. No, they do not reflect all of the unit impact costs discussed by Mr. Lefton, and because they do not, they understate the magnitude of the negative avoided cost impacts. The simulations only reflect the effects of unit start-ups, short-term replacement power costs and a fixed charge for unit maintenance.

Q. Are there still other costs that may not be reflected in the Unit Commit simulations?

A. Yes. One good example is the lost opportunity to make Broker sales of energy during the day following a minimum load period whenever a coal unit that is cycled off to match the falling load thereby becomes unavailable later in the day. It is difficult to quantify such costs in

advance, but it is not hard to understand how this can occur. When a coal unit is cycled off, the remaining units are forced to operate at higher capacity factors, thereby reducing or eliminating the option to market available coal capacity.

Q. Have you examined the actual curtailment events using any other method to verify that negative avoided costs would have been incurred if curtailments had not been ordered?

A. Yes. As additional confirmation of the existence of negative avoided costs, we examined each of the first seven curtailment events using manual cost calculations.

Q. What were the results of this analysis?

A. The results corroborate the conclusions drawn from Unit Commit. Based strictly on coal unit start-up costs, negative avoided costs would have existed for each of the seven events. The negative avoided cost attributable to start-ups ranged from approximately $2/MWH to $85/MWH and averaged $13/MWH for the seven events. The derivation of these costs is shown in Part A on page 2 of my Exhibit No. 7 (HIS-3). Supporting information for these results is included on page 3 of Exhibit No. 7 (HIS-3).

Q. Did you examine the likely effect of replacement power costs?

A. Yes. Even though the avoided costs would have been negative without considering replacement power costs, we went on to assess the

potential exposure to replacement power costs in addition to unit start-up costs. The resulting estimates of negative avoided cost including both unit start-up costs and an expected value of replacement power cost as shown in Part B ranged from $6/MWH to $122/MWH and averaged $22/MWH for the seven events. On average for the seven events, the incremental effect of replacement power cost drives the avoided cost negative by an additional $9/MWH.

Q. Why do you refer to the negative avoided cost impacts of replacement power as "expected values"?

A. We know that start-up costs are incurred every time that a unit is cycled off. On the other hand, the incurrence and extent of any replacement power cost would depend upon the particular circumstances that would have been encountered if the curtailments were not made. The major uncertainty is the length of time that a baseload unit would have been unavailable to follow load because it had been cycled off. In order to account for this uncertainty, we constructed a set of proxy restart scenarios which assigned a cost and probability to each alternative to determine when a coal unit would be expected to return to service. Summing the product of cost and probability for all alternatives produces an expected value for this event that captures the effect of uncertainty.

Q. What was the basis for your assumptions as to how long it may take a coal unit to return to service after being cycled off?

A. The assumptions regarding coal unit performance are based on actual operating experience with Crystal River Units 1 and 2 during 1994, which included 38 events where one of these units was returned to service after being cycled off. It has been assumed in this analysis that the coal units would return to service after being cycled off during a minimum load period with performance and reliability equivalent to that experienced for these units during 1994.

Q. Did your manual calculations also estimate the effect of unit impact costs other than start-up costs?

A. Yes. As a final step in this analysis, unit impact costs were included using the lower end estimate of $30,000 for a cycling event. Recognizing that start-up costs were included in Part A, only the balance of unit impact costs were included in Part C to arrive at a total unit impact cost of $30,000 for each cycling event. When these costs were included, the total negative avoided cost ranged from $29/MWH to $257/MWH and averaged $60/MWH for the seven events.

Q. What conclusions do you draw from the studies discussed in this section of your testimony?

A. The studies conclusively demonstrate that negative avoided costs would have been incurred if curtailments had not been ordered for each of the seven curtailment events studied. These results have been validated by using different methodologies (Unit Commit and manual cost calculations) as well as by analyzing the components of negative

avoided cost separately and in combination. Although the magnitude of negative avoided cost will depend upon a variety of variables which cannot be measured precisely in advance, the Company can predict with a high degree of confidence that negative avoided costs will be incurred whenever it is compelled to cycle off one of the Crystal River coal units in order to continue purchasing power from QFs.

The FERC rules and this Commission's rules contemplate this kind of forward looking method of reasonably predicting the incurrence of negative avoided costs. Based upon such reasonable expectations, QFs are to be given notice in advance of the event that they should cease deliveries in order to avoid the conditions that would give rise to the predicted negative avoided cost. Therefore, the Curtailment Plan appropriately calls for QF curtailments before the Crystal River coal units are forced to shut down. If curtailments occur as anticipated, then an after-the-fact analysis should show that the Curtailment Plan operated successfully to avoid the predicted negative cost impact. The studies discussed above demonstrate that the Curtailment Plan has met this criterion for each and every actual event subjected to after-the-fact analysis.

VII. THE OBJECTIVES OF FLORIDA POWER's CURTAILMENT PLAN

Q. Having characterized the nature and estimated scope of the minimum load problem, please explain how the Curtailment Plan strives to address that problem.

A. Perhaps I can do that best by restating the purposes and goals articulated in the Plan itself. The Curtailment Plan is a document designed primarily to provide instruction and guidance to the Company's operating personnel when the need to address minimum load conditions arises. In the process, it affords notice to this Commission and to the affected QFs of the measures which the Company intends to take in these circumstances. It is an operating tool -- not a rigid set of irrevocable rules meant to hamper sound operator discretion.

The Curtailment Plan was intended to establish a set of working guidelines and priorities which:

- address minimum load conditions in an efficient, operationally sound and cost-effective manner;
- comply with outstanding contracts and regulatory requirements;
- are compatible with applicable NERC, SERC and FCG criteria;
- operate in an equitable manner to Florida Power and all QFs from whom the Company purchases power;
- will be known in advance and readily understood by system operating personnel and by affected QFs;
- will be relatively uncomplicated to implement whenever the need arises; and

- contain sufficient detail to provide meaningful operational guidance while remaining flexible enough to accommodate changing generation and load conditions over time.

VIII. THE PRINCIPLES UNDERLYING THE PLAN's CURTAILMENT PRIORITIES

Q. Mr. Charles J. Harper's testimony describes how the Curtailment Plan works, but would you please explain the basic principles which the Company applied in determining the Plan's curtailment priorities.

A. An overriding principle is that the Curtailment Plan should achieve equity and fairness while being capable of efficient administration by the system operating personnel. In addition, there are at least four more key principles.

First, the Plan recognizes the principle that the Company will, as I have already testified, exercise efforts on an ongoing basis to limit exposure to minimum load emergencies and thereby attempt to minimize the QFs' exposure to curtailments.

Second, when curtailments nonetheless become necessary, the Plan calls for the Company to first curtail its "as-available" energy purchases, including amounts in excess of QF Committed Capacities and other amounts purchased on an as-available basis. This Commission's rules recognize the principle that as-available energy sales carry no "assurances as to the quantity, time, or reliability of delivery." Rule 25-

17.0825 F.A.C. Likewise the Curtailment Plan recognizes the lack of firmness of as-available energy.

Third, the Plan operates from the principle that certain QFs who have voluntarily agreed in writing to follow specific output reduction plans already have assisted greatly in Florida Power's overall efforts to address a significant operational problem. As a result, it would be unfair to require still greater interruption of deliveries from these QFs until after the remaining QFs have been called upon to bear their fair share in solving this problem. Based on this principle, the Plan directs the Company's system operating personnel to look to the remaining QFs to curtail a specified portion of their firm Committed Capacity amounts before returning to the QFs with pre-arranged output reduction plans for more interruption of energy deliveries than initially made pursuant to those plans.

Fourth, the Plan endeavors to fairly apply the additional principle that the percentage reduction initially applicable to QFs who have not negotiated a specific output reduction plan should be high enough to make a meaningful contribution to the excess generation "solution," but not so high as to unduly penalize or burden these QFs. The Plan uses a 50 percent reduction from the Committed Capacity amount for this purpose. The across-the-board reduction of up to 50 percent was selected as an amount which (i) shares the burden of curtailments in a roughly proportionate manner; (ii) is compatible with existing contracts

and this Commission's rules; (iii) is consistent among the affected QFs; (iv) is administratively convenient to administer when system dispatchers are called upon to make immediate operating decisions; and (v) appeared as if it would avoid unintended problems relating to emission standards, thermal host requirements for cogenerators or other regulatory conditions. I should add that the Plan invited any QFs who might have unique operational problems from the 50 percent reduction level to bring those problems to the Company's attention so that an alternative load reduction plan could be considered.

Q. Are these principles reflected in the curtailment priority classifications set forth in Appendix B of the Curtailment Plan (Exhibit No. __(RDD-1)?

A. Yes. Applying these principles, the Company developed three curtailment classifications as shown on Appendix B. Group A includes all QFs that have agreed in writing to follow specific output reduction plans. Group B consists of those of the Company's firm QF suppliers that have not specified particular output reduction plans in writing. Group C includes the Company's as-available energy purchases which (i) are made under the Company's Rate Schedule COG-1; or (ii) exceed the firm Committed Capacity under a negotiated power purchase contract. Mr. Dolan has updated the Appendix B groupings in his Exhibit No. __(RDD-4) to reflect the current status of the negotiated output reduction plans.

Q. Before leaving your discussion of the Curtailment Plan, would you please comment on the principles underlying the Plan's compliance procedures?

A. Certainly. I will start by saying emphatically that I hope no compliance measures ever will have to be invoked. Throughout our efforts to deal with the minimum load problem, the Company's goal has been to achieve cooperative assistance from our QF suppliers. This has been evidenced by the Company's significant efforts to negotiate voluntary output reduction plans, the repeated attempts to solicit input from QFs, and the very substantial generation reductions which the Company itself will accept in order to mitigate QF curtailments. Moreover, I agree wholeheartedly with the statement in the Curtailment Plan (Exhibit No. __/__(RDD-1) at page 28) that:

> The Company anticipates that its NUG suppliers will appreciate the need for a coordinated curtailment program, and that all of the affected NUGs will follow the instructions issued by the system operating personnel pursuant to this Generation Curtailment Plan. Such cooperation should be expected as a matter of prudent operating practice....

Q. In the event that your expectations are not entirely correct, how does the Curtailment Plan deal with the compliance issue?

A. The Curtailment Plan recognizes that perfect compliance at all times may be unattainable. Even the Company cannot always achieve a precise targeted megawatt output level for all its units. The Plan acknowledges that there will be small errors and that marginal non-compliance will be tolerated. In most cases, the small errors will be

remedied by making small adjustments to the curtailments required of other QFs. The expectation is that this kind of marginal non-compliance will be transitory and should balance out over time.

A different situation exists, of course, if a particular QF significantly or repeatedly fails to comply with the Curtailment Plan. In this instance, that QF is unfairly leaning on other QFs to accept the curtailment shortfall. The Plan seeks to avoid inequitable effects, but it cannot anticipate and protect in advance against intentional or material non-compliance.

The Company expressly reserves the right to withhold payments for energy delivered in amounts not in compliance with the Curtailment Plan, to assess additional Company costs against the QF and to pursue any other legal or equitable remedies in the event of non-compliance. In addition, in the event of material or repeated instances of non-compliance, the Company reserves the option to physically interrupt deliveries from the QF or to refuse schedules from intervening utilities if the QF is not directly interconnected with Florida Power.

Q. Will physical interruption of deliveries be used as a remedy without further notice to the Commission?

A. No. Although any non-compliance may adversely affect the Company and/or other QF suppliers, Florida Power would prefer to give any non-complying QF a reasonable opportunity to cure its non-compliance. I

will repeat again that the Curtailment Plan attempts to resolve difficult problems as equitably as possible. Therefore, before the Company initiates any physical disconnection, it will first provide written notice to the QF and to the Commission and will provide for a reasonable cure period.

IX. QF INPUT INTO THE CURTAILMENT PLAN AND RELATED ISSUES

Q. Did the Company solicit input into the Curtailment Plan from affected QFs?

A. Yes, it did. Early in 1993 Florida Power began discussions with its QF suppliers explaining that minimum load problems were anticipated, that curtailments might be required under Rule 25-17.086, and that the QFs' assistance in working toward mutually acceptable procedures would be appreciated. As evidenced by the various negotiated output reduction plans described by Mr. Dolan, the Company's efforts to approach the problem cooperatively continued with some success up to and even after the filing of the Curtailment Plan.

The Plan itself took considerable time and effort to develop and was not completed until shortly before the October 12, 1994 filing date with the Commission. It was, nevertheless, imperative to distribute and file the Plan in a timely manner so that it could be implemented as soon as October 15, 1994, when the Company expected to begin experiencing its first minimum load emergencies. The Company distributed the

Appendix C curtailment procedures to all affected QFs on October 3, 1994, and invited interested persons to an open-house discussion of the Plan on October 7, 1994 (a copy of the Company's invitation letter is included in Exhibit No. 7 (HIS-3)). Approximately 30 QF representatives attended that meeting and many questions and concerns were aired. In addition, the Company invited and received further written comments on the Plan and mailed out additional explanatory materials after the October 7th meeting.

Following the meeting, the Company continued to discuss output reduction plans with a number of interested QFs. As Mr. Dolan's testimony makes clear, those efforts succeeded in moving two more QFs from curtailment Group B into Group A. Also, the Company carefully reviewed the written follow-up comments and considered whether responsive changes to the plan could be made. One such change was the addition of footnote 6 at page 29 of the Plan to acknowledge that individual QFs might prefer to arrange different outage sharing agreements among themselves and that the Company generally would not object to such alternative arrangements as long as the Company can depend upon assured output reductions and the arrangements are otherwise feasible to implement.

The Company was and still is willing to work cooperatively with its QF suppliers to achieve equitable and effective procedures for operating the system in minimum load periods.

Q. Mr. Harper's description of the events that occurred on October 18-19, 1994 indicates that several of the Company's units -- specifically Anclote 2, Bartow 2 and the University of Florida unit -- were not cycled off during that minimum load emergency because of temporary equipment problems. How can those decisions be reconciled with the instructions provided in the Curtailment Plan?

A. As I have explained, the Curtailment Plan is designed to achieve fairness and equity, while simultaneously ensuring safe, reliable and economic operation of the electric system. While the Plan attempted to narrow the need for dispatcher discretion, it is neither possible nor prudent to remove all elements of judgment and still ensure that the system is operated soundly. Thus, while the Plan lays out specific procedures and expresses the Company's expectations of how the system will be run under normal conditions, it also recognizes in very clear terms that the stated procedures will not be construed as hampering the day-to-day decisions of the Company's system operating personnel. Ultimately, the system operates reliably and economically because of the informed judgment of our highly experienced operating personnel.

The decisions not to cycle off Anclote 2, Bartow 2 and the University of Florida unit on October 19, 1994 for sound operational reasons therefore were consistent with and in the furtherance of the Curtailment Plan's objectives. As the procedures specified in Appendix C to the Plan acknowledge, the Plan itself allows for necessary exceptions to be

made from time to time, so long as they are fully documented at the time.

It is significant to note the temporary nature of these equipment problems. These problems at Anclote, Bartow, and the University of Florida unit have been corrected.

Q. Mr. Harper's testimony also notes that several QFs who were asked to curtail their output on October 19, 1994 stated that they were unwilling or unable to do so. How do you respond to these concerns?

A. I believe that Florida Power should attempt to be responsive to the QF's legitimate operational problems, just as it is with respect to its own units. If a QF is experiencing a temporary, uncontrollable equipment problem that prevents it from reducing output without tripping off-line or causing other physical damage, then I would expect the system operating personnel to consider excusing that unit from the Curtailment Plan on that particular occasion if they would do so with respect to a similar problem on a Florida Power unit. This judgment should be made on a non-discriminatory basis.

This does not mean that all QF requests to be excluded from curtailments will be accepted. I am referring to non-chronic, mechanical problems of the type that would prevent cycling of a Company-owned unit. Moreover, if the problem is reoccurring, it will have to be addressed in other ways, since one QF's non-compliance with the

Curtailment Plan means that other QFs must share the impact of the non-compliance. As I testified earlier, the Company remains willing to discuss these other types of problems with any affected QF in an effort to achieve a mutually satisfactory solution.

Q. In order to accommodate a limited measure of flexibility to handle temporary QF operating problems, are any changes to the Curtailment Plan required?

A. No. Although the Curtailment Plan does not specifically carve out any exceptions, it does, as I previously explained, contemplate a measured degree of discretion by the system operating personnel. I view temporary but significant QF operating problems of the type I described as falling within that band of discretion. As I have also stated, equity and fairness are fundamental objectives of the Curtailment Plan. Therefore, after evaluating the events that occurred on October 18-19, 1994, I instructed the appropriate personnel at Florida Power's Energy Control Center to consider these kinds of temporary QF operating problems as if they were problems on the Company's own equipment and to act accordingly. They also have been instructed to document any resulting exception to the normal curtailment practices that otherwise would have been followed under the Plan. Any persistent problems will have to be handled on a case-by-case basis.

Q. Does that conclude your testimony, Mr. Southwick?

A. Yes.

Q (By Mr. McGee) Mr. Southwick, would you please give us a summary of your testimony.

A Yes. My testimony begins with the definition of a minimum load emergency is a situation in which a utility's total system demand falls to such a low level that the minimum generation input into the system exceeds the load.

This is significant in that under such a condition a utility can no longer match its generation and load, which would be a violation of a fundamental principle of utility operation that generation must equal load at all times.

With the addition of over 1,000 megawatts of QF facilities added to Florida Power's system, we're now into a situation where sometimes, given certain combinations of events, we can find ourselves approaching a minimum load emergency. This typically would occur during the early morning hours of spring, winter or fall when the weather is mild. Because of this, Florida Power has taken several actions. We have worked on our baseload coal units to allow them to reduce their loadings from previous levels, and we have worked with several of our QF suppliers to set up agreements under which they will voluntarily reduce their outputs during low load periods.

In addition, since my direct testimony was filed, we have successfully negotiated an agreement with the Southern Company that will significantly reduce the impact of the

minimum take requirement of Southern UPS contract. And I've included a discussion of this in my rebuttal testimony.

While these efforts will minimize the occasions of minimum load problems, with the operation of only our Crystal River baseload units and QFs, we will still occasionally face the situation of excess generation. At that point, if we cannot sell power off-system, we have only two choices left: To further reduce generation by shutting off a baseload coal unit or reducing the level of QF purchases. Of these two alternatives, the shutting off of a baseload coal unit results in higher cost to the company and the ratepayers.

These are precisely the operational circumstances both FERC and this Commission had specifically in mind when adopting rules that authorized an exception to the utility's obligation to purchase QF energy. These higher costs incurred in lieu of curtailing QF generators are what is referred to as negative avoided cost.

In my testimony I've demonstrated using three different methods that these negative avoided costs will occur whenever a baseload coal unit is shut off in lieu of curtailing QF generation.

To avoid this situation and the resulting higher cost to the ratepayers, we developed the curtailment plan that is the subject of this hearing today. This plan is based on the overriding principle of equity and fairness, while being

capable of efficient administration by the system operating personnel.

In addition, other key principles include that we will make every reasonable effort to minimize the number and magnitude of curtailing events. Also, when curtailments still become necessary, we will first curtail as available energy purchases. Then before we turn to those QFs who have voluntarily agreed to perform reductions in their committed capacity during low load periods, we will first ask the others to contribute, and their contribution needs to be meaningful to achieve fairness with those who have made voluntary reductions.

Even though the Commission's rules do not require the development of a formal plan, the Company nevertheless has developed a plan and submitted it for Commission approval so we can rely on it with confidence. The plan is fair, reasonable and practical, minimizes the need for curtailments and avoids the incurrence of higher costs for Florida Power ratepayers.

MR. McGEE: We tender the witness for cross examination.

CHAIRMAN CLARK: Ms. Walker.

MS. WALKER: No questions.

CHAIRMAN CLARK: Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q First of all, Mr. Southwick, when you use the expression "minimum load emergency," you refer to a situation in which the Company has to take some action to balance generation and load within tolerances; is that correct?

A The Company continually has to take action to balance generation and load. It's a continuous thing. It has to be that way all of the time. High loads, low loads and everywhere in between.

Q Well, when you use the minimum load emergency, use that term, are you talking about a situation where it has to consciously make some decision to restore balance?

A Minimum load emergency is defined as a situation where the generation would exceed the load, and that's a situation we have to avoid getting ourselves into.

Q By taking some appropriate action to restore the balance? Correct, sir?

A To take appropriate action to maintain the balance, to prevent it from occurring.

Q All right. In your opening you said you have to maintain an identity between generation and load at all times, but to be precise isn't it true that the system incorporates some protective measures to withstand a threshold level of imbalance?

A Could you be more specific, please?

Q Well, for instance, the governors that are part of the design and operation of any generating plant.

A Yes. There are ways in which we are able to do what we do, and one of those ways is a certain amount of generation on line has to be under what we call automatic generation control, which allows those generators to follow the load and thereby maintain that balance.

Q And you refer in your direct testimony to some NERC standards and guidelines with which the Company must comply, do you not, sir?

A Yes.

Q Don't those guidelines and standards contemplate that Florida Power may be above or blow an identity by 30 megawatts?

A Yes, you're allowed to operate within a recognized bandwidth, which our bandwidth is in that order of 30 megawatts.

Q Inadvertent energy is a fact of life in the electric energy business, isn't it?

A At all times every company is slightly above or blow its exact match and it goes back and forth and that's one of the NERC criteria. And during that time you're either slightly over or slightly under. The nature of the interconnected grid is such that it all balances out and the

highs and lows will offset at any point in time, but there is always a slight mismatch. It's when those slight mismatches get too large that the big problems start to occur.

Q And that requires that you take some appropriate action, right?

A We always have to take action to make sure that the mismatch stays slight and within the approved bandwidth that's allowed.

Q I want to change subjects now. We just heard from Mr. Lefton who sponsored some testimony regarding unit impact costs.

And with respect to the calculation of the costs Florida Power Corporation would incur if it cycled a baseload unit off-system to manage an imbalance as opposed to curtailing, in certain of your calculations you incorporate some of those impact costs; is that correct, sir?

A Did we include the calculation of cycling cost in some of our calculations?

Q That's the question.

A Yes. Yes, we do.

Q You would agree with me that those unit impact costs reflecting future plant additions, changes in depreciation or future maintenance are in the nature of long-term costs, Mr. Southwick?

A Some of them are.

Q Is it true that Florida Power Corporation does not presently use such long-term costs as the incremental impacts of creep and fatigue in some of its short-term operational decisions?

A No. Our short-term operational decisions are generally driven by more short-term costs.

Q As an example, when you prepare a generation commitment, you do not look at those long-term costs, do you, sir?

A Not all of them.

Q You don't look at creep and fatigue, do you?

A No, we do not.

Q When you prepare the generation dispatch decisions you don't look at creep and fatigue over time, do you?

A Not in -- you said generation dispatch decisions; not in a operating sense we do not, no.

Q Just when you want to curtail, correct?

A When we curtail, as my testimony clearly showed, we don't have to look at those costs to demonstrate negative avoided cost. We do it with strictly our short-term out-of-pocket costs, such as start-up costs and energy replacement cost.

Q Does that mean --

A Those are what we use in our unit commit program. That's what we've demonstrated here.

Q Does it follow, sir, that we should ignore those schedules that include the effects of creep and fatigue in your calculation of the base case?

A No, I don't think it follows that at all. What it shows is we don't need those costs to demonstrate negative avoided cost, but I think it's proper to recognize that even above and beyond the short-term costs there are, in fact, even other costs.

Q Well, you want to recognize it for this purpose but you just testified that you don't recognize the same costs in other short-term operational decisions; is that correct?

A We don't need to get the same answer.

Q Do you not recognize them, sir? Question is do you take them into account?

A I've already said we do not.

Q We've talked about generation commitment and generation dispatch. When Florida Power Corporation has to make the decision whether to increase the output of one of its baseload units in order to make a sale off-system, does it incorporate the costs of creep and fatigue over time as a component of its cost of power?

A No.

Q And is that because in your opinion such a situation calls for the inclusion of only short-term costs, that is real hard dollar costs that you can point to that come out of your

pocket right now?

A Yes. And but those are the costs -- because those are the costs that are immediately paid for and in turn paid for by the ratepayers.

Q Would the example of an off-system sale be an example of an operational decision, Mr. Southwick?

A Yes.

Q Would the decision to cycle off a baseload unit or curtail be an example of an operational decision, Mr. Southwick?

A Yes.

Q Now, the word "cycling" has been used a lot in the proceeding. Would you agree that incorporates both up and down types of operations as well as on/off cycling?

A It probably has. It's a word that I don't think has a real clear standard definition in the industry, and I think our use of it, unfortunately, gets a little sloppy. But I think we need to make sure generally we are clear what we're talking about. I'm not sure that we always are.

Q Well, you're familiar with the term "load following cycling," are you not, sir?

A Well, I know what load following means. To add the word "cycling" to it is probably where some of the confusion might start.

Q Is it true in order to match generation and load

it's necessary for the Company to vary the output of its units, including its baseload units, in order to track the changes and demand on the system?

A Yes. A certain number of units have to be on load control to be able to follow load.

Q And does that require that the output of the unit vary over time?

A Yes, it does.

Q To your mind is that an example of the kind of cycling that we have been talking about in this proceeding?

A I think we have been talking about all different kinds of cycling.

Q Yes, sir, including this kind?

A It would be, yeah.

Q Would you agree that Florida Power Corporation would have to cycle its units to follow load whether or not it had cogenerators on its system?

A Using that definition of cycling, we would have to use -- some units will have to always be on load following.

(Pause)

Q I'm going to change subjects on you again, Mr. Southwick. I want to propose to you this hypothetical situation.

I want you to assume that the company's baseload units are operating at minimum levels, and the cost of that

operation -- the cost of operating is $800,000. I want you to assume that at the same time there is an excess generation of 600 megawatts, but that the Company can sell that 600 megawatts at a dollar per megawatt-hour and does so. Would you agree that in that situation the company's units continue to operate at minimums at a cost of $800,000?

A I have a lot of problem with that hypothetical.

Number one, we're not allowed under FERC regulations to sell power at a cost less than our incremental cost, and to sell it at a dollar a megawatt-hour is clearly below our incremental cost. So number one, we couldn't do it for that reason.

Number two, even if we were to, the difference between the dollar that we sold it for and the actual costs that we had to generate it at, that difference would be passed through as an increase in our costs to our ratepayers, which would totally violate the principle of ratepayer neutrality, which is the whole premis of PURPA.

Q Mr. Southwick, we'll get to all those points in good time, sir, but I want you to accept for the purpose of the question these assumptions.

A Well, it's difficult to accept assumptions that don't make sense. But even still, to answer your question if I remember it correctly, the cost of our generation in that example, if you only looked at the fuel cost, which stayed

$800,000, but our total cost --

Q Excuse me, sir, please just answer the question as posed to you.

A Okay. Did you say --

MR. McGEE: The witness must be given the opportunity to finish the question.

(Simultaneous conversation.)

MR. McGLOTHLIN: I think he's answering a different question. You'll have your opportunity on redirect. He's straying from the assumptions and I'm entitled to an answer to the question.

A Okay. Say it again.

Q All right. This is the hypothetical.

Your generators are operating at minimums and incurring cost of generation at $800,000. At that time there's excess generation that you sell off-system at a dollar per megawatt-hour, 600 megawatt-hours, so that there's now a balance of generation and load.

Would you agree, in that situation, that your generators continue to operate at minimums so that the status of the generators have not changed?

A That's correct.

Q And would you also agree that the cost of generation, $800,000, has not changed?

A That's correct.

Q Would you agree that based on the PURPA definition of negative avoided cost, in that situation FPC would not have incurred negative avoided cost as a consequence of accepting to deliver so many QFs on line at the time? (Pause)

A I would agree. (Pause)

Q In your prefiled testimony, Page 8, at Line 11 you paraphrase the preamble to the PURPA regulations and there you say that the baseload units in a certain situation might not be able to ramp up in time. Do you see that statement?

A Yes.

Q Would you agree that whether baseload units are or are not able to ramp up in time would be a factual determination based on circumstances in a given situation?

A Yes.

Q Now, if you will turn to Page 21 of your testimony.

A Okay.

Q Give me a moment and I'll do the same. At the bottom of Page 21, Mr. Southwick, you say "Florida Power has determined that it would incur unacceptable operational risk and costs if it cycled these units off entirely." Referring to your baseload coal units. "These units are needed on the system for Automatic Generation Control and load following purposes." But at the bottom of Page 22, would you agree with respect to the column identifying end requirements for either security or automatic generation control, the entries for

Crystal River 1 and 2 are zero respectively?

A Yes.

Q Now, Page 27 of your prefiled testimony. At Line 18 you make this statement: "So long as the total cost to take a unit off-line exceeds the fuel savings that result from not running the unit, the net economic effect of cycling the unit off must be an increase in net system cost or a negative avoided cost." Is it true that summarizes the methodology you've employed in your evaluation of avoided costs with and without QFs?

A Yes.

Q And your comparison there is to identify any start-up costs associated with bringing a unit back and compare that with any fuel that's not burned as a consequence of taking it off line; is that correct?

A I believe it includes start-up costs and replacement costs.

Q All right. Would you agree with me that any start-up costs would be incurred after the minimum load situation has passed?

A It may or may not.

Q I couldn't hear your answer.

A It may or may not. It depends on when you started up the unit.

Q Well, would you agree depending on circumstances it

may occur in periods following the alleviation of the minimum load situation?

A It could.

Q Would you agree that replacement costs may occur following the minimum load situation?

A It could.

Q Would you agree also that replacement costs may be less expensive than the operation of the baseload unit that is cycled off? (Pause)

A It's not likely.

Q Would you agree that when a baseload coal unit is operated at minimums that it's one of the least efficient modes of operation --

A Yes.

Q -- concerning its heat rate?

A Yes.

Q In that situation is it possible that a replacement unit could come on more efficiently than the minimum operation of the baseload unit?

A I think it's possible, yes.

Q In that event would the replacement cost be more economical than the baseload unit cost?

A It would be at some points in time, yes.

Q All right. In your evaluation do you include any O&M?

A You mean other than fuel?

Q Other than fuel, yes.

A In some of the evaluation we did; in some of it we didn't. We looked at replacement fuel cost, we looked at start-up fuel costs and we looked at other costs and the other costs clearly include O&M.

MR. McGLOTHLIN: If I could just walk to the easel a second. (Pause)

Q (By Mr. McGlothlin) Can you see this, Mr. Southwick?

A Yes.

Q I used this yesterday in my opening statement at which time I experienced a little inadvertent energy and ran over in excessive argument.

But to make a point that some of the costs that you included in your comparison, and we talked about start-up costs and replacement costs, depending on circumstances may incur during the minimum load period, but could very well incur after that load period has passed; is that correct?

A Some of them could, yes.

Q Would you agree with me that when you compare -- let me back you up.

And when you perform what is called a base case, that is the calculation of a cost the company would incur to meet the load with its own generation, you include start-up

costs and replacement costs whether they are incurred here or there; is that correct? (Pause)

A You said in the base case?

Q Yes.

A The base case in my example in my testimony? I'm not sure I'm with you. Are you speaking generally or are you speaking specifically?

Q When you -- I'm talking about your methodology in general, and your comparison of the cost to meet the load with your own generators compared to any -- to continue to receive from QFs. Maybe I misspoke.

But in your comparisons do you incorporate -- when comparing, when calculating the costs of cycling the unit off, do you incorporate start-up costs and replacement costs regardless of the time period they occur?

A Yes.

Q And that's because you have utilized a unit commit run that includes a 24-hour component; is that correct? The full day of the curtailment event?

A Well, in the examples that we utilized the unit commit run it would have been captured in that 24-hour period. In the other examples, we captured it in other ways. But in every case we captured it.

Q Now, when you do the change case and calculate the costs of generation if you had continued to receive QF

deliveries, is it true you add back the curtailed QF generation only during the hours of the curtailment then?

A Add back to the QF?

Q Yes.

A What do you mean add back?

Q Incorporate their generation in the scenario, the curtailed generation.

A The rest of the time they weren't taken out. There was nothing to add back. So, yes, it would be added back during the period they were taken out.

Q And only that period, correct?

A That's the only time it was taken out.

Q Okay. Would you agree that methodology values the QF generation only during the period of curtailment?

A No.

Q Why not?

A Because the rest of the time their model is on line running and generating their power. When they are not taken out, they are there.

Q In your profiled testimony you describe some manual calculations you made as one approach to comparing the costs with and without cogeneration. Do you recall that?

A Yes.

Q Isn't it true that some of those values had to use a unit commit program as a starting point?

A I don't believe so.

Q For instance, the start-up costs of a coal unit, is that one of the entries in your manual calculations?

A Yes.

Q Was that taken from unit commit data?

A It's not taken in a unit commit data. It's taken from a formula that represents what start-up cost is. That same formula that represents start-up cost is used in unit commit.

Q I see. You also utilize some what you describe as proxy calculations for the replacement cost; is that correct?

A Fuel replacement costs?

Q Yes.

A I believe so.

Q You did?

A Let me be sure I understand the question. Could you be more specific? Are you looking at my Exhibit 3?

Q I think it's page -- let me find the reference.

A If I understood the question, which I believe the numbers are shown on Exhibit 3, Page 3, which unfortunately is not a numbered page, the avoided energy cost used in that manual calculation is shown on the fourth line down at $15.38, and as it says in Footnote 4, that was the average energy price during midnight to 6 a.m. for the first five curtailment days. That's actual data.

Q But you refer to it in your testimony at Page 38, Line 18. You say, "we constructed a set of proxy restart scenarios which assigned a cost and probability to each alternative to determine when a coal unit would be expected to return to service."

So you prepared those proxy calculations when you performed the manual calculations of comparing the costs of generation with and without QF deliveries; is that correct?

A Yes.

Q Isn't it true that when you make analogous decisions regarding the units you're going to commit prospectively, utilize the start-up times that are incorporated in the unit commit program?

A Well, in the daily planning, every unit has certain characteristics that are recognized, and those unit characteristics are recognized in everything that we do, including unit commit. It's not that unit commit tells us to use that data, we tell unit commit to use that data.

Q Yes, sir. Let's say your dispatcher is going about his task of preparing a commitment schedule, and among the other things he's going to analyze everything operational he needs to know to make his decision as to what it's going to cost to operate the system. On his left hand he's got these proxy calculations, on the right hand he's got his on-line commit. Which one is he going to use for that purpose?

A On a daily basis we use the on-line unit commit primarily.

But you have to understand it's not that simple because the ultimate decisions are not made by the computer, they are made by the dispatchers. And if the start-up time on the Crystal River 2, let's say, is six hours, it's a minimum downtime, and he would use six hours because that's his highest probability of the actual occurrence; that he's going to know that it may not be six hours. And if it's that critical, if the consequences of it not being six hours are of significance in his decision making, he may do something differently, and that's a judgment call.

Q Now, I think you agreed earlier that whether a baseload unit that's been cycled off returns in time to meet rising load or not would be a factual circumstance, did you not, sir?

A It either will or it won't.

Q That's right. Now, have you examined the unit commit runs that you've sponsored here to determine whether in those analyses it appeared that the baseload unit did come back and was available to meet load without the incurrence of replacement costs?

A I'd have to go back and refresh my memory on exactly when they came back and how fast they wrapped up.

Q You don't know the answer to that question?

A Not at the moment, no, sir.

MR. McGLOTHLIN: If I could have just a couple of minutes.

CHAIRMAN CLARK: It's a good time to take a ten-minute break.

(Brief recess.)

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CHAIRMAN CLARK: We'll reconvene the hearing. Mr. McGlothlin.

Q (By Mr. McGlothlin) We're almost through, Mr. Southwick, but I do want to go back to one series of questions.

I believe we established with respect to the comparisons of avoided costs with and without QFs that you sponsored, you utilized unit commit programs that analyzed a 24-hour period; is that correct? (Pause)

A Well, I actually compared three different methods, one of which was a unit commit computer-based method.

Q My question is focused --

A And you're talking only on that one of the three.

Q That's correct.

A Given that, then yes, that was based on a 24-hour period.

Q And if, for instance, a particular curtailment period lasted five hours, then the base case would calculate

the costs that the company would have incurred meeting the 24-hour period with its own generators including the five-hour period; is that correct?

A Yes.

Q Then that would be compared to a change case in which the curtailed generation would have been added back during that five-hour period, the cost calculated; is that correct?

A That's correct.

Q Then you would simply take the base case costs and subtract the change case costs to see if the avoided costs were negative or positive?

A Yes.

Q Since the curtailment period was five hours and the only piece of generation that changes from QFs in the two comparisons is for the five-hour period, would you agree that that particular analysis values only the five hours of QF generation? (Pause)

A I'm sorry, I didn't follow that.

Q Well, would you agree that since all other hours include -- in the 24-hour period -- include the QF generation in both cases, that the only adding and subtracting going on is within the five-hour period?

A No. The QFs in all of the hours they weren't curtailed were the same, so in that respect that's common to

both cases.

Q That's my point, sir.

A But the other units are moving around during the hours after the curtailment period.

Q Except for the five-hour period, the QFs are the same in both cases; is that correct?

A Yes.

Q All right. Now, the Company utilizes an unit commit program for the purpose of preparing a commitment schedule for its entire system; is that correct?

A Yes.

Q And that's typically done for periods longer than 24 hours, isn't it?

A "Typically" is not a good word. It's done for all different lengths of time; from very short-term up to as long as a week.

Q Wouldn't you agree that four days to a week is more representive of the Company's routine?

A It depends on what the purpose is.

Q If the purpose is to prepare --

A We have an on-line computer -- excuse me -- on-line unit commit computer program that's run by the dispatchers on shift for very short-term purposes, and then we have applications where we need longer look-aheads. It just depends on the situation.

Q All right. I'm not talking about any midcourse corrections. I'm talking about the routinely performed forward-looking commitment schedules prepared on a regular basis, would those be more likely to be based on an analysis of four days to a week?

A You're going to find this hard to believe but I'm not sure. I don't personally do that. And I'm not sure how long they run those for. If I knew I don't remember.

Q If you'll just accept that or assume it for the purpose of the question, sir.

A Okay.

Q If it's established that unit commit programs analyze period of four days to a week for that purpose, would you agree that the analysis would incorporate consideration of all costs and all benefits for each of the units under consideration for that entire length of time?

A Yes.

Q If the Company analyzes all costs and benefits associated with the inclusion or exclusion of its own units for a period as long as four days to a week when establishing a commitment program, wouldn't it be appropriate then for purposes of measuring the avoided cost calculation, with and without generation, to consider all of the hours that would be taken into account by unit commit for that same period of time?

A I don't believe that you'd get a different answer in this application of unit commit if you ran it longer than 24 hours, because at the end of 24 hours everything is going to have to come back together and you're going to have three, four more days that are identical in either case and the difference would be nothing.

Q Well, you and I may disagree on what the answer is but with respect to the methodology, you agree it could be done that way appropriately?

A It could be done that way. But it could be done this way, and either way would be appropriate in my opinion because I think you'd get the same --

Q Okay. You and I may disagree on what the answer is, but you agree that the methodology is appropriate?

A It could be appropriate; it's not the only appropriate way.

Q What's your qualifications?

A I think this is also appropriate. Either way would be appropriate.

Q Either way would be appropriate?

A I believe so.

Q And you believe the answers would be the same?

A I do.

Q And if the answers are different, it's not because of any inappropriateness to the methodology?

A I don't think the answers would be different.

Q But if they are, the methodology is okay?

A I'm not sure I know how to answer that.

I don't think they would be different. So you say "Well, if they are." I think this method is okay. I think that method would be okay, and if I were to learn later on that they gave different answers I'd have to reconsider my opinion. (Laughter)

Q All right. I think this has established this, but I just want to understand your question.

I believe you said in your opinion it would be appropriate to utilize an analysis of a longer period, perhaps four days to a week, for the purpose of comparing the avoided cost with and without cogeneration when looking at a decision to cycle off your own unit or to curtail; is that correct?

A That would be one appropriate way to look at it.

Q All right, sir. Thank you.

MR. McGLOTHLIN: Those are all the questions I have.

MR. WATSON: No questions.

CHAIRMAN CLARK: Mr. Wright.

MR. WRIGHT: Thank you Chairman.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good morning, Mr. Southwick.

Mr. Southwick, I'm going to hand you copies of what

have been admitted to the record of this hearing as exhibits No. 4 and 5. (Hands document to witness.)

Q Exhibit No. 4 is an interrogatory response that was averred by Mr. Harper, but he suggested if I have questions about it I should ask you, and Exhibit 5 is two of the late-filed deposition exhibits from your deposition. Apparently, they were prepared by Mr. Harper. And that's why I had them admitted as part of his -- during his testimony.

I'd like to ask you a quick question about the third page of Exhibit No. 5. I'm at the last page.

A The last page.

Q Yeah, third page not counting the cover page. That's a table that represents units that were asked to go below their minimum operating levels during curtailment events, correct? (Pause)

A I believe so.

Q That table indicates that in one instance no units were asked to go below their minimum, and in other instances up to three of Florida Power's coal units, Crystal River 1, 4 and 5, I think, were asked during the same curtailment event to go below their minimum.

My question for you is why did FPC request other units to go lower during other events there?

A I'd have to sit down and analyze each one of these in detail, Schef. I can speculate but I do not know the

answer.

For example, on 11 it says CR-1; it doesn't say CR-2. Maybe CR-2 was off-line, I don't know. Maybe there was a known reason why CR-2 couldn't go below. Maybe CR-2 was being operated on AGC at that time, which this would be totally inappropriate. It could be any one of those reasons.

If the dispatcher knew -- well, the obvious, let's say the unit wasn't even on line. Obviously we wouldn't call them and ask them to go below. Maybe there were some other reasons that he knew about; he wouldn't waste his time or their time talking about something that wasn't possible.

Q Okay. I'll move on.

In a Level 1 or Level 2 event, Florida Power's in the posture of telling QFs that they will need curtailments; that they'll need the Group As to go to their committed maximum operating levels, and at that point do you also ask for additional voluntary curtailment? Do I have that right somewhere in there?

A I'd have to go back and read the plan. I don't know if it's exactly in the plan or not, but if it's not I hope they do.

Q Okay. And if they do, does Florida Power incorporate the additional voluntary curtailments that a QF tells them they will give in determining how much curtailment to request later on in the event?

A Yes.

Q I asked Mr. Harper this question and I'll ask you.

If you know, how far in advance can you predict the likelihood that there would be a curtailment event?

A You don't know for sure until it happens. Obviously you can anticipate -- I mean, if we're going into a mild weather period in January when all of the baseload units are on line and we know the loads are going to get down fairly low, we know that the situation is approaching where we could get into a low load problem, and we'd know that several days in advance.

But, believe me, things happen very quickly as far as all the other factors other than load, and that's where the uncertainty comes in. And we could go into 6:00 or 8:00 at night thinking there's going to be -- for sure tonight it's going to happen and a unit could come down or one of the larger cogenerators could come down. This has happened. Or another company could lose a unit and we could sell them a block of power on that line. So we don't know for sure until the last minute, and some days we can get a heads-up two or three days in advance sometimes.

Q My next question relates to the interrogatory response that has been designated as hearing Exhibit No. 4.

A Yes.

Q In what I think is the second paragraph of the

answer you make the statement that you can't know the costs that will be incurred during a curtailment event or during an event with and without cogeneration in advance. Is that an accurate paraphrase of what it says there?

A It says, "FPC would note that the precise amount of costs cannot be fully known in advance because it is not until the curtailment period has been experienced and actual load levels and system conditions are known that the full extent of such costs are susceptible to determination."

Q Would it be fair to characterize that statement as saying that you can't accurately predict the costs with and without curtailment in advance?

A The plan is built on -- one of the basis of the curtailment plan and the reason for the plan is to go further to reduce our own generation would mean to shut off one of our baseload coal units and that will necessarily put us into the situation of negative avoided cost. How far -- and this is all in the testimony -- how far that negative cost is going to go is what we don't know for sure and can't possibly know until after it is all said and done and we can go back and try to piece it together, and even then it's an educated guess.

But to know exactly in advance can't be done. But to know it's going to be a negative avoided cost, we do know And that's how the plan got put together the way it did and that's what this answer is trying to address.

Q I'd like to ask you to look at your revised Page 1 of 3 of Exhibit HIS-3.

A Okay.

Q Will you agree with me that for several of these events the difference in total cost between the base case and change case is very small?

A Very small is a value judgment. We can read the numbers.

Q Well, I'll tell you, I did the arithmetic and the greatest difference I got was about 7%, and I got one as small as .44; that is forty-four-hundreths of a percent, and and another seventy-three-hundredths and another 1.1%. Do you agree those are small differences?

A I haven't done that arithmetic. The smallest number I see is $2,315.

Q On a base of $526,000?

A It's a small percentage.

Q You agree that's a small percentage?

A I think so. Of course, the point is it doesn't have to be a large number, it just has to be negative.

Q I understand that that's your position, but don't you think that if the result of less than half a percent one way, that there might be some occasions where it's less than half a percent the other way?

A Some of the numbers are bigger than that, that's the

smallest one, but, again, it's just a matter of how far are you going to go. We're going to start piling up the costs on the ratepayers and I think anything over zero is unacceptable.

Q Well, Mr. Southwick, I appreciate that that's your position, but my question was don't you think that if the difference, or the differential is very small, less than half of a percent one way, there might be some occasions where it's less than half a percent the other way?

A No, I don't think you'll find that when we shut off a baseload coal unit it's going to not go negative.

Q It appears to me that that's going to be largely because of start-up costs based on the analysis shown on your exhibit?

A It depends on the situation. It could be start-up costs predominantly or it could be replacement, but it's both; it's the sum of both either way.

Q I want to talk to you about an alternate change case, and I'll preface this with the following: I understand that it's Florida Power's position that you all cannot charge less than your incremental fuel cost for off-system sales. I understand that it's at least your belief that that's not permitted either by Federal Energy Regulatory Commission regulations or by the tariffs for such off-system sales that you all have in place. Okay.

So I want to ask you some questions about whether it

might be prudent and reasonable for Florida Power to seek to change those tariffs, and it's toward that end that I'm going to pose you an example.

Isn't it true that there is another possible change case where Florida Power could sell some off-system power, not curtail QFs and not cycle off one of its coal units?

A You mean could we assume we could sell enough off-system power so we could not cycle off coal units or curtail; is that what you're saying?

Q Yes.

A We could assume that.

Q Would it be correct that in that scenario you would not incur the start-up costs that are shown here because you wouldn't shut down a coal unit, you wouldn't incur start-up costs, true?

A That's true.

Q Okay. My question is if you can avoid these start-up costs, and it's a case where there are positive energy cost/benefits of keeping the QFs on line, wouldn't it be prudent to somehow reflect these avoided costs or benefits in the price that you charge for your off-system sales?

A No, I don't believe so.

Q Well, it seems to me that avoided start-up costs would be an incremental benefit or an avoided cost of not shutting down your coal unit, which you could do by

hypothesis, at least, by not cycling your unit off, wouldn't it be reasonable and prudent for Florida Power to seek to incorporate those direct financial effects in its rates for off-system sales?

A No, I don't agree with that and the reason I don't agree with that is because we have another alternative available to us and that is to curtail the QFs in that situation, which gives us even lower costs. And that's the lowest cost scenario; that's the ratepayer neutrality concept. To do anything other than that is going to raise the rates to the ratepayer.

Q Well, it may or may not, it depends on what price you can sell the power at, doesn't it?

A Oh, I agree, if we could sell the power at or above our incremental cost that's a good thing and that's what we try to do.

Q Let's look at the October 19th curtailment event as reported in your exhibit?

A Okay.

Q I read this as showing that there's an energy cost saving attributable to cycling off your unit, keeping the QFs on of nearly $7,700, correct?

A Yes.

Q The total cost of cycling off the unit as reported in your exhibit, however, is negative because that $7,700 is

overwhelmed by the $17,404 in start-up fuel costs. Also correct?

A Yes.

Q Okay. By doing a simple arithmetic calculatation it appears to me that we're talking about 600 megawatts in this case, 600 megawatt-hours, excuse me, and I calculated that by dividing the voided cost impact of $9,708 by the avoided cost per megawatt-hour of $16.18. Is that an accurate calculation?

A I'm sorry, Schef, you lost me.

Q I'm trying to get at megawatt-hours that are involved in that curtailment.

A Oh. So you took the 9708 and worked backwards from the 1618?

Q Yes, sir. I divided the first by the second and got 600 megawatt-hours.

A 600.

Q You're welcomed to use my calculator to verify that.

A Okay. I'll accept that for now.

Q Okay. So if you could have sold 600 megawatt-hours off-system during that event, assuming you could have done it in the hours you needed to do it, you could have avoided curtailing the QFs and avoided the start-up fuel costs, true?

A Can you say that again, please?

Q If you could have sold that 600 megawatt-hours during the curtailment event, you could have avoided

curtailing QFs and you could have avoided cycling off your coal unit, thereby avoiding the start-up costs, correct?

A Yes.

Q And I'm certainly willing to give you that if you could have sold it at your incremental cost or greater you would have done so?

A Right.

Q Now, my question is, suppose your incremental cost in an hour was, let's say, $14 a megawatt-hour?

A Okay.

Q And you could have sold that 600 megawatt-hours at $10 a megawatt-hour, I understand that it would be your position that you would not nominally have lost $4 a megawatt-hour on that sale. Right?

A Right.

Q What's four times 600?

A 2,400.

Q Okay. Isn't it true that 2,400 is less than $7,696?

A Yes.

Q Okay. So if you could have made the sale in this example at $10 a megawatt-hour, kept your units on line, avoided the start-up fuel cost, kept the QFs on line and realized the energy cost benefits of doing so, you actually would have come out to the good by $5,296, right?

A Yes.

Q And my question to you is: Wouldn't it be reasonable and prudent for Florida Power Corporation to at least consider going to the FERC to explore the possibility of modifying its off-system sales rates to deal with these kind of events; it would make your ratepayers better off.

A It could be. In this scenario that would work out and there may be a couple more down here. Now, clearly it wouldn't in the next one. Overwhelmingly it wouldn't in the next one. It might in the next one.

Q Well, I think to cut to the chase, I think --

A You're right, there are some situations where that could be right.

Q Okay. And would you agree it would be reasonable and prudent for FPC to explore that possibility?

A If I became convinced it was realistic enough to make a meaningful difference I would, yeah.

Q Okay. We've got four out of the seven events we've had you've had positive avoided energy cost benefits, you know, of cycling your unit off, and it's only because of the start-up fuel cost that the total cost has gone negative?

A That could be. It's something worth looking at, I will agree.

Q Thank you.

I want to preface my last three questions, I think, by saying that I'm not trying to pin you down to a predicted

number of curtailment events that I'm asking the PSC to hold you to, okay. I'm asking these questions as predicate, information for other issues.

Do you agree that we have probably just come through the worst period we're ever likely to experience from the perspective of Florida Power needing to curtail QFs?

A I'm not one to go so far as saying I agree it's the worst, it's one of the worst. Situations change so that the next one for some reason -- unit outages, if Panda comes on line and is not -- depending on how that arrangement works out, but I agree it's going to be one of the worst.

Q Is it possible that the total number of curtailments over the next five years may be less than 35 events? And I've got 35 by multiplying five years times the seven events we've experienced to date. (Pause)

A I think it's possible but not likely.

Q Is it possible that the number could be even lower than 35?

A It's possible.

Q That's all I have. Thank you, Mr. Southwick.

CHAIRMAN CLARK: Before Staff begins their questioning, I'd like to follow up on the examples that you and Mr. Wright were talking about. And the indication was if you could have sold it for less than the $14 --

WITNESS SOUTHWICK: If we were allowed to sell for

less under that particular situation, we might could have slightly lowered the overall cost and that would be good.

CHAIRMAN CLARK: During those same periods, do you know if anyone was buying power at costs less than that?

WITNESS SOUTHWICK: I'd have to go look at the record. That's always a problem. Sometimes in low loads nobody buys at any price.

CHAIRMAN CLARK: Okay. But you don't know for these cases.

WITNESS SOUTHWICK: I believe it's in the record. We could find it. There's a history of -- I do not know, no, ma'am.

CHAIRMAN CLARK: Okay. Go ahead, Staff.

COMMISSIONER DEASON: Let me ask a question.

In the example I was assuming you could sell at ten as your incremental cost was at 14, and there was a $4 per megawatt-hour difference times the assumed 600; you're talking about a $2,400 loss in that sense, but I think Mr. Wright's question was if there are positive fuel benefits by keeping the QFs on line that exceed $2,400, then there's an overall net benefit. Is that the way you understand the hypothetical?

Well, let me ask you this, where do the positive benefits come from?

WITNESS SOUTHWICK: Well, in that example -- let me see if I can find it here, I definitely should have tabbed

these pages -- in that example, under October 19th under the change case, the energy cost actually went down.

COMMISSIONER DEASON: That's what I'm talking about. Is that by keeping -- that's the benefit by keeping the QFs on line in terms of fuel. Where does that fuel -- where does that benefit arise? From where does it arise?

WITNESS SOUTHWICK: Well, in the base case we generated all of the electricity ourselves. In the change case we shut down the unit and took the QF power and so the figure went down. There's a potential problem --

COMMISSIONER DEASON: So the benefit is by keeping the QF on line.

WITNESS SOUTHWICK: Yes, sir. In the real world we have to pay that QF for that energy that he would have delivered. And the way the rules work, he actually would have been paid way more than $10. And that figure isn't included in this 873 and that's why I wouldn't rush to agree with Schef that it would always work out; we've got to work it through. Because it still could increase the charge to the ratepayer. These costs here are just Florida Power's fuel cost and the total cost is what we have to pay. This doesn't include what we pay for the QF power.

COMMISSIONER DEASON: But if that difference, in this hypothetical, in that difference, if that difference is more than $2,400, it would be beneficial for you to keep the

QFs on line and to sell and keep your baseload on line, and sell the excess, the 600 megawatt-hours at 10, assuming you could sell at 10.

WITNESS SOUTHWICK: In that particular case, yes.

COMMISSIONER DEASON: But now, it seems to me there's some risk in that you don't know what the market is going to be. You don't know if you can sell at 10. You have to make the decision before you may know if you can sell at 10 or whether it would have to be at 11 or 12 --

WITNESS SOUTHWICK: You'd have to have arranged the sale in advance and it would have to be firm for the entire evening. Couldn't do it on the broker, because the broker is uncertain in every hour; it's subject to going away. So in this case to make that work you'd have to know in advance you've got the deal wrapped up with somebody.

COMMISSIONER DEASON: But you do agree in that case if you knew you could sell it at 10, it would be a win-win situation. A win-win situation in that you could keep your baseload unit on line, you could keep the QFs on line, you could sell the 600, and even though you'd have a 2,400 paper loss, the fact of the matter is that there's still more than $2,400 of fuel savings by that scenario so that there's a net benefit overall.

WITNESS SOUTHWICK: I'd have to go back and add back in the price we would pay the cogenerators for that 600

megawatt-hours and that may swing it back the other way.

COMMISSIONER DEASON: I thought that was calculated into the energy differential of 7,696?

WITNESS SOUTHWICK: No, sir, it's not. This is just our fuel cost to generate.

COMMISSIONER DEASON: How is the $873,683 calculated in the change case column?

WITNESS SOUTHWICK: That energy was treated as zero cost. The QFs delivered that energy, we did not generate it, but there's no payment in here to the QFs for that energy. This is just our fuel cost. So our fuel costs went down. We didn't generate that energy but we still had to buy it. That's why it's more complex than the simple example that Mr. Wright put together. We assumed away part of the problem when we built it.

COMMISSIONER DEASON: Explain to me what the difference is between the base case and the change case?

WITNESS SOUTHWICK: Okay. The base case is what actually happened. We curtailed the QFs and we generated the power ourselves and our fuel cost was 881 for that day.

In the change case we did not curtail the QFs but instead cycled off two of our own units and our fuel costs went to 873. So we did not generate that power. Our fuel costs actually went down in this example. But we bought the power from the QF. And we had to pay him for it. And those

figures aren't in here. This is just our fuel cost.

COMMISSIONER DEASON: So you're saying that your fuel costs went down only $7,696 by you cycling off those units for six hours?

WITNESS SOUTHWICK: Our fuel cost went down $7,696, yes.

COMMISSIONER DEASON: For the baseload unit for six hours.

WITNESS SOUTHWICK: Well, that's what happened physically, but this is measured over a whole day, so there's lots of things moving around. You can't think of just those six hours. There's stuff that -- after the six hours the units are going to be loaded differently as they come back on line. So the fuel cost wiggles around for several hours before it all stabilizes out.

CHAIRMAN CLARK: Staff?

CROSS EXAMINATION

BY MS. BROWN:

Q Now, Mr. Southwick, I just want to clarify something I think everyone probably understands. But during a low load condition, Florida Power Corporation continues to pay the QFs their capacity payments; is that correct?

A Yes, it is.

Q The only part of the contractual payment that the QFs do not receive during that condition is the energy

payment, correct?

A During a curtailment situation.

Q Yes.

A They are not paid the energy payment for the amount of power that they are curtailed.

Q That's correct.

Now, we have been -- we talked a little bit yesterday with Mr. Dolan about the scope of this problem, and Mr. Wright has mentioned it as well. I want to discuss it with you for a minute, also.

I'm not going to belabor the duration or the uncertainty that you have, the hesitancy you have to make any firm projections about something that can change with circumstances so much. But what I wanted to do was ask you a couple of other things. Just give me a minute to get organized here.

Q You spoke in your summary, and in your -- this morning about the change in the Southern Company contract?

A Yes.

Q And how you believed that that has helped at least once, and will help in the future, to alleviate some of the need to curtail QFs. Do you agree with that?

A Yes.

Q Okay. Are you familiar with the proposed southeast broker?

A Yes.

Q Could you describe the southeast broker for the Commission and give us a brief analysis of the current status of that project?

A Yes, I can.

The southeast broker is a concept that's been kicking around for several months. Can I start by assuming everybody is familiar with the Florida broker? The Florida hourly energy broker? Is that --

Q Why don't you explain just briefly about the Florida broker?

A Let's start with the Florida broker, because that's the easiest way to understand the southeast broker.

We have had in Florida for many years, I believe it started in the early '80s what we called the Florida energy broker, where all of the Florida utilities that are members of it, and it's essentially all of the Florida utilities, participate in a arrangement where we buy and sell power back and forth on a hourly basis, nonfirm sales, interruptible we call it.

The mechanism is set up to facilitate and make this easy to handle and, therefore, encourage more sales and lower everybody's cost.

There's a computer system that's actually -- the program is administered by the FCG Operating Committee, and

there's a computer system that is actually operated for the FCG under contract by Tampa Electric Company and located in Tampa. And this computer -- all of the utilities' control centers are tied to the computer and every hour, if we chose to, which is essentially every hour for the bigger companies, we put in buy-and-sell quotes on to the broker. We give our incremental cost of a block of power that we're willing to sell or are able to sell at. For example, if our next block of power was $16 we may quote 100 megawatts at $16 and we may quote our decremental costs for a block of power, and we put those out on the broker. All of the utilities do that simultaneously. It's a very fast process right before the hour and it's done every hour, 24 hours a day.

So we all send in our bids into the computer. The computer matches these bids high and low. So, for example, maybe one hour, we put in 100 megawatts at $16 to sell, and maybe Florida Power and Light has a bid in, let's say, to buy at $20 a megawatt-hour, because that's their decremental cost; that's what it would have cost them to generate that 100 megawatts. The computer would match -- if we were the high and low, they would match those two together, our 16 and their 20, and make the match at $18, and we would, in fact, sell that 100 megawatts to Florida Power and Light for the next hour at $18, which would be a $2 profit for our company, and a $2 savings for their company.

And this goes on every hour, 24 hours a day, seven days a week, and it has since the early '80s. And it has saved the ratepayers of Florida millions and millions of dollars.

Recently, within the past -- I don't remember exactly -- surely within the past year, and probably half a year, there's been an activity to develop a similar type broker throughout the southeastern United States, and actually it's not even limited to the southeast. That's where it started, but the participants go as far away as Chicago, St. Louis and, I think, a couple maybe even further, Philadelphia.

But there's been activity underway to develop a similar type broker system that would be over a bigger geographic area. It gets more complicated because the broker recognizes, and has to recognize transmission constraints because everybody can't just ship everything to every place. There are physical limitations, and those are included in the system.

So there's an activity underway to expand the Florida broker into a bigger broker to include more utilities throughout the southeast and beyond. It would operate very similar to the Florida broker I just described. It would be a nonfirm hourly -- what we call the "next-hour market." Is that --

Q That's fine.

A Thank you.

Q If this southeast broker comes to pass, that would give you more opportunities to make off-system sales during minimum load periods, would it not?

A Yes, it would.

Q But in order to make sure that we're clear about this, this is not something that has come to pass at present, correct?

A No, it has not, and it may not because there are some companies that are apparently not in favor of it and it may not happen.

Q Okay. But if it did it would help?

A I believe it would.

Q One more scope question, if I could. We're going to pass out an exhibit. (Hands document to witness)

Do you have a copy of that exhibit entitled, "Nonutility Generator Curtailed Energy, January 1995"? We'll pass it out. It's a Staff exhibit that we'd like you to look at.

CHAIRMAN CLARK: Ms. Brown, do you want a number on this exhibit?

MS. BROWN: Yes, I'd like to have it marked for identification, please.

CHAIRMAN CLARK: We'll mark it as Exhibit 8 and its

title is "Nonutility Generator Curtailed Energy, January 1995."

(Exhibit No. 8 marked for identification.)

Q (By Ms. Brown) Mr. Southwick, do you have that before you?

A Yes.

Q Staff prepared this exhibit that we'd like you to review. We used data from Mr. Harper's testimony from FPC's curtailment summary report for the month of January 1995 to give the Commission some idea of how much energy we're really talking about here.

Do you agree with the figures that are on this exhibit?

A No, I don't.

Q Well, could you correct them?

A Yes. I will. A copy of this was handed to me earlier this morning and I have been advised that the top number, the 618,480 is correct. The next number down is not correct. Apparently, there was a hour-timing problem in calculating that number, and the correct number, instead of 5730 should be 4549.

Q All right. It's your understanding then that in the month of January the amount of energy that Florida Power Corporation curtailed in megawatt-hours was 4,549?

A Yes. And that changes a percentage, of course.

Q Right. Is that what was curtailed or was that what Florida Power Corporation requested?

A That's what we requested.

Q What you requested. All right.

Would you agree that the 5,730 number is what was curtailed by the QFs?

A No.

Q Okay.

A That's not my understanding, no.

Q Okay. The amount of energy that Florida Power Corporation purchased from all of its cogenerators you do agree was 618,480?

A Yes.

Q Okay. And the amount of energy that was curtailed you say was 4,549?

A Yes.

Q What percentage, then, of the total amount of energy purchased is the amount of energy curtailed?

A 0.74.

Q So that's the amount of energy, less than 1% of all of the energy that Power Corp purchased in January from its QFs was what was curtailed?

A Yes.

Q How much money are we talking about here?

A To who?

Q How much money did Florida Power Corporation save by curtailing this amount of megawatt-hours from QFs? What's the value of that block of --

A I don't have that number.

Q Excuse me, I can't hear you?

A I don't have that number.

Q Can you get it? Can you give me a ballpark estimate?

MR. McGLOTHLIN: I'm confused. I'd like some clarification. You say how much did you save. Is that a comparison between what it costs them to generate as opposed to what it would have cost to pay the QF?

MS. BROWN: No. I just want to know the value of the energy that Florida Power Corporation did not purchase from the cogenerators.

WITNESS SOUTHWICK: I'm sure we could work up an estimate of that. To my knowledge it has not been done.

Q (By Ms. Brown) It wouldn't be very much, would it --

A In the big scheme of things, no, it would not.

Q In the great scheme of things, just in the month of January, compared to the amount of energy you purchased, we're not talking about very much money, are we?

A No, we're not.

Q That will do fine. That's the answer that I wanted.

MS. BROWN: If you'd just give me a minute, Chairman Clark, we're almost done with our questions.

COMMISSIONER DEASON: Let me refer you again to your exhibit HIS-3, and look at the analysis for 1-1-95. There was a negative energy difference of $2,262 --

WITNESS SOUTHWICK: Yes, sir.

COMMISSIONER DEASON: Are you with me?

WITNESS SOUTHWICK: Yes.

COMMISSIONER DEASON: Now, can you explain to me how there is a negative energy difference when in that analysis you are cycling off a baseload unit, and that shows a higher energy cost than your base case, which I assume your base case is when you do not cycle off your baseload unit.

WITNESS SOUTHWICK: The reason that the costs went up even though we didn't generate the amount of power in the change case that we did in the base case is because of the replacement costs phenomenon of when the units were cycled off, then they were not available immediately to serve load when it was later required for them because of the minimum downtime phenomenon that occurs. So they weren't available. That's what this replacement energy cost is all about.

COMMISSIONER DEASON: So the replacement energy cost is captured in the energy row there.

WITNESS SOUTHWICK: Yes, sir.

COMMISSIONER DEASON: And that's not calculated in

with the start-up costs.

WITNESS SOUTHWICK: That's right. That's two different phenomenas. In the change case there we actually generated less electricity but it cost more money to do so.

COMMISSIONER DEASON: Okay. Thank you.

MS. BROWN: We have no further questions.

COMMISSIONER JOHNSON: I had a question just on the last -- did we identify --

CHAIRMAN CLARK: 8.

COMMISSIONER JOHNSON: -- Staff on Exhibit 8. And perhaps Staff could clarify it for me.

Is the .74 curtailment or the 4,549 megawatt-hours, is that just for one month or is that -- so that is just for the month of January?

MS. BROWN: Just for the month of January, yes.

COMMISSIONER JOHNSON: To the extent energy was curtailed from the qualifying facilities, it amounted to .74% of what? What does that represent?

MS. BROWN: The energy that Florida Power Corporation purchased from QFs during the month of January.

COMMISSIONER JOHNSON: So if you look at it another way, they purchased 99-point what percent of whatever they were --

MS. BROWN: Required.

COMMISSIONER JOHNSON: -- required to purchase.

MS. BROWN: Yes.

COMMISSIONER JOHNSON: Do we have a diagram -- that's what I thought this said. I was wondering why we did just one month or do we have this information --

MS. BROWN: That was the worst month of curtailments during this year's curtailment period.

CHAIRMAN CLARK: The only other month was October and it was one time in October?

MS. BROWN: Yeah.

COMMISSIONER JOHNSON: Okay.

CHAIRMAN CLARK: I guess it would be appropriate to ask Mr. Southwick if you agree with the characterization of those numbers on this exhibit?

WITNESS SOUTHWICK: The characterizations --

COMMISSIONER DEASON: That the first number is the total amount of energy purchased from QFs for the month of January.

WITNESS SOUTHWICK: That's correct.

CHAIRMAN CLARK: And the 4,549 figure is what was actually curtailed in the whole month of January.

WITNESS SOUTHWICK: Yes. And the only thing I would disagree with that I heard was we bought 99-point something percent of what we were required to buy. We actually bought 100% of what we were required to buy, which was 99-point something percent of what was potentially available. We were

not required to buy this 4,549.

COMMISSIONER JOHNSON: Because it was curtailed.

WITNESS SOUTHWICK: Yes, ma'am.

COMMISSIONER JOHNSON: Another question -- I was following along just fine until this diagram, but -- and perhaps you're the right person to answer it, and it just goes to the whole curtailment process.

In one of your other witness's testimony, Mr. -- I think it was Robert's testimony -- he stated that under the curtailment plan that you're required -- this was in his direct testimony and you could perhaps clarify this for me -- that you have to pay the capacity charges, but are relieved just of the energy charges; even if you curtail, you still have to pay the capacity charges but you're relieved of the energy deliveries?

WITNESS SOUTHWICK: That's correct. We don't pay an energy charge for the energy we don't take, but we do pay the capacity payment.

COMMISSIONER JOHNSON: Under any circumstances.

WITNESS SOUTHWICK: Yes, ma'am.

COMMISSIONER JOHNSON: So although this was curtailed, you still paid the capacity charges.

WITNESS SOUTHWICK: Yes.

COMMISSIONER JOHNSON: Okay. Thank you.

CHAIRMAN CLARK: Any further questions? Redirect.

REDIRECT EXAMINATION

BY MR. McGEE:

Q Mr. Southwick, you were asked some questions by Mr. McGlothlin concerning a negative avoided cost hypothetical in which Florida Power sold excess generation off-system at a price less than its incremental cost.

MR. McGLOTHLIN: I object to the question as posed because my example involved no negative avoided cost, as the question assumes.

Q (By Mr. McGee) All right. You were asked a question designed to illustrate, for the purposes of the question, that there weren't negative avoided costs. And I believe you indicated in response to a question, that under the PURPA characterization of negative avoided cost, that under that example, with the off-system sales at less than your incremental costs, that no negative avoided costs would have occurred under that example. Is that correct?

A In that question, if I remember correctly, we had been constrained to narrowly defined cost as only Florida Power Corporation's fuel cost, when, in fact, the total cost includes the fuel cost as well as purchased power cost, including the power purchased from QFs.

Q That was the question I wanted to ask you.

If in the narrow confines of the PURPA definition, should we assume that meant that no additional cost would have

been imposed on the Company and its ratepayers under that --

A To me it make no sense to assume that. We have to look at total cost because the principle of ratepayer neutrality means the ratepayer will pay no more from QF purchases than he would if we didn't do the QFs purchases. That's dollars out of the ratepayers' pocket and I don't think you'd care so much if it's exactly purchased power cost or fuel cost; it's total cost.

Q You were asked another question by Mr. McGlothlin concerning the possibility that replacement power cost for a baseload unit cycled off line in your unit commit simulations, that the replacement cost might have been less than the baseload generation that it did replace.

Could you indicate to me in your opinion whether it would be likely that the replacement power cost would be less than the baseload generation for the entire period of the start-up cycle?

A No. It's very unlikely it would be less for the entire period. It could easily be less from time to time, depending on the situation as it unfolds. But over a period of time the costs would go up.

Q You were asked --

COMMISSIONER DEASON: Let me interrupt just a second. But it did happen four times in January, did it not?

WITNESS SOUTHWICK: Yes.

Q (By Mr. McGee) You were asked another series of questions in which you agreed that a four to ten day review period in conducting your unit commit planning runs could be an appropriate way to evaluate negative avoided cost after the fact.

What I wanted to ask you is that even if that methodology is appropriate, would it nonetheless be necessary that proper unit input assumptions and modeling techniques be utilized in order to achieve a reasonable result?

A I actually didn't hear the tail end -- you trailed off, Jim, sorry.

Q You indicated that the methodology might be appropriate. What I'm asking you is whether or not to achieve a reasonable result it would also be necessary to have appropriate input assumptions and modeling techniques utilized.

A Yes.

MR. McGLOTHLIN: Objection. Leading, Chairman Clark.

Q (By Mr. McGee) Then I'll rephrase it.

In addition to having a proper methodology, what other considerations are necessary to assure that a reasonable result is achieved from a computer simulation?

A You'd have to have reasonable data.

MR. McGEE: Those are all of the questions I have.

We'd move admission of Exhibit 7 into evidence.

CHAIRMAN CLARK: Exhibit 7 is admitted into the record without objection.

(Exhibit No. 7 received in evidence.)

MS. BROWN: Staff moves Exhibit 8.

MR. PRESNELL: Chairman Clark, I think on Exhibit 8 there's a problem, and that exhibit is either objectionable and not admissible, or at the very least should be accepted by the Commission with a caveat.

And that caveat is that the parties in this proceeding entered into a stipulation whereby they agreed that the QFs would not contest as an issue the adverse effect of Florida Power's curtailment plan upon the QFs. Clearly, there are adverse effects upon the QFs beyond the energy that is not delivered and paid for.

We all agreed that wouldn't be an issue in this case. We haven't presented any evidence as to that. There has been no discovery as to that, and so we want to make sure the Commission, by this exhibit, not knowing about the stipulation, simply assumes that the only adverse effect on the QFs is the energy not delivered. That is only one component of adverse effect which the parties agreed was not an adverse proceeding.

So I guess our position is that the exhibit does not go to an issue that is involved in the proceeding and which

clearly is in and of itself only part of what the issue would be if it were being litigated. And that is the overall adverse effect on the QFs of these curtailments.

MR. WATSON: I'd like to join in that objection. And the real reason that it was not made an issue is because the impact on a particular QF, or QFs as a whole, is irrelevant. For the purpose of the issue, the ultimate issue in this proceeding, which is does Florida Power's plan comply with the rule? I don't think you could find that, well, it doesn't comply but because there's not much involved, that's okay, or it doesn't comply because there's a lot involved. I mean it's a nonissue. It's not something that the rule goes to, and that's exactly why we agreed with Florida Power to get them to cease pursuing some of the discovery that they had on that point. That it was irrelevant and that neither side would present any evidence on it. I think it's misleading to have this exhibit, for whatever it's worth, in the record. My position is it's simply irrelevant and should be excluded.

CHAIRMAN CLARK: Staff.

MS. BROWN: Chairman Clark, one of the advantages, it seems to me, in this case, as the Commission is looking to approve Florida Power Corp's curtailment plan, which is a projection of how you're going to behave under certain circumstances, that is a future thing, is that we have actual events that have taken place to measure the proposed plan

against. We know what happened under certain circumstances. And I think that's a good way for the Commission to sort of have a reality check on looking ahead to some plan that we proposed.

And I think it's important for the Commission to understand the scope of what has happened when Florida Power Corporation has had these curtailment events. That's been Staff's perspective through this hearing, and we offer this exhibit simply to inform you in another way of what the scope of this particular curtailment problem at least has been to this point.

We don't offer it as any demonstration that QFs have not been harmed, but that the great scheme of things we are not, perhaps, talking about anything that is of a duration of decades or any terribly great moment.

With respect to the issues about whether the plan complies with the rules, this exhibit does not address that. That's an issue in the case. And we can proceed.

We wanted you to have an understanding of what we believe the actual circumstances that have taken place demonstrate.

MR. PRESNELL: Chairman Clark, the clear implication, it seems to me the reason for submitting this exhibit is an effort for the Staff to persuade you that if the plan is approved, there will be minimal impact upon the QFs.

That's simply not the case.

We do not believe that's a relevant issue, but if it is, we're prepared to rebut it but I would suggest that we need to set aside several more days for this hearing.

CHAIRMAN CLARK: Thank you, Mr. Presnell.

MS. BROWN: Chairman Clark, I have to object to Mr. Presnell telling you what Staff's intent it.

CHAIRMAN CLARK: Go ahead.

COMMISSIONER JOHNSON: I think Mr. Watson, perhaps, suggested that, and I just need to better understand why the impact that this plan would have on the QFs, why isn't that relevant?

MR. WATSON: The central issue in this docket is does Florida Power's plan comply with the rule of this Commission and the rules of the FERC on which this Commission's rule is based. And none of those rules say that a QF can curtail unless there's an adverse impact on QFs, or it can curtail despite adverse impact. It's something that is not addressed in the rule. The rules lay out conditions under which an electric utility is permitted to refuse purchases from a qualifying facility. And whether there's an impact to that curtailment, if it's justified, is just a nonissue. Because the impact is small or large has nothing to do with whether the conditions under which the curtailment can take place in the first instance exists or not.

COMMISSIONER JOHNSON: One of the things that's a bit confusing to me that we're taking this particular rule and isolating it, where throughout the testimony -- and I know one of your witnesses talks about the purposes of promoting cogeneration and the statutes and the rules that kind of promote the kind of activity that you are saying is being curtailed, and perhaps wrongfully curtailed. And to the extent that we could have a feel for what does this do to this industry, what does this curtailment plan -- what kind of an impact does it have as we look at the totality in what we're trying to promote under FERC's rulings under some of the Federal statutes, it appears as if, perhaps, this would be relevant in a broader way as I sit here as a policy maker.

MR. WATSON: Commissioner Johnson, to the extent the Commission wants to get into that, I agree with Mr. Presnell, that we would need to set aside an equal number of days of hearings. Because to the extent that there is an adverse impact, it goes far beyond the energy that is not purchased. It results in all sorts of ramifications for the contractual commitments that the QF has entered into with the fuel suppliers and steam hosts --

COMMISSIONER JOHNSON: Help me understand.

MR. WATSON: -- cycling.

COMMISSIONER JOHNSON: You also stated that there was a stipulation. Is it in the prehearing that you all

agree -- so this has already been determined to be a nonissue and it's in the prehearing, or was it something the parties decided?

MR. WATSON: It was something that was resolved prior to or at the time of the prehearing conference in one case.

COMMISSIONER JOHNSON: Just that we wouldn't litigate that in this proceeding anyway.

MR. WATSON: If you'll look at the Prehearing Order, there's no issue that really goes to the question of whether any QF is adversely impacted by curtailments of the plan other than the issue of whether the plan discriminates between QFs in the groupings in Florida Power's plan.

MR. McGEE: May I address that for a moment? There is one important exception to that stipulation that we agreed to, and as Mr. Watson suggested, it was an agreement that we would not bring into the hearing as an issue adverse impacts upon the QFs as a result of curtailment.

In defining adverse impacts, an exception was made for sales to Florida Power, and this is precisely what is contained on Staff's exhibit. This was an exception that was made and actually was insisted upon by Mr. Watson. So that in case questions came up from the Commission, or otherwise, as to the effect of the sales on the particular transaction between Florida Power and the QF, as opposed to other indirect

consequences, that that could be addressed because these are obviously matters of the Commission's interest.

So I think the stipulation does not preclude this kind of information and does not need to have the consequences that Mr. Watson was suggesting in terms of bringing on other witnesses or scheduling additional hearing days.

COMMISSIONER KIESLING: Mr. McGee, where can I look at that agreement?

MR. McGEE: I have a copy right here I could --

CHAIRMAN CLARK: I don't recall seeing that agreement.

MS. BROWN: No, Chairman Clark. My understanding of the agreement -- which Staff acquiesed in, is probably the best way to say it -- was that there would not be a specific issue in the case. That there would not be a specific issue in the case. I had worked one up, and --

MR. PRESNELL: We have some extra copies.

MS. BROWN: There was considerable discussion about whether QFs would be able to comply with their air quality permits and on and on and on. And Florida Power Corporation issued a rather extensive discovery package that went to whether QFs would be able to continue to be QFs, and it was very extensive. And this was what the QFs objected to. And Florida Power Corporation agreed that if there would not be an issue of whether QFs had been harmed, that they would withdraw

their discovery. So it was a stipulation or an agreement, really, to resolve a discovery dispute, which was resolved and that's why it doesn't appear in the Prehearing Order.

MR. McGEE: Madam Chairman, if I might, could I make a suggestion on perhaps how this exhibit might be dealt with?

CHAIRMAN CLARK: Mr. McGee, before you do that, where is the particular portion on the --

MR. McGEE: In Paragraph 2 you'll find two definitions, the first of which is adverse effect. And on the second line from the bottom of that paragraph you'll see a parenthesis that says "other than sales to Florida Power."

CHAIRMAN CLARK: You were going to make a suggestion.

MR. McGEE: Might I suggest that the exhibit be entered into the record on a limited basis, and that limited basis be that it only is an indication of the effect on the sales -- excuse me, the purchases by Florida Power. This can be fairly shown to indicate what the effect was on Florida Power in terms of the reduction in the megawatt-hours purchased during the month of January because of curtailments. Without having any effect or given any consideration by the Commission in terms of impact on the QFs.

CHAIRMAN CLARK: I think what Mr. Watson has suggested is that even if that's what it does, it's not relevant, as I understand your point.

MR. WATSON: That's correct, Commissioner.

CHAIRMAN CLARK: Not relevant to the determination of whether the plan complies with the rule because the rule doesn't address that you can do something else if the impact is not significant. Commissioner Kiesling, have you asked all of your questions?

COMMISSIONER KIESLING: Yes. I think I've formed my conclusion.

CHAIRMAN CLARK: Is there any other question from Commissioners or any further comment?

COMMISSIONER KIESLING: My comment would be that in light of the agreement among the parties, and the fact that there will be no other evidence in the record from the parties as to impacts, I think that it would be prejudicial to have this in there because once it's in the record, it stands for the proposition that this is the impact. And I don't see where that is a relevant issue, nor do I see where there will be any other evidence in the record that would go to that, and were it me, I would grant the objection.

CHAIRMAN CLARK: Any other comments? Mr. Pruitt.

MR. PRUITT: Madam Chairman, if any useful purpose would be served by having this before you, I think with the admonition you've gotten from counsel and what has been stated, that the Commission is mature enough to know that this is only a segment of costs involved, and know that when you

look at it you'll only be dealing with a segment of it, I think you can keep it in the record if you wanted to.

MS. BROWN: Madam Chairman, if I might direct you to testimony that is not in the record yet. It's been prefiled -- yes, it is, or will be soon, Mr. Southwick's rebuttal testimony -- if you look on Page 4 of that testimony, there's some figures there. It's the second paragraph.

MR. McGLOTHLIN: Martha, before you direct her to that, I think you should be aware it's the understanding of counsel that FPC intends to withdraw that testimony.

CHAIRMAN CLARK: I had understood some of Southwick's testimony would be withdrawn. Do we know if that is part of the testimony that's --

MS. BROWN: I have not been told what would be withdrawn and what wouldn't.

MR. PRESNELL: Specifically that sentence begins "Likewise, OCL/Pasco do not cite or document," Florida Power has agreed that was an inappropriate statement to be made and they intend to withdraw it at the time Mr. Southwick's rebuttal is sponsored.

MR. McGEE: That is correct. The two sentences on Line 21 through 24.

MS. BROWN: That is not the testimony that I was going to direct your attention to. I was going to direct your attention to the testimony that begins on Line 16 and goes

down through the end of that first sentence on Line 21.

CHAIRMAN CLARK: So you're offering this document for the corroboration that they have narrowly defined the circumstances under which curtailment would take place because it's evidence of the narrow curtailment of energy sales.

MS. BROWN: Yes. And it also fills out this information which is based on 1994 figures. This is 1995 with curtailment events that have occurred.

CHAIRMAN CLARK: I'm going to allow the exhibit with the understanding that it certainly does not cover all of the -- I'll allow it in in light of the stipulation, that there are certainly other impacts to the cogenerators.

MR. PRESNELL: I assume that we'll be allowed to address that exhibit then during our case since we have not had an opportunity to see this exhibit before; it's new evidence.

CHAIRMAN CLARK: I would point out that you don't see exhibits that other parties are going to offer on cross examination. To the extent it's relevant to the cross examination conducted of your witnesses or otherwise fits, it may be appropriate to do that.

(Exhibit No. 8 received in evidence.)

MR. PRESNELL: Okay. Mr. Shanker.

MR. McGLOTHLIN: Yesterday you indicated you wanted to set a time certain to deal with our objections to

certain --

THE REPORTER: Mr. McGlothlin, is your mike on?

MR. McGLOTHLIN: Yes, it's on.

CHAIRMAN CLARK: Mr. McGlothlin, clarify for me, I thought that was supposed to be done before Mr. Slater.

MR. McGLOTHLIN: That was the request, and I think you had said at the time that we would do it at the conclusion of Power Corp's direct case.

CHAIRMAN CLARK: Okay.

MR. McGLOTHLIN: Whatever your pleasure is.

But before we get into any argument or the motion, I'd like to set the motion to one side for a moment and suggest, or make a proposal, that our objections to portions of the rebuttal testimony of witness Linda Brousseau fall into two categories.

With respect to the first category, and without arguing it yet, but we regard certain of that testimony as being in the nature of repetitions of testimony offered by others; answers that responded to the first round of testimony, not the supplemental, and other testimony of a similar nature which we think is technically objectionable, but not nearly so prejudicial as that which falls in the second category.

And the second category consists of those statements that describe additional changes to unit commit program

simulations that go beyond anything that Mr. Slater did in his work.

Now, there are two reasons for the objections. The first reason was at the time --

CHAIRMAN CLARK: You are launching into your argument.

MR. McGLOTHLIN: I don't intend to. I think I'm about to make the proposal.

CHAIRMAN CLARK: Okay.

MR. McGLOTHLIN: We were concerned about the opportunity for Mr. Slater to have a chance to review those and critique them. We're also concerned about any procedural opportunity he would have at this point of presenting any views he has on it.

We resolved one because of the pace of the hearing and because he's been sitting at the computer hour after hour, he is in a position to respond. However, we can't resolve the other without some kind of workout. And that is we need for him to be able to say from the stand what work he has done on those and what his comments are, including what alternative change case he would propose to the new deal. And we're prepared to do that. And if he has that opportunity, we will withdraw our Motion to Strike and he would do that when he takes the stand. And then Florida Power Corporation would have their rebuttal in the usual sequence.

But I want it understood that his testimony from the stand would incorporate not only what has been prefiled, but the additional work he's done given the extensive nature of the additional simulations that have been submitted after his work was done.

CHAIRMAN CLARK: Well, as I understand what you're saying, you need to know the ruling on the two bases: One it being redundant, the recap of the testimony that's already been filed.

MR. McGLOTHLIN: No. I'm saying that if you're willing to give him that latitude when he takes the stand, to include comments that are not prefiled and that address the additional simulations that have been made available very late, then we would withdraw our Motion to Strike.

CHAIRMAN CLARK: He is prepared to do that?

MR. McGLOTHLIN: He will be by the time he takes the stand. He's performed his work and he's in the process of putting together a schedule that will serve as a basis for his testimony.

CHAIRMAN CLARK: Okay. Mr. McGee.

MR. McGEE: Well, I appreciate --

CHAIRMAN CLARK: Which would -- now, let me be clear. If he does that, there is no opportunity beyond that for FPC to respond to his response to the new information.

MR. McGLOTHLIN: They will have the last word in

that they are rebutting, but they will have in hand a schedule showing the additional -- his alternative change case commitments that are designed to correspond to the additional simulations, then they would have the last word on that, which --

CHAIRMAN CLARK: When Ms. Brousseau takes the stand on rebuttal.

MR. McGLOTHLIN: On rebuttal, that's correct.

CHAIRMAN CLARK: Mr. McGee.

MR. McGEE: I think what Mr. McGlothlin is asking for is to give his witness an opportunity for surrebuttal and I think it might be within your discretion to do so. It's certainly not the practice that's customarily followed, and I think the questions you just asked indicate the reason why that is. At some point we have to draw the line to keep from going back and forth and back and forth.

CHAIRMAN CLARK: I guess his Motion to Strike is suggesting that you stepped over the line when you responded in a --

MR. McGLOTHLIN: That's correct. We're not asking for surrebuttal because the nature of that testimony was not rebuttal. It's additional direct because -- and if we could get into it, I can lay out chapter and verse why it's additional direct, but it's different than what he was given to work on the first ground.

CHAIRMAN CLARK: Okay. Commissioners, how long do we need to take for lunch? And is there a time you all want to take lunch?

COMMISSIONER JOHNSON: Short.

CHAIRMAN CLARK: Short lunch. What I would propose is I will go ahead and hear the argument on this case because I'm not -- I mean on this motion. I've looked over it and then I'll take a recommendation from Staff, and then we'll break for lunch and we'll take up Mr. Slater and I'll give myself about a half an hour.

Let me get to -- Mr. McGlothlin, did you file a motion, a written motion?

MR. McGLOTHLIN: No, ma'am.

CHAIRMAN CLARK: Okay. I have the supplemental direct testimony of Mr. Slater and the rebuttal of Ms. Brousseau, and if you would go ahead and once again for me go through the testimony that you think should be striken. And if you would likewise tell me at that time the basis on whether it's redundant to that which is already -- a resummation of that which was already filed, or it's additional testimony which is not in reponse to the supplemental testimony, let me know that.

MR. McGLOTHLIN: All right.

CHAIRMAN CLARK: Would you go through -- the last time you did it we went back to some -- back to Page 17 or

something. I hope we can go through it from Page 1 to 27.

MR. McGLOTHLIN: All right. By way of quick background, Mr. Slater has filed testimony on two occasions. The first consisted of the comments he was able to make prior to the ability to utilize the unit commit program to make simulations in alternative cases. On April 25th he filed the supplemental testimony consisting of about six-and-a-half pages all directed to describing the additional work he had done on unit commit and his conclusions regarding negative avoided cost, or the absence of negative avoided costs in each of the seven curtailment events.

Ms. Brousseau's testimony, beginning on Page 4, the rebuttal testimony, there's a section entitled "General Rebuttal to OCL/Pasco Supplemental Testimony" and the first question says, "Please begin by summarizing Florida Power's direct evidence on the question of negative avoided cost." And her first statement is, "As explained in Mr. Southwick's direct testimony at Pages 35 and 40," and then she proceeds to simply reiterate and paraphase statements that have already been made in direct testimony in an earlier phase of the case. We think that is certainly ligitimate rebuttal to a very limited and narrow testimony that Mr. Slater filed in his supplemental document.

CHAIRMAN CLARK: And that goes on over to Line 6 on Page 8?

MR. McGLOTHLIN: Line 7 on Page 7, I believe.

CHAIRMAN CLARK: Okay.

MR. McGLOTHLIN: I might add with respect to the content there, during her deposition I asked Ms. Brousseau, "Is there anything here that responds to the specifics and Mr. Slater's application unit commit?" And she says, "Not to his specific applications on those pages, no."

At the bottom of Page 7, beginning on Line 9, there's this question: "What are your general impressions of Mr. Slater's response to the Company's analysis of the avoided cost issue?" And her answer, first sentence says, "I will repeat a point made by both Mr. Southwick and Dolan." So here's testimony that's already in twice and she's going to repeat it again. And it goes not to the simulations but to an overall more general comment regarding Mr. Slater's response that is not in the nature of rebuttal to the settlemental testimony. That goes from that point until Page 8, Line 8.

On Page 10, beginning at Line 17, this statement appears. "Also, in reviewing the original unit commit runs we discovered several other items which we have adjusted to make the simulations more accurate and realistic. I will discuss these later in my testimony." The witness there is announcing there's been a new deal made.

CHAIRMAN CLARK: I'm sorry. Give me that page number again.

MR. McGLOTHLIN: Page 10.

CHAIRMAN CLARK: Okay.

MR. McGLOTHLIN: Beginning at Line 17.

CHAIRMAN CLARK: All right.

MR. McGLOTHLIN: Clear acknowledgement that any additional work there is not in response to Ms. Slater's simulations but are separate and apart from that.

Page 11, beginning at Line 2, this statement appears. "When we prepared corrected unit commit cases they again --"

CHAIRMAN CLARK: Just a minute. You're getting ahead of me.

MR. McGLOTHLIN: I'm sorry, Madam Chairman.

CHAIRMAN CLARK: The sentence that begins, "Also" it's your position it goes beyond rebutting the supplemental testimony.

MR. McGLOTHLIN: Clearly.

CHAIRMAN CLARK: All right. Go ahead.

MR. McGLOTHLIN: On Page 11, beginning at Line 2, and ending at the end of Line 7, there's a statement that says, "Corrected unit commit runs corroborate the earlier conclusion." This is a statement in which it is impossible to segregate anything that relates to his work with the additional work they did that's unrelated to those simulations. But clearly the conclusion is based not only on

responses to Mr. Slater, but on additional work that was done.

CHAIRMAN CLARK: You're saying you cannot tell from the answer -- or you can tell from the answer that in reaching their conclusion that they are still negative costs. They included in there further changes they made to the simulations.

MR. McGLOTHLIN: I believe in context it's clear they performed changes to the simulations that go beyond, or are separate and apart from anything related to Mr. Slater's work. And now they are reporting the conclusions of those additional runs that incorporates such work.

On Page 17, beginning at Line 16, this question appears: "Mr. Slater suggested in his direct testimony that generation excesses of 11 megawatts or so presented significant problems," etcetera. That relates not to the supplemental testimony on unit commitment simulations but to his first round of testimony. That goes through Page 18, Line 5.

Beginning on Page 18, Line 7, this question appears: "What is your reponse to Mr. Slater's last assertion that Florida Power has used an improper short time frame of analysis to evaluate the curtailment events?" The answer extending to Page 19, Line 5, is not in response to the simulations he prepared and submitted in supplemental testimony.

CHAIRMAN CLARK: I thought his supplemental testimony did refer to longer time periods.

MR. McGLOTHLIN: We'll get the two documents out, Chairman Clark, but I made the objection because I believe it was raised in direct testimony.

CHAIRMAN CLARK: But I think it was also raised in the supplemental.

MR. McGLOTHLIN: If that's the case, I'll withdraw the objection.

MS. BROWN: Chairman Clark, one place it appears is on Page 6 in answer to the question that starts on Line 13, the answer starts on 17. And specifically on Line 19, that sentence addresses it. There may be other places that I haven't found.

CHAIRMAN CLARK: All right. Go ahead, Mr. McGlothlin.

MR. McGLOTHLIN: On Page 20, beginning at Line 7, this statement appears: "In doing so, we also discovered we should make several other adjustments to the data in order to better accomplish the original objective," etcetera, etcetera. "Consequently, we amended our simulations of the seven curtailment events." Clearly this testimony is designed to support simulations that are not only responsive to Mr. Slater's work but involved a new set of data and assumptions to which he could not respond at the time.

Then beginning at Page 21, Line 1, the question is: "What additional refinements have been made to the Company's amended simulations?" That entire page, all of Page 22, Page 23, Page 24, Page 25 and Page 26 to the extent that the question on Page 26 asks what are the results of all of the additional work that you've done. All the way --

CHAIRMAN CLARK: Down to where?

MR. McGLOTHLIN: Page 27, Line 3.

CHAIRMAN CLARK: Let me just ask a question, did you previously identify everything on Page 22, starting on Line 6? You did? It wasn't in my notes.

COMMISSIONER KIESLING: If it's of any assistance, my notes reflect he cited Page 21, Lines 1 through 25 through Page 27, Line 3.

MR. McGLOTHLIN: That's correct.

CHAIRMAN CLARK: Okay.

MR. McGLOTHLIN: Then we also moved to strike the two pages of exhibits that are attached in that they reflect and incorporate the results of the simulations that were prepared with the changeouts that were described in the prefiled testimony, many of which are separate and apart from any consideration in Mr. Slater's supplemental testimony.

And just to illustrate that, Commissioner, if I may, turning first to the second of the two pages, LDB-2.

CHAIRMAN CLARK: I'm sorry.

MR. McGLOTHLIN: Last page of the package. On that page there is something called Category II, "Changes made to more accurately represent system conditions," and consists of Item C through J. I'm informed by Mr. Slater that only Item G is even arguably related to his supplemental testimony. That gives you some appreciation of the number and magnitude of the changes.

And then referring back to the first of the two pages, you'll see that this displays on the right-hand column what is called the base and change case differences. In other words, this is designed to describe in FPC's view the actions that would have been necessary had they continued to receive QF purchases rather than curtail, and describe certain units going on and off.

A side-by-side comparison of Mr. Southwick's corresponding exhibit with this one shows that only one of the seven scenarios shows the same response by the operation. Again, that is an indication that the changes here are extensive.

So for the reasons I indicated earlier, first of all there were two reasons. At the time we raised the motion we had no way of determining whether Mr. Slater would have an adequate opportunity to review the information. And, secondly, because of the procedural posturing we're in, where his supplemental testimony ends, and unless something happens,

he will not have a opportunity to say to the Commissioners, "I've looked at this. I've worked with it and here's what I think and I can prove it." We are severely prejudiced.

I might also point out that not only are we prejudiced, but if the state of the record is left this way, the Commission is in a quandry because these changes indict the earlier runs that were submitted with Mr. Southwick's testimony. They are materially and significantly different. So which set are you going to rely on? Even Florida Power Corporation has acknowledged in his work on the first set of runs, Mr. Slater found some errors, and that they agree with some of the changes he made.

At this point, unless Mr. Slater is given that opportunity, not only has he had no chance to critically review these things, but nobody else has either. So which set would you trust?

That's why I think that our proposal not only serves to provide us the procedural opportunity to which we're entitled, but also is the best means to give the Commission the best record on which to make a decision.

CHAIRMAN CLARK: Your preference would be that you be allowed to supplement the testimony when he takes the stand on rebuttal?

MR. McGLOTHLIN: We're prepared to do that, yes, ma'am. We think that that opportunity resolves the prejudice

with which we would otherwise be confronted.

CHAIRMAN CLARK: Okay. Mr. McGee.

MR. McGEE: Madam Chairman, would you prefer me to go through the areas identified by Mr. McGlothlin in the same order?

CHAIRMAN CLARK: Well, I understand what his positions are on them and I think you can divide your argument into those that he says are redundant and those he claims are beyond the scope of the supplemental rebuttal.

MR. McGEE: The beginning portion, I think, was properly characterized as background material that summarized information from other people's testimony. It was put in solely for the purpose of providing in one place the information necessary to follow the argument if you will. If that's troublesome with the Commission, I think it's certainly within your discretion to strike it. We put it in only as a proper lead in.

Beginning on Page 17, Line 16, Mr. McGlothlin has identified an area that responds to Mr. Slater's direct testimony as opposed to his supplemental testimony.

You will recall that Mr. Slater's supplemental testimony was filed on April 25th. Florida Power filed its rebuttal testimony to previously submitted OCL and Pasco testimony on May 2nd. As the rebuttal testimony was being finalized, Mr. Slater's supplemental, having recently arrived,

was available to us.

Mr. Southwick was planning to address three points in Mr. Slater's direct testimony, which we now realized had to do with an evaluation of our unit commit runs that was more fully explained in his supplemental. At that point, Mr. Southwick included in his direct testimony the following statement: "Because there is a clear -- " I should say Mr. Slater's direct testimony identified three problems with Florida Power's unit commit runs and indicated he was performing further analysis. Mr. Southwick says in his rebuttal testimony, "Because there is a clear inter-relationship between the three 'problems' listed in Mr. Slater's direct testimony, and the somewhat more detailed assertions presented in his April 25th supplemental testimony, we are evaluating those allegations as part of a thorough review of the unit commit simulations. The results of that review will be presented before the hearing in this docket in a further piece of company rebuttal testimony." That further piece is Ms. Brousseau's. So it was intentionally taken out of the rebuttal testimony and included here for the interest of consistency.

And with the exception of a few minor lead-ins, references to amended simulations, I think the essence and the real important point before us right now begins on Page 21 of Ms. Brousseau's testimony where Mr. McGlothlin has asked you

to strike the remainder of her testimony as well as the two exhibits.

When Florida Power submitted its unit commit evaluations in Mr. Southwick's direct testimony, and as explained there, the base case utilized what is referred to as QF billing runs. Every month Florida Power compares a computer simulation in the preparation of monthly energy payments to the QFs.

Those computer runs existed, were in place, had been prepared in the normal course of business at the time that Mr. Southwick's direct testimony was being prepared. Florida Power elected to use those billing runs prepared for other purposes as the base case in its simulations to determine whether a negative avoided cost existed, and did not attempt to change or modify those.

Mr. Slater's supplemental testimony finds fault with several aspects of those billing runs used as a base case. In some cases Florida Power agreed that there were instances where because of the different purpose for which they were originally prepared they may not have accurately reflected reality as well as might have been possible. He made those changes, with which we agreed, as well as several with which we did not agree.

So Ms. Brousseau's testimony acknowledges the areas and the changes that were made in agreement with Mr. Slater;

explains why a number of other changes that were made by him were not correct and had to be undone.

CHAIRMAN CLARK: You mean made by him in his supplemental --

MR. McGEE: Correct.

CHAIRMAN CLARK: -- testimony?

MR. McGEE: Correct.

CHAIRMAN CLARK: Where does he refer to that?

MR. McGEE: Where does she refer to that?

CHAIRMAN CLARK: No. Where in his supplemental direct testimony is there an indication he made other changes to which she is responding in her rebuttal testimony? I thought that's what you just said.

MR. McGEE: If is misspoke myself, I'm sorry. He identified in his supplemental testimony a number of changes made.

What I meant to say was that of those changes, there were several that constituted, in his opinion as well as Florida Power's, corrections of some errors.

Florida Power, in reviewing it, saw those, agreed he had a point and included those in Ms. Brousseau's evaluation. But he also, of the total changes that he made, Ms. Brousseau did not agree with many of them and those required some further manipulation to undo.

Having gone through this review of these billing

runs for purposes of evaluating Mr. Slater's supplemental testimony, it became apparent that there were other refinements that could and should be made to make this base cause as properly reflective of reality as possible.

The reason that was not done in the first place was because we attempted to use some billing runs off the shelf, if you will, to eliminate controversy and to utilize information that was prepared in the normal course of business.

Since Mr. Slater is the one who has questioned whether or not those are the proper runs to use, Florida Power has simply attempted to complete the process; to convert these off-the-shelf billing runs into something that truly represent a base case from which a proper change case comparison can be made.

At the prehearing conference we had a discussion about Mr. Slater's supplemental and Florida Power's response and some contention as to whether or not that supplemental testimony should be allowed. Your concern, as I recall it being expressed, was that you wanted the Commission to have the best information from both sides available to it so you could properly sort through it, sift it out.

We're now in a situation where if Mr. McGlothlin's motion was granted, we would have gone through and corrected those areas that Mr. Slater has identified. But when we

identify other refinements, and these are characterized by Ms. Brousseau as minor refinements, that we couldn't make those.

CHAIRMAN CLARK: Did Mr. Slater make those refinements as part of his further reviewing the runs for his supplemental direct testimony?

MR. McGEE: No. Ms. Brousseau, on Page 21 at the top, identifies six categories that constitute the additional changes that are really the bone of contention before us right now.

CHAIRMAN CLARK: Right. Now, I'm having trouble understanding the nexus between the supplemental direct testimony of Mr. Slater, and the rebuttal testimony of Ms. Brousseau with regard to the six types of refinements that are included in her revised simulations. They seem to be beyond the scope of the supplemental direct testimony.

MR. McGEE: In Florida Power's view, they were a natural and necessary consequence and follow-up of a review process that was necessary to be performed because of Mr. Slater's supplemental testimony.

MR. McGLOTHLIN: Chairman Clark, they thought --

CHAIRMAN CLARK: Hang on a minute. Let him finish and I'll give you a chance to rebut. Go ahead.

MR. McGEE: We started out with unadjusted billing runs because they represented some independent

prepared-in-the-course-of-business information. Since the use of that unadjusted data was challenged by Mr. Slater's testimony, we went in and followed up on his process of attempting to make refinements to that base case so that it better reflected reality. We agreed with some of his; we disagreed with others. And in the course of doing that identified other refinements which would further the same process that he identified in his supplemental testimony. He wanted the runs, according to his testimony, to reflect a proper comparison between the base and change case.

CHAIRMAN CLARK: Let me see if I can repeat back what I've understood from you and you tell me if I'm right or wrong.

Because he wanted to use unadjusted billing runs and he used them in his supplemental testimony, by using that base date he needed to make other refinements to make the data a correct analysis.

MR. McGEE: Florida Power used the unadjusted billing runs in Mr. Southwick's direct testimony. Mr. Slater responded to that with his supplemental testimony and found there needed to be some adjustments made to that.

CHAIRMAN CLARK: And you're saying as a result of making those adjustments, he didn't go far enough in the number of adjustments he made, and you're saying that the six other adjustments had to be made, and that's why it's

responsive to his supplemental testimony. Is that correct?

MR. McGEE: That is essentially correct.

MR. McGLOTHLIN: May I respond?

CHAIRMAN CLARK: As soon as I finish writing it down. Go ahead.

MR. McGLOTHLIN: Chairman Clark, what we're talking about here is a matter of fundamental due process.

Let's assume for the sake of argument that late in the game Florida Power Corporation discovered ways it wanted to do -- make a do-over, things that would make an improved product.

The situation is we are an intervenor with due process rights, Mr. Slater is entitled to an opportunity to review and critically critique and then testify to the Company's position. What we have here is a moving target. And for him to have an adequate opportunity to present his views and for Orlando CoGen and Pasco Cogen to have their rights protected, the moving target is going to have to hold still at some point.

And I'd like to point out that with respect to these six additional items that represent significant changes, as I understand the latest offer, they are a natural consequence of reviewing Mr. Slater's work. Let me just read you a short passage from the deposition of Ms. Brousseau, beginning on Page 82.

"Question: Beginning on Page 23 you identify several categories of modifications to the earlier runs. We've talked about one, which is the actual prior operating status of some units. You also identified changes to the curtailment amounts, changes to the minimum operating levels of units, and three miscellaneous refinements: Correction to the normal minimum generation level for Crystal River 4, correction of the must-run status of two units, and corrections of minor discrepancies in the must-take amounts for the Southern companies. Would you agree that none of those are in response to anything that is contained in Mr. Slater's supplemental testimony?" And after a short exchange the answer is, "I agree."

Now, that's a major redeal, and the prejudice to Orlando CoGen is perhaps -- there could be the impression or the appearance that, well, Mr. Slater, for whatever value his work had, it's now water under the boards because here's a whole new situation that his work doesn't attach to. That's fundamentally and basically unfair. And the Company should not be able to get out from under any ligitimate comments he had by the expediency of having a different product in front of the Commission at this point.

And as I say, their new products indicts what has been done before, and I don't see how the Commission could have any confidence that this is any better. Unless my

suggestion, which is that Mr. Slater be given the latitude to comment on this product as well be accepted, and he's prepared to do that.

CHAIRMAN CLARK: Staff.

MS. BROWN: Chairman Clark, we recommend that Mr. McGlothlin's motion to strike the testimony be denied in all respects except for the testimony that begins -- I guess it's on Line 20 that's in the most serious contention here.

We think the background information, the statement on Page 17 about responding to Mr. Slater's direct testimony and the longer time frame issues all should be left in under the general principle that the Commission has considerable discretion and often uses latitude in admitting evidence into the record.

With respect to the question of due process problems, though, we agree with Mr. McGlothlin, and would recommend to you that you strike that portion of the testimony or accept Mr. McGlothlin's proposition to correct the problem.

CHAIRMAN CLARK: Let me ask Staff at this point. In your analysis would you find it more helpful to have the testimony in and allow Mr. Slater to respond on the stand, but with the understanding that there is no opportunity for Ms. Brousseau to respond. Because I think that would be inappropriate to allow her then to respond to what Mr. Slater has said.

MS. BROWN: That would be the way we would like to do it. With the understanding, of course, that Florida Power Corporation would have the opportunity to cross examine Mr. Slater and rebut his testimony.

COMMISSIONER KIESLING: Through cross examination.

MS. BROWN: Yes.

CHAIRMAN CLARK: Or test the validity of the --

MS. BROWN: No. Wait, wait. I'm afraid I'm confused.

CHAIRMAN CLARK: At I understand what Mr. McGlothlin has offered is that Mr. Slater, when he takes the stand to do his direct testimony, will also respond to the -- I'm sorry, when he does his rebuttal -- he doesn't have rebuttal, does he?

MR. McGLOTHLIN: He has direct and supplemental direct.

CHAIRMAN CLARK: Right. When he takes the stand at that time he will respond to the additional information provided by Ms. Brousseau.

MR. McGLOTHLIN: The that's correct.

CHAIRMAN CLARK: And Florida Power Corporation will have the opportunity to cross examine him on those points.

MR. McGLOTHLIN: That's correct.

MR. McGEE: And Ms. Brousseau would have the opportunity to respond through her testimony.

CHAIRMAN CLARK: No.

MR. McGLOTHLIN: Through whatever has been filed.

CHAIRMAN CLARK: What has been filed.

MR. McGEE: Then at least in that respect, while we have the burden of proof, then they would have the right to close on this point? That seems to me to be inconsistent in that respect.

MR. McGLOTHLIN: No. I think --

CHAIRMAN CLARK: What I find inconsistent is that there appears to be instead of rebuttal to the supplemental direct, there seems to be further direct testimony that I think the intervenors need the opportunity to respond to.

I guess, Mr. McGee, I'm giving you your choice. I'm either going to strike it or I'm going to allow Mr. Slater, when he takes the stand, to respond to it. And you may cross examine him on that.

MR. McGEE: I was not trying to be contentious. I thought when we described -- when Mr. McGlothlin described this procedure before, his position was that his client needed to have an opportunity to respond to new information. I think you're agreeing that it is new information and they should have that opportunity to respond.

That has been how the case has unfolded in a general sense. We have put ours in and they've put theirs.

CHAIRMAN CLARK: And you respond to their --

MR. McGEE: But then we have the last opportunity to deal with the issue in contention through rebuttal. In this case it would be through rebuttal on the stand if we followed the procedure that's been consistently applied through the case.

CHAIRMAN CLARK: Commissioner Kiesling.

COMMISSIONER KIESLING: I don't think that I would permit Ms. Brousseau to go beyond what is contained in her rebuttal testimony. Otherwise, this just becomes an unending cycle of adding new information and getting to respond to that, and I would suggest that if that cycle starts then perhaps you should just strike it before we ever get to that cycle.

MS. BROWN: Staff would recommend that you decide as you have suggested; that Florida Power Corporation not be permitted to rebut the rebuttal to the rebuttal.

CHAIRMAN CLARK: Well, the dilemma I have is I'm interested that we have all relevant facts before us, and I understand that these are computer runs and adjustments to inputs that you could make. And I am interested in having information before us to test the validity of the plan. But I'm also aware of the fact that we have to comply with due process requirements, and I think this is further testimony and I'm trying to address the due process concerns in order to accommodate getting necessary information into the record.

Mr. Pruitt.

MR. PRUITT: Thank you, Madam Chairman.

Let's talk about rebuttal just a minute, then we'll go into the other end of it.

Generally speaking, rebuttal testimony is directed to new matters brought out by evidence of the opposing party and does not consist of testimony which should have properly been submitted at the presentation of the case in chief.

It's not the purpose of rebuttal testimony to add additional facts to those submitted in a presentation of the case in chief unless such additional facts are required by a new matter developed by the opposing party.

If the proffered testimony appears to be cumulative rather than rebuttal, it's still within the sound discretion of the presiding officer to allow its admission and to exercise -- and to exercise this discretion will not be disturbed on appeal unless it appears to be so prejudicial that the result also indicates an abuse of discretion as Driscoll versus Morris, 114 So.2d 314.

Now -- if I can find my note over here -- as to what you can do and can't do, courts usually decide cases on relatively fixed principles of law for the purpose of settling the rights of parties litigant. The actions of administrative agencies are usually concerned with deciding issues according to a public interest that often changes with the shifting of

circumstances and the passage of time. Such considerations should warn us against a two doctrinaire analogy between courts and the administrative agencies." Peoples Gas System versus Mason, 187 So.2d 335.

You have a lot of discretion the way you want to handle it.

CHAIRMAN CLARK: Do you have a recommendation?

MR. PRUITT: Commissioner, I generally don't recommend on merit.

CHAIRMAN CLARK: Commissioner Keisling?

COMMISSIONER KIESLING: I guess I would just kind of try to paraphrase what Mr. Pruitt just said, which is that proper rebuttal is a clearly defined thing. And that if we were to stick strictly with that definition, it should be stricken.

However, this is a quasi-legislative proceeding as opposed to a quasi-judicial one, and, therefore, I think we do have more discretion about what we let into the record in order to develop fully the record.

And in this particular instance I certainly think that the accommodation that Mr. McGlothlin has suggested, which protects their due process rights to respond to new information, is a reasonable accomodation that solves the problem. And I do think it's within our discretion then to say and that's the end of it. That we are then not going to

let Ms. Brousseau have surrebuttal of the response to her inappropriate rebuttal to begin with.

You just have to draw the line some place. And I think that allows all of us to have what we need. We'll have a full record and the intervenors' due process rights will be protected.

CHAIRMAN CLARK: I'm inclined to agree with you in that Florida Power Corporation, you may cross examine Mr. Slater while he's on the stand as to the oral response he makes to the information included in Ms. Brousseau's rebuttal. Ms. Brousseau will not have the opportunity to provide oral surrebuttal on that point.

With that, none of the testimony of Ms. Brousseau will be stricken. And we'll reconvene at 1:30.

(Thereupon, lunch recess was taken at 12:50 p.m.)

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(Transcript follows in sequence in Volume 4.)