BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040817-EI

In the Matter of

PETITION FOR DETERMINATION OF NEED FOR HINES 4 POWER PLANT IN POLK COUNTY BY PROGRESS ENERGY FLORIDA, INC.
_______________________________/

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PROCEEDINGS: HEARING

BEFORE: CHAIRMAN BRAULIO L. BAEZ
COMMISSIONER J. TERRY DEASON
COMMISSIONER LILA A. JABER
COMMISSIONER RUDOLPH "RUDY" BRADLEY
COMMISSIONER CHARLES M. DAVIDSON

DATE: Wednesday, November 3, 2004

TIME: Commenced at 10:40 a.m.
Concluded at 10:50 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and Administrative Services
(850) 413-6732

APPEARANCES:

GARY SASSO, ESQUIRE, JAMES WALLS, ESQUIRE, Carlton Fields Law Firm, P.O. Box 3239, Tampa, Florida 33607-5736, appearing on behalf of Progress Energy Service Co., LLC.

COCHRAN KEATING, ESQUIRE, FPSC General Counsel's Office, and JUDY HARLOW, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

# I N D E X

## WITNESSES

# EXHIBITS

| NUMBER: | | ID. | ADMTD. |
|---|---|---|---|
| 1 | Comprehensive Stipulated Exhibit List | 8 | 8 |
| 2-28 | (Detailed description of exhibits contained in Exhibit 1.) | 8 | 8 |

PROCEEDINGS

CHAIRMAN BAEZ: We'll go on the record. Call this hearing to order.

Good morning. Counsel, read the notice.

MR. KEATING: Pursuant to notice this time and place have been set for a hearing in Docket Number 040817-EI, petition for determination of need for Hines 4 Power Plant in Polk County by Progress Energy Florida, Inc.

CHAIRMAN BAEZ: Take appearances.

MR. SASSO: Gary Sasso, Carlton Fields, for Progress Energy.

MR. WALLS: Mike Walls with Carlton Fields for Progress Energy.

CHAIRMAN BAEZ: Can you spell your name? I couldn't hear you.

MR. WALLS: Mike Walls, W-A-L-L-S.

CHAIRMAN BAEZ: Thank you.

MR. KEATING: Cochran Keating on behalf of the Commission.

CHAIRMAN BAEZ: Mr. Keating, do we have some preliminary matters?

MR. KEATING: Correct. The notice for this hearing indicates that any persons who wish to testify concerning the company's need petition should be present at the start of the hearing. I believe at this point it would be appropriate to take testimony from anyone who may be here to offer it.

CHAIRMAN BAEZ: Very well. Is there anyone in the audience that is here to offer public comment at this hearing?

Seeing none, go ahead, Mr. Keating.

MR. KEATING: Staff and the company have agreed to positions to resolve all of the issues in this docket. These stipulated issues and positions are set forth in Section XI of the prehearing order at Page 8. In light of these stipulations, all the witnesses who prefiled testimony have been excused today.

As provided in the prehearing order, I believe it would be appropriate at this time for the prefiled testimony of each of the witnesses listed in Section VII of the order, that is at Page 4, be inserted into the record as though read.

CHAIRMAN BAEZ: Very well. Do we need to have them presented individually or have Mr. Sasso present them individually?

MR. KEATING: I think we can do it either way.

CHAIRMAN BAEZ: Mr. Sasso, it's at your -- you can have wholesale introduction of testimony or --

MR. SASSO: We would move the admission of the testimony of all of these witnesses into the record as though read.

CHAIRMAN BAEZ: Without objection, show the testimony filed on the company's behalf as found on Page 4 of the prehearing order, that will be Witnesses Waters, Roeder, Murphy, Robinson, Hunter, McNeill, and Beuris entered into the record as though read.

Mr. Keating.

MR. KEATING: Also in the prehearing order it indicates that all exhibits submitted with the prefiled testimony can be identified and admitted into the record.

Staff has prepared and distributed to the Commissioners and the court reporter and the company a list of these exhibits plus two additional exhibits that the company has stipulated to admitting into the record consisting of responses to staff's discovery in this docket. These additional exhibits have also been provided to the court reporter.

In lieu of reading and marking each exhibit for the record, I would suggest that this exhibit list itself be marked as the first hearing exhibit, and then have the exhibits included on the list be marked for identification in sequential order as set forth on the list.

CHAIRMAN BAEZ: Very well. Without objection, we will show the comprehensive exhibit list for entry into the hearing record marked as Exhibit 1. And all other exhibits, including exhibits attached to the prefiled testimony on behalf of the petitioner marked as reflected therein and moved into the record.

(Exhibits 1 through 28 marked for identification and admitted into the record.)

**IN RE: PETITION FOR DETERMINATION OF NEED**

**BY PROGRESS ENERGY FLORIDA**

**FPSC DOCKET NO. ________**

**DIRECT TESTIMONY OF SAMUEL S. WATERS**

## I. INTRODUCTION AND QUALIFICATION

**Q. Please state your name, employer, and business address.**

A. My name is Samuel S. Waters and I am employed by Progress Energy Carolinas (PEC). My business address is 410 S. Wilmington Street, Raleigh, North Carolina, 27601.

**Q. Please tell us your position with PEC and describe your duties and responsibilities in that position.**

A. I am Manager of Resource Planning for Progress Energy Florida (PEF or the Company) and Progress Energy Carolinas. I am responsible for directing the resource planning process for both companies. Our resource planning process is an integrated approach to finding the most cost-effective alternatives to meet each company's obligation to serve, in terms of long-term price and reliability. We examine both supply-side and demand-side resources available and potentially available to the Company over its planning horizon, relative to the Company's load forecasts. In this regard, System Resource Planning prepares and presents the Progress Energy Florida Ten-Year Site Plan (TYSP) documents that are filed with the Florida Public Service Commission (FPSC or Commission), in accordance with applicable statutory and regulatory requirements. In my capacity as Manager of Resource Planning, I oversaw the completion of the Company's most recent TYSP document filed in April 2004.

**Q. Please summarize your educational background and employment experience.**

A. I graduated from Duke University with a Bachelor of Science degree in Engineering in 1974. From 1974 to 1985, I was employed by the Advanced Systems Technology Division of the Westinghouse Electric Corporation as a consultant in the areas of transmission planning and power system analysis. While employed by Westinghouse, I earned a Masters Degree in Electrical Engineering from Carnegie-Mellon University.

I joined the System Planning department of Florida Power & Light Company (FPL) in 1985, working in the generation planning area. I became Supervisor of Resource Planning in 1986, and subsequently Manager of Integrated Resource Planning in 1987, a position I held until 1993. In late 1993, I assumed the position of Director, Market Planning, where I was responsible for oversight of the regulatory activities of FPL's Marketing Department, as well as tracking of marketing-related trends and developments.

In 1994, I became Director of Regulatory Affairs Coordination, where I was responsible for management of FPL's regulatory filings with the FPSC and the Federal Energy Regulatory Commission (FERC). In 2000, I returned to FPL's Resource Planning Department as Director.

I assumed my current position with Progress Energy in January of this year. I am a registered Professional Engineer in the states of Pennsylvania and Florida, and a Senior Member of the Institute of Electrical and Electronics Engineers, Inc. (IEEE).

**Q. Have you previously testified before this Commission?**

A. Yes. I have testified in several dockets related to resource planning and the need for power, including Docket 870197-EI, Petition for Florida & Light Company for Non-Firm Load Methodology and Annual Targets; Docket Nos. 890973-EI and 890974-EI, FPL's Determination of Need for the Lauderdale and Martin Projects; Docket Nos. 900709-EQ and 900731-EQ, Joint Petition of Indiantown Cogeneration Limited (ICL) and FPL to Determine Need for the ICL Facility; Docket No. 900796-EI, Petition for Approval of the Purchase of Robert W. Scherer Unit No. 4 from Georgia Power Company; Docket No. 910004-EU, Annual Hearings on Load Forecasts, Generation Expansion Plans and Cogeneration Prices; Docket No. 910816-EI, Petition of Nassau Power Corporation to Determine Need; Docket No. 911103-EI, Complaint of Consolidated Minerals, Inc. (CMI) Against Florida Power & Light Company for Failure to Negotiate Cogeneration Contract; Docket Nos. 920520-EQ and

920648-EQ, Joint Petition to Determine Need for Electrical Power Plant to be located in Okeechobee County by Florida Power & Light Company and Cypress Energy Partners, Limited Partnership; and Dockets 900001-EI, 910001-EI, 920001-Ei and 930001-EI concerning FPL's Oil Backout Cost Recovery Factor and Capacity Cost Recovery Factor. I also submitted testimony in FPL's rate review, Docket No. 001148-EI.

In addition to appearing on FPL's behalf in the above cases, the PSC Staff submitted my testimony in Docket No. 960409-EI, Tampa Electric Company's Petition to Determine Need for Polk Power Station.

## II. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony in this proceeding?**

A. I am testifying on behalf of Progress Energy Florida in support of its Petition for Determination of Need for Hines Unit 4. My testimony will introduce all of the Company's witnesses in the proceeding. I will provide an overview of the Hines 4 unit that the Company proposes to build. Then I will discuss PEF's Resource Planning process and how that led the Company to identify the Hines 4 unit as its next-planned supply-side alternative. I will also explain the Company's need for the Hines 4 combined cycle unit, and describe the steps the Company has taken to seek out available, superior supply-side alternatives through the Request for Proposal (RFP) process. Next, I will provide an overview of the Company's evaluation of competing proposals. I will conclude my testimony by explaining the Company's decision to proceed with the Hines 4 unit. Detailed information concerning the Company's decision to build Hines 4 is contained in the Need Determination Study for Hines 4, provided as Exhibit___ (SSW-1) of my testimony.

**Q. Are you sponsoring any sections of Progress Energy Florida's Need Study (SSW-1)?**

**A.** Yes. In general I am the sponsor of the Need Study, and in particular I am sponsoring Section III, "Resource Need and Identification." The Need Study was prepared under my direction, and it is true and accurate.

**Q. Are you sponsoring any exhibits to your testimony?**

**A.** Yes. I am sponsoring the following exhibits to my testimony:

**SSW-1 Progress Energy Florida Need Determination Study for Hines Unit 4**

**SSW-2 Forecast of Winter Demand and Reserves With and Without Hines 4**

**SSW-3 Levelized Busbar Cost Curves**

**SSW-4 Progress Energy Florida 2008 System Energy Mix**

Each of these exhibits was prepared under my direction, and each is true and accurate.

**Q. Please give an overview of the Company's presentation.**

**A.** In addition to my own testimony, the Company will present the testimony of the following witnesses:

- Mr. John Robinson, who will testify about the site and unit characteristics for the Hines 4 combined cycle unit, including the size, equipment configuration, fuel type and supply modes; the estimated costs of Hines 4; and the unit's projected in-service date;
- Mr. John J. Hunter, who will describe the Hines Energy Complex (HEC) site, discuss the environmental benefits of the HEC site and Hines Unit 4, and discuss the environmental approval process associated with the construction and operation of Hines 4;
- Ms. Pamela R. Murphy, who will discuss the Company's oil and natural gas forecast and the fuel supply plan for Hines Unit 4;
- Mr. Alfred G. McNeill, who will discuss the transmission requirements for Hines 4 and the transmission requirements for the proposals submitted in response to Progress Energy Florida's RFP;
- Mr. Greg Beuris, who will discuss the financial impacts of power purchases on Progress Energy and Progress Energy Florida and the treatment of those impacts in evaluating proposals submitted in response to Progress Energy Florida's RFP, and
- Mr. Daniel J. Roeder, who will describe Progress Energy Florida's RFP, the proposals we received in response to the RFP, the implementation of the RFP, and the results of the evaluation of the proposals.

**Q. Please summarize your testimony.**

A. On an ongoing basis, Progress Energy Florida conducts a robust resource planning process to project its future resource needs to serve its customers' future electricity needs in a reliable and cost-effective manner. Through this process the Company identified Hines Unit 4 as its next-planned generating addition, offering economic benefits to customers superior to any other alternative. Our evaluation of these alternatives included an evaluation of generating projects proposed by outside parties in response to PEF's RFP solicitation. Bids were evaluated, and none compared favorably to the Company's proposed expansion of the HEC. Through its planning and RFP processes, Progress Energy Florida has demonstrated that the Hines 4 unit is the best alternative for maintaining its electric system reliability and integrity, and providing its customers with adequate electricity at a reasonable cost.

## III. OVERVIEW OF THE HINES 4 PROJECT

**Q. Please provide an overview of the Hines 4 unit.**

A. The Hines 4 unit will be a state-of-the-art, gas-fired, combined cycle power unit with an expected winter rating of 517 megawatts (MW). Progress Energy Florida will build the unit at its HEC site in Polk County, Florida, with an in-service date of December 2007. The unit will be highly efficient, with a winter full load heat rate of approximately 7062 Btu/kWh, and will be fueled with natural gas. We currently project the unit to serve as intermediate capacity, although it is projected to operate in more of a base load mode out in time.

Although the Company has previously obtained Site Certification from the Florida Siting Board for the HEC in order to build the Hines 1, 2, and 3 units (and for 3,000 MW of ultimate site capacity), we are seeking at this time Supplemental Site Certification and related environmental permits for the purpose of building the Hines 4 generating unit.

The cost for Hines 4, excluding transmission facilities, is estimated to be $221.5 million plus $27 million for Allowance for Funds Used During Construction (AFUDC), for a total cost of $248.5 million. This includes the cost of equipment; the Engineering, Procurement, and Construction (EPC) contractor; licensing; and internal costs such as construction management and start-up costs.

Construction of a 21-mile, 230 kV line from Hines to West Lake Wales, expansion of the Hines Energy Substation, and the replacement of sixteen 230 kV breakers will be necessary to accommodate the connection of Hines 4 at the HEC to Florida's interconnected electrical grid. The estimated cost for these transmission projects is $33.4 million, plus $4.2 million for AFUDC, for a total cost of $37.6 million.

We believe that the Hines 4 unit will enable the Company to meet the reliability needs of our customers, and that it will provide a superior source of efficient, low-cost power to our customers during its life, as well as add to the balance of energy sources on the Progress Energy Florida system.

## IV. THE COMPANY'S RESOURCE PLANNING PROCESS

**Q. Please explain Progress Energy Florida's Resource Planning Process.**

A. The Resource Planning process is an integrated process in which the Company seeks to optimize its supply-side options along with its demand-side options into a final, integrated optimal plan, designed to deliver reliable, cost-effective power to Progress Energy Florida customers. We evaluate the relationship of demand and supply against the Company's reliability criteria to determine if additional capacity is needed during the planning period. With the inclusion of cost-effective DSM programs, the generation plan is optimized to establish the most cost-effective overall plan, which becomes the Company's Integrated Optimal Plan. This optimal plan is presented to the FPSC in April of every year in the Company's annual TYSP filing. The April 2004 TYSP is included as Appendix F to the Need Determination Study, Exhibit ___ (SSW-1).

**Q. What are the reliability standards the Company used to determine the need for additional resources?**

A. Progress Energy Florida plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. The Company plans its resources to satisfy a minimum Reserve Margin criterion and a maximum Loss of Load Probability (LOLP) criterion. Progress Energy Florida has based its planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. By using both the Reserve Margin and LOLP planning criteria, PEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions.

**Q. Why are reserves needed?**

A. Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. At any given time during the year, some plants will be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserves must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

**Q. What is Progress Energy Florida's Minimum Planning Reserve Margin?**

A. Progress Energy Florida's current minimum Reserve Margin threshold is 20 percent. The PSC, in Order No. PSC -99-2507-S-EU, approved a joint stipulation from the investor-owned utilities in peninsular Florida – Progress Energy Florida, Florida Power & Light Company, and Tampa Electric Company – to increase minimum planning Reserve Margin levels to at least 20 percent by the summer of 2004.

**Q. What is LOLP and what does it measure?**

A. In contrast to Reserve Margin, which is a deterministic measure of reliability, LOLP is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. Where Reserve Margin considers only the peak load and amount of installed resources, LOLP also takes into account a utility's load shape, generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by Progress Energy Florida, is a maximum of one day in ten years loss of load probability.

**Q. How does the Progress Energy Florida Resource Planning process begin?**

A. The Resource Planning process begins once a forecast of system load growth has been developed for the next ten years. This forecast draws on the collection of certain input data, such as population growth, fuel prices, interest and inflation rates, and the development of economic and demographic assumptions that impact future energy sales and customer demand.

**Q. Briefly describe Progress Energy Florida's System demand and energy forecasts.**

A. Between the winters of 2003/04 and 2012/13, winter net firm demand is projected to grow from 8,626 MW to 10,606 MW, which represents approximately a 2.3 percent annual growth rate. The net energy for load is projected to grow from 43,911 GWh in 2003 to 54,608 GWh in 2013, which represents a 2.2 percent growth rate. The demand and energy forecasts, and the methodology used to develop them, are discussed in detail in Section III of the Need Determination Study and in Chapter 2 of the Company's TYSP, which is Appendix F of the Need Study.

**Q. How are demand-side programs quantified and incorporated into the Company's planning process?**

A. Through analysis conducted during the last DSM Goals and DSM Plan proceedings (Docket Nos. 971005-EG and 991789-EG respectively), to assess the projected cost, performance, viability, and cost-effectiveness of a wide range of dispatchable and non-dispatchable DSM program options, the Company identified a set of DSM programs that were cost-effective and met Commission-established goals. With the approval of its DSM plan by the PSC, Progress Energy Florida offers five residential programs, eight commercial and industrial programs, and one research and development program. Progress Energy Florida's DSM programs have successfully met the Commission-established DSM goals in the past, and the current plan, which includes these programs, anticipates achieving all of the future year goals.

Progress Energy Florida proposed new conservation goals for the ten-year period from 2005 through 2014, as well as a new DSM Plan for meeting the proposed goals, in a filing with the Commission as part of Docket No. PSC-040031-EG. Over the next five years (2005-2009), the proposed conservation goals are generally lower than the existing set of goals, reflecting less available savings from demand-side resources. All other things being equal, this change causes an increase in PEF's firm winter and summer peak demand and, therefore, further establishes the need for Hines 4.

**Q. How are off-system supply resources reflected in the Company's planning process?**

A. Progress Energy Florida's plan takes into account its future supply of firm capacity from purchased power contracts, as well as its own existing and committed generating units that will be in service during the study period.

**Q. How are new supply-side alternatives identified?**

A. If a need for additional capacity during the planning period is identified, Progress Energy Florida examines alternative generation expansion scenarios. Supply-side resources are screened to determine those that are the most cost-effective. The Company begins with a wide range of options, identified from various industry sources and Progress Energy Florida's experience, and pre-screens those that do not warrant more detailed cost-effectiveness analysis. The screening criteria include costs, fuel sources and availability, technological maturity, and overall resource feasibility within the Company's system.

Generation alternatives that pass the initial screening are considered viable capacity alternatives and are included in the next step of the planning process. That step involves an economic evaluation of generation alternatives in a computer model called Strategist. The primary output of Strategist is a Cumulative Present Worth Revenue Requirements (CPWRR) comparison of all of the viable resource combinations that will satisfy Progress Energy Florida's reliability requirements. The most cost-effective supply-side resource (or combinations) are evaluated, resulting in a ranking of the various generation plans by system revenue requirements. Strategist considers many tens or hundreds of thousands of combinations. Each of these resource combinations is ranked based on cost performance over both the study period (40 years) and the planning period (10 years). Generally, the generation plan with the lowest CPWRR over the study period is chosen as the Base Generation Plan.

## V. HINES 4 IS THE NEXT-PLANNED GENERATING UNIT

**Q. Please explain how the Company's Resource Planning efforts identified Hines 4 as the Company's next-planned generating unit.**

**A.** Through the Resource Planning process I have just described, we developed the April 2004 TYSP. The plan includes the Hines 3 unit, currently under construction for commercial operation by December 2005. Following this addition, the plan calls for the projected combined cycle expansion of the HEC with Units 4 through 6, which are forecast to be in service by December 2007, 2009, and May 2010, respectively. The new HEC units will be state-of-the-art combined cycle units similar to HEC Units 1, 2, and 3.

The plan also calls for the addition of three simple-cycle combustion turbines (CTs) in December, 2006, and two new, unsited combined cycle units in May of 2012 and December of 2013. The company is currently in negotiations to purchase power instead of building these combustion turbines.

Progress Energy Florida's present Determination of Need Petition, its April 2004 TYSP, and its Commission-approved DSM Plan are all consistent with the Company's Resource Planning process as described. Subject to identifying superior opportunities by issuing an RFP, we concluded that Hines 4 was the next-planned generating unit.

**Q. Why does Progress Energy Florida need additional new generation in December 2007?**

**A.** Progress Energy Florida maintains its Reserve Margin for both its summer and winter peak demands to ensure reliable electric service to its customers. Currently, the Company's winter peak season triggers the need for additional resources. Progress Energy Florida needs additional generation in December 2007 to meet its 20 percent minimum Reserve Margin commitment. Exhibit ___ (SSW-2) shows Progress Energy Florida's forecast of winter peak demand and reserves, with and without the Hines 4 capacity addition. For the period from the winter of 2004/05 to the winter of 2008/09, Progress Energy Florida projects that the growth in firm winter peak demand will average approximately 247 MW a year with a projected peak in 2007/08 of 9,737 MW and in 2008/09 of 9,891 MW. The exhibit also shows that Progress Energy Florida will have a total generating capability of approximately 11,561 MW by the winter of 2007/08. This capacity includes the installation of Hines 3 in December 2005, as previously approved by this Commission, and purchased power currently in negotiations. As demonstrated in this exhibit, without the Hines 4 capacity addition, Progress Energy Florida's Reserve Margin will decrease to about 19 percent in 2007/08 and 16 percent by 2008/09.

**Q. What impact will the addition of the Hines 4 capacity have upon Progress Energy Florida's Reserve Margin and ability to provide reliable service to its customers?**

**A.** As shown in Exhibit ___ (SSW-2), the addition of the Hines 4 capacity will increase Progress Energy Florida's winter peak Reserve Margin to about 24 percent in 2007/08 and 21 percent in 2008/09. The Hines 4 addition allows

Progress Energy Florida to satisfy its commitment to maintain a minimum 20 percent Reserve Margin.

Q. **Are there other considerations in balancing demand- and supply-side resources?**

**A.** Yes. The Company calculates its Reserve Margin based on the relationship between firm load and total capacity available to serve that load. Firm load represents firm customer load after all demand-side management (DSM) capability has been implemented. Progress Energy Florida believes that its dispatchable demand-side resources provide important and cost-effective resources when appropriately utilized. Although DSM is available as a resource to reduce load if needed, it cannot be used as often or as long as physical generation without eventually affecting customer participation levels, as was demonstrated by the customer attrition experience of 1998 and 1999. As the Company has learned, when interruptions in service increase in frequency, customers are less willing to accept such service for lower rates. For this reason, Progress Energy Florida is planning to rely more on additional physical reserves to ensure a reliable power supply than on the consent of customers to interruptions in service for reduced tariffs. Based on projected load growth, the addition of Hines 4 will increase the Company's share of physical reserves to approximately one half of total reserve capacity (which includes DSM) in the winter of 2007/08, a level of physical reserves sufficient to maintain coverage of an unplanned outage of the fleet's largest unit.

**Q. Why has Progress Energy Florida chosen the combined cycle generator as the type of generating capacity to install?**

A. The results of our resource planning analyses show that the economics favor combined cycle units to serve intermediate to base load need. Progress Energy Florida has been projecting the need for combined cycle capacity in its TYSP filings for many years, including its most recent April 2004 filing.

Perhaps this can most easily be explained using a tool known as "levelized busbar screening curves." Exhibit ___ (SSW-3) is a graph of levelized busbar costs for potential new generation resources, including combustion turbine, combined cycle, and coal technologies. It illustrates a technology's total levelized annual cost in $/kW-year as a function of capacity factor. In this analysis, the costs were levelized and then present valued to 2007. At zero capacity factor, only a technology's capital and fixed costs are depicted. The slope of the line is a function of the variable costs like fuel, variable O&M (operations and maintenance), and consumables that increase in direct proportion to the energy produced. As the capacity factor increases, the line reflects increasing total costs since variable costs such as fuel and variable O&M increase. The steeper the slope of the line, the higher the variable costs per unit of energy (e.g., $/MWh). For example, the line corresponding to a CT has a steeper slope than the line for a coal unit. This is because the fuel and variable O&M costs for a CT are higher than those of a coal unit. In this type of analysis, various technologies can be compared in the range of their expected capacity factors based on total levelized annual cost.

For any given capacity factor, the lowest line on the chart represents the lowest cost technology. The graph shows as the capacity factor increases, the technology identified as lowest cost changes. The busbar screening curves show that CT capacity is the most economical new generation alternative at capacity factors less than about 20 percent. The curves also demonstrate that combined cycle generation is the most cost-effective new resource when a generator is needed to run more than approximately 20 percent of the time. The figure also shows that combined cycle units are less expensive than a new coal (here, conventional pulverized coal) unit at any capacity factor, due largely to the higher capital and fixed O&M costs of new coal plants. Thus, combined cycle generation is the resource of choice for both intermediate and base load operation.

Since combined cycle generation is the most economical resource for intermediate duty (and could also economically operate as a base load resource, as shown in the busbar screening diagram), Hines 4 is an ideal resource to satisfy not only the projected growth in customers' peak load, but also to serve customers' growing energy requirements in the most cost-effective way. Hines 4 is projected to operate in a capacity factor range of 50-70 percent, averaging 67 percent over its expected 25-year life, and will also provide the flexibility to serve as economical base load capacity operating at higher capacity factors should future system conditions require this type of service. This is both an economic and a strategic benefit of Hines Unit 4.

**Q. You mentioned earlier that the Hines 4 unit will add to the balance of energy sources on the Progress Energy Florida system. Is Progress Energy Florida becoming too dependent on natural gas?**

**A.** No. Current economics overwhelmingly favor natural gas units, as shown in the busbar screening curves. Progress Energy Florida has a good base of coal and nuclear capacity, and there is a limited outlook for cost-effective renewables. As shown in Pam Murphy's testimony, the natural gas supply is abundant over the study period.

To show the balance of the energy sources that will result after the addition of Hines 4, Exhibit ___ (SSW-4) shows the percentages of total Net Energy for Load (NEL) expected to be supplied by the various energy sources in the year 2008. The exhibit demonstrates that the Progress Energy fuel mix is well balanced, with 14% of NEL supplied by nuclear, 34% by coal (totaling 48% for base load technologies), 27% from natural gas, and the remainder from oil and power purchases from both Qualifying Facilities (QFs) and other utilities. In practical terms, Progress Energy Florida customers will be receiving energy from the full spectrum of available sources in nearly equal parts. This balance provides benefits against price volatility and interruption of supply of any single source, in addition to the economic benefit of adding Hines 4 to the system.

**Q. What are the environmental benefits of Hines Unit 4?**

A. A combined cycle facility fueled by natural gas, such as Hines 4, is the cleanest and most efficient fossil-fueled generation currently available. There are virtually no sulfur dioxide ($SO_2$) emissions, and nitrogen oxide ($NO_x$) emissions are approximately one tenth the level of coal-fired generation utilizing low $NO_x$ burners. Therefore, the proposed combined cycle generation will provide cleaner air for Florida compared to other alternative feasible generation technologies, and will help the Company comply with current environmental regulations, as well as prepare the Company to meet any more stringent regulations that may be enacted in the future.

## VI. Progress Energy Florida's RFP

**Q. Please describe Progress Energy Florida's efforts to solicit proposals from other supply-side providers.**

A. In accordance with Rule 25-22.082, F.A.C., Progress Energy Florida issued an RFP on October 7, 2003, soliciting proposals for other generating resources that might prove superior to Hines 4 as a supply-side alternative. The RFP is included as Appendix H of Exhibit ___ (SSW-1).

In our RFP, we explained that we had identified Hines 4 as our next-planned generating unit, and we invited interested parties to make alternative proposals that offered superior value. We sought proposals that would be in service by December 1, 2007 and that would be reliable, dispatchable, and technically sound. We were looking for the proposals to come from experienced, financially-sound developers that would be able to secure the necessary permits, and that had planned for an adequate fuel supply. We evaluated all proposals by systematically following a structured, orderly evaluation process, which we identified in the RFP, along with the criteria by which we evaluated the proposals.

**Q. Briefly, what were the results of the RFP?**

A. We received five proposals from four bidders. In addition, one of the bidders provided two alternatives to their proposal. One of the proposals from one of the bidders did not pass the threshold requirements and was eliminated. One proposal from each of the four bidders was put on the Short List and compared to our self-build alternative, Hines Unit 4. We performed a significant amount of analysis, evaluating the price and non-price attributes of the alternatives. The final evaluation of the non-price attributes showed Hines Unit 4 to be one of the top two ranked alternatives in nearly all of the categories. The detailed economic analysis found Hines Unit 4 to be approximately $55 million (2004 dollars) less expensive than the least-cost third-party proposal. The least-cost New Unit Proposal (another combined cycle unit) was found to be more than $95 million

(2004 dollars) more expensive than Hines Unit 4. Finally, we performed sensitivity analyses, in which we either gave advantages to the third-party proposals by assuming decreases in their costs or assumed increases in the costs associated with Hines Unit 4. In all cases, Hines 4 was the least cost alternative, demonstrating that the selection of Hines 4 is a sound choice. The testimony of Daniel J. Roeder describes in detail the RFP, the process we followed, the evaluation of the proposals, and the results of the analysis.

## VII. MOST COST-EFFECTIVE ALTERNATIVE

**Q. Is the Hines 4 unit the Company's most cost-effective alternative for meeting its need?**

A. Yes, it is. As I have described, the Company conducted a careful screening of various other supply-side alternatives as part of its Resource Planning process before identifying Hines 4 as its next-planned generating alternative. We were able to screen out less cost-effective supply-side alternatives, identifying Hines 4 as the most cost-effective alternative available to us. Further, through our RFP process, we determined that the Hines 4 unit was also more cost-effective than any of the proposals made to us.

**Q. Why do you think Hines Unit 4 is the most cost-effective alternative?**

A. There are a number of factors, with the significant cost differences being primarily related to the lower fixed costs of Hines 4. First, Progress Energy

Florida is able to take advantage of its prior investment in infrastructure at the HEC. Second, by virtue of owning and operating three other power stations on the same site, Progress Energy Florida will need to add a much smaller number of new employees to operate the four units at the HEC than bidders would have to employ to operate a greenfield facility. Finally, Progress Energy Florida has as good, or better, credit rating than many of the IPPs today. Thus, the Company has a financing advantage.

## VIII. Benefit to the State

**Q. Is the Hines 4 unit consistent with the needs of Peninsular Florida?**

A. Yes, the Hines 4 unit will assist Progress Energy Florida in meeting its 20 percent planned Reserve Margin and will assist Peninsular Florida in attaining the 15 percent minimum level of planning reserves targeted for the FRCC region.

## IX. Consequences of Delay

**Q. What will be the impact of delay in implementing the Hines 4 project?**

A. If the Hines 4 unit is delayed, Progress Energy Florida would not be able to satisfy its minimum 20 percent Reserve Margin planning criterion by the winter of 2007/08 in the most reliable and cost-effective manner. This would expose Progress Energy Florida's customers to a risk of interruption of service in the event of unanticipated forced outages or other contingencies for which Progress Energy Florida maintains reserves. Even without an interruption in service, without the efficient Hines 4 unit, Progress Energy Florida's customers would be subject to higher fuel costs as less efficient units are used to serve their needs.

## X. CONSERVATION MEASURES

**Q. Did Progress Energy Florida attempt to mitigate its need for the proposed unit by pursuing conservation measures reasonably available to it?**

A. Yes, we did. As I discussed previously, the Company identified and has implemented a set of cost-effective DSM programs that have successfully met Commission-established goals. We anticipate that we will achieve all of the future year goals also.

## XI. CONCLUSION

**Q. Please summarize the benefits of the Hines 4 unit.**

A. Progress Energy Florida needs the Hines 4 unit to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost. By building the unit, the Company will be able to meet its commitment to maintain a 20 percent Reserve Margin, and it will do so by improving not just the quantity, but also preserving the quality, of its total reserves, maintaining an appropriate portion of physical generating assets in the Company's overall resource mix. The unit will also add diversity to Progress Energy Florida's fleet of generating assets, in terms of fuel, technology, age, and functionality of the unit. Having exhausted conservation measures reasonably available to the Company, Progress Energy Florida selected the Hines 4 unit as its most cost-effective alternative for meeting its needs. The unit will be a state-of-the-art, fuel efficient, environmentally preferable installation that will be located on a site substantially pre-approved for exactly this kind of power resource. We are pleased to be able to add this unit to the Company's fleet and to Peninsular Florida, and we urge the Commission to approve the plan.

**Q. Does this conclude your testimony?**

**A.** Yes, it does.

**IN RE: PETITION FOR DETERMINATION OF NEED**

**BY PEF CORPORATION**

**FPSC DOCKET NO. ______________**

**DIRECT TESTIMONY OF DANIEL J. ROEDER**

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, employer, and business address.**

A. My name is Daniel J. Roeder and I am an employee of Progress Energy Carolinas (PEC), 410 S. Wilmington Street, Raleigh, North Carolina, 27601.

**Q. Please tell us your position with PEC and describe your duties and responsibilities in that position.**

A. I am a Project Leader in the System Resource Planning Section of the System Planning & Operations Department. The System Resource Planning Section is responsible for the resource planning for both Progress Energy Florida (PEF or the Company) and PEC systems. My responsibilities are usually of the nature of special projects, such as the Request for Proposals (RFP) that is the subject of this testimony. I served as the Project Leader and "Official Contact" for PEF's Hines 4 RFP.

**Q. Please tell us about your educational background and experience.**

A. I graduated from the University of Tennessee with a B.S. in Engineering Science and Mechanics in 1980, and I obtained my M.S. in Mechanical Engineering in 1982. I have been a PEC employee since 1982 and, with the exception of a one-year rotational field assignment, I have worked the entire time in the System Planning & Operations Department, performing analyses such as production costing, generation reliability, integrated resource planning, and Clean Air Act compliance. During the year prior to the completion of the merger between PEF and PEC, I was a core member of the Integration Team, working as an integration analyst. I am a registered Professional Engineer in the state of North Carolina.

**Q. Have you been responsible for leading RFPs before?**

A. Yes, I served as the Project Leader for the Hines 3 RFP. I also participated in two of PEC's RFPs. I was the Manager of the Resource Planning Unit and part of the team that developed PEC's first RFP, which was issued in 1996, and for which I led the Economic Evaluation Team. I was involved to a lesser extent in the second RFP PEC issued in 1997.

## II. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to describe PEF's RFP for 2007 power supply resources (the Hines 4 RFP), the proposals we received in response to the RFP, the evaluation performed on the proposals, and the results of the evaluation.

**Q. Are you sponsoring any sections of PEF's Need Study (SSW-1)?**

A. Yes, I am sponsoring Section IV, "Resource Selection—The 2007 Request for Proposals (RFP)" of the Need Study. I am also sponsoring the confidential Appendix J to the Need Study, "Description of Proposals."

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

Exhibit ___ (DJR-1) Results of Detailed Economic Analysis

Exhibit ___ (DJR-2) RFP Evaluation Process

Exhibit ___ (DJR-3) Summary of Proposals

Exhibit ___ (DJR-4) Threshold Requirements

Exhibit ___ (DJR-5) Results of Threshold Screening

Exhibit ___ (DJR-6) Results of Economic Screening

Exhibit ___ (DJR-7) Results of Optimization Analysis

Exhibit ___ (DJR-8) Minimum Evaluation Requirements

Exhibit ___ (DJR-9) Technical Criteria

Exhibit ___ (DJR-10) Final Results of Technical Evaluation

Exhibit ___ (DJR-11) Results of Detailed Economic Analysis-Costs by Component

I prepared each of these exhibits, and each is true and accurate.

**Q. Please summarize your testimony.**

A. Upon determining the need for additional generating capacity as described in the testimony of Mr. Samuel S. Waters, PEF embarked upon the RFP process. The Company followed Rule 25-22.082 F.A.C. in the development and implementation of the RFP. We issued the RFP, providing the notification required by the Rule and information about the Company's self-build alternative, Hines Unit 4. We sought proposals that would be in service by December 1, 2007 and that would be reliable, dispatchable, and technically sound. We were looking for the proposals to come from experienced, financially-sound developers that would be able to secure the necessary approvals and permits, and that had planned for an adequate fuel supply. We fairly evaluated all proposals by systematically following a structured, orderly evaluation process, which we identified in the RFP, including the criteria by which we evaluated the proposals.

**Q. Briefly, what were the results of your RFP?**

A. We received five proposals and two variations from a total of four bidders. One proposal from a bidder did not pass the Threshold Screening. The remaining four proposals and two variations from the four bidders were narrowed down to one proposal from each bidder and were compared to our self-build alternative, Hines Unit 4. We performed a significant amount of analysis, evaluating the price and non-price attributes of the alternatives. The final evaluation of the non-price attributes showed Hines Unit 4 to be one of the top two ranked alternatives in most of the categories. The detailed economic analysis found Hines Unit 4 to be over $55 million (2004 dollars) less expensive than the least cost alternative proposal. The least cost New Unit Proposal (another combined cycle plant) was found to be more than $95 million (2004 dollars) more expensive than Hines Unit 4. Exhibit ___ (DJR-1) shows the results of the analysis. Finally, we performed sensitivity analyses, in which we either gave advantages to one of the third-party proposals by assuming decreases in its costs or assumed increases in the costs associated with Hines Unit 4. In all cases, Hines 4 was the least cost alternative, demonstrating that the selection of Hines 4 is a sound choice. Based on the analyses, the Company concluded that Hines Unit 4 is the most cost-effective alternative for meeting the need for additional generating capacity beginning in 2007 to serve PEF's customers. My testimony will discuss all of the analyses we performed, in detail.

## III. THE RFP PACKAGE

**Q. How did Progress Energy Florida construct the RFP?**

A. The RFP Package consisted of three key components. The first part was the Solicitation Document, which outlined PEF's need for generating capacity, the objectives of the RFP, the Company's next-planned generating unit, PEF's system specific conditions, and a schedule of key dates in the RFP process, and it identified myself as the RFP contact. The document also discussed PEF's requirements for submission of bids, and it described the criteria that we would use to compare and evaluate the price and non-price attributes of the proposals.

The second component was the Response Package, which contained a description of the information bidders were to provide in their proposals. It defined the required organizational structure and contents of any submitted proposal and it contained instructions on how to complete the schedules (or forms) provided to the bidders.

The third component consisted of the Schedules (Microsoft Excel worksheets) that bidders were required to use to provide data, including pricing, to PEF. Included in the RFP package were two attachments to the Solicitation Document. The first was a version of the proposed Key Terms and Conditions of a purchased power agreement and the second was PEF's April 2003 Ten-Year Site Plan (TYSP).

**Q. How does the RFP you issued for Hines 4 differ from the RFP for Hines 3?**

A. There were a number of differences between the two RFPs. Some were as a result of the changes to the Bid Rule, and some were changes we made with the idea of opening up the RFP to get more participants and give more flexibility to potential bidders.

**Q. What kind of changes did you make as a result of changes to the Bid Rule?**

A. One of the changes was to hold a Pre-Issuance meeting to discuss the requirements of the RFP prior to actually issuing the RFP. In the spirit of discussing the RFP prior to issuing it, we also issued a draft of the RFP, which was not required by the Bid Rule. We included a copy of our latest Ten-Year Site

Plan and we included a section discussing system-specific conditions, both as required by the revised Rule 25-22.082 F.A.C. While we described our evaluation process quite thoroughly in the Hines 3 RFP, we provided even more explanation in the Hines 4 RFP. Finally, we added a discussion about the calculation of the equity adjustment in the Hines 4 RFP because imputed debt is a cost of purchased power and, therefore, we must calculate it, when necessary. In the Hines 3 RFP, we did not apply an equity adjustment in our evaluation because Hines 3 was significantly more cost effective than any other proposal without the adjustment. In this RFP evaluation, as I'll explain later, we did apply the equity adjustment because we said we would in the RFP, even though Hines 4 can be shown to be more cost effective without it.

**Q. What kind of changes did you make to open up the RFP and give potential participants more flexibility?**

A. First, to open up the RFP to more participants, we eliminated the minimum capacity requirement of a proposal (in the Hines 3 RFP, there was a 100 MW minimum). Second, to provide bidders more flexibility, we allowed proposals to have a start date as early as December 1, 2006, a year before Hines 4 is to be placed in service. Third, we allowed bidders to increase the capacity of their proposal after the first year. This change was the direct result of a request from a potential bidder at the Pre-Issuance meeting. Fourth, we shortened the minimum term of the proposal from five years to one year for proposals that did not require a need determination hearing. Finally, we told the bidders we would allow them to propose a fuel tolling arrangement whereby PEF would be responsible for acquiring fuel for the project.

## IV. THE EVALUATION METHODOLOGY

**Q. Did PEF provide a detailed description of the evaluation process it was going to use?**

A. Yes, we did. The Solicitation Document described in detail the seven-step evaluation process we planned to use in the evaluation of the proposals.

**Q. Please briefly describe the evaluation process.**

A. The process, described in detail in the Solicitation Document itself, is shown in flowchart form in Exhibit ___ (DJR-2). This is the same flowchart that was included in the Solicitation Document. Briefly, the seven steps of the process were:

1) Screening for Threshold Requirements. In this step, the proposals would be reviewed to ensure they met the informational requirements of the RFP. The Threshold Requirements were provided in a table in the Solicitation Document such that the bidders could check to ensure their proposals fulfilled the requirements. Proposals not meeting the Threshold Requirements would be eliminated from further evaluation.

2) Segregation of Bids. In this step, proposals that passed the Threshold Requirements were to be separated into categories distinguished by the type of

bid and term. The purpose of this step was to ensure a consistent and fair evaluation by categorizing "like type" proposals and allowing PEF to identify the best proposals in each category.

3) Economic Evaluation. In this step, the proposals would be screened based on the fixed, variable, and start payments and optimization analyses would be performed. Proposals that were significantly higher in cost compared to other proposals could be eliminated from further evaluation.

4) Technical Evaluation. In this step, proposals that passed the economic screening would be evaluated on a technical basis to assess their feasibility and viability. Proposals were to be reviewed to ensure they conformed to the Minimum Evaluation Requirements (which were different from the Threshold Requirements) and would be evaluated based on established Technical Criteria. Tables in the RFP provided both the Minimum Evaluation Requirements and the Technical Criteria. PEF included a description of each of these non-price attributes, as well as the Company's preferences with regard to the attributes.

5) Selection of Short List. In this step, those bids that were found to be inferior to other bids, based on the Economic and Technical Evaluations, would be eliminated from further consideration.

6) Detailed Evaluation. In this step, proposals that were included on the Short List would be compared to PEF's self-build alternative, Hines Unit 4. Proposals would be subjected to a more detailed assessment, and transmission cost impacts would be incorporated into the analysis. Scenario and sensitivity

analyses would also be conducted, if deemed appropriate based on the proposals submitted.

7) Selection of Final List. In this step, PEF would identify those bidders with which it would begin contract negotiation. In the event that Hines Unit 4 was found to be clearly superior to the short-listed proposals, a final list would not be selected. We also anticipated contract negotiations and an announcement of an Award List, but that was dependent on the results of the evaluation and would not take place if Hines Unit 4 was found to be better than the other proposals.

## V. THE RFP PROCESS: PRE-SUBMISSION

**Q. Let's go through the RFP process. What was the first step?**

A. The RFP process started with our announcement that we were going to be issuing an RFP for generating alternatives. We announced this using several methods, beginning with a notice of the RFP on September 10, 2003. The public notice was published in newspapers of state and national circulation. A press release was also published and referred to in articles by a number of news services, both in print and on-line, including the Electric Power Daily, Energy Info Source, and Morningstar.com.

**Q. Did you publish public notices as required by Rule 25-22.082?**

A. Yes, we did. We published public notices in newspapers of state and national circulation such as the Lakeland Ledger, Tallahassee Democrat, Miami Herald, Tampa Tribune, St. Petersburg Times, Orlando Sentinel, the (Jacksonville) Florida Times-Union, and the Wall Street Journal on various dates between September 10 and October 1, 2003. The notice provided a general description of the Company's next-planned generating unit, the name and address of the contact person from whom to request an RFP package, the Company's RFP web site address where the RFP package could be obtained, and the schedule of critical dates for the RFP process. Twenty-seven parties that had previously expressed an interest in other RFPs in the State of Florida were sent an electronic copy of the public notice, via e-mail, including the Florida Office of Public Counsel and the staff of the Florida Public Service Commission.

**Q. You mentioned the RFP package was available on the RFP web site. When was it first available?**

A. Draft versions of the Solicitation Document and the Response Package were available on September 10, 2003. We decided to make drafts of the documents available to potential applicants so a more informed discussion about the RFP could take place at the Pre-Issuance meeting.

**Q. What was the Pre-Issuance meeting and when was it held?**

A. The Pre-Issuance meeting was held on September 23, 2003 at the Tampa Airport Marriott. Potential participants could also participate in the meeting via conference call. The purpose of the Pre-Issuance meeting was to discuss the requirements of the RFP. The meeting consisted of a presentation covering the objective of the RFP, the types of proposals allowed, the RFP package, the RFP process, and our requirements of bidders. Throughout the presentation, questions were asked, and answers were provided. All questions and answers were later posted on the RFP web site.

**Q. Did you make any changes to the RFP based on the Pre-Issuance meeting?**

A. Yes, we did. The RFP documents were revised, taking into account questions that were asked and comments that were expressed by the participants at the Pre-Issuance meeting. Clarifications were also made to some of the wording.

**Q. When did PEF actually issue the RFP?**

A. The RFP package was issued on October 7, 2003 and it was available for downloading from the RFP web site. By December 16, 2003, more than 80 copies of the RFP package had been downloaded.

**Q. When did the potential participants get involved in the RFP process?**

A. The first major activity for bidders was to submit a Notice of Intent (NOI) to bid. Bidders were asked, but not required, to submit this form by October 14, 2003. Submission of this form would ensure that bidders received all information pertaining to the RFP. NOI forms were received from nine bidders.

**Q. Did Progress Energy Florida hold a Bidders' Conference?**

A. Yes, we held a Bidders' Conference on October 21, 2003 at the Tampa Airport Marriott. The purpose of the Bidders' Conference was to provide interested parties the opportunity to ask questions and seek additional information or clarification about the solicitation process. I made a brief presentation similar to the one I made at the Pre-Issuance meeting, summarizing the RFP process and the requirements of the RFP. Bidders were encouraged to submit questions ahead of time, and one bidder provided written questions. Those questions were answered first, and then I opened the floor for questions. All questions and the corresponding answers were posted on the RFP web site shortly after the Bidders' Conference. The Q&A section of the web site was updated as additional questions were posed.

**Q. When did PEF receive proposals?**

A. We received five proposals from four bidders on December 16, 2003. In addition, one bidder provided two variations to its proposal. To simplify the discussion, the variations will be referred to as proposals also; thus, we had a total of seven proposals from four bidders. The Hines 4 self-build team provided details of the Hines 4 project on the same date. The proposals were identified by bidder as Proposal A through Proposal D. Numbers were appended to the letter designation for bidders that provided more than one proposal or variation. Therefore, we had Proposal A, Proposal B, Proposals C1, C2, and C3, and Proposals D1 and D2.

**Q. What kinds of proposals did you receive?**

A. Four of the seven proposals were New Unit Proposals and two were Existing Unit Proposals. One proposal is best described as a combination Existing/New Unit proposal. The New Unit Proposals involved building new combined cycle units. Two of these proposals involved selling only a portion of the output to Progress Energy Florida. The proposals varied in length from five to 25 years, and all but one would be fueled primarily with natural gas. The start date for all the proposals was December 1, 2007 with the exception of one proposal, which could start as early as December 1, 2006. A summary table of the proposals is provided in Exhibit ___ (DJR-3). Also provided in the exhibit is a list of the names of the bidders, listed in alphabetical order. A more detailed description of the proposals, based on summaries provided by the bidders, can be found in confidential Appendix J of the Need Study.

## VI. THE RFP PROCESS: EVALUATION – THRESHOLD SCREENING

**Q. What happened next?**

A. We began our bid evaluation process. The first step in the process was threshold screening. We evaluated all of the proposals with respect to the Threshold Requirements identified in Table IV-1 of the Solicitation Document and shown in Exhibit ___ (DJR-4). Threshold Requirements represent the minimum requirements that all proposals are required to meet to be evaluated, and with which a Bidder's compliance can be easily assessed. Some examples of Threshold

Requirements are general requirements, such as the proposal being received on time, the submittal fee being included, and the power being available for delivery by December 1, 2007. Others include operating thresholds, such as operating the project to conform to voltage and frequency control requirements and agreement by the bidder to coordinate maintenance scheduling, and having control of the site. Another requirement was that the proposal had to have complete and credible answers provided to all questions.

The threshold screening provided a "sanity check" of the proposals by asking, "Is everything here that we asked for? Do we have everything we need to perform our analyses?" If they didn't pass the threshold screening based on our initial review, we went back to the bidders with questions in an effort to help them resolve the deficiencies in their proposals and to make sure we had everything we needed to conduct a thorough evaluation of the bids.

Q. **What were the results of the threshold screening?**

A. A summary of the Threshold Requirements and the results of the threshold screening are shown in Exhibit ___ (DJR-5). None of the proposals initially passed the Threshold Requirements screening process without any deficiencies; all of the proposals required at least some clarification.

Proposal D1 was for the capacity of an existing unit that is currently under contract to Progress Energy Florida, which expires at the end of 2008. This proposal provides no new capacity to the Progress Energy Florida system by December 1, 2007 and, thus, does not pass the Threshold Requirement that power must be available for delivery by December 1, 2007. Proposal D1 was therefore eliminated from the RFP process and the submittal fee was returned to Bidder D.

**Q. Did PEF contact the bidders and inform them of deficiencies in their proposals?**

A. Yes. On January 13, 2004, PEF informed each of the bidders of the various deficiencies in their proposals with respect to the Threshold Requirements. The Company also requested additional clarification from the bidders on portions of their proposal. All of the bidders submitted clarifications and additional information to pass the Threshold Requirement screening.

**Q. Did you tell the bidders anything else?**

A. Yes, we provided them the cost and operating characteristics of Hines 4.

**Q. Why did you do this?**

A. Up until this point in time, we had provided cost and operating characteristics associated with our next planned generating unit, which were planning estimates. The information provided about Hines 4 was information provided by the Hines 4 self-build team to the RFP Evaluation Team on December 16, 2003, when all bidders submitted their proposals. We provided this information to the bidders and we provided them the opportunity to revise their bids in accordance with Rule 25-22.082(14) F.A.C. We gave the bidders 10 days to revise their bids.

Q. **Did any of the bidders revise their bids?**

A. Bidder B was the only bidder to provide revised prices. In addition to providing revised prices, Bidder B also provided PEF the option to increase the proposal term to as many as 10 years (through the end of 2016). We used the new prices in our economic evaluation and we examined the impact of the optional longer term.

## VII. THE RFP PROCESS: EVALUATION – ECONOMIC EVALUATION

Q. **Please explain the economic evaluation process.**

A. There were two parts to the initial economic evaluation process: a screening analysis and an optimization analysis. The screening analysis compared the six remaining proposals to each other in terms of $/kW-year, based on the total prices proposed by the bidders and an assumed capacity factor. The purpose of the initial economic screening was to get a simple perspective of the economics of the proposals compared to each other.

Q. **What capacity factor did you assume for your screening analysis?**

A. We assumed a capacity factor of 50 percent. This capacity factor was assumed because this was the expected capacity factor for Hines 4 as indicated in the 2003 Ten-Year Site Plan.

Q. **What was the result of your analysis?**

A. The evaluated costs of all but one of the proposals were within a reasonable range of each other. Exhibit ___ (DJR-6) shows the results. The evaluated costs of Proposal D2 are higher compared to the other proposals. Option C2 looks to be economically superior to the other options proposed by Bidder C.

**Q. What was the purpose of the optimization analysis?**

A. The purpose of the optimization analysis was to develop an optimal resource plan for each bidder's proposal assuming the proposal as a given. These resource plans would later be used in the detailed economic analysis. The optimization analyses were performed for a period of 30 years to capture all of the costs associated with each alternative, and, in particular, to determine the type of units that make up the optimal resource plan including a bidder's proposal. The supply alternatives that could be selected were generic combustion turbine, combined cycle, and coal units.

**Q. Please explain the optimization analysis you performed.**

A. The optimization analysis was performed using the PROVIEW optimization model. While the screening analysis compared the proposals to each other based simply on the cost of the proposals in isolation, the optimization analyses assessed the impact of each proposal on total system costs and compared those costs to the costs of a Base Case optimal plan. The impact on total system costs is important because it shows the net impact on the customer of choosing an alternative, including both the project cost and the impact the alternative would have on system operating costs. Such an analysis explicitly examines the relative impacts on system costs for fuel and variable O&M of the other units on PEF's system, and any impact the alternative would have on PEF's purchased power costs.

**Q. What was in the Base Case, and why did you compare the alternatives to it?**

A. The Base Case was an optimal resource plan assuming only generic combustion turbine, combined cycle and coal units; in other words, Hines 4 was not included in the resource plan. This ensures that all alternatives, including Hines 4, would be treated in the same manner and compared to a common reference point.

**Q. Where do you get the assumptions for generic unit costs and operating characteristics?**

A. We develop our generic cost and operating characteristics using the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG) software. EPRI gathers information about generating technologies, such as construction cost, O&M costs, and heat rates, and the software allows us to take the data and apply adjustments to adapt the information such that it is appropriate for the Southeastern United States. While the data is appropriate for a region, they are not site-specific. Therefore, they do not take into consideration costs or conditions that might be particular to a given site.

**Q. Why do you use EPRI data?**

A. We use the EPRI TAG data because it ensures the information is unbiased and developed for different technologies using a consistent methodology.

**Q. How does the generic EPRI data compare to Hines 4?**

A. The generic data are very good estimates of the cost and performance characteristics of the technologies. They are planning estimates, however, and are not meant to be "budget quality" estimates. In general, they are conservative estimates. In other words, the costs are higher, and the performance is less efficient. For example, the construction cost of Hines 4 is estimated to be $221.5 million; the generic combined cycle cost estimate for a 2007 in-service date is $233.7 million. The fixed O&M costs for Hines 4 are estimated to be $1.29/kW-year and $2.64/kW-year for the generic combined cycle. The reason for the big difference in fixed O&M is Hines 4 is being built at an existing site; whereas, the generic combined cycle is assumed to be at a new site. Hines 4 will be able to take advantage of the existing operating personnel, allowing us to add fewer new workers than what would be required at a new plant.

**Q. Please explain what the PROVIEW model is and what it does.**

A. As I mentioned before, PROVIEW is an optimization model, which we use to develop optimal resource plans, where the objective function is to minimize the cumulative present worth of revenue requirements for the PEF generation system, subject to the 20 percent Reserve Margin constraint. Thus for each bidder's proposal, PROVIEW provides us the optimal generation expansion plan for the 30-year study period, if we selected the bidder's proposed resource.

Inputs to the model include the load and energy forecast and the costs and characteristics (such as heat rates, outage rates, and maintenance requirements) of the existing generating units and purchase power agreements. A user also provides costs and operating characteristics of potential future supply-side resources, which could be generating units or purchases.

With these descriptions of the demand and existing and future resources, PROVIEW develops alternative resource plans to meet the projected future customer requirements using all possible combinations of resources, and it calculates the cumulative present worth of revenue requirements for each combination. The model then sorts each alternative plan from lowest to highest cost. From an economics-only perspective, the lowest cost plan is the optimal plan.

**Q. What were the results of the optimization analyses?**

A. Exhibit ___ (DJR-7) shows the economic results of these optimization analyses. The exhibit shows the difference in total system cumulative present worth of revenue requirements associated with each alternative compared to the Base Case. The analysis shows that a resource plan built around Proposal C2 would have the lowest future cost for the PEF customers of any of the responses we received from bidders to the RFP.

We examined two alternative proposals from Bidder B: an alternative ending at the end of 2011 and an alternative ending at the end of 2016. The optimization analysis shows the five-year alternative to have lower costs than the 10-year alternative. Therefore, the detailed evaluation considered only the five-year proposal from Bidder B.

The analysis also shows option C2 to be the lowest cost alternative from Bidder C. Thus, the detailed evaluation considered only option C2 from the three options proposed by Bidder C.

Because Proposals A and D2 were both less than the approximate 500 MW supply being requested in the RFP, we looked at the impact of combining the two proposals. The analysis shows that the combination of Proposals A and D2 would be more expensive than either proposal on its own, but slightly less than the cost of the two proposals summed together.

For comparison purposes, the figure also shows the costs associated with an optimal resource plan based on the addition of Hines 4. This analysis shows Hines 4 to be approximately $48 million less expensive than the least-cost proposal from Bidder C.

## VIII. RFP PROCESS: EVALUATION – TECHNICAL EVALUATION

<u>Methodology</u>

**Q. What was the purpose of the Technical Evaluation?**

A. The purpose of the Technical Evaluation was to assess the non-price attributes of the proposals by evaluating the quality of the proposals from a technical perspective. There were two parts to the Technical Evaluation—one, the Minimum Evaluation Requirements and two, the Technical Criteria. (Note that these are different than the Threshold Requirements, discussed earlier in my testimony, which were designed to ensure that proposals contained all the information we needed to evaluate the proposals and that the proposals addressed the basic requirements of the RFP.) We used the Technical Evaluation to help us get to the Short List by ensuring that all the proposals that went to the Short List were technically viable.

**Q. Briefly, what were the Minimum Evaluation Requirements?**

A. The Minimum Evaluation Requirements (MERs), which were provided in the RFP and are shown in Exhibit ___ (DJR-8), were the technical "must have" elements of a proposal. They were the components, or characteristics, the proposals had to have to move forward in the process. If a proposal did not meet one of the MERs, it would not make the Short List.

**Q. How were proposals evaluated on the MERs?**

A. Each proposal was evaluated on each requirement on a "Go" / "No Go" basis.

**Q. Briefly, what were the Technical Criteria?**

A. The Technical Criteria were characteristics (non-price attributes) we wanted proposals to have, and that would make a proposal more attractive to us. The criteria fell into three categories: operational quality, development feasibility, and project value, as summarized in Exhibit ___ (DJR-9). While the Minimum Evaluation Requirements are the "musts," the Technical Criteria are the "wants." We didn't necessarily envision that the Technical Criteria would eliminate anyone unless, of course, a proposal consistently ranked at the bottom of the pack. If a proposal didn't have something we wanted or, perhaps, it had what we wanted but not to the quality we desired, we would ask the bidder about it, to see if they would be willing to improve their proposal in that respect.

**Q. How were proposals evaluated on the Technical Criteria?**

A. Each proposal was assessed on each criterion, and the proposals were ranked relative to the other proposals. In this ranking system, "one" is considered the best. This method of ranking the alternatives allowed us to see if any of the proposals were significantly better or worse than any of the rest, based on the Technical Criteria.

**Q. Who evaluated the proposals in the Technical Evaluation?**

A. We established separate teams staffed with personnel with expertise in the areas of development and construction, engineering (operations), environmental, financial viability, fuel, key terms and conditions, and transmission to review the proposals. Each of the teams received the executive summaries of the proposals and only those portions of the proposals that dealt with its area of expertise. The technical experts were instructed, to the greatest extent possible, to disregard anything they knew about the Hines Energy Complex. Only the economic evaluation team had access to the pricing proposals, since the other technical evaluators did not need to know the pricing proposals to perform the evaluation of the proposals on their technical merits. Thus, the technical evaluations were performed blind to the economics of the proposals. This was done to make the Technical Evaluation as impartial as possible.

**Minimum Evaluation Requirements**

**Q. Please explain the Minimum Evaluation Requirements in more detail. What were they, and why were they important?**

A. There were eight MERs in five different categories: Environmental, Engineering and Design, Fuel Supply and Transportation Plan, Project Financial Viability, and Project Management Plan, as shown in Exhibit ___ (DJR-8). The MERs are what PEF feels are the most important non-price attributes of supply alternatives.

The two requirements in the environmental category, that a preliminary environmental analysis had been performed and that a reasonable schedule for securing permits be presented to PEF, applied only to New Unit Proposals. The purpose of these requirements was to ensure, to the greatest extent possible, the proposed project could obtain the necessary environmental permits.

There were also two requirements in the engineering and design category. The purpose of the requirements in this category was to determine if the proposed technology was viable from an engineering and operations perspective. To pass the requirements in this category, bidders had to provide an operation and maintenance plan indicating the project would be operated and maintained in a manner to allow the project to satisfy its contractual commitments, and bidders had to demonstrate the project technology would be able to achieve its operating targets.

For the fuel supply and transportation plan category, bidders of New Unit Proposals had to provide a preliminary fuel supply plan that described the bidder's plan for securing fuel supply and transportation for delivery to the project. Alternatively, as a feature in our RFP, bidders had the option to propose a fuel tolling arrangement whereby PEF would be responsible for acquiring fuel for the proposed project. All of the bidders proposed tolling arrangements. Since PEF has experience acquiring the types of fuels required by the projects, all of the proposals passed this requirement.

The purpose of the project financial viability MER was to ensure the bidder had the financial backing to construct and operate the project through the term of the proposal. For New Unit Proposals, evidence had to be provided that demonstrated the project would be financially viable. All proposals had to demonstrate that the bidder would have sufficient credit standing and financial resources to satisfy its contractual commitments.

The final component for the Minimum Evaluation Requirements applied to New Unit Proposals only. Bidders of that type had to submit a construction management plan to show that the project could be built in time to serve PEF's need.

**Q. How were the proposals evaluated with respect to the Minimum Evaluation Criteria?**

A. As I mentioned before, the proposals were judged on a "Go"-"No Go" (or Pass-Fail) basis. As discussed in the RFP Solicitation Document, failure to demonstrate conformance with the MERs would be grounds for elimination from the process. Failing to meet a minimum requirement should result in the elimination of a proposal because it doesn't meet a minimum standard for a good project—one that PEF feels has a high probability of being able to get the necessary permits, approvals, financing, etc. to enable the project to be built in time to serve the needs of the PEF customers and one that will continue to be able to serve the customers over the term of the proposed contract.

For most of the requirements, the proposals were reviewed to see if they had the documents, schedules, or plans as I discussed above. For example, the project management plan required the bidders to provide a critical path diagram and schedule for the project that specified the items on the critical path and demonstrated that the project would achieve commercial operation by December 1, 2007. For requirements such as this, they either provided the information (and it was judged as acceptable), in which case they would pass; or they didn't provide the information (or it was deemed unacceptable), in which case they would fail. The evaluation teams used their years of knowledge and technical expertise to determine if the information provided was valid.

**Q. Did all of the six remaining proposals pass the Minimum Evaluation Requirements?**

A. Yes, they did.

**Evaluation of Technical Criteria**

**Q. Please explain the results of the second part of the Technical Evaluation, the evaluation of the proposals with respect to the Technical Criteria, in more detail.**

A. With respect to the Technical Criteria, the proposals were ranked relative to each other for each of the criterion. The proposals were evaluated in terms of 15 technical criteria in three major areas: (1) development feasibility, (2) project value, and (3) operational quality. The evaluation criteria contained within these areas were identified in the Solicitation Document, and are included here as Exhibit ___ (DJR-9). The Solicitation Document also discussed the purpose of each criterion and PEF's preferences.

**Q. Please explain the factors you considered in development feasibility.**

A. This area of evaluation was our judgment of the bidder's ability to bring the proposed unit on-line on time. We assessed the developer's plan to obtain the necessary land use and environmental permits, including a water supply, for the proposed project.

Another aspect of project feasibility is the developer's financial viability. We focused on the developer's financial capability and credit. If the bidder was proposing to obtain project financing for its proposal, we would focus on the financial viability of the proposal. If the bidder indicated it would be providing equity to the project or would be self-financing the project, we would also assess the bidder's ability to provide the required equity or financing.

We also evaluated the likelihood of the project coming on line on time by evaluating the developer's planned permitting, licensing, and construction milestone schedules.

Finally we considered the bidder's experience in successfully developing and operating a project of the magnitude proposed.

**Q. Please explain the factors you considered in project value.**

A. We examined four factors that fall within this category:

- Acceptance of key terms and conditions;
- Fuel supply and transportation reliability;
- Reliability assessment;
- Flexibility provisions.

These are all factors that will ultimately affect the cost and flexibility of the project that we wanted to consider to see if one project provided a clearly better deal.

**Q. What key terms and conditions are you referring to in the project value category?**

A. The Solicitation Document included a set of terms and conditions of a power purchase agreement that would be critical to PEF. Bidders were instructed to mark the terms and conditions for any changes that they would like to make. We then evaluated the proposals on the extent to which the proposed deal was contingent on changing the key terms and conditions. The terms and conditions are too numerous to detail in my testimony but they cover subjects one would customarily expect to see addressed in a power purchase agreement, and, as I mentioned, they were provided to the bidders as an integral part of the RFP.

**Q. Didn't you evaluate fuel supply and transportation as part of the Minimum Evaluation Requirements?**

A. Yes, we did. As I mentioned before, the MER was that the bidders were to provide us a preliminary fuel supply plan; instead, all the bidders proposed fuel tolling arrangements. Here, we ranked the proposals based on the location of the plant and whether it was in the Southwest Fuel Group; whether the plant was connected through a local distribution company (LDC); whether a backup fuel was available; and how much backup fuel storage was available.

**Q. How did you evaluate the contractual flexibility of each proposal?**

A. In the RFP Solicitation Document, PEF reserved the right to consider any unique flexibility provisions offered by a bidder that were not going to be considered elsewhere, such as in the economic evaluation. Examples typically include contract options such as buyout provisions, or options to extend the contract, among others. However, none of the bidders offered any unique contract flexibility provisions. Bidder B offered options regarding contract term and Bidder C offered pricing and plant configuration options; however, these alternatives were captured in the economic evaluation process. Thus, the proposals were not ranked for the contractual flexibility criterion.

**Q. What did you examine in your reliability assessment?**

A. Here we considered the guarantee the bidder offered for the availability of the unit; that is, what percentage of time the bidder would guarantee that the unit would be available if we called on it. Specifically we did this by ranking the bidders based on the equivalent forced outage rate (EFOR) they offered to guarantee.

**Q. Please explain the operational quality factors you considered as part of the Technical Evaluation.**

A. The criteria that were evaluated in this area included:

- Minimum load;
- Start time;
- Ramp rate;

- Maximum starts per year;
- Minimum run-time constraint;
- Minimum down-time constraint;
- Annual operating hours limit.

In general, these attributes measure the flexibility of the proposed unit to operate in ways that respond to changes in demand. Thus, we evaluated the proposals with respect to how long it would take to get the proposed unit started, how long it would take to get the unit up to the desired output level, the number of times in a year the unit could be started and stopped, the minimum amount of time the unit would have to run once it was started, the amount of time the unit had to be off-line once it was shut down, and the number of hours in a year the unit could operate.

**Q. What were the results of your Technical Evaluation?**

A. The Technical Evaluation of the proposals uncovered some minor issues that needed further clarification from all of the bidders, and which they provided. Overall, the Technical Evaluation results were mixed—no proposal was clearly the best proposal for all of the criteria, although the quality of each of the proposals was acceptable.

## IX. THE RFP PROCESS: SELECTION OF SHORT LIST

**Q. So far, you have explained the Threshold Screening analysis, the initial economic analysis, and the Technical Evaluation. Were you then ready to announce your Short List?**

A. Yes, we were. From the technical perspective, the six remaining proposals met the minimum evaluation criteria, and none of the six proposals appeared to be technically deficient to the extent they should be eliminated from the RFP. Based on the results of the economic screening and optimization analyses, however, it may have been possible to eliminate one or more of the proposals. Because of the limited number of bidders remaining after the threshold screening, the Company decided not to eliminate any bidder at this point in the evaluation process. We did, however, reduce the number of proposals to one from each bidder, keeping the 5-year proposal from Bidder B and Proposal C2 from Bidder C, as well as Proposal A and Proposal D2.

**Q. When did you notify the short-listed bidders of this decision?**

A. All of the bidders were notified on March 5, 2004 that they would be placed on the Short List.

**Q. Did you tell the short-listed bidders anything else?**

A. The bidders were also provided with a list of questions for clarification or additional information derived from the technical evaluation of their proposals. The bidders were given 10 days to provide answers to the questions. At the same time, we informed the bidders that PEF was revising the cost and operating characteristics for Hines Unit 4 and that each of them could submit a revised bid. Thus, each bidder on the Short List had an opportunity to beat the final cost estimate of PEF's self-build option, as required in Rule 25-22.082 (14) F.A.C. In fact, this was the second opportunity we provided the bidders to enhance their proposals.

**Q. Why did you revise the cost and operating characteristics of Hines 4 a second time?**

A. In analyses performed for the April 2004 Ten-Year Site Plan, Hines 4 was projected to run more than the 50% indicated in the RFP (which was based on the 2003 TYSP). The current analysis projected an annual average capacity factor of 67% over the life of the unit. This revision to the estimated capacity factor reduced the major maintenance costs from $2.71/MWh to $2.02/MWh (the major maintenance costs in dollars remained the same but the amount of energy in the denominator increased). The estimated cost of natural gas for Hines 4 in 2007 was reduced from $4.69/mmBtu to $4.64/mmBtu, and the estimated pipeline reservation cost was reduced from $0.76/mmBtu to $0.66/mmBtu, both reflecting the difference in cost of using a different pipeline to deliver the gas for Hines 4 (from FGT to Gulfstream).

**Q. Did any of the bidders revise their prices?**

A. Yes, Bidder B lowered its prices. We used the new prices in our detailed analyses.

## X. THE RFP PROCESS: EVALUATION – DETAILED EVALUATION

<u>**Methodology**</u>

**Q. Please describe the Detailed Evaluation analysis performed and the results of the analysis.**

A. The purpose of the detailed evaluation was to subject the proposals on the Short List to a more detailed assessment and compare them to PEF's self-build alternative, Hines 4, incorporating transmission cost impacts based on system impact studies. The detailed evaluation was performed using the most up-to-date information supplied by the bidders on the Short List.

**Q. What were the tasks involved in the detailed evaluation?**

A. There were three main tasks: finalizing the Technical Evaluation, evaluating the transmission impacts of the proposed plants, and conducting the detailed economic analysis, which included detailed production costing and financial analyses.

<u>**Finalized Technical Evaluation**</u>

**Q. What did you do to finalize the Technical Evaluation?**

A. The Technical Evaluation of the proposals was updated based on the responses from the short-listed bidders to the requests for clarification and additional information. The Technical Evaluation of the short-listed proposals revealed no "show-stoppers." However, the ranking of the proposals on some of the criteria did change.

We also performed a self-assessment of Hines 4, and ranked it among the proposals. As can be seen in the final results, shown in Exhibit ___ (DJR-10), Hines 4 ranked either first or second among the alternatives for many of the criteria. An evaluation of Hines 4 determined that it, like the short-listed proposals, would provide satisfactory operational quality. Because the Hines site was originally approved for 3,000 MW of generation and because environmental issues pertaining to development beyond Unit 1 were considered during the original certification, many environmental initiatives are underway or already completed. Thus, from an environmental perspective, the Hines site ranks highest among the New Unit alternatives. Compared to the other bidders on financial viability, PEF was ranked first. Relative to all of the alternatives, Hines 4 compares favorably on fuel supply and transportation reliability because of existing connections with two major pipelines. The Hines 4 unit is considered to have "good" reliability, similar to that of Proposal C and better than Proposals A and B.

**Transmission Analysis**

**Q. Please describe the evaluation of the transmission impacts.**

A. Bidders of New Unit Proposals were required to provide as part of their RFP Response Package detailed information regarding their proposed power plants to enable Progress Energy Florida to perform transmission system impact studies.

The same type of studies were performed on the proposals as are performed when an independent power plant developer submits a generation interconnection service request to Progress Energy Florida through FLOASIS. These studies included load flow, stability, and short circuit analyses and are necessary to determine the impacts on the transmission system of building the proposed power plants at the proposed sites or of transferring power into the PEF System. These analyses and their findings are discussed in detail in the testimony of Mr. Alfred G. McNeill.

Q. **Would any of the proposals require changes to the transmission system?**

A. Yes. Proposals A, B (5-yr), and C2 all required changes to the transmission system. The total construction cost of the transmission modifications for Proposal A was estimated to be $51 million (2004 dollars) and would take 84 months to complete. The total construction cost of the transmission modifications on the PEF transmission system required for Proposal B (5-yr) was estimated to be $68 million (2004 dollars) and would also take 84 months to complete. As mentioned in Mr. McNeill's testimony, no cost or time estimates were developed to address the potential problems caused by Proposal B (5-yr) on other systems.

For both Proposals A and B (5 yr), an 84-month construction time would mean the transmission work would not be completed before the beginning of the proposed purchases. In the case of Proposal B (5 yr), the transmission work would not be completed until near the end, or perhaps even after, the term of the proposal. While this puts the feasibility of the purchases in question, the proposals were not eliminated at this point.

The construction cost for the transmission system modifications for Proposal C2 was estimated to be $11 million (2004 dollars) and would take 43 months to complete. Due to the small capacity increase and the nature of the facilities in Proposal D2, PEF determined that a detailed study was not required. For Hines 4, the total construction cost was estimated to be $33.4 million (nominal dollars), with the construction work being completed prior to the in-service date of the unit. All of the cost estimates mentioned exclude AFUDC.

**Detailed Economic Analysis**

**Q. Please describe the detailed economic analysis of the proposals you performed.**

A. Detailed economic analyses were performed on all of the short-listed proposals and Hines 4. In the detailed economic analysis, we calculated the incremental system revenue requirements associated with each alternative.

The first step in the detailed economic analysis was to perform detailed production costing analyses of the alternatives. Progress Energy Florida used the PROSYM production costing model to perform the analyses. PROSYM is a detailed, chronological production costing model that simulates each generating resource on the Progress Energy Florida system, both existing and future, and how it is used to serve the forecasted peak demand and energy requirements of Progress Energy Florida's customers.

Each alternative (i.e., the proposals and Hines 4) was modeled as a separate "case," which included the alternative and the future units as determined during the optimization analysis. Just as in the initial economic analysis, we also modeled a "Base Case." In order to treat all alternatives the same in the economic analysis, all cases were compared to the Base Case. The cases were run through the end of 2032, capturing the entire 25-year book life of a combined-cycle unit placed in service by December 1, 2007.

**Q. How were the results of the production costing analysis used?**

A. The results of the production costing analyses were incorporated into the financial analysis of each alternative. In addition to the production costs associated with each alternative (that is, the energy charges of each proposal and the operating costs of Hines 4), the change in system production costs as a result of each alternative, relative to the base case, was also a part of the financial analysis. The analysis must capture these costs because each alternative, due to its size, heat rate, proposed pricing, etc., causes the other resources of the PEF generation system to operate in a different manner, resulting in different total system production costs.

**Q. Were any other cost impacts included in the analysis?**

A. Yes. The fixed costs of the alternatives (that is, the fixed charges of the proposals and the construction costs and fixed O&M costs of Hines 4) were captured in the financial analysis. As mentioned before, each alternative was compared to a Base

Case that consisted only of generic future additions; thus, the fixed cost impact of changes to the base case resource plan had to be reflected in the analysis of the alternatives.

The cost impacts of the changes in the resource plan were reflected in the financial analysis by way of an economic carrying charge, which is the same concept as the Value of Deferral used to determine standard offer rates. Because the proposals had different contract lengths, using an economic carrying charge allows each of the alternatives to be evaluated consistently and eliminates problems associated with "end effects." Each alternative received a credit for fixed cost savings equal to the economic carrying charge of a planned unit being deferred in the Base Case. In cases where a planned unit was advanced in the resource plan, the alternative received a cost equal to the economic carrying charge of the unit being advanced. The economic carrying charge captured both the construction costs and fixed O&M costs of the generic units.

The transmission construction costs to integrate each of the proposals and Hines 4 into the transmission system were included in the detailed economic analysis. The annual cash flow pattern of the construction costs was based on expenditure patterns typically experienced for transmission lines and transformers, with one exception. For both Proposal A and Proposal B (5-yr), even though the estimated time to construct the required facilities is 84 months and, therefore, beyond the start of the proposed purchases, the projects were assumed to be completed prior to the beginning of the terms of the purchases and, therefore, the cash flow patterns were compressed to fit the available time.

Finally, we also included the cost of imputed debt by determining the additional equity cost related to the purchased power proposal.

**Q. Why did you include the cost of imputed debt in your analysis?**

A. The cost of imputed debt was applied to proposals to assure that the total costs of proposals include the marginal impact of the fixed future commitment on PEF's capital structure. This additional cost is the direct result of incurring fixed future payment obligations. Rating agencies make these adjustments to a utility's balance sheet to reflect the existence of debt-like commitments. Also, Rule 25-22.081(7) F.A.C. requires a utility to include a discussion of the potential for increases or decreases in its cost of capital should a purchase power agreement with a nonutility generator be made. The cost of imputed debt quantifies that potential. Mr. Greg Beuris discusses the need for this adjustment more fully in his testimony.

**Q. What were the results of the detailed economic analysis?**

A. In terms of cumulative present value of revenue requirements (CPVRR), Hines 4 was found to be approximately $55 million less expensive than the least cost alternative (Proposal D2). Hines 4 was found to be more than $95 million less expensive than the least cost New Unit Proposal (Proposal C2). The charts in Exhibit ___ (DJR-1) show the results of the analysis. The top chart shows the difference in the total CPVRR associated with each alternative compared to the base case. The bottom chart shows the results on an annual basis. The results of the detailed financial analysis of the proposals and Hines 4 demonstrate that Hines 4 is clearly the most cost-effective alternative for supplying generation to meet the needs of the Progress Energy Florida customer.

**Q. What caused Hines 4 to be less expensive than the other alternatives?**

A. One reason is the generation costs of Hines 4 are less than the proposals. Exhibit ___ (DJR-11) shows Hines 4 to be $35 million less expensive than the Base Case's generation costs, while all the other proposals are more expensive than the Base Case when looking at only the generation costs. When looking at only the generation portion of the total costs, Hines 4 is approximately $53 million less than any other alternative. Compared to Proposal C2, the closest proposal in terms of generation-only costs, Hines 4 has higher net energy costs (the energy costs of the plant less the avoided energy costs resulting from adding the plant) than Proposal C2. Proposal C2 has lower net energy costs primarily because it is a larger unit and, when power is generated from the duct burners and power augmentation portions of the plant, it displaces less efficient generating units on the PEF system. However, Hines 4 has even lower net fixed costs (fixed costs of the plant less the avoided capacity costs resulting from adding the plant). Relative to Proposal C2, Hines 4's lower fixed costs are due largely to its lower O&M costs (due to having to hire only six additional people rather than having to hire staff for an entire plant) and because of the common site facilities at the Hines Energy Complex that Proposal C2 would have to build (such as roads, a cooling pond or cooling towers, buildings, etc.). Finally, PEF has a better credit rating that the other bidders, giving Hines 4 a financial advantage.

Hines 4 also has an advantage over the other proposals because of the additional equity costs associated with purchased power agreements. The costs associated with imputed debt are small for three out of the four proposals. The additional equity costs for Proposal C2 are larger than the other proposals because the term of the proposal was longer than the other proposals and the capacity of the project was greater than that of the other proposals.

With respect to transmission costs, Hines 4 is more costly than Proposals C2 and D2, but less expensive than Proposals A and B (5-yr). Keep in mind that even though we show costs for Proposals A and B (5-yr), it is highly unlikely the transmission work would be able to be completed prior to the start of the proposed purchases.

<u>**Sensitivity Analyses**</u>

**Q. Did you perform any sensitivity analyses?**

A. Yes, we performed three sensitivity analyses in an effort to make the third-party proposals appear more economically beneficial. One of the analyses was performed on Proposal B (5-yr) and the others were performed on the costs of Hines 4.

**Q. Please explain the analysis performed on Bidder B's proposal.**

A. All of the bidders desired to have Progress Energy Florida provide fuel tolling services for the project. All of the proposals except Proposal B (5-yr) are natural gas fired combined-cycle units; Proposal B (5-yr) burns No. 6 oil. While fuel prices typically move in parallel, there have been periods in time when this has not been the case, and one fuel becomes relatively cheaper than another. The sensitivity analysis performed on Proposal B (5-yr) was to determine the impact of a lower fuel price for No. 6 oil. The prices used in the sensitivity analysis were between 25 cents/mmBtu and 40 cents/mmBtu lower during the term of Proposal B (5-yr) than the original price forecast. In this sensitivity analysis, the value of Proposal B (5-yr) improved by approximately $20 million. While this reduced the generation component of costs by around 35%, Proposal B (5-yr) is still more expensive than all other proposals.

**Q. Did you perform any sensitivity analyses on Hines 4?**

A. Yes, we did. We performed sensitivity analyses on both the construction costs and the O&M costs of Hines 4.

**Q. Please explain the analyses and the results.**

A. Two sensitivity analyses were performed on the costs of Hines 4. Both analyses used the goal seek function of Excel to determine how much higher the construction costs and the O&M costs of Hines 4 would have to be such that it had the same revenue requirements as the next best alternative; in other words, to increase the cost of the self-build alternative by $55 million in cumulative present value of revenue requirements.

To eliminate the $55 million cost advantage that Hines 4 has over the next best alternative, the total installed costs of Hines 4 (including AFUDC) would have to increase more than $47 million, or approximately 19 percent. The O&M costs would have to increase by over $6.5 million per year over the 25-year life of the unit to equate to a $55 million CPVRR cost increase. This compares to Hines 4's expected annual average O&M cost of less than $11 million, and would represent a 59% increase in annual average O&M costs.

**Q. Did this complete your economic analysis of the proposals?**

A. Yes, it did.

## XI. THE RFP PROCESS: SELECTION OF FINAL LIST

**Q. What was the final step in the PEF RFP process?**

A. The seventh and final step in the process was to select the Final List. However, as discussed previously and as stated in the RFP, in the event Hines 4 was found to be clearly superior to the other alternatives, a Final List would not be selected. Based on the results of the detailed analysis, Hines 4 was found to be clearly superior to the other alternatives. Thus, Progress Energy Florida announced on April 27, 2004 that Hines 4 was the most cost-effective alternative for adding electric generation to serve its customers' needs. This announcement concluded the RFP process.

**Q. Does this conclude your testimony?**

A. Yes, it does.

# IN RE: PETITION FOR DETERMINATION OF NEED

# BY PROGRESS ENERGY FLORIDA

# FPSC DOCKET NO. ____________

# DIRECT TESTIMONY OF PAMELA R. MURPHY

## I. INTRODUCTION AND QUALIFICATIONS

**Q: Please state your name, your employer, and business address.**

**A.** My name is Pamela R. Murphy and I am employed by Progress Energy Carolinas (PEC). My business address is 411 South Wilmington Street, Raleigh, North Carolina, 27602.

**Q. Please state your position with Progress Energy and describe your duties and responsibilities in that position.**

**A.** I am currently the Director of the Gas & Oil Trading Section in the Regulated Commercial Operations Department. I have held that position since December 2000. As the Director of Gas & Oil Trading, part of my responsibilities include the procurement of residual fuel oil, distillate oil, and natural gas for PEC's and Progress Energy Florida's (PEF) electrical power generation facilities, and the administration of PEC's and PEF's (hereinafter collectively referred to as Progress Energy or the Company), gas and oil contracts with various suppliers.

**Q. Please summarize your educational background and work experience.**

**A.** I graduated in 1984 from West Virginian State College with a Bachelor's Degree in Accounting. I have been in the natural gas industry for approximately 29 years. My previous positions have been with several subsidiaries of the Columbia Energy Group (now known as Nisource, Inc.). Part of my experience was with the energy marketing and trading organization, Columbia Energy Services, where I was Vice President of Operations. Prior to this position, I was Director of Marketing for Columbia Natural Resources, the exploration and production company of the Columbia Energy Group.

In March 1999, I accepted a position in the Gas Supply & Transportation Department of CP&L (now known as PEC) as Manager, Gas Supply Procurement & Logistics. In December 2000, I was promoted to Director, Gas & Oil Trading.

## II. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony in this proceeding?**

**A.** I am testifying on behalf of PEF in support of its Petition for Determination of Need by (1) generally describing and explaining the reasonableness of the fuel forecast developed by Enterprise Risk Management Risk Analytics, (2) identifying the types and amounts of fuel that PEF plans to use at Hines Unit 4, including the expected availability of those fuels for that facility, and (3) generally describing the options available to transport the types and amounts of fuel the Company plans to use at the Hines Energy Complex (HEC) where Hines 4 will be located.

**Q. Are you sponsoring any sections of PEF's Need Study?**

**A.** Yes, I am sponsoring "Fuel Supply and Transportation" in Section II, Description of Hines 4, and "Fuel Price Forecasts" under Other Planning Assumptions in Section III, Resource Need and Identification, of the Need Study.

**Q. Are you sponsoring any exhibits to your testimony?**

**A.** Yes, I am sponsoring the following exhibits to my testimony:

**PRM-1** **Natural Gas Forecast Compared to Other Industry Forecasts**

**PRM-2** **Base, High and Low Case Natural Gas Forecasts**

**PRM-3** **Fuel Price Forecast for Hines**

Each of these exhibits was prepared under my direction, and each is true and accurate.

**Q. Please summarize your testimony.**

**A.** The fuel forecast was prepared by Enterprise Risk Management Risk Analytics, reviewed by me, and relied upon by the Company. Fuel forecasts and relevant fuel prices and their differentials are important economic factors in determining the kinds of new generation to be added to Progress Energy's system. The fuel forecast projects both short- and long-range prices for the various types and grades of fuel available to and used by the Company on its electrical generation system. The fuel forecast is based on an extensive review and a rigorous analysis of available and relevant information on fuel prices. The fuel forecast for Progress Energy is reasonable and in line with the forecasts of other recognized industry sources.

Natural gas is the primary fuel planned for Hines 4. It is a readily available fuel source, given current and projected levels of long-term supply of natural gas in the United States; and, as a result, is an economical fuel source for Hines 4. Backup fuel for Hines 4 will be distillate fuel oil, which is also readily available as a fuel source now and in the future.

Compared to coal and oil, natural gas is a clean burning fuel. As such, natural gas results in favorable construction capital costs and minimal air compliance issues relative to current and future environmental regulations.

PEF is confident that it will be able to arrange for all of the firm gas transportation service it will require for Hines 4 in time to meet the expected in-service date for that unit.

**Q. Do you have an opinion about natural gas as a fuel source for Hines 4?**

A. Yes. Natural gas is and will be a competitively-priced fuel source for Hines 4 compared to other types of fuel and generation technologies, based on the forecast of natural gas price trends compared to oil and coal price trends. It is also an attractive fuel source because, compared to coal and oil, it is a clean burning fuel. This has a favorable impact on the capital cost of constructing generating facilities capable of complying with current and possibly future environmental regulations.

Exhibit ___ (PRM-1) shows PEF's natural gas forecast along with the natural gas forecasts of other widely recognized and generally accepted third-party sources. As demonstrated by this exhibit, the Company's natural gas forecast is in line with the natural gas forecasts of the third-party sources reported there.

Furthermore, the final forecast for gas reflects PEF's best professional judgment of future costs, at the time the forecast was prepared.

## III. PROGRESS ENERGY FLORIDA'S FUEL FORECAST

**Q. Why does PEF develop a fuel forecast?**

A. Fuel forecasts are an integral part of our planning and operations. Relevant fuel prices and their differentials are important economic factors in determining the kinds of new generation to be added to Progress Energy's system. Additionally, fuel prices are relevant to the determination of the most efficient method of operating existing and proposed generating units on the Company's system in compliance with environmental and system requirements.

**Q. Please describe the methodology behind PEF's gas and oil fuel forecasts.**

A. Progress Energy depends on observable market data for near-term price forecasts. For long-term prices, the Company uses PIRA Energy Group (PIRA) as a forecasting consultant service for both gas and oil. PIRA provides the Company, on a monthly basis, a forecast of prices for the various fuels that potentially could be used at PEF's existing and future generating plants. Those fuels are natural gas, No. 6 oil (1 percent and 3 percent sulfur), and No. 2 fuel oil (0.5 percent and 0.05 percent sulfur).

Long-term forecasts use the PIRA forecast as a starting point. Progress Energy reviews and compares other widely recognized and generally accepted third-party sources of information relevant to the projected supply and price of each fuel, combined with the Company's historical experience with fuel prices, to arrive at a final forecast. For both gas and oil, some examples of other sources that might be used for validation include the Energy Information Administration (EIA) forecasts, Energy Ventures Analysis (EVA) forecasts, Cambridge Energy Research Associates (CERA) forecasts, New York Mercantile Exchange (NYMEX) futures market prices, current contracts and current market data. The final forecast includes a base case, which is considered the most likely scenario, as well as a high and low forecast for each fuel.

Once a fuel forecast is prepared, it is periodically reevaluated against various standard third-party fuel price forecasts, developments, and trends with respect to each fuel type, to verify that Progress Energy was and is reasonable in developing its fuel forecasts. When and if necessary, the Company will adjust its fuel forecast to take into account changes in the fuels markets. A chart of Progress Energy's base, low, and high natural gas price forecast is shown in Exhibit ____ (PRM-2). This forecast was developed in December 2003 and is the forecast upon which the April 2004 Ten-Year Site Plan (TYSP) is based, and which was used in the RFP analysis.

Oil transportation costs are estimated based on existing contracts and expected escalation. Exhibit ____ (PRM-3) presents the base oil and gas forecast, including variable transportation, applicable to Hines 4. For the natural gas forecast, a fixed transportation cost is also applicable for Hines 4. The fixed natural gas transportation cost used in the TYSP and RFP analysis was \$0.6639/MMBtu.

## IV. FUELS FOR THE HINES 4 UNIT

**Q. Please describe the types and amounts of fuels PEF expects to use for the Hines 4 unit.**

**A.** The Hines 4 unit will be a state-of-the-art, combined cycle unit similar to the Hines 1, 2, and 3 units. Hines 4, like Hines 1, 2, and 3, will operate primarily on natural gas. At peak operation, Hines 4 would require approximately 88,000 million British thermal units (MMBtu) of gas a day, and its average use will be around 61,000 MMBtu per day. The Hines 4 combustion turbine will be designed with the capability to burn distillate fuel oil as a backup fuel. Progress Energy Florida intends to construct an additional one (1) million gallon tank for Hines 4 at the Hines Energy Complex.

**Q. Will PEF be able to obtain sufficient natural gas supplies for Hines 4 at a reasonable cost?**

**A.** Yes. The natural gas exploration and production industry, in this country and in Canada, is engaged in aggressive efforts to maintain and expand the North American natural gas reserve base, spurred by both greater demand for gas and higher gas prices. Florida is situated close to significant existing and potential gas reserves. There is a substantial amount of exploration and development activity going forward in the deeper waters of the Gulf of Mexico, where large new gas reserves have been and are expected to be discovered and developed. In addition, several new liquefied natural gas terminals are being proposed in the Gulf of Mexico as well as The Bahamas. This new source of supply has been proposed to directly connect with FGT and/or GNGS to serve the Florida market. The relatively short transportation distances for natural gas into Florida should result in lower transportation costs for gas sold for consumption in the state, making it inevitable that natural gas will be aggressively and competitively marketed here.

**Q. Has PEF signed any contracts or letters of intent for its gas supply to Hines 4?**

A. No. Progress Energy Florida anticipates no difficulty in obtaining contracts for gas supply adequate for Hines 4 on competitive terms and conditions at market-based prices. Progress Energy Florida has developed and will maintain gas supply relationships with a number of gas producers and gas marketers in preparation for securing a contract at the appropriate time.

## V. FUEL TRANSPORTATION FOR HINES 4

**Q. Will PEF be able to obtain sufficient and reliable transportation service for the Hines 4 gas supplies?**

A. Yes. In addition to existing FGT and GNGS pipeline resources, Southern Natural Gas Company (Southern) has proposed an expansion of its existing natural gas pipeline system (Cypress Project) to transport gasified liquefied natural gas (LNG) from its Elba Island LNG terminal located in Savannah, Georgia, to an interconnection with FGT in north Florida.

Additionally, PEF has been approached by three (3) independent companies to bring LNG into south Florida from terminals located in The Bahamas. They are: Tractebel Calypso LNG Marketing LLC, Sailfish Natural Gas, Ltd., and Repsol Commercializadora de Gas S.A. One of The Bahamas companies has proposed a "bundled" arrangement where gas transportation and supply are contracted together and delivered to Hines 4 using the FGT pipeline system.

Progress Energy Florida has discussions ongoing with all these companies concerning its requirements for firm gas transportation capacity for Hines 4.

Progress Energy Florida is confident that it will be able to obtain a contract(s) for all of its gas transportation service requirements for Hines 4. Progress Energy Florida expects to be able to arrange for all of the firm gas transportation service it will require for Hines 4 at attractive rates in time to meet the gas requirements for Hines 4.

**Q. Does this conclude your direct testimony?**

**A.** Yes.

**IN RE: PETITION FOR DETERMINATION OF NEED**

**BY PROGRESS ENERGY FLORIDA**

**FPSC DOCKET NO. ________**

# DIRECT TESTIMONY OF JOHN M. ROBINSON

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, your employer, and business address.**

A. My name is John M. Robinson and I am employed by Progress Energy Carolinas (PEC). My business address is 410 S. Wilmington Street, Raleigh, North Carolina, 27601.

**Q. Please state your position with PEC and describe your duties and responsibilities in that position.**

A. I am employed by PEC as Manager, Engineering & Commercial Support. In this position, I am responsible for the overall management of licensing, engineering, equipment procurement, and construction contracting activities associated with new supply-side, generation projects at the Hines Energy Complex (HEC). This includes the Hines Unit 4 combined cycle generation unit.

**Q. Please summarize your educational background and work experience.**

A. I received a Bachelor of Science Degree in Electrical Engineering from North Carolina State University in 1970. I am a Registered Professional Engineer in the State of North Carolina. I joined PEC in 1970. I have served in numerous management positions responsible for engineering, construction, operations and maintenance of transmission lines, and the engineering, modification and construction of fossil fuel and gas-fired power plants.

## II. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony in this proceeding?**

A. I am testifying on behalf of Progress Energy Florida (PEF or the Company), in support of its Petition for Determination of Need for the Hines 4 unit, by describing (1) the site and unit characteristics for the Hines 4 combined cycle unit, including its size, equipment configuration, fuel type, and supply modes, (2) the estimated costs of Hines 4, and (3) the unit's projected in-service date.

**Q. Are you sponsoring any sections of PEF's Need Study?**

A. Yes, in Section II of the Need Study, I am sponsoring the "Projected Costs" and "Projected Performance" sections under the Hines Unit 4 heading.

**Q. Are you sponsoring any exhibits to your testimony?**

A. Yes. I am sponsoring the following exhibits to my testimony:

**JMR-1** **Hines Energy Complex Map.**

**JMR-2 Site Arrangement – Overall Plan.**

**JMR-3 Site Arrangement – Power Block Area.**

**JMR-4 Typical Combined Cycle Schematic.**

**JMR-5 Projected Cost Estimate for Hines Unit 4.**

**JMR-6 Project Schedule for Hines 4.**

Each of these exhibits was prepared under my direction, and each is true and accurate.

**Q. Please summarize your testimony.**

A. The Company plans to build Hines 4 at the HEC, its existing generation site in Polk County, Florida. That site contains the Hines 1 and 2 combined cycle generation units and their associated facilities. Hines Unit 3 is currently under construction with an expected commercial operation date in December 2005. In 1994, the Governor and Cabinet, sitting as the Siting Board, certified the HEC for construction and operation of the Hines Unit 1 and for 3,000 megawatts (MW) of ultimate generation capacity at the site. In 2001, the Governor and Cabinet certified the addition of Hines 2. In 2003, the Governor and Cabinet certified the addition of Hines 3.

Hines 4 will provide for an expected 517 MW (winter rating) of capacity at the site, and it will share many of the existing facilities at the site with Hines 1, 2, and 3. The ability to share facilities at the site adds to the cost-effectiveness of Hines 4. The Company and its customers will reap the benefit of the cost savings associated with the economies of scale achieved from using the existing facilities for the operation of the combined Hines units 1, 2, 3, and 4.

Hines 4 is a sister unit to Hines 1, 2, and 3. It is a state-of-the art, highly efficient combined cycle unit that will operate on natural gas, with the capability to operate on distillate fuel oil. The unit's beneficial heat rate, availability, and responsiveness, among other attributes, provide the Company with a low-cost, highly flexible source of power. Hines 4, therefore, enhances the overall operation and efficiency of the Company's system to the direct economic benefit of the Company and its customers. Hines 4 is scheduled to come on line in December 2007..

Apart from the cost savings achieved by placing in operation a state-of-the-art, highly efficient generation unit, the Company and its customers will further benefit from a competitive initial cost for the unit. The total projected cost for Hines 4 is estimated to be $221.5 million excluding transmission costs and AFUDC. AFUDC is estimated to be approximately $27 million, giving a total installed cost of $248.5 million, excluding transmission.

There are a number of factors why Hines 4 is the most cost-effective alternative. First, Progress Energy Florida is able to take advantage of its prior investment in infrastructure at the HEC. Second, by virtue of owning and operating three other power stations on the same site, PEF will need to add a much smaller number of new employees to operate the four units at the HEC than bidders would have to employ to operate a greenfield facility. Third, a significant advantage is due in part to the Company negotiating favorable equipment terms for the major equipment during a time when the power plant equipment market was depressed. Finally, Progress Energy Florida has as good, or better, credit rating than many of the IPPs today. Thus, the Company has a financing advantage.

In summary, Hines 4 allows the Company to meet its reliability needs with the most efficient technology on the market at a below market cost, giving the Company and its customers substantial economic benefits in terms of technology, efficiency, and flexibility in operation, and cost of generating power.

## III. DESCRIPTION OF THE HINES 4 SITE

**Q. Please describe the location of the HEC.**

A. The HEC is an 8200 acre site located in southwest Polk County, Florida, approximately 40 miles east of Tampa, 7 miles south of Bartow, and approximately 3.5 miles northwest of Ft. Meade. County Road 640 is on the northern boundary of the HEC, and County Road 555 runs through the site north to south. The location of the HEC is shown in Exhibit ____ (JMR-1).

**Q. Please describe the location of Hines 4 at the HEC.**

A. Exhibit ___ (JMR-2) is the HEC site plan and shows the development of the site. It depicts the relationship of the current power blocks to the existing cooling ponds and water treatment and wastewater disposal areas for the units. It also shows the existing rail lines, state roads, and access roads that will serve all units, and the existing dikes and former phosphate mining areas on the HEC site. Exhibit ___ (JMR-3) is the power block layout for Hines 4 in relation to the existing power blocks.

**Q. What are the benefits to Progress Energy Florida and its customers from locating the Hines 4 unit at the HEC?**

A. The location of the Hines 4 unit at the HEC offers the Company and its customers the ability to achieve economies of scale by using existing infrastructure at the site for operation of the Hines 4 unit. By building Hines 4 at the HEC, the Company will be able to use the existing access road, cooling pond, reclaimed water supply pipeline, water treatment and wastewater disposal facilities, gas laterals, and transmission facilities, among other site facilities, for the Hines 1, 2, and 3 units and the proposed Hines 4 unit. Because the Company can use the existing site facilities for the four units, the Company will only have to design and construct enhancements to these facilities for the Hines 4 unit. The location of the Hines 4 unit at the HEC will save site development costs the Company otherwise would have incurred. As a result, the Company and its customers will save additional engineering and construction costs by locating Hines 4 at the HEC.

## IV. DESCRIPTION OF THE HINES 4 UNIT

**Q. Please describe the proposed design of the Hines 4 unit.**

A. Hines 4 is a state-of-the-art combined cycle unit similar to the Hines 1, Hines 2, and Hines 3 units. It consists of two combustion turbines, two unfired heat recovery steam generators, one steam turbine, and a recirculating water cooling system. The unit is a dual-fuel generation system, meaning that the combustion turbines can be operated on natural gas or distillate fuel oil. For Hines 4, natural gas is the primary fuel, and low sulfur (0.05 percent) distillate fuel oil is the alternative fuel.

The combustion turbines and steam turbine for the Hines 4 unit are configured in sequential stages, as shown in the typical schematic for a combined cycle unit in Exhibit ___ (JMR-4). The first stage includes the combustion turbines, much like utility peaking units, which generate electricity. In the second stage of the process, hot gas from the combustion turbines is passed through the heat recovery steam generator, where steam is produced and fed into the steam turbine to generate additional electricity -- hence, the term "combined cycle" generation technology.

**Q. What are the advantages of combined cycle technology for PEF?**

A. Combined cycle generation technology is very efficient because it generates electricity from the input fuel both directly, with the combustion turbines turning a generator, and indirectly, by using the waste heat from the combustion turbines to produce steam, which powers a steam turbine that turns another generator. Combined cycle technology makes the most of the input fuel, achieving increased efficiency in the generation of electricity from the available fuel source. For these reasons, the modern combined cycle power facility is one of the most efficient power technologies available today.

Another advantage of the combined cycle design is that it allows for greater flexibility in matching system operating characteristics over time. Because of its technological efficiency, it can readily be called on to meet varying operational load requirements in an economical manner. Thus, the Hines 4 combined cycle unit can function as a baseload or intermediate unit, as required by the Company's system.

In addition to its high efficiency, Hines 4 will have a low environmental impact. Combined cycle units operating on natural gas, like Hines 4, are one of the cleanest sources of fossil generation. Whether the unit is burning natural gas or distillate fuel oil, flue gas is the only byproduct of the combustion process that would leave the HEC. Both are low sulfur, low ash fuels. Thus, sulfur and particulate emissions are virtually nonexistent. Nitrogen oxides will be controlled by selective catalytic reduction and water injection. Airborne emissions, therefore, will be minimized by the use of a relatively clean fuel and the appropriate application of control technologies.

**Q. How will fuel be provided and handled for the Hines 4 unit?**

A. Natural gas is currently delivered by pipeline to the HEC by Florida Gas Transmission (FGT) and Gulfstream Natural Gas System (GNGS). In addition, there are other proposals to transport gas to the HEC for Hines 4. These additional options are discussed by Pamela R. Murphy in her testimony. No additional gas lateral is necessary at the HEC. Enhancements will be required to the metering and regulation stations for the addition of Hines 4.

An additional storage tank and fuel oil unloading facility for the backup fuel are necessary for the Hines 4 unit. The distillate fuel oil for the HEC units is delivered to the HEC by tanker trucks.

**Q. How does the Company plan to construct Hines 4?**

A. PEF will maintain direct overall management of the project, including participation in construction management functions, by having a substantial presence onsite during the construction and startup phase. PEF may elect to competitively select equipment suppliers, the architect/engineering (A/E) firm, and the constructors, or the Company may opt to contract for a design-build, turn-key approach. The exact method will be evaluated considering the competitive market while minimizing the Company's risk.

**Q. What will it cost the Company to build Hines 4?**

A. The total projected cost for the Hines 4 unit is approximately $221.5 million (excluding AFUDC and transmission costs) in nominal dollars. This cost was developed on the basis of replicating the design and layout of our Hines 1, 2, and 3 units. A breakdown of the major cost items for the Hines 4 unit is included in Exhibit ____ (JMR-5).

The project cost for Hines 4 reflects competitive equipment pricing because the Company was able (1) to benefit from a depressed power equipment market at the time the equipment negotiations occurred, and (2) to share common site utilities and facilities with the Hines 1, 2, and 3 units, thus reducing or eliminating site development and construction costs and associated facilities costs the Company would have otherwise incurred.

Q. **What will it cost the Company to operate the Hines 4 unit?**

A. The estimated incremental annual fixed operation and maintenance (O&M) cost for Hines 4 is $1.29/kW-Yr (based on winter capacity of the unit and expressed in 2007 dollars). The largest fixed costs are wages and wage-related overheads for the permanent plant staff, as well as expenses for unplanned equipment maintenance. Six employees are expected to be added to the staff at the HEC upon the addition of Hines 4 (five Operations and Control Personnel and one Planner).

Variable O&M costs, which vary as a function of unit generation, include consumables, chemicals, lubricants, water, and major maintenance costs such as planned equipment inspections and overhauls. The estimated non-maintenance variable O&M cost is $0.30/MWh and the estimated major maintenance variable O&M costs is $2.14/MWh (both based on the 489 MW average capacity of the unit, operating at 67 percent capacity factor, and expressed in 2007 dollars).

Q. **When Hines 4 is constructed and in operation, what operational characteristics will it have?**

A. As noted above, Hines 4 will have state-of-the-art, combined cycle technology. As a result, it will be a highly efficient unit with an excellent heat rate, operating with an average summer full load heat rate of approximately 7079 BTU/kWh and an expected average winter full load heat rate of approximately 7062 BTU/kWh (HHV). The Hines 4 unit will have an expected equivalent forced outage rate of approximately three percent. Hines 4 is expected to operate in a capacity factor range of 50 percent to 70 percent, averaging 67 percent over its expected 25-year life. When placed in operation, Hines 4 will be one of the most efficient units on the Company's system.

## V. PROPOSED SCHEDULE

**Q. What is the in-service date for the Hines 4 unit?**

A. Hines 4 is scheduled to come on line in December 2007.

**Q. Will the Company meet that in-service date?**

A. Yes, barring any unforeseen and significant delays. The proposed schedule for the permitting and construction of the Hines 4 unit is contained in Exhibit ____ (JMR-6). In my opinion, this schedule is reasonable and can be met by the Company.

**Q. Does this conclude your direct testimony?**

A. Yes.

# IN RE: PETITION FOR DETERMINATION OF NEED BY PROGRESS ENERGY FLORIDA

## FPSC DOCKET NO. ________

## DIRECT TESTIMONY OF JOHN J. HUNTER

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, employer, and business address.**

**A.** My name is John J. Hunter and I am employed by Progress Energy Florida (PEF or the Company). My business address is 100 Central Avenue, St. Petersburg, Florida, 33701.

**Q. Please state your position with the Company and describe your duties and responsibilities in that position.**

**A.** I am employed by the Company as a Lead Environmental Specialist in the Environmental Services Section of the Technical Services Department. My primary responsibilities currently include project management of environmental activities related to siting, licensing, and permitting of new electric power generating facilities in the State of Florida. This includes activities related to obtaining the necessary certification under Florida's Electrical Power Plant Siting Act for new facilities, as well as any additional Federal environmental permits required to construct new generating facilities. In addition to the above, I also coordinate activities related to the management of water resources required to support the existing and proposed water supply demands associated with the Hines Energy Complex (HEC).

**Q. Please summarize your educational background and work experience.**

**A.** I earned a Bachelor of Science degree in Chemical Engineering from the University of South Florida. Prior to coming to PEF in 2001, I was employed for 14 years by Tampa Electric Company (TECO) where I held various engineering and supervisory positions within TECO's Environmental Affairs Department, including Administrator of Water Programs (1995-1998) and Administrator of Air Programs (1998-2000). In these various positions, I was responsible for ongoing environmental permitting and compliance activities for existing generating facilities, and I was involved in studies for the siting of new generation.

In 2001, I joined PEF where my responsibilities largely consist of those previously outlined. More specifically, as it relates to this testimony, I am responsible for obtaining the supplemental site certification for Hines Unit 4 at the HEC. This includes overall management of the project, providing technical resources, overseeing all aspects of the application preparation, handling responses to comments, meeting with regulatory agency managers, and ensuring that the certification of the project is completed on schedule.

## II. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony in this proceeding?**

A. I am testifying on behalf of PEF in support of its Petition for a Determination of Need for Hines Unit 4 to (1) describe the HEC site, (2) discuss the environmental benefits of the HEC site and the Hines 4 unit that Progress Energy Florida proposes to build, and (3) discuss the environmental approval process associated with the construction and operation of Hines 4.

I am responsible for preparation and submittal of the Supplemental Site Certification Application (SSCA) for the proposed Hines 4 unit, which includes the application for the Prevention of Significant Deterioration (PSD)/Air Construction Permit approval, obtaining the Florida Department of Environmental Protection (DEP) approval of the PSD application, negotiating appropriate Conditions of Certification with the participating regulatory agencies for the addition of the Hines 4 unit to the existing site, and obtaining final certification approval from the Governor and Cabinet sitting as the Florida Power Plant Siting Board.

**Q. Are you sponsoring any sections of Progress Energy Florida 's Need Study?**

A. Yes, I am sponsoring "Environmental Considerations" in Section II of the Need Study.

**Q. Please summarize your testimony.**

**A.** I am responsible for preparation and submittal of the SSCA for the proposed Hines 4 unit. The Hines 4 unit will be a state-of-the-art gas-fired, combined cycle power unit that will be located at the HEC.

The HEC continues to represent a beneficial reuse of an environmentally impacted, mined-out phosphate area that was specifically selected as a power plant site because of its minimal environmental impact. Site certification evaluations included assessments of air quality impacts, water quality and wildlife impacts, water use and noise impacts, socioeconomic impacts and benefits, traffic impacts from construction and operation, and other impacts of the entire planned site capacity of 3,000 megawatts (MW).

Hines 4 requires only a supplemental application and review that will require less time, and, as an additional benefit, it will cost less to obtain the necessary environmental approvals. In the original Hines 1 proceeding, the Siting Board specifically made a determination that the HEC had the ultimate site capacity to support 3,000 MW of electrical generating facilities fired by either natural gas or coal gasification.

Based on my review and analysis, it is my professional opinion that certification of the Hines 4 unit should be approved by the Governor and Cabinet and the PSD permit issued by DEP in a timely fashion and in accordance with all applicable environmental laws and regulations to allow for its commercial operation by December 2007.

## III. DESCRIPTION OF THE SITE AND THE PROPOSED UNIT

**Q. Is the HEC permitted for electric power plant usage?**

A. Yes. In 1994, the Governor and Cabinet, sitting as the Siting Board pursuant to the Florida Electrical Power Plant Siting Act, granted certification to Florida Power to construct and operate Hines Unit 1 and for 3,000 MWs of ultimate site capacity. In 2001and 2003, the Siting Board approved the separate SSCA's allowing for the construction and operation of Hines Units 2 and 3, respectively.

In the original proceeding, the Siting Board specifically made a determination that the HEC had the ultimate site capacity to support 3,000 MWs of electrical generating facilities fired by either natural gas or coal gasification. The original proceeding that culminated in that 1994 Certification included extensive evaluations of the worst case capacity constraints and maximum potential environmental effects of the operation of the expected 3,000s MW of capacity. These evaluations included assessments of air quality impacts, water quality and wildlife impacts, water use and noise impacts, socioeconomic impacts and benefits, traffic impacts from construction and operation, and other impacts of the entire planned capacity of 3,000 MWs. This evaluation was undertaken, in large measure, to provide assurances that the HEC has adequate air, water, and land resources to accommodate additional electrical generating units like those proposed in the current SSCA. Confirming the Polk County Board of County Commissioners' finding, the Siting Board also concluded that the HEC was consistent, and in compliance, with the land use plans and zoning requirements of Polk County.

After receiving the initial Certification, the Company constructed the Hines 1 unit, which began commercial operation in April 1999. Under previous

SSCA processes, the Hines 2 and Hines 3 units were approved. The Hines 2 unit has been constructed and began commercial operation in December 2003. The Hines 3 unit is currently under construction and is expected to begin commercial operation in December 2005. The combined total power rating for these three units is approximately 1500 MWs, half of the certified site capability.

**Q. Please briefly describe the proposed unit.**

A. The Hines 4 unit will be a natural gas-fired, combined cycle power block consisting of two combustion turbines, two heat recovery steam generators and one steam turbine generator. The Hines 4 unit will add approximately 500 MWs of additional generation capacity to the HEC site. The Company proposes to place the unit into commercial operation in December 2007. The Hines 4 unit will also be capable of firing a low sulfur (0.05 percent) distillate fuel oil as a backup to natural gas.

**Q. What environmental permits are necessary for the construction and operation of the proposed Hines 4 unit?**

A. Siting Board approval of the Conditions of Certification developed through the SSCA process and the PSD/Air Construction permit are necessary to begin construction and operation of Hines 4. Although the Company has previously obtained Site Certification from the Florida Siting Board for an ultimate capacity of 3,000 MWs at the HEC, and for the construction and operation of the Hines 1, 2 and 3 units, the proposed addition of Hines 4 requires that a SSCA process specific to the issues related to Hines 4 be performed and approved. Pursuant to the requirements of the Electrical Power Plant Siting Act and Chapter 62-17, F.A.C., Progress Energy Florida has submitted a SSCA for the purpose of adding the Hines 4 unit to the HEC. This SSCA will be reviewed by various state and local agencies, including the DEP, the Southwest Florida Water Management District, local government, and others. After extensive review, a Department of Administrative Hearings (DOAH) administrative law judge will issue an order recommending approval or denial to the Governor and Cabinet, sitting as the Siting Board. If approval is recommended, the Florida DEP Siting Office will also recommend Conditions of Certification as part of the Siting Board's approval. Ultimately the Governor and Cabinet will issue or deny Site Certification for the addition of the Hines 4 unit to the HEC site, considering the need for power balanced with the expected environmental impacts.

**Q. What information does Progress Energy Florida's SSCA include?**

A. The SSCA addresses the environmental and socioeconomic aspects of the additional generating unit at the HEC by presenting information on the existing natural and human environments, the additional generating facilities proposed to be constructed and operated, and the impacts of those additional facilities on those environments. Much of the information contained in this SSCA is updated information from the SCA filed in 1992 for Hines 1 and ultimate site certification for the HEC, as well as the SSCA's for Hines 2 and 3, with a focus on the environmental impacts of the construction and operation of Hines 4. Similar to

Hines 1, 2 and 3, Hines 4 will consist of two combustion turbines, each equipped with one heat recovery steam generator, and a single steam turbine electrical generator.

## IV. ENVIRONMENTAL BENEFITS OF THE SITE AND THE PROPOSED UNIT

**Q. What environmental benefits do the HEC and the proposed unit offer?**

A. Hines 4 will be located adjacent to Hines 3 at the HEC, an existing power plant site in Polk County, Florida, that the Florida Siting Board approved on January 25, 1994 for up to 3,000 MW of generating capacity. The addition of Hines 4 to the site is well within the confines of the site's ultimate generating capacity. The HEC is an 8,200-acre site located on land used formerly for a phosphate mining operation. Progress Energy Florida specifically selected the HEC as a power plant site because of its minimal environmental impact. As such, there are no major environmental limitations that will be associated with the addition of the Hines 4 unit to the site. Most, if not all, of the environmental issues associated with the site were resolved during the initial certification of the site, along with the first Hines 1 unit. Accordingly, Hines 4 requires only a supplemental application and review that will require less time, and, as an additional benefit, it will cost less to obtain the necessary environmental approvals.

With regard to air emissions, Hines 4 will be considered a major stationary emission source and will be subject to Prevention of Significant Deterioration

(PSD) permitting requirements. Air emissions will be minimal because the Hines 4 unit will burn a relatively clean fuel with good combustion practices to ensure complete combustion and will use appropriate emission control technologies. Combined cycle units operating on natural gas, like the Hines 4 unit, are one of the cleanest sources of fossil generation.

Both natural gas and distillate fuel oil are low sulfur, low ash fuels. Flue gas is the only byproduct of the combustion process at the HEC, whether burning natural gas or distillate fuel oil. Full load nitrogen oxide (NOx) emission levels of 2.5 ppm or less are expected for Hines 4 while burning natural gas. This will require the installation of selective catalytic reduction (SCR) technology to control NOx emission levels. While firing distillate fuel oil as a backup fuel, water injection along with SCR will be used to limit NOx levels.

The HEC is a zero surface water discharge facility with respect to the National Pollution Discharge Elimination System (NPDES) program for industrial wastewater, and therefore does not require a NPDES water discharge permit. Process wastewater streams are treated and retained on-site or are returned to the cooling pond as a source of make-up water. An on-site groundwater monitoring system is in place to monitor groundwater discharges.

Water consumption at the site occurs primarily through evaporation from the cooling pond. Accordingly, a key feature of the HEC design is the existing cooling pond, which serves as the heat dissipation device and the source of most process water at the site. Additional cooling pond modifications will be required for the Hines 4 addition.

Reclaimed water from the City of Bartow, direct rainfall, on-site storm water runoff, and water cropping (use of on-site rainfall collection basins), limited groundwater, and re-use of process water provide the makeup cooling water required to maintain the cooling pond level within acceptable operating limits. The incremental water supply necessary to support the addition of Hines 4 to the site will come from additional groundwater. Alternative water supply sources will be utilized to offset the incremental groundwater if they become available.

Because the Florida Siting Board approved the HEC for up to 3,000 MWs, and given that the Company developed the property to support the construction and operation of the Hines 1, 2 and 3 units, little additional development is necessary for Hines 4. In fact, the principal infrastructure is already in place, including extensive site development (excavation, fill, access roads, sewer systems), a cooling pond, and two fully-sized natural gas lateral pipelines. Many other common facilities will require only minor modifications to support the addition of Hines 4.

The HEC's large size also provides a substantial buffering of the proposed unit, which minimizes environmental and socioeconomic impacts. The HEC is located in a low population density area, not close to any residential areas, and is zoned to accommodate electrical power facilities.

County Road 555 provides vehicular access, with rail access provided by existing CSX rail lines, including an on-site rail spur. Progress Energy Florida completed a traffic impact analysis to assess traffic impacts for the construction and operation of the full build-out of the HEC (3,000 MWs) on Polk County roadways.

Conditions of Certification addressing those impacts were included in the original 1994 Certification. Area roadways have capacity to accommodate traffic from construction and operation of Hines 4 as previously demonstrated.

Finally, noise impacts from the full 3,000 MW site were assessed for several residential receptors around the HEC as part of the 1994 Certification. Fractional noise increases observed at any nearby residential receptor will not be noticeable or significant. The isolated location and buffer area around the HEC results in the lack of a significant noise impact.

**Q. What is the licensing schedule for the Hines 4 unit?**

A. Progress Energy Florida filed the SSCA and the PSD/Air Construction Permit Application with the Florida DEP in August 2004 for the Hines unit 4. The final approvals are expected prior to the end of 2007. This schedule will allow for the commencement of commercial operations of Hines 4 by December 2007.

## V. CONCLUSION

**Q. What is your opinion regarding the Company's ability to obtain all necessary licenses to allow for commercial operation by December 2007?**

A. Based on my review and analysis, it is my professional opinion that certification of the Hines 4 unit should be approved by the Governor and Cabinet and the PSD permit issued by Florida DEP in a timely fashion and in accordance with all applicable environmental laws and regulations.

**Q. Are you aware of any reason why the Hines 4 unit would not be successfully approved?**

A. No.

**Q. Does this conclude your direct testimony?**

A. Yes.

**IN RE: PETITION FOR DETERMINATION OF NEED**

**BY PROGRESS ENERGY FLORIDA**

**FPSC DOCKET NO. ______**

# DIRECT TESTIMONY OF ALFRED G. MCNEILL

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, employer, and business address.**

A. My name is Alfred G. McNeill and I am employed by Progress Energy Florida (PEF or the Company). My business address is 6565 38th Ave. North, St. Petersburg, Florida, 33710.

**Q. Please state your position with the Company and describe your duties and responsibilities in that position.**

A. I am a Senior Engineer in the Company's Transmission Planning Unit. One of my responsibilities includes evaluating transmission capability for Generator Interconnection Service (GIS) requests. I also perform generator siting studies, including analyzing transmission additions needed to accommodate future generation additions or asset procurement.

I am also the Florida Reliability Coordinating Council (FRCC) Loadflow Databank Coordinator and a member of the FRCC Transmission Working Group (TWG). I represent the FRCC on the NERC Multiregional Modeling Working

Group (MMWG). Additionally, I am a member of the Southern/Florida Reliability Coordination Agreement Working Group.

**Q. Please summarize your educational background and work experience.**

A. I joined Florida Power Corporation (later Progress Energy Florida) in August 1973. I was originally employed in the Company's Relay Design Department and worked there until 1978. From 1978 to the present I have been employed in the Transmission Planning Department. In Transmission Planning I am currently responsible for performing various power flow and stability studies to determine the future needs of the Company's Transmission System with regard to additional generation facilities and the constantly growing customer load. In December of 1984, I received my Bachelor of Science degree in Electrical Engineering from the University of South Florida.

## II. PURPOSE AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your testimony in this proceeding?**

A. I am testifying on behalf of Progress Energy Florida in support of its Petition for Determination of Need by explaining the transmission analyses performed on proposals submitted in response to the RFP for Hines 4 and the need for transmission facility modifications required by the addition of Hines 4 at the Hines Energy Complex (HEC) in December 2007.

**Q. Are you sponsoring any sections of Progress Energy Florida's Need Study (SSW-1)?**

A. Yes. I am sponsoring "Transmission and Distribution Facilities" in Section I and "Transmission Requirements" in Section II, which describe the transmission system and facility modifications and costs associated with the addition of Hines 4 at the HEC, respectively.

**Q. Please summarize your testimony.**

A. Progress Energy Florida regularly performs transmission planning analyses consistent with FRCC and NERC guidelines and processes and in compliance with sound transmission engineering practices in the utility industry. I will describe our processes and the sources of the data used in our analyses.

Using these standard processes, we evaluated the impact bidders' proposals would have on the PEF transmission system to determine what modifications would be necessary to incorporate the proposed generation into the PEF system. I will discuss the transmission analysis performed on the RFP proposals and the results of the analyses. Briefly, all but one of the proposals evaluated would have a substantial impact on PEF's transmission system, requiring extensive transmission modifications at substantial costs.

The addition of Hines 4 was also analyzed using the same standard processes. I will describe the transmission system and facility modifications required for the addition of Hines 4. In summary, the existing HEC substation must be expanded by adding one 230 kilovolt (kV) substation bay to accommodate the interconnection of Hines 4 and a 230kV transmission line from the HEC substation to the West Lake Wales substation. Also, a total of 16 circuit breakers must be replaced due to increased fault current. I will describe those modifications and explain the need for them.

## III. TRANSMISSION ANALYSIS PROCESS

**Q. Please generally explain the process by which PEF determines that transmission facility upgrades or modifications might be required with the addition of generation to Progress Energy Florida's system?**

A. On a yearly basis, Progress Energy Florida's Transmission Planning Department reviews the transmission facility additions or upgrades required on the Company's transmission system based on the latest FRCC load flow cases. These load flow cases reflect the planned generation additions as proposed in each utility's Ten-Year Site Plan (TYSP) as filed in April of each year, including PEF's TYSP showing its proposed generation additions. Since 1997, the Company has included Hines 4 in its TYSP, and the FRCC load flow cases have included a Hines 4 unit as a result.

Based on the FRCC load flow cases, the Company's Transmission Planning Department performs load flow, stability, and short-circuit analyses and determines the need for transmission facility additions or upgrades based on meeting PEF's "Transmission Planning Reliability Criteria," Section 4, as filed on FERC Form No. 715 "Annual Transmission Planning and Evaluation Report."

The purpose of a load flow analysis is to determine the impact of a generating unit on the PEF system by running a computer simulation model to compare the performance of the system with and without the unit. Load flow studies analyze the effects of common single contingency events on the transmission system. The typical events that are simulated include loss of a single line or transformer. If overload situations are encountered in the simulations, determinations are made as to what corrective actions would be required to integrate the proposed unit into the PEF transmission system.

Stability studies analyze the effects of major events on the transmission system. The typical events that are simulated are the loss of one or more major transmission lines (e.g., 230 kV lines).

The purpose of the short circuit analysis is to determine if the addition of a generating unit causes the fault current in the immediate area to exceed the rating of the affected circuit breakers.

**Q. What models do you use to perform these analyses?**

A. For the load flow and short circuit analysis the cases from the current FRCC load flow database are used for analysis. The cases are developed on an annual basis using Power Technologies Incorporated's (PTI) load flow simulation program, a simulation package widely used in the industry. For the stability analysis, the most current version of the stability base cases was used. The cases are developed on an as needed basis by the FRCC stability working group using PTI's dynamics simulation program, a simulation package widely used in the industry.

**Q. What databases do you use to perform these analyses?**

A. The load flow analysis was performed using modified versions of the FRCC 2003 cases for 2007 & 2008 winter and 2008 & 2009 summer. FRCC 2003 cases are the most current cases available. The modifications to the published standard FRCC cases were to correct known database errors identified by PEF after final publication of the database and contained in the FRCC database correction files.

For the stability portion of my analysis, a 2005 winter peak case was used. This was the most current FRCC Stability work group base case available. Modifications to the base case were made to reflect transmission and generation additions from 2005 winter up to 2007 winter, the planned in-service date for Hines 4.

For the short-circuit analysis portion of this study, the FRCC 2003 cases for 2007 and 2008 winter and 2008 and 2009 summer were used. The FRCC 2003 cases are the most current cases available for short-circuit analyses.

## IV. TRANSMISSION ANALYSIS OF RFP PROPOSALS

**Q. Please describe the analyses performed in the evaluation of the RFP proposals.**

A. The analyses of the RFP proposals were either performed by me or under my direction. The analyses consisted of load flow, stability, and short-circuit analyses to determine the need for transmission facility additions or upgrades, and followed our standard evaluation process. To evaluate the proposals, we first had to remove Hines 4 and its associated transmission facilities out of the FRCC cases. The bidder-proposed facilities were then added to the cases and their impacts analyzed. If overload situations were encountered in the simulations, determinations were made as to what corrective actions would be required to integrate the proposed unit into the PEF transmission system.

**Q. What were the results of your analyses?**

A. The load flow study for Bidder A's proposal resulted in an overload of the Higgins-to-Griffin 115 kV line and two transformers. The Higgins-Griffin line is a 44-mile line that would need to be upgraded to a 230 kV line. The time to design, permit, and construct this line is estimated to be 84 months. The total construction cost of the transmission modifications was estimated to be $51 million (2004 dollars). Since Bidder A's proposal was an off-system project, no stability or short circuit analyses were performed, as this analysis would be performed by the host utility, and the costs of transmission modifications, if any, should have been reflected in the proposal.

Due to its close proximity to critical interfaces between utilities, the load flow study for Bidder B's proposal was performed as an inter-utility power transfer, consistent with FRCC/NERC transfer analyses. The analysis found a number of overloads, including the Econ-Rio Pinar, Barwick Tap to Turner, Rio Pinar-Stanton East, Higgins-Griffin, Econ-Winter Park, and Curry Ford-Stanton West lines, in addition to potential problems on other utility systems. As with Bidder A's proposal, the longest lead-time project is the upgrading of the

Higgins-Griffin line. The time to design, permit, and construct this line is estimated to be 84 months. The total construction cost of the transmission modifications on the PEF transmission system was estimated to be $68 million. Since Bidder B's proposal was an Existing Unit Proposal, stability and short circuit analyses were not required, as they would have been performed when the units were initially installed. As mentioned above, potential problems were indicated on other utility systems. No cost or time estimates were developed to address these potential problems.

Bidder C's project would require the construction of a two-mile line to connect the project to the PEF transmission system. The load flow analysis of Proposal C2 resulted in the overload of the Barwick Tap-Turner line and three transformers. The construction cost for these modifications and the two-mile line was estimated to be $11 million and would take 43 months to complete. The stability analysis showed no stability issues with the projects and the short circuit analysis did not show a need to replace any equipment due to increases in fault current.

Bidder D is an existing facility of the Progress Energy Florida system. A brief inspection of the facilities surrounding this existing plant did not indicate any problems with increasing the output of the plant as proposed. Due to the small increase and the nature of the facilities around the plant and their existing load levels, PEF determined that a detailed study was not required. Since Bidder D is an existing facility, stability and short circuit analyses were not required, as they would have been performed when the unit was initially installed.

**Q. What are the construction cost and construction time estimates based on?**

A. Transmission line project costs were estimated on a per mile basis. PEF uses the same cost estimate(s) every day for screening site studies, Generator Interconnection Service (GIS) requests, and initial-phase planning projects. The cost estimates have been developed based on years of actual experience on the PEF system.

For 230 kV transmission line projects, the cost estimate is $1 million per mile. For 115 kV and 69 kV transmission line projects, the cost estimate is $300,000 per mile. The estimate of the construction duration is based on the following: transmission line projects that are from one to three miles in length are estimated to take 36 months; transmission line projects greater than three miles are estimated to take 42 months, plus one month for every mile over the three miles. These project duration estimates, again, have been developed through years of actual experience on the PEF system.

## V. TRANSMISSION ANALYSIS OF HINES 4

**Q. What kind of transmission analysis was performed on Hines 4?**

A. The analysis consisted of load flow, stability, and short-circuit analyses to determine the need for transmission facility additions or upgrades using the same processes, models, and data used in the analyses on the bidders' proposals.

**Q. What were the results of the analyses?**

A. The load flow analysis found that, with the addition of Hines 4, the loss of the Barcola to Pebble Dale 230 kV line results in overloading of the Ft Meade to Tiger Bay 230 kV line and the Ft Meade to West Lake Wales line. In PEF's initial petition for the Hines Energy Complex, the Hines to West Lake Wales 230 kV line was identified as a needed transmission facility. Recent load flow analysis confirmed the need for the Hines to West Lake Wales 230 kV line with the addition of Hines 4. The stability analysis did not find any problems with the addition of Hines 4. In the short circuit analysis, with Hines 4 dispatched, sixteen 230 kV breakers were found to be over-dutied. Replacement of these breakers is required prior to the in-service operation of Hines 4.

In summary, the results of all evaluated criteria indicate the need to expand the Hines substation, construct the Hines to West Lake Wales 230 kV line, and replace 16 circuit breakers.

**Q. Why does the HEC 230 kV Substation need to be expanded for Hines 4?**

A. To accommodate the Hines 4 power block connection to the Progress Energy Florida transmission grid.

**Q. How much will the 230 kV substation expansion for the Hines 4 unit cost?**

A. The transmission facility expansion is currently estimated to cost $4.0 million, which includes the cost to tie the generator into the substation. This is the amount presently estimated by Progress Energy Florida's Substation and Relay Engineering Departments.

**Q. How much will the 230 kV line from Hines to West Lake Wales cost?**

A. The engineering estimate for the 230 kV line from Hines to West Lake Wales is $26.5 million. This is the amount presently estimated by Progress Energy Florida's Substation and Transmission Departments.

**Q. How much will it cost to replace the sixteen 230 kV breakers?**

A. The engineering estimate is $2.9 million. This is the amount presently estimated by Progress Energy Florida's Substation and Transmission Departments.

**Q. What is the total cost of the transmission modifications required for Hines 4?**

A. The total cost of the transmission work associated with the addition of Hines 4 is estimated to be $33.4 million in nominal dollars, excluding AFUDC. The total installed cost including AFUDC is $37.6 million.

## VI. CONCLUSION

**Q. In your opinion, are the results of the analyses that you have performed for the addition of the Bidders' proposed projects and the Hines 4 unit to Progress Energy Florida's system reasonable and accurate?**

A. Yes. In my professional opinion, and based on my experience and evaluation of the impact of adding the Bidders' proposed projects and the Hines 4 unit to Progress Energy Florida's systems, respectively, these results are accurate and reasonable. The costs and duration of the transmission and substation facility modifications discussed in my testimony are also what will be reasonably required to add the Bidders' proposed projects and the Hines 4 unit, respectively, to the Progress Energy Florida transmission system.

**Q. Does this conclude your testimony?**

A. Yes, it does.

**IN RE: PETITION FOR DETERMINATION OF NEED**

**BY PROGRESS ENERGY FLORIDA**

**FPSC DOCKET NO. ____________**

**DIRECT TESTIMONY OF CHARLES G. BEURIS**

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, your employer, and business address.**

A. My name is Charles G. Beuris and I am employed by Progress Energy Service Company. My business address is 410 S. Wilmington Street, Raleigh, North Carolina, 27601.

**Q. What is your position with Progress Energy?**

A. I hold the position of Director of Financial Operations for Progress Energy.

**Q. Would you please briefly outline your qualifications and professional experience?**

A. I came to Progress Energy as Director – Financial Operations in November 2000 immediately following the acquisition of Florida Progress. I report directly to the Treasurer and am responsible for all capital raising activities for Progress Energy and its subsidiaries. My responsibilities include short-term and long-term financing, bank credit facilities and cash management.

Prior to joining Progress Energy, I was employed by Florida Progress for 17 years. My experience with Florida Progress included various financial positions in accounting, budgeting, treasury, and investor relations.

I have a bachelor's degree from the University of Florida and a master's degree in business administration from the Florida Institute of Technology. I have the following professional certifications: Certified Public Accountant, Chartered Financial Analyst and Certified Cash Manager.

## II. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to discuss the credit analysis performed by nationally recognized rating agencies related to long-term purchased power agreements (PPAs) and their impact on our financial policy. Their treatment of these contracts affects financial ratios, in particular leverage ratios, used to determine a company's credit rating. As Director of Financial Operations, it is my responsibility to maintain Progress Energy Florida's capital structure in a manner which supports our target credit rating, therefore I must take into consideration the adjustments a rating agency may make when developing its financial ratios to assess its credit rating.

## III. TREATMENT OF PPAs IN RATING AGENCY CREDIT ANALYSES

**Q. How many rating agencies perform credit analysis on Progress Energy Florida (PEF or the Company)?**

A. We currently engage three rating agencies, Standard & Poor's Rating Service, Moody's Investor Service, and Fitch Ratings who provide credit ratings for PEF.

**Q. How do these rating agencies treat long-term purchased power agreements when evaluating a company's credit profile?**

A. While each one's specific method may vary, they all base their analysis on the premise that long-term fixed payments associated with these contracts are essentially debt-like in nature, much like a long-term lease on property, plant, and equipment. Excerpts from the three rating agencies follow:

***MOODY'S***

*"Moody's will continue to view these off-balance sheet obligations as debt – in particular those purchased power obligations that are above market."*

*Credit Implications of Power Supply Risk, Moody's Special Comment, June 2000.*

***STANDARD & POOR'S***

*Standard and Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk-spectrum".*

*Standard & Poor's Research: "Buy versus Build": Debt Aspects of Purchased-Power Agreements. May 8, 2003.*

***FITCH***

*For purchased power agreements, operating leases, tolling arrangement, and synthetic leases, Fitch policy varies from GAAP accounting rules in order to capture operating leverage.*

*Fitch presentation to Progress Energy, October 2003.*

**Q. What is the impact on a company's credit profile when rating agencies treat long-term purchased power contracts as debt-like?**

A. The main effect is that a company is considered to have more leverage than if you calculated its leverage ratio based only on the debt recorded on its balance sheet.

**Q. Does PEF have long-term purchased power contracts?**

A. Yes, PEF has a substantial amount of purchase power commitments relative to its total generation mix. As of December 31, 2003, PEF had 474 MWs of purchased power with other utilities and 833 MWs with certain cogenerators (QFs).

**Q. Does each of the rating agencies make the same adjustment to PEF's financial ratios for long-term purchased power supply contracts?**

A. No. In addition to each rating agency's having its own general methodology, each agency also has its own view of the impact these long-term PPAs have given the nature of the contracts and the recoverability of these payments through tariffs.

**Q. What adjustments do the rating agencies make when evaluating PEF's credit profile?**

A. It does not appear that Moody's makes an adjustment to PEF's credit ratios due primarily to the recovery of payments associated with these contracts through approved regulatory pass-through clauses. While Moody's certainly recognizes the significance of these contracts, particularly the high-priced QF contracts, they also take into account the high degree of certainty surrounding the recovery of these costs through pass-through clauses, such as those in Florida.

Fitch does not make an adjustment for contracts with "Qualifying Facilities" (QF) due to the regulatory status of these contracts and the recoverability through pass-through recovery clauses. For other purchase power contracts, Fitch will evaluate these individually and make a determination on how much debt should be imputed.

S&P's approach has recently been modified. (See Exhibit ___ CGB-1, *"Buy versus Build": Debt Aspects of Purchased-Power Agreements. May 8, 2003*). S&P takes the net present value of future capacity payments and discounts those payments using a 10% discount rate. That amount is then multiplied by a risk factor, the result of which is the amount of imputed debt. For PEF, S&P uses a risk factor of 30%.

**Q. What is the basis for S&P's risk factor adjustment?**

A. As stated in their article *"Buy versus Build,"* the overriding factor influencing the risk factor is the likelihood of payment by the buyer. It notes that the probability of non-delivery by independent generators is quite low, thus the probability of a buyer having to pay for purchased power is quite high. Given the high likelihood of payment by the buyer, these long-term fixed obligations are assigned a higher risk factor for purposes of imputing debt.

S&P's generic guideline for utilities with PPAs having terms over three years is to use a 50% risk factor. S&P further states that:

*"This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery."*

**Q. How much debt does S&P impute when assessing the impact of PPAs on PEF's credit ratios?**

A. As of December 31, 2003, the present value (using a 10% discount rate) of PEF's future capacity payments for its QF and utility PPAs was approximately $2.4 billion. S&P then computes the amount of imputed debt by applying a 30% risk factor for PEF, which results in approximately $730 million of imputed debt.

**Q. Why does S&P use a 30% risk factor for PEF instead of its generic 50% risk factor for utilities with PPA terms over three years?**

A. S&P uses a risk factor of 30% for PEF instead of 50% primarily due to the favorable regulatory recovery mechanism which exists to recover these costs.

**Q. What is the impact of S&P's approach on PEF's capital structure when imputing debt associated with long-term PPAs?**

A. PEF's leverage ratio before making any adjustments for off-balance sheet obligations was 51.5% as of December 31, 2003. After adjusting for purchase power commitments, the leverage ratio increases to 58.3%.

**Q. How does S&P's treatment of these contracts affect your financial policy?**

A. Our financial policy must take S&P's adjustments into consideration if we are to achieve our target debt rating for PEF. This means that when developing target capital structure ratios, we must consider the impact of off-balance sheet items, in particular long-term power supply agreements due to their materiality and the impact it has on PEF's leverage.

S&P clearly adjusts PEF's credit ratios and Progress Energy's consolidated credit ratios, since PEF is a wholly-owned subsidiary of Florida Progress, which is wholly-owned by Progress Energy. If we were to ignore long-term purchase power contracts, as well as other off-balance sheet obligations, we would be setting target leverage ratios which would be inconsistent with S&P's view of our leverage.

**Q. How should your financial policy affect the evaluation of long-term PPAs?**

A. We manage Progress Energy's and PEF's capital structure to achieve a certain long-term credit rating. The amounts of leverage associated with a particular credit rating and how it is calculated are established by the rating agencies, and I must recognize their methodology if we are to achieve our goals.

In particular, for PEF, long-term PPAs are material off-balance sheet obligations and have a significant impact on our leverage ratios. Under S&P's methodology, every additional PPA would increase the amount of imputed debt and, all else being equal, require additional equity to offset the effect of the incremental imputed debt.

**Q. Can you generally address the appropriateness of the specific adjustments described in the RFP?**

A. Yes. Since long-term PPAs can have the same effect as issuing debt and equity to build a power plant, analyzing the all-in costs of a PPA should include the full impact on the capital structure of PEF.

Therefore, including an adjustment to costs for the additional equity that would be required to ensure we meet our target capital structure is appropriate in the evaluation of the proposals in the RFP analysis. The adjustment PEF has made is consistent with S&P's methodology for imputing debt associated with PPAs.

**Q. You have stated that two rating agencies, Moody's and Fitch, do not make adjustments, and only S&P makes an adjustment. Why do you follow S&P and not Moody's or Fitch?**

A. We adjust for PPAs primarily for two reasons. First, it is recognized by all three rating agencies that long-term fixed payments are debt-like in nature and should be treated as debt. While each agency differs in how they adjust for these types of fixed payments, they all start from the same basic premise that the PPAs are debt-like in nature. Second, the capital markets generally price debt securities based on the lowest rating when there is a difference among rating agencies on the rating assigned. Therefore, in order to achieve the benefits of PEF's long-term target debt rating of single A, the lowest rating must be single A. This market convention forces us to recognize S&P's methodology as it pertains to the treatment of long-term PPAs.

**Q. Does this conclude your direct testimony?**

A. Yes.

MR. KEATING: With all the testimony and exhibits admitted into the record, I believe at this point the record could be closed unless the parties have anything else to add.

CHAIRMAN BAEZ: Mr. Sasso, is there anything else that we need to address before we close the record?

MR. SASSO: No, Mr. Chairman. We would just say that we are pleased that we were able to arrive at these stipulations with staff, and always appreciate the professionalism and courtesy of staff, and join with staff in asking, respectfully, that the Commission approve the proposed stipulation and resolve all issues in this docket.

CHAIRMAN BAEZ: Very well. Thank you, Mr. Sasso.

Mr. Keating, where are we at this point?

MR. KEATING: The proposed stipulations to resolve the issues in this docket are set forth in Section XI of the prehearing order that starts on Page 8. At this point, staff is prepared to address any questions you might have concerning these proposed stipulations. If there are no questions, staff could recommend that the proposed stipulation be approved as the Commission's final action on this need determination petition.

COMMISSIONER JABER: Mr. Chairman.

CHAIRMAN BAEZ: Commissioner Jaber.

COMMISSIONER JABER: I don't know if Commissioners have questions. If not, I'm prepared to make a motion to resolve the case.

CHAIRMAN BAEZ: Let me confirm that there are no questions.

Commissioners, on Page 8 of the prehearing order you have the stipulated positions listed on all issues. Do you have any questions at this time?

COMMISSIONER DEASON: Just one, Mr. Chairman. I think it is fairly self-explanatory, but just to confirm it. Issue 6 is a requirement to provide annual reports concerning budgeted and actual costs. This is for information purposes, but it allows staff to continue to monitor that. And if and when there is to be any type of a rate proceeding or cost-recovery, it may be used at that time to determine the outcome of any issues pertaining to that question?

MS. HARLOW: Yes, sir, that's correct.

CHAIRMAN BAEZ: Any other questions?

Seeing none. Commissioner Jaber, you have a motion?

COMMISSIONER JABER: I do. Rather than have staff go issue-by-issue, I'm prepared to make a recommendation that we find all proposed stipulations in Issues 1 through 6 reasonable and acceptable, and I would move staff on Issues 1 through 7.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: There is a motion and second on Issues 1 through 7. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: A resounding aye from the heavens.

Do we have anything else pending at this point?

MR. KEATING: I don't believe so. In light of the events and vote today, no post-hearing filings will be required, and there are no other matters that staff is aware of.

CHAIRMAN BAEZ: Very well.

Mr. Sasso, anything you need to bring to our attention before we --

MR. SASSO: Nothing further, Mr. Chairman.

CHAIRMAN BAEZ: Thank you all for coming. I think we can adjourn this hearing. Thank you all. Thank you, Staff.

(The hearing concluded at 10:50 p.m.)

STATE OF FLORIDA )
: CERTIFICATE OF REPORTER
COUNTY OF LEON )

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 8th day of November, 2004.

JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732

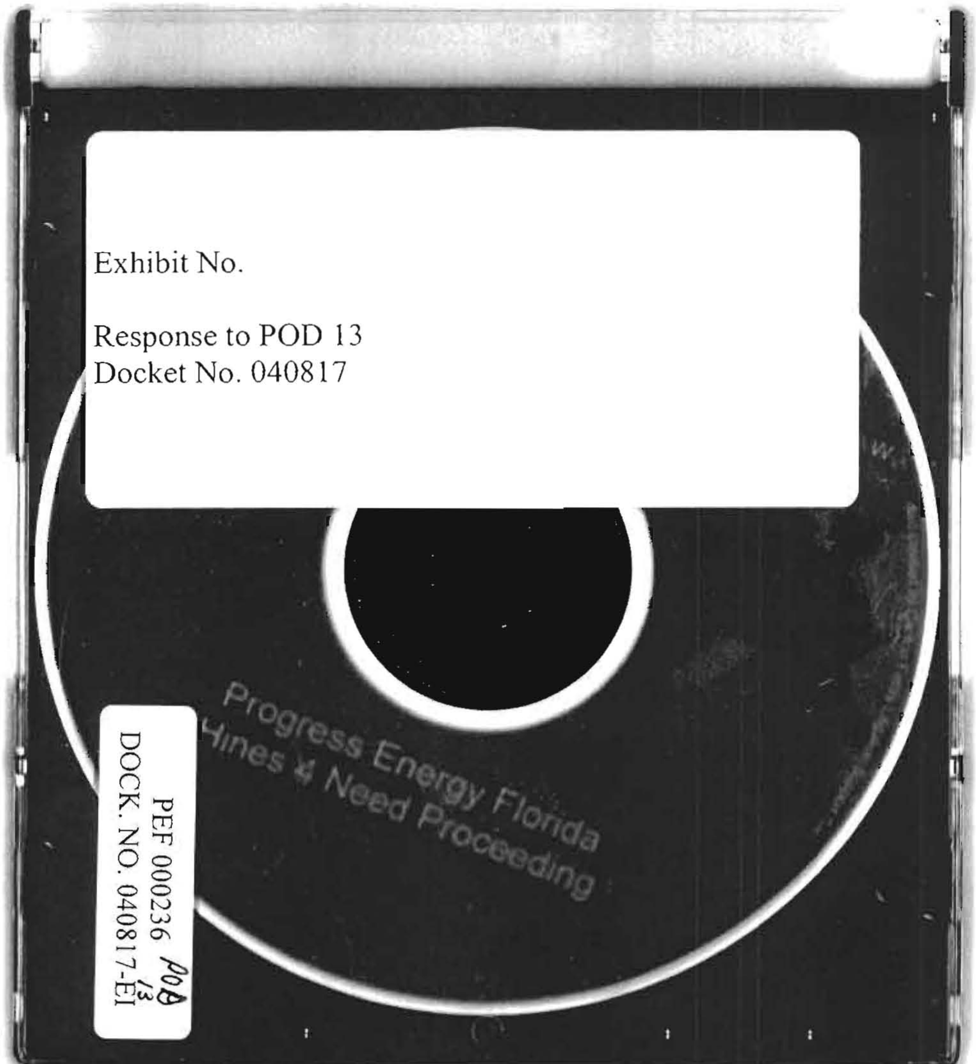
Exhibit No.
Response to POD 13
Docket No. 040817
Progress Energy Florida
Hines 4 Need Proceeding
PEF 000236 POD 13
DOCK. NO. 040817-EI

| Comprehensive Exhibit List for Entry into Hearing Record | | | |
|---|---|---|---|
| **Hearing I.D. #** | **Witness** | **I.D. # As Filed** | **Exhibit Description** |
| *Staff* | | | |
| 1 | | Exhibit List-Stip-1 | Comprehensive Stipulated Exhibit List |
| 2 | | Stip-2 | Specified Public Responses to Staff Discovery |
| 3 | | Stip-3 | Specified Confidential Responses to Staff Discovery |
| *Testimony Exhibit List* | | | |
| *PROGRESS ENERGY FLORIDA* | | | |
| 4 | Samuel S. Waters | (SSW-1) | PEF's Need Determination Study for Hines Unit 4 (with attachments), a composite exhibit |
| 5 | Samuel S. Waters | (SSW-2) | Forecast of Winter Demand and Reserves With and Without Hines Unit 4 |
| 6 | Samuel S. Waters | (SSW-3) | Levelized Busbar Cost Curves |
| 7 | Samuel S. Waters | (SSW-4) | PEF's 2008 System Energy Mix |
| 8 | Daniel J. Roeder | (DJR-1) | Results of Detailed Economic Analysis |
| 9 | Daniel J. Roeder | (DJR-2) | RFP Evaluation Process |
| 10 | Daniel J. Roeder | (DJR-3) | Summary of Proposals |
| 11 | Daniel J. Roeder | (DJR-4) | Threshold Requirements |
| 12 | Daniel J. Roeder | (DJR-5) | Results of Threshold Screening |
| 13 | Daniel J. Roeder | (DJR-6) | Results of Economic Screening |
| 14 | Daniel J. Roeder | (DJR-7) | Results of Optimization Analysis |
| 15 | Daniel J. Roeder | (DJR-8) | Minimum Evaluation Requirements |
| 16 | Daniel J. Roeder | (DJR-9) | Technical Criteria |
| 17 | Daniel J. Roeder | (DJR-10) | Final Results of Technical Evaluation |
| 18 | Daniel J. Roeder | (DJR-11) | Results of Detailed Economic Analysis—Costs by Component |
| 19 | Pamela R. Murphy | (PRM-1) | Natural Gas Forecast Compared to Other Industry Forecasts |
| 20 | Pamela R. Murphy | (PRM-2) | Base High and Low Case Natural Gas Forecasts |
| 21 | Pamela R. Murphy | (PRM-3) | Fuel Price Forecast for Hines |
| 22 | John M. Robinson | (JMR-1) | Hines Energy Complex Map |
| 23 | John M. Robinson | (JMR-2) | Site Arrangement – Overall Plan |

| Comprehensive Exhibit List for Entry into Hearing Record | | | |
|---|---|---|---|
| **Hearing I.D. #** | **Witness** | **I.D. # As Filed** | **Exhibit Description** |
| 24 | John M. Robinson | (JMR-3) | Site Arrangement – Power Block Area |
| 25 | John M. Robinson | (JMR-4) | Typical Combined Cycle Schematic |
| 26 | John M. Robinson | (JMR-5) | Projected Cost Estimate for Hines Unit 4 |
| 27 | John M. Robinson | (JMR-6) | Project Schedule for Hines 4 |
| 28 | Charles G. Beuris | (CGB-1) | Standard and Poors Article: "*Buy versus Build": Debt Aspects of Purchased-Power Agreements*. May 8, 2003 |

EXHIBIT NO. ________

DOCKET NO: 040817-EI

COMPANY: Progress Energy Florida, Inc.

DESCRIPTION: COMPOSITE EXHIBIT:

1) PEF's responses to staff's interrogatories 1 through 6; 12 through 15; 18 through 25; 27, 29, and 30.

2) PEF's responses to staff's request for production of documents 1 through 11; portions of response to number 12; 13, and 14.

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040817-EI EXHIBIT NO. 2
COMPANY/ F.P.S.C. Staff
WITNESS: Specified Public Responses to Staff Discovery
DATE 11-03-04

## INTERROGATORIES

1. What cost of capital did Progress Energy Florida assume in the determination of the total cost of its self-build option (Hines Unit 4)? For purposes of this response, please identify the relative mix of equity and debt and the respective cost rates.

**Response:**

| Capital Component | Ratio | Rate |
|---|---|---|
| Debt | 48% | 6.5% |
| Equity | 52% | 12.0% |

2. Please explain in detail why the cost of capital identified in response to the above interrogatory is appropriate for purposes of determining the total cost of Hines Unit 4.

**Response:**

The cost of capital shown in response to Interrogatory 1 is appropriate because it represents the marginal cost of funding for PEF. The 8.16% weighted average cost of capital (WACC) is supported by the utility's target mix of debt and equity funding and the long-term incremental costs of capital for Progress Energy Florida. The 12% equity cost of capital is equivalent to the allowed equity return stated by the FPSC in PEF's most recent rate case. The 6.5% cost of debt funding represents PEF's incremental borrowing rate in the debt capital markets. The rate is supported by current market rates, pricing, yields and credit spreads.

3. What AFUDC rate did Progress Energy Florida use in its Hines Unit 4 need determination study? For purposes of this response, please show the calculation of the AFUDC rate.

**Response:**

The AFUDC rate used in the need determination study was the same as the incremental after-tax weighted cost of capital, 8.16%. With a composite tax rate of 38.58%, the AFUDC rate is calculated as:

$$0.48 * 0.065 * (1-0.3858) + 0.52 * 0.12 = 0.0816 = 8.16\%$$

4. What is Progress Energy Florida's actual relative mix of equity and debt as of December 31, 2003? For purposes of this response, the sum should total 100% as assumed in PEF's need determination study assumptions.

**Response:**

The actual mix of debt and equity as of 12/31/2003 was:

| Capital Component | Ratio |
|---|---|
| Debt | 51.54% |
| Preferred Stock | 0.74% |
| Equity | 47.72% |

5. On page 2 of its need determination study, PEF states that it "purchases over 1,300 MW of capacity from 20 qualifying facilities and two investor-owned utilities." Please identify which, if any, of these power purchases are "above market."

**Response:**

The price for any purchase depends on the term of the agreement, the type of capacity purchased, and the purchaser's proposed utilization of the resource. The determination of the price in comparison to "market" depends upon the type of product (i.e. peaking, intermediate, base, full requirements, firm, non-firm, etc.) and the proposed time frame since markets change with capacity availability and fuel prices. Therefore, it is not possible to answer this question without a specific definition of what "market" would provide the basis of comparison for the specified contracts.

6. What is Progress Energy Florida's current corporate credit rating as assigned by Standard & Poor's Rating Service, Moody's Investor Service, and Fitch Ratings, respectively? For purposes of this response, please indicate when each rating was established.

**Response:**

| | S&P | | Moody's | | Fitch | |
|---|---|---|---|---|---|---|
| **Progress Energy Florida** | | | | | | |
| Outlook | Stable | | Negative | | Stable | |
| Corporate Credit Rating/Issuer Rating | BBB | 8/29/2003 | A2 | 11/22/2000 | NA | 2/14/2003 |
| Commercial Paper | A-2 | | P-1 | | F2 | |
| Senior Secured Debt | BBB | | A1 | | A- | |
| Senior Unsecured Debt | BBB | | A2 | | BBB+ | |
| Preferred Stock | BB+ | | Baa1 | | BBB | |

12. Based on the time frames identified in response to the above three interrogatories, would the Cypress project be completed in sufficient time to provide the capacity necessary to transport fuel supplies to Hines Unit 4?

**Response:**

Yes, we believe that the Cypress project should be completed in sufficient time to transport fuel supplies to Hines Unit 4. The time frames identified in response to Interrogatory 11 are "typical" time frames for a greenfield project, as requested, and do not apply to the Cypress project.

13. On page 9, lines 1 through 2, of Pamela Murphy's direct testimony, it states that PEF has been approached by three independent companies to bring LNG into South Florida from terminals located in The Bahamas. Are any LNG terminals currently under construction in The Bahamas?

**Response:**

PEF is not aware of any LNG terminals currently under construction in the Bahamas.

14. With respect to each of the Bahamian terminals referenced in Pamela Murphy's testimony, has the Bahamian government granted approval for those terminals to be built? If not, when will the Bahamian government make a decision on whether to grant approval to each proposed terminal?

**Response:**

PEF is not aware of any approval of LNG terminals in the Bahamas by the Bahamian government. PEF does not know when the Bahamian government will grant approval to each proposed terminal.

15. Based on the time frame identified in response to the above interrogatory, would any of the Bahamian projects be completed in sufficient time to provide the capacity necessary to transport fuel supplies to Hines Unit 4 in December 2007?

**Response:**

Based on PEF's response to Interrogatory 14, PEF does not know the commencement dates of the Bahamian projects. Because PEF does not know with certainty when such projects will commence, PEF cannot say whether the Bahamian projects could be completed in time to transport fuel to Hines Unit 4 in December 2007.

18. On page 9, lines 9 through 13, of Ms. Murphy's direct testimony, it states that PEF is confident that it will be able to obtain a contract for all of its gas transportation service requirements for Hines 4. Does PEF anticipate that it will contract with a single supplier, or multiple suppliers, for the total pipeline capacity required?

**Response:**

PEF anticipates contracting with multiple suppliers for pipeline capacity requirements.

19. Please explain the basis for PEF's belief that it will be able to obtain a contract for its pipeline capacity requirements within the time frame necessary to begin operation of Hines 4 in December 2007.

**Response:**

PEF believes that it can obtain contracts for its pipeline capacity requirements within the time frame necessary to begin operation of Hines 4 in December 2007 because PEF has received credible proposals from several pipeline sources.

20. In Order Number PSC-04-0609-FOF-EI, regarding the need determination for Florida Power & Light Company's Turkey Point Unit 5, FPL agreed to provide annual reports on the budgeted and actual cost compared to the estimated in-service cost for Turkey Point Unit 5 in the following categories: Major Equipment/EPC; Permitting; Transmission Interconnection and Integration; FGT infrastructure Upgrades; Operations and Start-Up; Project Management: Owners Cost; and AFUDC. Would PEF be willing to provide the same information on an annual basis for Hines 4? If not, why not?

**Response:**

The Bid Rule does not require that a utility annually report budgeted and actual costs associated with a proposed power plant. However, PEF will provide information in the categories noted above for Hines Power Block 4, if requested, upon the understanding that some costs may be higher than estimated and other costs may be lower, but that providing this information on an annual basis will allow Commission Staff to monitor PEF's progress towards achieving its estimated total cost for Hines 4.

21. At page 16, lines 12 through 22, of his direct testimony, Dan Roeder discusses the revised cost and operating characteristics of Hines 4 that was provided to bidders on January 13, 2004. Please provide additional detail on how these revised cost and operating characteristics differed from the information provided in PEF's most recent Ten-Year Site Plan and from the information provided in PEF's request for proposals. What were the primary reasons for the change in the cost and operating characteristics of Hines 4?

**Response:**

The information provided in the RFP Solicitation Document (and subsequent revisions prior to the bid submission date) represented preliminary cost and operating characteristics. The revised cost and operating characteristics provided to bidders on January 13, 2004 were developed from information provided to the RFP Evaluation Team on December 16, 2003 by the Hines 4 self-build team and are consistent with the information provided in PEF's most recent Ten-Year Site Plan (TYSP). The primary reason for the changes is the revised cost and operating parameters are based on information from vendors; whereas, the RFP costs and operating parameters were planning estimates, as explained in the Solicitation Document.

Compared to the TYSP, the winter and summer capacities are the same in both documents and the planned and forced outage factors are also the same in both documents. The O&M costs provided in the TYSP are in 2004 dollars and, when escalated at 2.5% per year, are the same as provided bidders in 2007 dollars. The direct construction cost provided in the TYSP, when multiplied by 517 MW, is $221.5 million, as provided to bidders. The heat rate data provided to bidders are expected heat rates at minimum and maximum load for the summer and winter seasons; whereas, the average heat rate provided in the TYSP is the projected annual average heat rate based on the simulated operation of Hines 4 as part of the PEF system.

The table below compares the information provided to bidders in the RFP Solicitation Document (and subsequent revisions prior to the bid submission date) to the information related to Hines 4 provided to bidders on January 13, 2004.

| Item | RFP Solicitation Document | January 13,2004 Document |
|---|---|---|
| Winter capacity (MW) | 565 | 517 |
| Summer capacity (MW) | 494 | 461 |
| Estimated total direct cost ($ Millions) | 249.9 | 221.5 |
| Estimated annualized revenue requirements ($ Millions, 2008$) | 39.9 | 35.3 |
| Estimated annual value of deferral ($/kW-yr., 2008$) | 58.09 | 56.40 |
| Estimated annual fixed O&M ($/kW-yr., 2007$) | 1.18 | 1.29 |
| Estimated variable O&M ($/MWh, 2007$) | 0.26 | 0.28 |
| Estimated major maintenance costs ($/MWh, 2007$) | 2.72 | 2.71 |
| Estimated delivered fuel cost ($/mmBtu, 2007$) | 4.03 | 4.69 |
| Estimated fuel fixed transportation ($/mmBtu) | 0.55 | 0.76 |
| Planned outage rate | 5.8% | 6% |

| | | |
|---|---|---|
| Minimum load (MW, winter) | 147 | 210 |

In addition to the changes above, the Seasonal Capacity States and Net Heat Rates were revised to reflect different capacity states and also to take into account the expected impact of degradation on the heat rate of the unit, as shown in the tables below.

RFP Solicitation Document

Capacity States and heat rates (based on HHV of fuel)

| Seasonal Capacity States and Net Heat Rates | | | |
|---|---|---|---|
| Capacity State (MW) | | Primary Fuel (Btu/kWh) | |
| Winter | Summer | Winter | Summer |
| 147 | 123 | 7731 | 8344 |
| 565 | 494 | 6720 | 6775 |

All values based on "new and clean" conditions

January 13, 2004 Document

Capacity States and heat rates (based on HHV of fuel)

| Seasonal Capacity States and Net Heat Rates | | | | | |
|---|---|---|---|---|---|
| Capacity State (MW) | | Primary Fuel (Btu/kWh) | | Secondary Fuel (Btu/kWh) | |
| Winter | Summer | Winter | Summer | Winter | Summer |
| 210 | 184 | 7710 | 7863 | 8206 | 8287 |
| 517 | 461 | 7062 | 7079 | 7802 | 7753 |

All values include impact of estimated degradation.

22. At page 15, lines 8 through 12 of his direct testimony, Samuel Waters states that PEF's resource plan calls for the addition of three simple-cycle combustion turbines in December 2006. When would construction have to begin on these combustion turbines for the CT's to be placed in-service by December 2006?

**Response:**

To meet an in-service date of December, 2006, construction on the three combustion turbines referenced in Mr. Waters' testimony would have to begin by September 1, 2005. However, please see PEF's response to Interrogatory 23 below. PEF does not plan to build these units now that PEF has a tolling agreement with Shady Hills Power Company, LLC.

23. Please provide a status update on PEF's negotiations to purchase power instead of building the planned December 2006 CT's, as discussed on page 15, lines 10 through 12 of Samuel Waters' direct testimony.

**Response:**

A tolling agreement between Progress Energy Florida (PEF) and Shady Hills Power Company, LLC, was completed on August 6, 2004. The agreement provides for the sale of 517 MW of demonstrated capacity to PEF for the term April 1, 2007 through April 30, 2014. This agreement effectively defers the need for the additional capacity to be provided by the 3 combustion turbines referenced in Mr. Waters' testimony. PEF is continuing negotiations to obtain capacity to bridge the winter of 2006/07.

24. Does the projected $221.5 million construction cost for Hines 4 include any natural gas infrastructure upgrades at the Hines site? Please describe any needed natural gas infrastructure upgrades at the site and provide the cost of these upgrades. If no such upgrades are required, please discuss why the existing gas infrastructure is adequate to meet the needs of the proposed plant.

**Response:**

Yes, the construction cost for Hines 4 does include money for natural gas infrastructure upgrades at the Hines site for the metering and regulating station. The construction cost estimate for Hines 4 included $2 million for the natural gas infrastructure upgrade.

25. Alfred McNeill's direct testimony addresses the need for a 230 kV transmission line addition from the Hines site to West Lake Wales. Please describe the permitting process and expected timeframe for permitting this transmission addition.

**Response:**

The Hines-West Lake Wales 230kV transmission line will be permitted as an associated linear facility in connection with the development of the Hines 4 project. Therefore, the information and permitting related to the transmission line is included within the Supplemental Site Certification Application (SSCA) for the Hines 4 project that was filed with the Florida Department of Environmental Protection on August 5, 2004, and will be processed under the Florida Power Plant Siting Act accordingly. The current SSCA schedule is provided in response to Interrogatory No. 29 below.

27. Considering the increase in natural gas capacity required to fuel Hines 4, will there be any off-site natural gas mainline improvements needed to supply the facility? If so, please describe the needed upgrades and the cost responsibility for these upgrades.

**Response:**

It is our understanding that Gulfstream would not require any mainline improvements to supply Hines 4. If PEF elects the Cypress Project option, Southern would need to extend its pipeline system to interconnect with FGT and Southern would provide the capital funding associated with extending its pipeline system. Southern would recover these capital costs through its reservation charge it would bill to PEF and others who contract to use the pipeline. FGT would require mainline improvements for the Cypress Project and FGT would provide the necessary capital to fund these mainline improvements. Like Southern, FGT would recover the capital costs associated with the mainline improvements through its reservation charge that it would bill to PEF and others who contract to use the pipeline.

29. Please provide a schedule for the supplemental site application process for Hines 4 at the Department of Environmental Protection, including the planned site certification hearing date.

**Response:**

What follows is a copy of the current schedule for the processing of the Hines 4 Supplemental Site Certification Application.

**PROGRESS ENERGY FLORIDA, HINES ENERGY CENTER**
**POWER BLOCK 4**
**POWER PLANT SITING APPLICATION NO. PA 92-33SA3**
**DOAH CASE NO. 04-2817EPP, OGC CASE NO. 04-1449**

**PROPOSED SCHEDULE FOR**
**REVIEW OF SITE CERTIFICATION**

| | |
|---|---|
| August 5, 2004 | Progress Energy files Site Certification Application (SCA) with DEP Siting Coordination Office (SCO). |
| August 12, 2004 | SCO requests DOAH to appoint Administrative Law Judge (ALJ) and files List of Affected Agencies. |
| August 16, 2004 | SCO determines that SCA is complete. |
| August 27, 2004 | Progress Energy completes distribution of SCA to affected agencies. |
| September 3, 2004 | Progress Energy publishes newspaper notice of filing SCA. |
| September 10, 2004 | DEP publishes notice of filing of SCA. |
| September 14, 2004 | DEP and other agencies submit sufficiency questions to SCO. |
| September 24, 2004 | SCO issues written determination as to whether SCA is sufficient. (Schedule assumes SCA is insufficient, if at all, only once.) |
| October 1, 2004 | DEP and Progress Energy file Response to Initial Order and Schedule |
| October 11, 2004 | DEP and other agencies issue preliminary statements of issues. |
| October 22, 2004 | Progress Energy files responses to DEP's sufficiency determination. |

| | |
|---|---|
| November 22, 2004 | DEP issues determination that Progress Energy's sufficiency responses render the SCA sufficient. |
| December 23, 2004 | Deadline for statutory agency parties to file notice of intent to be a party. |
| January 7, 2005 | DEP and other reviewing agencies submit reports to SCO. |
| February 6, 2005 | Deadline for DEP and Progress Energy to separately publish notice of the certification hearing. |
| February 16, 2005 | SCO issues DEP's report (Staff Analysis). |
| February 21, 2005 | Deadline to submit motions to intervene. |
| March 23, 2005 | Certification hearing before ALJ. |
| April 18, 2005 | ALJ to issue Recommended Orders on Certification. |
| June 17, 2005 | Deadline for hearing before Siting Board on certification. |

30. On August 23, 2004, Progress Energy filed a rate schedule with FERC providing for cost-based power sales to Reedy Creek Improvement District. Please provide additional information on this sale, including the proposed term and capacity. How will the proposed power sale to Reedy Creek Improvement District impact PEF's reserve margins during each year of the sale? Will the proposed Hines 4 generating unit provide capacity and energy to support this sale? Please discuss the regulatory treatment of the revenues and costs associated with the sale to Reedy Creek.

**Response:**

Progress Energy Florida and Reedy Creek Improvement District (RCID) signed the agreement in early May, 2004. The term of the agreement is five years, beginning January 2006, upon the expiration of a similar purchase Reedy Creek currently has with Orlando Utilities Commission. The monthly capacity amounts are shown in the table below.

Monthly Capacity Amounts
(MW)

| | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|
| January | 46 | 66 | 69 | 70 | 71 |
| February | 51 | 74 | 74 | 75 | 76 |
| March | 61 | 117 | 117 | 118 | 119 |
| April | 64 | 88 | 88 | 89 | 90 |
| May | 73 | 95 | 95 | 96 | 97 |
| June | 79 | 101 | 101 | 101 | 102 |
| July | 94 | 117 | 117 | 118 | 119 |
| August | 94 | 117 | 117 | 118 | 119 |
| September | 72 | 94 | 94 | 94 | 95 |
| October | 66 | 89 | 90 | 91 | 92 |
| November | 58 | 81 | 82 | 83 | 84 |

The transaction with Reedy Creek Improvement District was not included in the Company's Hines 4 Need Determination Study. The additional load associated with the RCID transaction decreases the Company's planning reserve margin shown in the Need Determination Study by approximately one percentage point in the winter and approximately 1.5 percentage points in the summer. The Company will continue to satisfy its minimum 20% reserve margin criterion. Each of the Company's firm resources, including Hines 4, will supply capacity to support the Reedy Creek transaction. Energy will come from those resources operating when Reedy Creek calls for energy under the agreement.

Since this sale is both long term (greater than 1 year) and firm, it would be treated as a "separated" wholesale sale and the revenues and related costs would be appropriately assigned to the wholesale jurisdiction. The assignment of costs would be consistent with the method used in PEF's last base rate proceeding.

# Research:

Return to Regular Format

## Summary: Progress Energy Inc.

**Publication date:** 16-Aug-2004
**Credit Analyst:** Jodi E Hecht, New York (1) 212-438-2019

**Credit Rating:** BBB/Stable/A-2

## Rationale

The 'BBB' corporate credit rating on Progress Energy Inc. (BBB/Stable/A-2) reflects the consolidated credit profile of Progress Energy and its various subsidiaries. The wholly owned subsidiaries include Carolina Power & Light Co. (doing business as Progress Energy Carolinas, PEC), Florida Power Corp. (doing business as Progress Energy Florida, PEF), and Progress Ventures.

Raleigh, N.C. based Progress Energy had about $10.3 billion in outstanding debt as of June 30, 2004.

Ratings reflect the two relatively stable regulated utilities, which contribute about 80% of the consolidated company's net income, offset by the higher risk unregulated operations at Progress Ventures. Strengths include the strong growth in the Florida service area and sound growth in the Carolinas. The industrial sector in PEC's service territory has recently stabilized after several years of significant declines. These strengths are offset by the higher risk businesses of merchant generation, the synthetic fuel operations and natural gas production in addition to the consolidated company's high leverage and uncertainty facing PEF as the current rate agreement expires in 2005.

Progress Energy's unregulated businesses include Progress Ventures and Progress Fuels. The recent announcement of additional contracts with several Georgia electric cooperatives for generation capacity is expected to improve the financial performance of the unregulated business. However, the contracts have additional risks relative to block power sales because under the terms of the full-requirements contract, which are in place from 2005-2015, the company must manage the volatile fuel prices in exchange for fixed prices from the cooperatives.

The synthetic fuel production continues to generate net income after considering the impact of the Section 29 tax credits but requires a significant amount of management's time and attention because of outstanding issues related to IRS audits. In June 2004, the IRS announced that it would withdraw from the pre-filing agreement program for the company's four EarthCo facilities, questioning if the plants were placed in service by July 1, 1998, one of three criteria used in determining eligibility for the Section 29 tax credits. If the four EarthCo plants are disallowed and past tax credits are revoked, Progress Energy estimates that, as of March 31, 2004, it would have to write down $942 million of tax credits and repay $229 million in net cash taxes. This worst-case outcome would reduce the company's liquidity and increase total debt to capital, which would worsen the company's credit protection measures and could cause a lower rating.

For the last 12 months ending June 30, 2004, adjusted total debt to capital was 59.1% and consolidated adjusted funds from operations (FFO) interest coverage was 2.9x, down from 3.3x in the previous year. The decline in the FFO interest coverage reflects the lower wholesale sales and increased nuclear operations and maintenance expenses. The company continues to focus on debt reduction, targeting 55% by 2005 using a combination of excess cash flow and proceeds from the sale of the rail assets. The reduction in consolidated debt is slower than Standard & Poor's anticipated. Projected adjusted debt to capital and adjusted FFO interest coverage, which is expected to be around 3.0x, are weak for the rating.

### Short-term credit factors.

Progress Energy's short-term rating is 'A-2', in large part governed by the company's corporate credit rating and adequate liquidity, enhanced by the expectation that the regulated electric businesses will continue to generate stable cash flow. However, the short-term rating also reflects the challenges posed by the company's nonregulated activities. Standard & Poor's expects that Progress Energy will be able to fund its dividend of $570 million and capital expenditure program of about $1.3 billion with internally generated funds of about $2.2 billion during 2004, as liquidity will benefit from a small equity issuance from the employee funds and asset sale proceeds. The cash flow trend is improving, with free cash flow expected to be positive at the end of the year 2004, the first time since 1998.

Progress Energy's liquidity position is sound. The company has three credit lines at the holding and operating companies totaling $1.98 billion. On Aug. 5, 2004, the company replaced its $700 million credit line at the holding company with a new $1.13 billion five-year credit facility. As of June 30, 2004, the company had about $600 million commercial paper outstanding. The company does not have any significant debt maturities for the remainder of 2004 but does face significant requirements in 2006 and 2007. Maturities at the utilities were either refinanced or repaid in 2004, and a $500 million maturity due at the holding company was paid off in March. However, the increase in the outstanding commercial paper offsets any significant debt reduction in the consolidated company's profile. Upcoming maturities include $348 million at the utilities in 2005, $908 million in 2006, including a $800 million maturity at the holding company, and $915 million in 2007.

## Outlook

The stable outlook reflects the stable nature of the regulated utilities and the reasonably predictable financial performance of Progress Energy over the next several years. Although the tax-driven synthetic fuel operations are expected to somewhat weaken Progress Energy's cash flow protection measures over the next few years, Standard & Poor's recognizes that there is a long-term benefit to such investment. Still, the stable outlook relies on the company's ability to continually improve its financial metrics until it reaches ratings-appropriate levels. If the IRS synfuel audit resolution is unfavorable and it weakens credit protection measures, then it may lead to lower ratings. However, the range and timing of outcomes are uncertain, and no rating action is appropriate at this time.

# Research:

Return to Regular Format

## Progress Energy's Ratings Affirmed; Outlook to Negative

**Publication date:** 28-Mar-2002
**Credit Analyst:** Jodi E Hecht, New York (1) 212-438-2019; Suzanne G Smith, New York (1) 212-438-2106

NEW YORK (Standard & Poor's) March 28, 2002--Standard & Poor's said today it affirmed its ratings on Progress Energy Inc. (triple-'B'-plus) and its subsidiaries Florida Power Corp. and Carolina Power & Light Co., and revised the outlook to negative from stable.

Raleigh, N.C.-based Progress Energy has $9.5 billion in outstanding debt.

"The action reflects the increased business risk at nonregulated subsidiary Progress Ventures, lower-than-projected credit protection measures, and a rate settlement for Florida Power Corp., whose reduction in retail rates will decrease future revenue growth," said Standard & Poor's credit analyst Jodi Hecht.

Florida Power and Carolina Power & Light, the two regulated operating utilities units, account for about 80% of Progress's consolidated assets and cash flow and support the average business position.

The current rating assumes a more conservative business strategy for the unregulated business than is currently being executed. Two-thirds of the merchant generation portfolio, expected to total 3,100 MW by 2003, have short-term contracts, or lack off-take contracts. In addition, Progress Energy's plan to divest noncore assets and use the proceeds to pay down acquisition-related debt is moving more slowly than Standard & Poor's anticipated. One-half of the sales were completed as expected, while the remaining sale of rail assets has been delayed. Factored into the current rating is an expectation that leverage, which is currently above 60%, would decrease further. Additional debt was incurred to finance the acquisition of two merchant generation plants in Georgia and construction of a portion of the nonregulated generation portfolio.

The recently announced rate settlement for Florida Power requires a $125 million annual reduction in base rates through the end of the agreement in 2005. The reduction in rates will be partially offset by projected growth in customers and usage of about 3%, or $37 million annually. The settlement replaces the revenue-sharing mechanism with the previously stipulated ROE range regulation. This mechanism provides a refund to the customer when sales exceed prescribed levels and allows Florida Power to receive the benefit of operational efficiencies. Under the mechanism, Florida Power can realize up to an additional $20 million annually.

A complete list of the ratings is available to RatingsDirect subscribers at www.ratingsdirect.com, as well as on Standard & Poor's public Web site at www.standardandpoors.com under Ratings Actions/Newly Released Ratings.

# Research:

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## Summary: Florida Power Corp d/b/a Progress Energy Florida Inc

**Publication date:** 09-Oct-2003
**Credit Analyst:** Jodi E Hecht, New York (1) 212-438-2019

**Credit Rating:** BBB/Stable/A-2

### Rationale

Florida Power Corp. (FPC), an integrated electric utility, is a wholly owned subsidiary of Progress Energy Inc. The rating on FPC reflects the consolidated credit profile of its parent, Progress Energy, and its affiliates, CP&L and Progress Ventures. The rating reflects weakened financial performance stemming from the economic downturn and rate reduction impacting the regulated utilities, compounded by overcapacity in the Southeast, which has weakened the financial performance of the unregulated generation portfolio, and high financial leverage. The company's tax-advantaged synthetic fuel business also has the effect of reducing the company's cash flow in the intermediate term.

The ratings on Progress Energy reflect the consolidated credit profile of Progress Energy and its various subsidiaries. The wholly owned subsidiaries include CP&L, FPC, and Progress Ventures. The average business position is supported by the relatively stable regulated utilities, CP&L and FPC, which contribute about 80% of the consolidated company's net income. Long-term growth prospects remain strong in the vibrant Florida service area while the negative trend in North Carolina's industrial sales is expected to stabilize in the near term after four years of significant declines. The merchant generation operations remain higher risk.

At year-end 2002, Progress Energy's adjusted total debt to capital was 61% and consolidated adjusted funds from operations (FFO) interest coverage was less than 3.5x. Standard & Poor's expects adjusted debt to capital to decline to 55%, as debt is repaid, and adjusted FFO interest coverage to remain at current levels, which are weak for the rating.

Cash flow from CP&L and FPC, which provide service to more than 2.8 million customers in North Carolina, South Carolina, and Florida, declined in 2002, primarily due to the FPC rate reduction implemented pursuant to the four-year rate stipulation. CP&L's operating cash flow, through the first half of 2003, increased slightly with the strong wholesale sales offsetting the continued weakness in industrial sales.

FPC serves 1.5 million electric customers in northern and central Florida. The company is in the second year of a four-year rate agreement requiring a $125 million annual reduction in base rates (about 9.25%) and revenue sharing with ratepayers when base revenues exceed revenue thresholds. Although Standard & Poor's considers this a favorable agreement and regulation in Florida general supportive, a recent Florida Public Service Commission (FPSC) ruling ordered the company to increase the amount of revenues rebated to customers.

There is no effort to wholly restructure the Florida retail or wholesale markets. However, efforts are proceeding regarding a regional transmission organization (RTO) and to open the bidding process for wholesale generation. FPC, with Florida Power & Light and Tampa Electric Co., filed an application for a Florida-only RTO entitled GridFlorida with the FERC and the FPSC. The FERC provisionally approved the proposal in March 2001 and initiated a review of GridFlorida in May 2001. Both regulatory bodies continue hearings on the proposal, but there is no agreement on which body has regulatory authority on the issue. In September 2003, the FERC held a technical conference to discuss market design, participant funding, and other issues discussed in the FERC's white paper, but it is unclear when and how the proposals will proceed.

The FPSC earlier this year issued new rules for companies soliciting bids for new generation. The new rules will be applied to FPC's new request for approximately 500 MW of firm generation needed in 2007 to serve its retail load. Responses from the request are expected in December and will compete with the company's proposal to add a 540 MW combined cycle unit in Polk County at an existing FPC-owned site.

In September 2003, the city of Winter Park approved a referendum to issue debt to purchase the distribution system from FPC. City officials have not made a final decision regarding the purchase and continue to negotiate with FPC. The value of the system was set during arbitration, and the FPSC approved recovery of the stranded costs associated with the new valuations. The loss of revenues and customers, if the sale is completed, will be offset by the $45 million purchase price; however, the current rate agreement includes the revenues and customers from Winter Park. While the loss of revenues and customers is minimal (13,000 customers generating $30 million gross revenues), the loss cannot be offset in the rate base until the current rate settlement expires in 2005. Since Progress Energy purchased FPC, the company has worked to improve the reliability throughout the entire service territory. Improvements to the company's distribution system, which is complete, were included in the rate settlement.

FPC continues to work through arbitration to resolve lawsuits filed by several municipalities regarding the franchise agreements. Three cities, out of a total of 104 that have signed franchise agreements, are considering purchasing its distribution systems. Similar to Winter Park, the number of customers and revenue lost would be minimal (about 1% of customers). However, the resolution of the Winter Park issue may provoke other municipalities to attempt to negotiate their respective franchise agreements. This issue, along with the changes to the request for proposals process and RTO, require ongoing attention from management while the company continues to address its growth needs.

FPC's total gross electric revenues declined by 5% in 2002, led by flat residential revenues (54% of operating revenues) and declines in revenues from the commercial (3% decline, 24% of operating revenues) and industrial (5% decline, 7% of operating revenues) sectors. This decline is largely due to the negotiated reduction in base rates. Revenues during 2003, excluding fuel revenues, showed improvement, declining by less than 1% during the first six month of the year. In terms of energy mix, the company remains concentrated in coal (33%) and purchased power contracts (21%). Additionally, there is some asset concentration in Crystal River 3 (CR3), a 834 MW nuclear plant, which represents 10% of the summer capacity. However, FPC's adequate reserve margin of 16% would provide replacement power to offset an extended unscheduled outage at CR3, offsetting some concerns regarding asset concentration. CR3 is scheduled to have its reactor head replaced this year, instead of incurring the ongoing expense of testing during each refueling.

Progress Energy's unregulated businesses, which include Progress Ventures and Progress Fuels, have a higher-risk profile than the operating utilities primarily due to its merchant power exposure. Progress Ventures will have about 3,100 MW of unregulated generation in service by the end of 2003. The portfolio of generation assets includes mostly peaking capacity, and all of the assets are located in the Southeast.

About 2,000 MW of the unregulated generation capacity have been sold under tolling agreements through 2004, and about 773 MW will remain under tolling arrangements after 2004, leaving a significant portion of the portfolio exposed to market trends. Progress has acquired a requirements contract from Williams Cos. to serve Jackson Electric Membership Corp. in Georgia. Under the contract, Progress Ventures has a 235 MW of partial requirements obligation through 2004 and an estimated 1,100 MW of full requirements obligation starting in 2005. The contract includes call rights on 640 MW of resources, which is Jackson's share of its Olgethorpe Power Co.'s resources.

Despite having a significant portion of its near-term capacity under contract, the unregulated generation's EBITDA contribution to the consolidated entity over the next few years is expected to be minimal, mainly because of the generation capacity surplus in the Southeast. Efforts to improve its margin by entering into requirements contracts may result in increased cash flow, but it also introduces additional risks that are not present in tolling agreements. Even though Progress Energy appears to have adequately mitigated the risks associated with the Jackson contract, the portfolio's risk profile could increase if the company enters into additional all requirements contracts.

Synthetic fuel production generates significant net income after considering the impact of the Section 29 tax credits (10% of FFO). Progress Energy continues to work with the IRS in a voluntary program to clarify qualifications under the program. In June 2003, field agents raised questions whether the synthetic coal manufactured at Progress's Colona plant produced a significant chemical change, one criterion needed to qualify for the credits. The range of possible IRS conclusions includes revocation of all past tax credits ($445.6 million utilized and an additional $582.4 million of alternative minimum tax credit carry forwards as of June 30, 2003), tightening the standards, or reducing or even completely eliminating all future tax credits.

Although it is difficult to predict the IRS outcome, the company believes there is no precedent to retroactively revoke tax credits, and a change in IRS policy is unlikely. Assuming tax credits are not revoked retroactively, the remaining possible outcomes could be neutral to slightly positive to Progress Energy's credit rating. Any reduction or closing of the synthetic fuel productions would decrease the cash operating loss, which ranges from about $130 million to $160 million annually. Furthermore, the company would draw down the accrued tax credits, consuming about $150 million annually and increasing cash flow. If the program is unaltered, the company projects it will begin to consume the approximate $1.2 billion of alternative minimum tax credit carry forwards in 2008, when synthetic fuel tax credits are no longer available under current IRS rules.

**Liquidity.**

Progress Energy's liquidity position is adequate. The company has three credit lines at the holding and operating companies totaling $1.73 billion. The company intends to reduce its back-up facilities to $1.55 billion later this year. As of Sept. 30, 2003, the company did not have any commercial paper outstanding. The company used the $400 million proceeds from the sale of North Carolina Natural Gas, which were received in September 2003, to temporarily reduce the outstanding commercial paper. The $500 million maturity in March 2004 at the holding company will be repaid from commercial paper, essentially replacing the long-term maturity with short-term debt. Upcoming maturities at CP&L and FPC will be refinanced with term debt issues.

## Outlook

The stable outlook reflects the stable nature of the regulated utilities and the reasonably predictable financial performance of Progress Energy over the next several years. Although the tax-driven synthetic fuel operations are expected to somewhat weaken Progress Energy's cash flow protection measures over the next few years, Standard & Poor's recognizes that there is a long-term benefit to such investment.

# Research:

Return to Regular Format

## Summary: Florida Power Corp d/b/a Progress Energy Florida Inc

**Publication date:** 12-Apr-2004
**Credit Analyst:** Todd A Shipman, CFA, New York (1) 212-438-7676

**Credit Rating:** BBB/Stable/A-2

## Rationale

The ratings on Florida Power Corp. (d/b/a Progress Energy Florida) reflect the consolidated credit profile of its parent Progress Energy Inc. The 'BBB' corporate credit ratings on Progress Energy and its utility subsidiaries reflect weakened utility financial performance stemming from the economic downturn and rate reduction, compounded by overcapacity in the Southeast, which has weakened the financial performance of the unregulated generation portfolio, and high financial leverage. The company's tax-advantaged synthetic fuel business also has the effect of reducing the company's cash flow in the intermediate term.

The wholly owned subsidiaries include Carolina Power & Light Co. (CP&L; d/b/a Progress Energy Carolinas), Florida Power, and Progress Ventures. The average business position is supported by the relatively stable regulated utilities, CP&L and Florida Power, which contribute about 80% of the consolidated company's net income. Long-term growth prospects remain strong in the vibrant Florida service area while the negative trend in North Carolina's industrial sales is expected to stabilize in the near term, after four years of significant declines. The merchant generation operations remain high risk.

At year-end 2003, adjusted total debt to capital was 62% and consolidated adjusted funds from operations (FFO) interest coverage was around 3x. Standard & Poor's expects adjusted debt to capital to decline to 55% as debt is repaid, and adjusted FFO interest coverage to remain at current levels, which is weak for the rating.

Progress Energy's unregulated businesses, which include Progress Ventures and Progress Fuels, have a higher risk profile than the operating utilities primarily due to its merchant power exposure. Despite having a significant portion of its near-term capacity of 3,100 MW under contract, the unregulated generation's EBITDA contribution to the consolidated entity over the next few years is expected to be minimal, mainly because of the generation capacity surplus in the Southeast.

Synthetic fuel production generates significant net income after considering the effect of the Section 29 tax credits (10% of FFO). The IRS is reviewing this program and has stopped issuing private letter rulings. The range of possible IRS conclusions includes revocation of all tax credits generated to date ($1.243 billion at the end of 2003), tightening the standards, or reducing or even completely eliminating all future tax credits. Although it is difficult to predict the IRS outcome, the company believes there is no precedent to retroactively revoke tax credits, and a change in IRS policy is unlikely. Assuming tax credits are not revoked retroactively, the remaining possible outcomes could be neutral to slightly positive to Progress Energy's credit rating in the near term. Any reduction or closing of the synthetic fuel productions would decrease the cash operating loss, which ranges between $130 million and $160 million annually. In addition, the company would draw down the accrued tax credits, consuming about $150 million annually and increasing cash flow.

### Liquidity.

Progress Energy's liquidity position is adequate. The company has three credit lines at the holding and operating companies totaling $1.6 billion. As of year-end 2003, the company did not have any commercial paper outstanding. The company used the $400 million proceeds from the sale of North Carolina Natural Gas, which were received in September 2003, to temporarily reduce its outstanding commercial paper. Upcoming maturities at CP&L and Florida Power will be refinanced with term debt issues.

## Outlook

The stable outlook reflects the stable nature of the regulated utilities and the reasonably predictable financial performance of Progress Energy over the next several years. Although the tax-driven synthetic fuel operations are expected to somewhat weaken Progress Energy's cash flow protection measures over the next few years, Standard & Poor's recognizes that there is a long-term benefit to such investment. Still, the stable outlook relies on the company's ability to continually improve its financial metrics until they reach ratings-appropriate levels.



The McGraw-Hill Companies

Moody's Investors Service

Global Credit Research
Credit Opinion
15 JUL 2004

**Credit Opinion:** Progress Energy Florida, Inc.

## Progress Energy Florida, Inc.

*Florida, United States*

### Ratings

| Category | Moody's Rating |
|---|---|
| Outlook | Negative |
| Issuer Rating | A2 |
| First Mortgage Bonds | A1 |
| Senior Secured Shelf | (P)A1 |
| Sr Unsec Bank Credit Facility | A2 |
| Senior Unsecured | A2 |
| Subordinate Shelf | (P)A3 |
| Preferred Stock | Baa1 |
| Commercial Paper | P-1 |
| **Ult Parent: Progress Energy, Inc.** | |
| Outlook | Stable |
| Sr Unsec Bank Credit Facility | Baa2 |
| Senior Unsecured | Baa2 |
| Jr Subordinate Shelf | (P)Baa3 |
| Preferred Shelf | (P)Ba1 |
| Commercial Paper | P-2 |

### Contacts


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### Key Indicators

**Progress Energy Florida, Inc.**

| | 1Q04 TTM | 2003 | 2002 | 2001 |
|---|---|---|---|---|
| Adjusted Funds from Operations / Adjusted Debt [1][2] | 20.0% | 17.0% | 27.7% | 45.5% |
| Retained Cash Flow / Adjusted Debt [2] | 15.0% | 8.7% | 13.3% | 31.5% |
| Common Dividends / Net Income Available for Common | 43.5% | 68.8% | 93.8% | 80.6% |
| Adjusted Funds from Operations + Adjusted Interest / Adjusted Interest [1][3] | 5.38 | 4.89 | 5.95 | 7.66 |
| Adjusted Debt / Adjusted Capitalization [2][4] | 52.5% | 53.0% | 50.3% | 46.3% |
| Net Income Available for Common / Common Equity | 12.7% | 13.8% | 15.8% | 15.2% |

[1] FFO is adjusted to reflect the deduction of preferred dividends. [2] Adjusted Debt reflects the adjustment made for operating leases. [3] Adjusted Interest reflects the addition of other interest, preferred dividends and the adjustment made for operating leases. [4] Adjusted Capitalization reflects the adjusted debt.

*Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.*

### Opinion

#### Credit Strengths

The credit strengths of Progress Energy Florida are:

- High growth, residential service territory with limited industrial customers

- Below average rates and a favorable regulatory environment

- Adequate debt service coverage ratios

**Credit Challenges**

The credit challenges of Progress Energy Florida are:

- Declining credit metrics over last several years

- Cash flow pressured by large capex program

- Increased leverage incurred to finance this capex

- Higher O&M, insurance, pension and benefit expenses

- Uncertainty surrounding upcoming 2005 rate case

**Rating Rationale**

Progress Energy Florida (PEF), maintains an A1 senior secured rating (negative outlook), reflecting its adequate debt service coverage ratios, a constructive regulatory environment in Florida, competitive rates, the service area's vibrant economy, limited industrial customers, and minimal in-state competition. These strengths are offset by declining credit metrics over the last several years, higher capital expenditures, and increased leverage incurred to finance these capital expenditures, which will continue to pressure the utility's financial performance going forward. PEF has also incurred higher O&M, insurance, pension and employee benefit expenses. As a result, free cash flow is likely to be limited for the next several years, constraining PEF's ability to reverse increasing leverage trends.

PEF has some nuclear exposure (one unit) that is being managed as part of Progress Energy Carolinas' larger nuclear fleet. PEF is also exposed to potential stranded costs from expensive power purchase contracts and regulatory assets. In March 2002, PEF announced a rate settlement providing for a one-time refund of $35MM, a rate reduction of $125MM annually through 2005, and a decrease of $50MM in fuel charges through 2002. The negative effect of the rate decrease has been partially offset by reduced depreciation, regulatory certainty to 2005, incentive-based revenue sharing, recovery of certain costs associated with PEF's Hines II generating unit beginning in 2004, an opportunity to file for a rate increase if ROE falls below 10%. This rate settlement expires on December 31, 2005 and PEF expects to file a new rate case next year.

PEF is a source of significant dividends for Progress Energy (Progress, Baa2 senior unsecured, stable outlook), its parent company. PEF exhibits a reasonable liquidity profile with between $44 and $48 million of long-term debt due per annum over the next three years. All of PEF's fuel, purchased power, and capacity payments are covered by recovery clauses, designed to permit recovery of these costs.

Progress acquired Florida Progress in late 2000, combining with Carolina P&L to create one of the nation's largest utilities. Since the merger was completed, Moody's believes that Progress management has increasingly operated its two utilities more as a single system, with financial characteristics becoming increasingly similar. Moody's will continue to review and monitor management's strategy with regard to both PEF and PEC to determine if their ratings should converge over time.

**Rating Outlook**

The negative outlook reflects declining credit metrics in recent years, higher capex, and increased leverage incurred to finance this capex, and the limited free cash flow generating ability of the utility.

**What Could Change the Rating - UP**

The negative outlook limits the near term upside potential for the rating. An upgrade would require a reversal of recent trends which have resulted in lower financial metrics, higher capex, and higher leverage.

**What Could Change the Rating - DOWN**

Continued negative trends with regard to financial ratios, unanticipated capex or additional debt issuances, and management's continued operation of both PEF and PEC as a single system, with financial characteristics converging over time.

## Recent Developments

In March 2004, the Florida legislature introduced a bill to sharply reduce air-pollution at PEF's power plants and freeze base rates for at least 5 years, in an arrangement similar to the one PEC has in North Carolina. Requirements included reducing NOx emissions from PEF's Bartow and Anclote plants by 20%. However, the legislature failed to pass the bill during its 2004 session.

Rating Action: Progress Energy Florida, Inc.

## MOODY'S PLACES THE LONG TERM DEBT RATING OF PROGRESS ENERGY (Baa1 SENIOR UNSECURED) ON REVIEW FOR POSSIBLE DOWNGRADE; CONFIRMS P-2 COMMERCIAL PAPER RATING

**Approximately $4.0 billion of Debt Securities Affected.**

New York, October 18, 2002 -- Moody's Investors Service has placed the long term debt rating of Progress Energy, Inc. on review for possible downgrade in response to Progress Energy's announcement today that it would write down its telecommunication assets by $225 million after-tax. Because of this writedown, Progress Energy's debt to capital ratio will remain at approximately 64% at the end of the third quarter, further delaying the deleveraging plan anticipated after the acquisition of Florida Progress in late 2000. This plan had already been delayed earlier this year following the issuance of new debt to finance the expansion of its Progress Ventures unregulated generation portfolio. Although Progress Energy this week announced an agreement to sell its North Carolina Natural Gas subsidiary for $425 million and use the proceeds to reduce debt, the closing of this transaction is not expected until mid-2003. Moody's notes that Progress Energy's higher leverage this year, although modest, comes at a time when much of the industry is deleveraging.

Under review are Progress Energy's Baa1 senior unsecured debt rating and the shelf registrations for the issuance of senior unsecured debt, (P)Baa1; junior subordinated debt, (P)Baa2; trust preferred stock, (P) Baa2; and preferred stock, (P)Baa3. Progress Energy's P-2 commercial paper rating is confirmed as Moody's does not expect the review to result in more than a one notch downgrade of the long term debt rating.

Moody's also confirms the ratings of Progress Energy's two operating utilities, Carolina Power & Light Company (A3 - senior secured, P-2 commercial paper) and Florida Power Corporation (A1 - senior secured, P-1 commercial paper). The outlook of the ratings of the two operating utility subsidiaries is stable.

To finance its acquisition of Florida Progress in late 2000, Progress Energy issued $3.2 billion of long-term debt, and its debt to capital ratio increased to 65% immediately following the acquisition. At the time, management indicated an intention to reduce this ratio to the 55% range two to four years following the acquisition. While debt to capital did decrease to below 63% during 2001, its has since again increased slightly to 64%, nearly two years after the acquisition. Aside from the telecommunications writedown and the issuance of new debt related to Progress Ventures, other reasons include the inability to sell its Progress Rail subsidiary, now expected in 2003, and delays in the sale of some other noncore businesses. Moody's review will focus on the likelihood of these asset sales and the effect they will have on leverage, as well as Progress Energy's other plans to reduce leverage going forward.

Moody's notes that Progress Energy continues to derive significant credit strength from the ample dividends upstreamed from its two operating utilities, Carolina Power & Light and Florida Power. Moreover, unlike many of its competitors, Progress Energy has pursued a modest unregulated generating strategy with a total of six plants (3,100 MW) in operation or under construction. All of this generation is located in or very close its service territory in the southeast region of the country and much of it is under contract, limiting Progress Energy's exposure to the depressed wholesale power markets. Moody's review will also examine the effect that low projected wholesale power prices and excess capacity will have on the unhedged portion of this portfolio in 2003 and 2004.

Progress Energy is a diversified energy company headquartered in Raleigh, North Carolina.

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Moody's Investors Service

Global Credit Research
Rating Action
7 FEB 2003

Rating Action: Progress Energy Florida, Inc.

# MOODY'S LOWERS PROGRESS ENERGY'S SENIOR UNSECURED DEBT RATING TO Baa2, STABLE OUTLOOK, AND LOWERS TRUST PREFERRED RATING OF FPC CAPITAL I TO Baa1, NEGATIVE OUTLOOK. MOODY'S ALSO CHANGES THE RATING OUTLOOK OF FLORIDA POWER CORPORATION TO NEGATIVE.

**Approximately $6.8 Billion of Debt Securities Affected.**

Moody's Investors Service has lowered Progress Energy's senior unsecured debt rating to Baa2 from Baa1 with a stable outlook and confirmed Progress Energy's Prime-2 commercial paper rating. In addition, Moody's has lowered the trust preferred rating of FPC Capital I to Baa1 from A3 with a negative outlook. Moody's has also changed the outlook of the ratings of Florida Power Corporation (A1 senior secured) and Progress Capital Holdings, Inc. (A3 senior unsecured) to negative.

Moody's has taken this action because of the high level of debt at the Progress Energy holding company ($4.8 billion) resulting from the acquisition of Florida Progress in late 2000, as well as the subsequent expansion of its Progress Ventures unregulated generation subsidiary. In the two years following the Florida Progress acquisition, Progress Energy has deleveraged at a slower pace than originally anticipated as a result of a number of factors, including plant acquisitions at Progress Ventures, the writedown of its telecommunications and other unregulated assets, and delays in the sale of various noncore businesses, including its Progress Rail subsidiary. Moody's notes that the company did issue approximately $600 million of common stock in November 2002, which has reduced total debt to capital to approximately 61%.

In addition, Moody's believes that the quality of the cash flows being upstreamed from its utility subsidiaries, as well as its Progress Ventures unregulated generating subsidiary, have marginally declined since the acquisition was consummated and the original Progress Energy ratings were assigned. At utility subsidiary Florida Power Corporation, a base rate reduction enacted earlier this year, higher capital expenditures, and increased leverage to finance these capital expenditures are expected to put pressure on the utility's financial performance going forward. Moody's also believes that Progress Energy management is operating its two utility subsidiaries as one system with financial characteristics likely to become increasingly similar. Moody's will continue to review and monitor management's strategy with regard to its two utility subsidiaries to determine if ratings should converge over time.

As a result of these factors, Moody's has changed the outlook of the ratings of Florida Power to negative. Because securities issued by Progress Capital Holdings, Inc. and FPC Capital I are guaranteed by Florida Progress Corporation (not rated), which derives its credit strength predominantly from Florida Power, the outlook on these ratings has been changed to negative as well. The trust preferred rating of FPC Capital I has been lowered to Baa1 from A3, a conforming adjustment to make its rating equal to the rating of the assets held by the trust, which is subordinated debt.

These trends will also limit the contribution of Florida Power to the overall dividends upstreamed to the parent company. Whereas Florida Power had historically generated positive free cash flow, Moody's does not anticipate that there will be sufficient free cash flow available going forward to provide substantial additional support to the parent company. Because of the more limited financial flexibility of Florida Power, Progress Energy is expected to rely on Carolina Power & Light Company (A3 senior secured) for a higher proportion of dividends upstreamed to service parent company debt and other obligations. CP&L has exhibited a generally stable financial performance within its rating category with manageable capital expenditures which should be slightly lower than in previous years. Because Progress Energy expects to derive an average of 70% of its upstreamed dividends from CP&L, the lower rated of its two utility subsidiaries, this has also put added downward pressure on the holding company rating.

The stable outlook for Progress Energy's rating reflects the company's modest unregulated generation strategy, which has been focused on markets in or very close to its service territory in the southeast region of the country, and has a high proportion of its generation under contract. Moody's believes that these factors limit the company's exposure to the depressed wholesale power markets. Progress Energy will still be somewhat exposed by the 30% of its unregulated generation portfolio which is unhedged for 2003 and 2004 and the renegotiation of a number of wholesale power contracts that expire over the next several years, at potentially lower prices. Although these factors may limit the cash flows upstreamed to the parent company from Progress Ventures, Moody's expects that dividends from CP&L and Florida Power will continue to be sufficient to maintain Progress Energy's ratings at the current Baa2 senior unsecured rating level.

Progress Energy maintains adequate liquidity, with two committed bank credit facilities totaling $880 million supporting its commercial paper programs, which were reduced from $1 billion in November 2002. In addition, Progress Energy maintains a $300 million uncommitted bank line. CP&L and Florida Power also maintain committed credit facilities of $570 million and $291 million, respectively, supporting their own commercial paper programs. Progress Energy currently has approximately $65 million of commercial paper outstanding at the parent company and projects average commercial paper borrowings of approximately $125 million during 2003. The credit facilities require the maintenance of a debt to total capital ratio of 70% (falling to 68% after June 30, 2003) and the maintenance of an EBITDA to interest expense ratio of at least 2.5x to 1. At December 31, 2002, Progress Energy was in compliance with these covenants, maintaining a debt to total capital ratio of 62.3% and an EBITDA to interest expense ratio of 3.42x. Long-term debt maturities are manageable over the next several years, with $500 million of Progress Energy debt due in 2004 expected to be paid off, for the most part with $400 million of proceeds from the sale of North Carolina Natural Gas.

Ratings lowered include Progress Energy's senior unsecured debt, to Baa2 from Baa1; and the ratings on the shelf registrations for the issuance of Progress Energy senior unsecured debt, to (P)Baa2 from (P)Baa1; junior subordinated debt, to (P)Baa3 from (P)Baa2; and trust preferred stock, to (P)Ba1 from (P)Baa3. The trust preferred rating of FPC Capital I has also been lowered to Baa1 from A3. Progress Energy's Prime-2 commercial paper rating is confirmed.

Progress Energy is a diversified energy company headquartered in Raleigh, North Carolina.

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*Press Release*

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**Fitch Downgrades Progress Energy Carolinas & Florida; Rates Progress Energy 'BBB-'**
Ratings
14 Feb 2003 1:53 PM (EST)

Fitch Ratings-New York-February 14, 2003: Fitch Ratings has downgraded the ratings of Progress Energy Carolinas, Inc. (formerly known as Carolina Power and Light, CP&L) and Progress Energy Florida, Inc. (formerly known as Florida Power Company, FPC) as listed below. The ratings are removed from Rating Watch Negative. Fitch has also assigned an initial 'BBB-' senior unsecured debt rating to the parent, Progress Energy, Inc. (Progress Energy). The Rating Outlook for each of the three entities is Stable.

The 'BBB-' senior unsecured debt rating assigned to Progress Energy reflects the high debt leverage at the parent and investment in unregulated businesses, while also considering the consistent performance of the regulated utilities CP&L and FPC. The Stable Outlook reflects the absence of any near term liquidity pressures and the scaling back of prior growth plans.

Substantial parent level acquisition and diversified business related debt continues to burden consolidated financial measures. Fitch does not anticipate significant debt reduction beyond the repayment of $500 million of acquisition debt in 2004 with proceeds from the recently announced sale of North Carolina Natural Gas. Longer term debt reduction will depend on more favorable market conditions to enable the sale of other non-core assets, primarily the rail business.

Progress Energy's most significant unregulated subsidiary, Progress Ventures, is comprised of merchant generation, energy marketing and trading and a fuels business. While a significant portion of the merchant generation portfolio is under contract for terms of 2 to 6 years, the remaining portfolio will continue to be challenged by depressed power prices. During 2003, the company will be bringing on line an additional 900 megawatts (mw) of merchant capacity. Other unregulated activities include Progress Telecom, a wholesale provider of voice and data transport services. While this business has not performed well, it is not expected to be a use of cash going forward.

The financial condition and risk profile of CP&L and FPC are relatively strong for the assigned ratings but are constrained by the parent rating. Both continue to operate as integrated utilities providing electric generation, transmission and distribution services and restructuring legislation is not expected in either state in the near term. Fuel adjustment mechanisms and company-owned generation substantially reduce commodity price exposure. Both companies benefit to some extent from growing service territories.

FPC's financial performance has been particularly strong with earnings before interest, taxes, depreciation and amortization (EBITDA) coverage of interest expense of approximately 7 times (x) while debt to EBITDA has remained below 2x. Prospectively, debt leverage is expected to increase somewhat at FPC based on expected capital expenditure and dividend requirements. The recent rate settlement reached in Florida required a onetime initial refund of $35 million in 2002 and ongoing annual reductions of $125 million. However, the settlement provides reasonable opportunity for FPC to increase earnings and cash flow through a revenue sharing mechanism.

CP&L is currently more leveraged than FPC with debt to EBITDA in the range of 2.5 times (x), although EBITDA interest coverage of nearly 6x is also strong. CP&L has substantial interests in four nuclear generating units.

Driving CP&L's increased capital expenditures in recent years are generation projects to meet its retail load growth. CP&L's ratings also consider the effects of recently enacted emissions legislation in North Carolina which will result in higher costs, although the legislation does provide a mechanism for compliance cost recovery.

Progress Energy is a diversified energy company with 21,800 mw of generating capacity both regulated (18,700MW) and merchant (3,100MW). The regulated utility subsidiaries together serve 2.9 million electric and gas customers in Florida and the Carolinas. Unregulated subsidiaries include Progress Rail, Progress Telecom and Progress Ventures.

The new ratings are as follows:

**Progress Energy Carolinas (formerly Carolina Power & Light Company)**
--First mortgage bonds to 'A-' from 'A+';
--Senior unsecured debt to 'BBB+' from 'A';
--Pollution control revenue bonds to 'BBB+' from 'A';
--Preferred stock to 'BBB' from 'A-';
--Short-term to 'F2' from 'F1';
--Rating Outlook Stable.

**Progress Energy Florida (formerly Florida Power Company)**
--First mortgage bonds to 'A-' from 'AA-';
--Senior unsecured debt to 'BBB+' from 'A+';
--Pollution control revenue bonds to 'BBB+' from 'A+';
--Medium-term notes to 'BBB+' from 'A+';
--Preferred stock to 'BBB' from 'A+';
--Short-term to 'F2' from 'F1+';
--Rating Outlook Stable.

**Progress Energy, Inc.**
--Senior unsecured assigned 'BBB-';
--Rating Outlook Stable.

These ratings were initiated by Fitch as a service to users of its ratings and are based on public information.

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Global Power/North America
Credit Update

# Florida Power Corporation

## Subsidiary of Progress Energy Inc.

### Ratings

| Security Class | Current Rating | Previous Rating | Date Changed |
|---|---|---|---|
| First Mtge. Bonds | A– | AA– | 2/14/03 |
| Senior Unsecured | BBB+ | A+ | 2/14/03 |
| Pollution Control Revenue Bonds | BBB+ | A+ | 2/14/03 |
| Med.-Term Notes | BBB+ | A+ | 2/14/03 |
| Preferred Stock | BBB | A+ | 2/14/03 |
| Commercial Paper | F2 | F1+ | 2/14/03 |

Rating Watch........None
Rating Outlook........Stable

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### Profile

FPC is an integrated electric utility that serves 1.4 million customers in central and northern Florida. The service territory includes St. Petersburg, Clearwater and areas surrounding Orlando. In addition to its native load, FPC also provides power to eight municipal systems.

### Related Research

- Carolina Power & Light Company, March 4, 2003.

### Key Credit Strengths

- Solid financial profile.
- Constructive regulatory environment.
- Growing service territory.
- Fuel adjustment mechanism reduces commodity price exposure.

### Key Credit Concerns

- Higher capital expenditures and rate reductions will pressure credit protection measures.

## ■ Rating Rationale

Florida Power Corporation's (FPC, d/b/a Progress Energy Florida) ratings recognize the integrated utility's solid financial profile, diverse and growing service territory and constructive regulatory environment in Florida. However, the ratings are constrained by the weaker financial profile and higher business risk of its parent, Progress Energy (senior unsecured rated 'BBB–'). On a stand-alone basis, leverage and coverage ratios are strong with earnings before interest, taxes, depreciation and amortization (EBITDA) interest coverage of approximately 7 times (x) and debt-to-EBITDA of more than 2x. Prospectively, leverage is expected to increase moderately based on expected capital expenditure and dividend requirements and a recent rate settlement.

The rate settlement required a one-time initial refund of $35 million in 2002 and an annual rate reduction of $125 million, as well as continuation of expenditures to improve system reliability. Favorably, the settlement does provide opportunity for FPC to increase future earnings and cash flow through a revenue-sharing mechanism. Existing fuel and purchased power adjustment mechanisms substantially reduce commodity price exposure. Modest movement toward electric competition has been characterized by an approach that would be neutral to utility ratings.

## ■ Recent Developments

During 2002, FPC reached a settlement with the Florida Public Service Commission that required the rate reductions discussed previously and established a revenue-sharing mechanism wherein one-third of revenues greater than specified thresholds but less than overall caps are retained by the utility and the remainder goes to ratepayers. Another key element of the settlement from a credit perspective is the requirement that FPC continue its "Commitment to Excellence" program to improve system reliability. This program will result in increased expenditures through 2004.

## ■ Liquidity and Debt Structure

Fitch Ratings anticipates that some external financing will be needed to meet higher capital expenditures and ongoing dividend requirements over the next couple of years. During 2003, $217 million of maturing first mortgage bonds are expected to be refinanced. During the fourth quarter of 2002, FPC's 364-day bank facility was extended for four months to April 2003 and was reduced to $90.5 million from $170 million. FPC also has a $200 million, five-year facility that matures in November 2003. Available capacity net of commercial paper outstanding was $33.4 million at Dec. 31, 2002. Significant off-balance sheet commitments are related to purchased power obligations and contracts with qualified facilities, both of which are recoverable through the fuel and purchased power adjustment clause.

**March 5, 2003**

## Financial Summary — Florida Power Corporation

($ Mil., Fiscal Years Ended Dec. 31)

| | 2002 | 2001 | 2000 | 1999 | 1998 | 1997 |
|---|---|---|---|---|---|---|
| **Fundamental Ratios** | | | | | | |
| Operating EBIT/Interest Expense (x) | 5.5 | 5.4 | 3.8 | 4.2 | 3.8 | 2.7 |
| Operating EBITDA/Interest Expense (x) | 8.2 | 9.3 | 6.9 | 7.0 | 6.3 | 5.5 |
| Debt/Operating EBITDA (x) | 2.2 | 1.5 | 1.9 | 2.0 | 2.0 | 3.0 |
| Common Dividend Payout (%) | 94.0 | 80.4 | 95.7 | 75.6 | 62.3 | 143.2 |
| Internal Cash/Capital Expenditures (%) | 23.5 | 182.3 | 83.4 | 104.5 | 201.7 | 62.5 |
| Capital Expenditures/Depreciation (%) | 167.6 | 80.0 | 67.7 | 93.8 | 81.1 | 116.0 |
| **Profitability** | | | | | | |
| Revenues | 3,062 | 3,213 | 2,872 | 2,649 | 2,648 | 2,448 |
| Net Revenues | 1,693 | 1,786 | 1,691 | 1,620 | 1,614 | 1,500 |
| O&M Expense | 572 | 487 | 589 | 545 | 547 | 663 |
| Operating EBITDA | 893 | 1,068 | 889 | 872 | 864 | 644 |
| Depreciation and Amortization Expense | 295 | 453 | 403 | 348 | 352 | 326 |
| Operating EBIT | 598 | 615 | 486 | 524 | 512 | 318 |
| Interest Expense | 109 | 115 | 128 | 124 | 136 | 117 |
| Net Income for Common | 323 | 310 | 210 | 266 | 249 | 134 |
| O&M Expense % of Net Revenues | 33.8 | 27.3 | 34.8 | 33.6 | 33.9 | 44.2 |
| Operating EBIT % of Net Revenues | 35.3 | 34.5 | 28.7 | 32.4 | 31.7 | 21.2 |
| **Cash Flow** | | | | | | |
| Net Operating Cash Flow | 428 | 928 | 456 | 576 | 779 | 433 |
| Dividends | (302) | (247) | (200) | (199) | (153) | (191) |
| Capital Expenditures | (538) | (373) | (307) | (361) | (310) | (387) |
| Free Cash Flow | (411) | 307 | (51) | 16 | 315 | (145) |
| Net Other Investment Cash Flow | 12 | (36) | 4 | (28) | (66) | (455) |
| Net Change in Debt | 418 | (132) | (37) | 14 | (248) | 602 |
| Net Change in Equity | 0 | (140) | 91 | 0 | 0 | 0 |
| **Capital Structure** | | | | | | |
| Short-Term Debt | 711 | 186 | 295 | 230 | 139 | 181 |
| Long-Term Debt | 1,244 | 1,465 | 1,397 | 1,479 | 1,555 | 1,745 |
| Total Debt | 1,956 | 1,651 | 1,692 | 1,709 | 1,694 | 1,927 |
| Preferred and Minority Equity | 33 | 33 | 33 | 34 | 34 | 34 |
| Common Equity | 2,048 | 2,032 | 1,965 | 1,885 | 1,820 | 1,768 |
| Total Capital | 4,038 | 3,716 | 3,690 | 3,627 | 3,548 | 3,728 |
| Total Debt/Total Capital (%) | 48.4 | 44.4 | 45.8 | 47.1 | 47.8 | 51.7 |
| Preferred and Minority Equity/Total Capital (%) | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| Common Equity/Total Capital (%) | 50.7 | 54.7 | 53.2 | 52.0 | 51.3 | 47.4 |

Source: Financial data obtained from SNL Energy Information System, provided under license by SNL Financial, LC of Charlottesville, Va. Operating EBIT – Operating income plus total reported state and federal income tax expense. Operating EBITDA – Operating income plus total reported state and federal income tax expense plus depreciation and amortization expense. O&M – Operations and maintenance. Note: Numbers may not add due to rounding.





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DOCK. NO. 040817-EI

# Fitch Ratings — Corporate Finance

Global Power/North America
Credit Update

# Florida Power Corporation

## Subsidiary of Progress Energy Inc.

### Ratings

| Security Class | Current Rating | Previous Rating | Date Changed |
|---|---|---|---|
| First Mtge. Bonds | A– | AA– | 2/14/03 |
| Senior Unsecured | BBB+ | A+ | 2/14/03 |
| Pollution Control Revenue Bonds | BBB+ | A+ | 2/14/03 |
| Med.-Term Notes | BBB+ | A+ | 2/14/03 |
| Preferred Stock | BBB | A+ | 2/14/03 |
| Commercial Paper | F2 | F1+ | 2/14/03 |

**Rating Watch**....................None
**Rating Outlook**....................Stable

### Analysts


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### Profile

FPC is an integrated electric utility that serves 1.4 million customers in central and northern Florida. The service territory includes St. Petersburg, Clearwater and areas surrounding Orlando. In addition to its native load, FPC also provides power to eight municipal systems.

### Related Research

- Carolina Power & Light Company, March 4, 2003.

### Key Credit Strengths

- Solid financial profile.
- Constructive regulatory environment.
- Growing service territory.
- Fuel adjustment mechanism reduces commodity price exposure.

### Key Credit Concerns

- Higher capital expenditures and rate reductions will pressure credit protection measures.

## Rating Rationale

Florida Power Corporation's (FPC, d/b/a Progress Energy Florida) ratings recognize the integrated utility's solid financial profile, diverse and growing service territory and constructive regulatory environment in Florida. However, the ratings are constrained by the weaker financial profile and higher business risk of its parent, Progress Energy (senior unsecured rated 'BBB–'). On a stand-alone basis, leverage and coverage ratios are strong with earnings before interest, taxes, depreciation and amortization (EBITDA) interest coverage of approximately 7 times (x) and debt-to-EBITDA of more than 2x. Prospectively, leverage is expected to increase moderately based on expected capital expenditure and dividend requirements and a recent rate settlement.

The rate settlement required a one-time initial refund of $35 million in 2002 and an annual rate reduction of $125 million, as well as continuation of expenditures to improve system reliability. Favorably, the settlement does provide opportunity for FPC to increase future earnings and cash flow through a revenue-sharing mechanism. Existing fuel and purchased power adjustment mechanisms substantially reduce commodity price exposure. Modest movement toward electric competition has been characterized by an approach that would be neutral to utility ratings.

## Recent Developments

During 2002, FPC reached a settlement with the Florida Public Service Commission that required the rate reductions discussed previously and established a revenue-sharing mechanism wherein one-third of revenues greater than specified thresholds but less than overall caps are retained by the utility and the remainder goes to ratepayers. Another key element of the settlement from a credit perspective is the requirement that FPC continue its "Commitment to Excellence" program to improve system reliability. This program will result in increased expenditures through 2004.

## Liquidity and Debt Structure

Fitch Ratings anticipates that some external financing will be needed to meet higher capital expenditures and ongoing dividend requirements over the next couple of years. During 2003, $217 million of maturing first mortgage bonds are expected to be refinanced. During the fourth quarter of 2002, FPC's 364-day bank facility was extended for four months to April 2003 and was reduced to $90.5 million from $170 million. FPC also has a $200 million, five-year facility that matures in November 2003. Available capacity net of commercial paper outstanding was $33.4 million at Dec. 31, 2002. Significant off-balance sheet commitments are related to purchased power obligations and contracts with qualified facilities, both of which are recoverable through the fuel and purchased power adjustment clause.

**March 5, 2003**

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**Moody's Investors Service**
*Global Credit Research*

July 2000

***Special Comment***

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# Credit Implications of Power Supply Risk

## Summary Opinion

Of all companies exposed to the risks of open competition in the power industry, power energy trading firms, aggregators, and energy service companies are most exposed to supply risk and the most vulnerable to volatile market prices during periods of high energy demand or capacity shortages. While transmission and distribution (T&D) companies remain regulated, they are not free of risk – particularly those companies still bound by capped rates that have sold their generating assets. For that matter, even certain vertically integrated utilities, those that are capacity short and operate without a purchased power adjustment clause, remain exposed to supply risk.

As the market shifts, Moody's analysis becomes increasingly focused on how well companies hedge the new supply risk and whether they do so in a manner that will enable them to maintain their financial integrity and their bond ratings. Part of this analysis will focus on the adequacy of the company's liquidity to withstand large shifts in electric prices. Moody's will make this determination on a case-by-case basis for regulated transmission and distribution utilities, supply companies, vertically integrated power companies and for all participants exposed to the price volatility associated with electricity supply.

*continued on page 3*

| Authors | Editors | Senior Associate | Production Associate |
| --- | --- | --- | --- |
| *Mo Ying W. Seto*<br>*A.J. Sabatelle* | *Dale Wagner*<br>*Robert Cox* | *Jonathan Newman* | *Don Linares* |

## The Impact Of Risk Migration

In a competitive environment, supply risk can be transferred and hedged, but it cannot be eliminated. Some party in the power chain must manage the risk. Unfortunately for both regulated and unregulated energy providers, managing this risk is no easy task.

Unregulated supply companies that have not secured all of their generating resources are exposed to increased costs when electric prices rise. Conversely, these same entities can be exposed to another type of supply risk when they secure additional resources and prices or demand decline.

Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages.

Moreover, transitioning utilities, particularly those that have sold their generation and are operating under a rate freeze, remain exposed to the risk, in many cases, by acting as a Provider of Last Resort (PLR), especially in power constrained markets. State commissions are still wrestling with the best approach toward dealing with PLR risk and in some cases, may transfer the risk to the customer or provide the regulatory mechanism for recovery.

Moody's ultimately believes that companies exposed to supply risk must demonstrate the ability to appropriately hedge this risk in order to preserve its financial integrity and maintain its bond rating.

Prospectively, Moody's ratings will adjust to reflect this changing market dynamic as the industry continues to make its transition and vertically integrated utilities "disintegrate".

### HOW MOODY'S VIEWS THE RISK IN CONTRACTUAL SUPPLY OBLIGATIONS

When analyzing companies that must secure supply for their customers, Moody's will review the company's risk policy and supply strategy as it relates to long-term purchase power agreements (PPAs), short-term to medium-term supply agreements and ownership of generating assets. As the separation of generation assets continues, Moody's will consider market-based arrangements as being akin to any other contracted operating expense. Higher cost or above market contracts will continue to be viewed in a more negative light.

- Vertically Integrated Companies with Long-Term PPAs:

  Traditionally, long-term off-balance sheet PPAs have been viewed as debt as the PPA obligation did not enhance rate base or returns to shareholders thereby compromising a degree of financial flexibility. Moreover, many of these contracts contained prices that proved to be above – market. Moody's will continue to view these off-balance sheet obligations as debt — in particular those purchased power obligations that are above market.

- Transitioning Companies with Long-Term PPAs:

  For companies that have divested all or substantially all of their generating assets but still have existing long-term PPAs in place and are focusing on T&D business, the manner in which cost recovery is being handled will help to determine the treatment of these obligations.

  To the extent that restructuring legislation provides pass-through recovery of the costs, Moody's will view these as being neutral to credit quality — particularly if the amounts of these above-market PPA obligations decline over time.

- Provider of Last Resort Obligation:

  Companies transitioning from a vertically integrated utility to a regulated T&D company remain vulnerable to a specific type of supply risk when they function (either by law or by choice) as Providers of Last Resort (PLRs). PLRs are required to serve as the default provider for all customers that do not make a choice of supplier. In many cases, PLR service defaults to the regulated T&D company, many of which are operating under some type of rate cap, thereby exposing these PLRs to supply risk.

  Adding to the uncertainty is the fact that a number of these transitioning T&D utilities have sold virtually all of their generating resources as a means of recovering stranded costs, with the view that customer choice would transfer the majority of this risk onto another provider. Although customers



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have switched providers, the number of customers that have opted for choice is below original expectations, and in some cases, customers that have switched have returned to the utility.

The degree of supply risk at any given time will depend on the regulatory policy that applies in terms of allocating costs, volatility risks, and the risks associated with commodity competition to the regulated company. Companies who retain PLR customers are likely to seek regulatory recovery of the costs associated with supplying this service. Others may be willing to assume supply risk without recourse to customers, particularly if the tariff is large enough to provide a meaningful cushion against the potential volatility in the commodity. Moody's views this strategy as being more risky.

Only "pure" T&Ds are not exposed to some manner of supply risk. "Pure" T&Ds would be those T&D companies that do not own or contract for supply, as well as those that have completely sold or transferred the PLR function with no regulatory expectation of any further involvement by the regulated utility and no cost exposure to the regulated utility.

## WHO ASSUMES THE COMMODITY RISK ASSOCIATED WITH ELECTRICITY SUPPLY?

It is important to recognize that the commodity risk associated with electric supply has always existed in the industry. That risk has largely been borne, however, by ratepayers.

## BEFORE DEREGULATION, IT WAS THE CUSTOMER...

When dealing with a vertically integrated utility, a fully bundled rate (determined by rate of return and return on rate base measures) masked the commodity risk contained within the electricity rate. In addition, utilities were typically able to recover (from ratepayers) changes in their electric prices incurred as a result of fuel cost adjustments or purchased power adjustments by implementing a purchased power or fuel adjustment clause or, at worst, a fuel rate case.

Although ratepayers have unknowingly assumed the commodity risk, the risk was passed on to them under the watchful eye of a regulator. Recovery typically was phased in over a 12-month timeframe, at a minimum, which served to levelize the cash impact on ratepayers, albeit creating a cash flow timing lag for the utility to be made whole.

## Nearly Half of the U.S. Passes Restructuring Legislation

As of July 2000, 25 states had passed restructuring legislation granting all retail customers choice of generation supplier. This means that half of the United States has changed the way its electric power industry is operated.

In most of the states that have restructured, the motivators were often customers tired of paying high prices for electricity – although a few states with relatively low power supply costs and reasonable service reliability, including Oregon, Oklahoma, and Montana, have undertaken such legislation. Some states, like New York, have not yet succeeded in passing restructuring legislation, but have nevertheless introduced retail customer choice through the regulatory process. Most states are phasing in retail choice for all customers by 2002 at the latest, with the exception of Virginia, which will be phased in between 2002 and 2004.

## Regulatory Support Helps Industry Transition to Competition

Generally speaking, states have permitted utilities to recover significant portions of their stranded investments, and have allowed for a multi-year phase-in of retail customer choice for generation supply. The phase-in or transition period and the implementation of a "competitive transition charge" are permitting utilities to recover sizable portions of stranded costs stemming mostly from large generation facilities and high-cost purchased power contracts.

For many utilities on the east and west coasts, large portions of stranded costs were attributable to "above-market" power purchase agreements, mandated under the Public Utility Regulatory Policy Act of 1978.

### ...UNDER DEREGULATION, IT'S THE CUSTOMER, THE SUPPLIER OR THE PLR PROVIDER

In a competitive environment, commodity risk still exists and is, in fact, more volatile than in other commodity industries because electricity cannot be stored. The ultimate price is driven by supply and demand requirements, which can deviate quickly under unmanageable events such as severe weather or a generating station's tripping off the electric grid.

Although commodity risk is acute for all parties it will, through market contracts or through regulatory action, be transferred from one party to another. Potential bearers of this risk include the customer, the unregulated supply company or the PLR provider — which could either be the utility or another party that purchases that business from the utility.

### The Logic of Keeping Commodity Risk with the Customer

Many of the early architects of electric restructuring legislation have been operating with the premise that the customer should bear all the commodity risk.

The logic holds that, in a competitive environment, customers have choices. Competition should, theoretically, force electric prices down over time. Also, customers have always assumed this risk, even though the state commission monitored the prudency of the resulting price changes and recovery was made in levelized payments.

Customers of some utilities may, over time, be more willing to bear this commodity risk — particularly those living and working in moderate climates with lower year-round usage and moderates peaks. Others, particularly customers of utilities located in the Southwest or Texas, may have difficulty accepting this risk, particularly during periods of high usage and high price volatility. (***See the California Case Study for further discussion of customer's reaction to bearing this risk.***)

### ENERGY SERVICE COMPANIES LIKELY TO ABSORB PRICE VOLATILITY, PUTTING MARGINS AT RISK

In most cases, we believe that energy service companies engaged in power supply aggregation will assume much of the price volatility risk through programs offered to customers where rates are fixed or indexed but set below the standard offer rate. Margins will be negatively affected, however, to the extent that the energy service company's cost to supply that load increases.

These at-risk entities, which can include affiliates of utilities, will likely hedge their relative contract positions with physical assets or bilateral contracts. Capacity-short markets, like those of the Midwest or portions of the West, have the potential to affect these entities negatively, particularly those that are more reliant on the market place for supply. An affiliation with a strong energy trading and marketing company is an absolute necessity for this business.

**Table 1**

**Examples of Companies that Have Sold or Contracted Out their Supply Obligation**

| |
|---|
| Bangor Hydro |
| Cambridge Electric |
| Central Maine Power |
| Commonwealth Electric |
| Connecticut Light & Power |
| Duquesne Light Company |
| Montana Power |
| New England Electric System |
| United Illuminating |
| Western Massachusetts Electric |

### PLR PROVIDERS REMAIN EQUALLY EXPOSED

PLR service poses risks to potential providers. For most distribution utilities, PLR customers are likely to be sizable in number and predominantly residential and small commercial. In most states, however, regulators remain unclear about the best way to handle PLR service. Adding to the uncertainty is the fact that a number of utilities have sold virtually all of their generating resources, making it financially risky for them



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to provide PLR service. In California, Pennsylvania, Illinois, and most of the New England states, for instance, a number of the utilities have sold large portions of their generating capacity.

In general, utilities have little incentive to accept the financial risk PLR service creates without being compensated by regulators with some form of pass-through. Each state will determine its own plan, and Moody's believes that elements of a purchased power adjustment clause will be retained for PLR service.

## The Varied Supply Risks Of Different Business

The level of supply risk varies given the type of business a utility elects to be in.

On the risk continuum, a regulated transmission and distribution company without generation assets and without a PLR obligation would be exposed to the lowest level of supply or commodity risk.

The regulated distribution company with the PLR obligation will have slightly higher risk, because it will remain obligated to purchase power from other suppliers to serve those customers on its delivery system who do not choose an alternate provider.

At the far end of the continuum (*Table 2*) is the unregulated supply company, whose energy costs are dictated by the market and who is exposed to the highest level of supply risk.

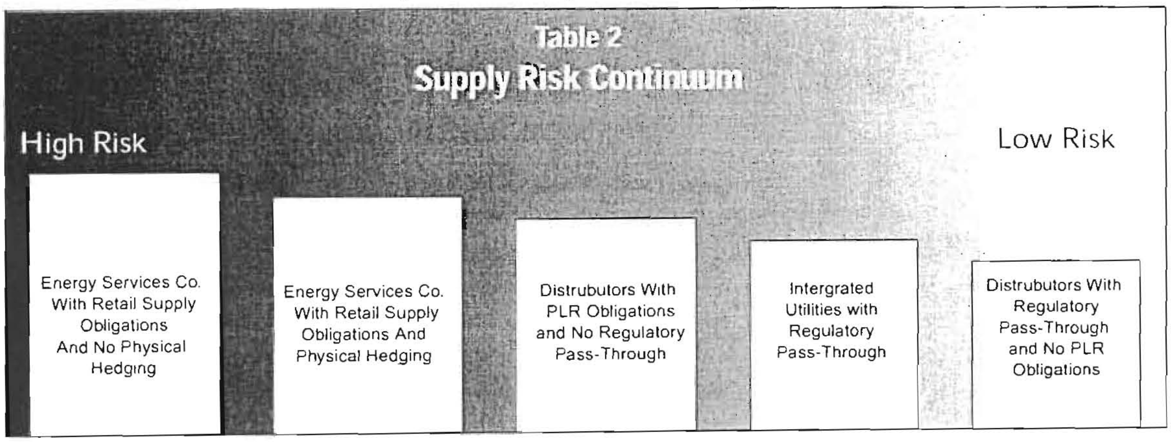

Table 2
Supply Risk Continuum

Following are examples of different business segments with different levels of supply risk. The order ranges from the business sector with the highest supply risk to the business segment with the lowest level of supply risk:

- **Energy Services Companies with retail supply obligations** clearly possess the highest form of supply risk. This business approach challenges these providers to implement strong supply risk hedging strategies, including, in some cases, securing physical plant.

  Moody's anticipates that this sector could be the source of unanticipated negative news as competition rolls out throughout the country. In all likelihood, the most competent supplier will be one that has access to all types of generating capability, (i.e., base load plants, mid-merit facilities, and peakers), has regional diversity, a strong fuel mix, and employs superior risk management strategies through its marketing and trading businesses.

- **Regulated transmission and distribution companies** remain vulnerable to energy price risk associated with power supply and purchased power if they have a PLR obligation in a deregulated environment.

### Texas Approach Can Insulate T&D Utility from Supply Risk

The Texas electric restructuring law, signed June 1999, requires a legal separation of the retail electric provider (REP) from the T&D company. The REP is defined as a person or entity that sells electric energy to retail customers in Texas. The new REP will perform the aggregation and supply role, with the T&D entity providing the transportation and delivery function. Moody's notes that the legal separation contemplated in Texas should insulate the T&D company from supply risk. The Texas law permits all retail electric customers a choice of generation supplier beginning January 1, 2002.



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The degree of risk will depend on regulatory treatment of these costs. Entities with regulatory mandated price caps or no regulatory pass-through mechanism could face higher risks. Entities without price caps and a regulatory pass-through mechanism should face lower risks.

The business and financial risks of these companies are relatively low given that their regulated revenues are more stable and predictable. For such PLR providers to mitigate supply risk, however, either the customer must assume it or the state regulatory agencies must permit recovery of supply costs associated with any necessary power purchases. Without regulatory permission to recover purchased power costs, the financial flexibility of these utilities could weaken.

### Massachusetts: Default Service exposes T&D's to Supply Risk

In Massachusetts, a unique supply risk is unfolding. The Massachusetts utilities, all of whom operate as T&D companies, are required to provide "default service" to those customers that first switch to competitive providers but elect to return to the utility system.

Under Massachusetts law, these customers must be served by the local T&D company at the default service rate. However, the rate for "default service" is substantially below the electric wholesale price that a T&D must pay to meet this load.

In Massachusetts, "standard offer customers" also exist and they represent those customers that have elected not to use a competitive provider. The standard offer rate tracks closley to the default service rate.

As depicted in Table 1, USGen New England secured the standard offer service from New England Electric System (NEES) when it purchased NEES's generating assets. Massachusetts Electric, then a NEES subsidiary and now a T&D utility owned by National Grid (USA), is the supplier for default service. Massachusetts Electric has publicly stated that it could lose up to $41 million on default service over the summer months, since the wholesale price to serve the load is much higher than the default service rate.

At the same time, generators including USGen NewEngland, which own the generating assets that had served customers of Massachusetts Electric, stand to benefit from default service.

To address this concern, the Massachusetts regulators have modified the terms and conditions for default service by increasing the tariff rate for default service to a rate that is aligned with the wholesale market. In this way, customers that have selected a new provider will have a lower incentive to switch to default service. The modification is effective January 1, 2001.

## HEDGING PRICE VOLATILITY AND SUPPLY RISKS

The effective use of financial hedging instruments such as derivatives to stabilize pricing volatility is necessary for energy service companies to mitigate the financial risk associated with providing power supply.

The risk associated with marketing and trading around generating assets is more manageable than the trading of derivatives based on the commodity prices. When a company uses financial derivatives, it is only to lock in prices. Certain financial derivatives do not mitigate supply and deliverability risk.

Supply risk can be mitigated only through access to a diverse pool of generation assets — either through physical assets or through contracts. Moreover, deliverability risk becomes minimal in instances where the power supply contracts are backed by reserves or generating plant.

The supply business can provide a natural hedge for generators. In Chile, which has been deregulated for some time, generators act as the suppliers for large customers as they sign bilateral contracts with distributors and large-end users. The generators' ability to sign these contracts provides them with a customer for their output thereby mitigating one element of supply risk. Similarly, in other commodities, such as petrochemicals or oil, the supply side of the business can provide a natural hedge for the producer.

Still, there are risks to hedging with physical assets or with contracts. Power providers (supply companies, marketers, or aggregators), who are long on capacity by signing additional purchased power contracts or by buying or building electric generation in anticipation of strong energy consumption, may not be allowed to recoup these costs from the market if there is a prolonged period of cool summers, a reduction in demand, or an overbuilt supply market with too much capacity. This would result in the power



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DOCK. NO. 040817-EI

## Will the Current Vintage of Tolling Agreements Become the Next Round of High-Priced PPA?

As competitive markets have developed, the market has created a tool that provides trading and marketing companies with dedicated supply to help support their marketing business. The cornerstone of this structure is the tolling agreement, which is typically a 20-year contract between a marketing company or a supply company and a generator.

Under a typical tolling agreement, the marketer or the supply company pays a tolling fee or capacity payment to the generating plant for the right to deliver gas to the plant for electric generation. The capacity payment is typically a fixed contracted amount and is paid based on predetermined capacity factors for the plant. Presumably, the generator will be asked to produce electricity when the marketing company believes it is economical to utilize the electric output from the plant.

If regional energy prices remain below a plant's marginal cost to produce electricity, it is plausible that the marketing company would not elect to utilize the plant's output. In this case, the toller would still be required to make capacity payments to the plant, assuming that the plant was available for output. More importantly, if this scenario occurred over an extended period of time, regional electric energy and capacity prices would likely be depressed for a sustained period due to severe regional overcapacity or materially lower than expected output. Consequently, a scenario could be realized wherein the capacity payments under a tolling arrangement end up becoming the next round of high priced PPAs.

Although this scenario is indeed plausible, particularly given the length of the tolling agreements and the still-uncertain outlook for future energy prices, Moody's believes that the market nature of these contracts serves to mitigate this risk. Unlike the PPAs of the eighties and nineties, which, in many cases, had terms that were driven by federal and state regulators, the current tolling arrangements are market driven and are entered into by marketing companies that are in the business of managing this type of risk.

Moody's recognizes that market-driven agreements do not always mean rational markets or rational counterparties. There are countless examples of irrational markets and irrational market decisions scattered throughout a number of industries. However, Moody's does believe that the current vintage of tolling agreements have contract terms for the toller that are currently economical for them, and are likely to remain competitive in an open market.

providers having to absorb the higher costs associated with operating the plant or with having an above-market purchased power contract.

*(Please refer to the following Special Comments: "Energy Trading: Essential to Energy Markets, But Risky", April 1999, and "Counterparty Risk Management After June 1998: Improvements in the Works", May 1999.)*

## ADEQUATE LIQUIDITY REMAINS AN IMPORTANT MITIGANT TO SUPPLY RISK

Moody's believes that access to adequate liquidity remains an important element to mitigating supply risk. Suppliers of electricity, particularly those that must purchase electricity in the spot market, can be exposed to higher cash costs and unpredictable cash needs during periods of high prices and high volatility. Additionally, suppliers of electricity are likely to have higher seasonal cash needs due to the higher usage that typically occurs in the summer months.

Companies, including vertically integrated utilities, transitioning utilities, nonregulated supply companies, and PLR providers are all exposed to this burgeoning risk. This liquidity need is a relatively new issue for financial officers to think about. Prior to deregulation, vertically integrated utilities provided the bulk of their own power needs and purchased any additional needs in a bilateral contract market. Although wholesale market prices fluctuated, the relative volatility pales in comparison to the price volatility experienced in today's power markets. Short-term liquidity was more manageable and purchased power adjustment clauses served to isolate the cash flow risk. Additionally, few companies, if any, were completely reliant on other providers for their supply, a condition that exists today for supply companies that have limited access to their own generating assets.

Moody's will examine the liquidity needs of companies assuming supply risk under a variety of downside scenarios to determine the company's access to liquidity should power markets move against a particular company for an extended period of time.



PEF 000028
DOCK. NO. 040817-EI

## SOME CASE STUDIES INDICATE THAT SUPPLY RISK REMAINS AN ISSUE FOR STATE REGULATORS

### *The California Case Study*

In California, retail customer choice began in January 1998. All the California investor-owned utilities are now largely state-regulated distribution companies. They have divested their in-state fossil-fueled generating assets and have plans to divest of most of their remaining generating assets.

These California utilities are permitted to recover all of their stranded investments through March 2002 and the high costs associated with their purchased power contracts through the life of each contract. Each utility maintains a PLR obligation.

During the transition period, the utilities are required to sell the generation from their purchased power portfolios to the California Power Exchange (PX). When the price received from the PX is lower than the price that the utilities must pay under their purchased power contracts, the utilities have the legal right to collect that difference from ratepayers over the term of the contracts. All three utilities must purchase power from the PX to meet the complete needs of the customers who have not chosen commodity service from a retailer.

During the transition period, the utilities cannot charge more than a frozen rate level, even if energy prices in the PX, when combined with the other components of the tariff are above the level of the frozen rates.

### CURRENT CALIFORNIA PRICES SHOWS THE VOLATILITY IN ELECTRIC PRICES

One unrelated but important observation from this current development in San Diego is the tremendous volatility that exists in electric prices and the impact that other markets have on the price of electricity. SDG&E's service territory has among the most moderate climates in the country and typically does not experience any material peaks. The 2000 summer, although warmer than most summers, has been fairly typically of past summers. However, the adjoining Southwest market that includes summer peaking markets like Las Vegas and Phoenix, impact regional demand and when coupled with reduced capacity in California and in the West, cause prices in the California PX to increase.

Two of the three utilities remain on the rate freeze as of July 2000 (only San Diego Gas and Electric Company (SDG&E) has concluded the rate freeze). The two utilities, Pacific Gas and Electric Company and Southern California Edison Company are taking supply risk during the transition period. After the transition period, however, it is contemplated that customers will bear the energy price risk, serving to shift the commodity price risk away from the utility.

In mid-1999, SDG&E fully collected its stranded costs and terminated its rate freeze with its customers. Because of this, all customers enjoyed further declines in rates beginning in July 1999 reflecting the collection of all stranded costs. However, because SDG&E was two and a half years ahead of schedule in collecting stranded costs, the California Public Utilities Commission (CPUC) was not prepared for this timing and still had not determined how PLR service should be implemented after the transition period. Not surprisingly, the CPUC reverted to traditional regulation for the summer of 1999 by authorizing that PLR customers be guaranteed that their price for generation would not be in excess of the average PX rate plus 12.5%. However, if energy costs for customers exceed this cap, SDG&E had the authority to create a regulatory balancing account that would be recoverable from these customers over the next nine-month period.

In effect, the commission reverted to a traditional approach for addressing PLR customers. This regulatory treatment was a temporary solution to the problem and now no longer applies. The future treatment of the PLR role is not yet determined.

During the summer of 2000, the CPUC adhered to the legislation by allowing customers to bear the commodity price risk associated with generation. Unfortunately for customers, generating prices in California have risen significantly due to greater regional usage and reduced regional capacity causing, in some cases, a doubling of customer's bills for certain summer months. Clearly, higher electric prices was not an expected outcome of deregulation so many of the architects of deregulation including members of the commission, the legislature and certain consumer groups have responded to this development by proposing a variety of solutions, including re-regulation.

### *The Pennsylvania Case Study*

Retail choice for generation began on January 1, 1999 for all customers in Pennsylvania. Through June 1, 2000, the state's electric utilities were to retain their PLR responsibility, providing default service for all customers.

The Pennsylvania Public Utility Commission (PPUC) conducted a competitive bidding program to phase in the competitive provision of PLR service: 20% of retail customers on June 1, 2000; 40% on June 1, 2001; 60% on June 1, 2002; and 80% on June 1, 2003. PLR service from any supplier will be subject to the generation rate cap. If no bids are received at or below the Pennsylvania electric utilities' generation rate cap, the utilities will furnish PLR service at the rate-cap levels.

On February 3, 2000, Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec), both operating subsidiaries of GPU, Inc., filed a report with the PPUC stating that they had received no bids from alternative generators to supply power to their default customers in Pennsylvania. These default customers are primarily residential and small commercial customers. The two operating utilities divested all of their generating assets recently, as part of GPU's competitive strategy to remain in the regulated transmission and distribution business. Now Met-Ed and Penelec must purchase sufficient capacity to furnish PLR service.

Based on the June 1998 restructuring order, these two companies can only charge their default customers at the generation rate-cap levels, regardless of what they are paying to purchase the power supply. The companies have been working with the PPUC to find a solution and a collaborative is expected to issue a report in the near term.

Moody's expects that the PPUC will be required to address any purchased power costs above the rate-cap levels that the GPU subsidiaries are incurring. As in the case of the Illinois utilities, if Met-Ed and Penelec cannot recover from their default customers the purchased power costs above the pre-determined generation rate-cap rates they will suffer earnings and cash flow erosion during the period in which they are honoring their service obligation as default provider.

### Illinois – A Problem Waiting to Happen?

Several Illinois utilities now operating under electric transition plans may be exposed to supply risk during the summer of 2000. The Illinois electric restructuring plan requires each year that a third party consultant determines the market generation component of the standard offer rate. The consultant set the current generation component at an artificially low level resulting in a very low standard offer rate. This potential risk is exacerbated by the fact that, because of market uncertainty and volatility, not many customers have selected choice.

Compounding the problem, the Illinois legislation eliminated the fuel adjustment factor, which means that rates that utilities can charge customers are fixed. Given the tight capacity market in the Midwest, a warm summer could lead to new price spikes which, given the rate cap, could affect some of the Illinois utilities financially. All of the utilities have initiated proceedings to modify the process for determining the market generation price, replacing the existing 'neutral fact finder' methodology. Additionally, most utilities have maintained rights to sufficient supply through PPA structures to mitigate exposure to volatile market conditions.



PEF 000030
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Report Number: 58449

FitchRatings

# Discussion with Progress Energy:

# Understanding the Rating Process and Methodologies

Rob Hornick, Ellen Lapson, and Donna DiDonato

Global Power

# Discussion Topics

- **Background on the Rating Process**
  - Committees, Ratings & Outlooks
  - Notching
- **Analytical Methods**
  - Financial Ratio Targets
  - Projections Analysis
  - Absolute versus Relative Analysis
  - Liquidity

Fitch Ratings

# Discussion Topics

- **Off Balance Sheet & Other Debt-Like Obligations**
  - Operating Leases
  - Tolling Arrangements
  - Synthetic Leases
  - Purchased Power Agreements
  - Corporate Guarantees
- **Hybrid Securities**
- **Use of Fitch Energy Price Forecasts**

FitchRatings

# Background: The Rating Process

- **Committee Presentation**
  - Annual and Periodic Reviews
  - Event or Scenario Analysis
- **Trend Designations**
  - Outlooks identify direction of ratings
    - Stable, Positive or Negative
  - Watches are generally associated with events and supercede Outlooks
    - Positive, Negative or Evolving
  - Rating actions are not limited by Outlooks or Watches

Fitch Ratings

# Background: The Rating Process

- **Appeal Process**
  - Generally limited to new information
  - Time is of the essence
  - Watch status or Outlook generally not up for debate.
- **Press Releases & Reports**
  - Rating actions (including outlook changes and watch listings) are disseminated in a press release.
  - Advance copies of press releases and reports are generally provided to the issuer for comments limited to issues of factual accuracy or elimination of non-public information.

FitchRatings

# Notching: Credit Rating Scale

| |
|---|
| **Investment Grade:** |
| AAA |
| AA |
| A |
| BBB |
| **Speculative Grade:** |
| BB |
| B |
| CCC |
| CC |
| C (Imminent default) |
| D (Default) |

| |
|---|
| A+ |
| A |
| A- |
| BBB+ |
| BBB |
| BBB- |

+ 3 notches

Fitch Ratings

# Analytical Methods

- **Financial Ratios and Targets**
  - Fitch uses some benchmark financial ratios internally, but generally doesn't publish them.
  - Primary financial ratios are defined in the Financial Peer Study attached as Exhibit A.
- **Projection Analysis**
  - Fitch analysts are required to develop an independent view of an issuer's financial prospects and to compare the Fitch forecast to management projections.
  - Stress scenarios are specifically tailored and incorporate possible negative outcomes – unfavorable regulatory decisions, etc.

FitchRatings

# Analytical Methods

- **Absolute versus Relative Analysis**
  - While issuers are evaluated independently, industry conditions and performance relative to peers is also considered.
  - This could include evaluation of financial measures, business strategy and performance, and quality of management.
- **Liquidity**
  - Targets for liquidity take into consideration the historic volatility of operating cash flow, potential working capital and collateral needs, plant outages for integrated utilities and regulatory lag.
  - Liquidity requirements for future capex and debt maturities depends on business risk, rating level, and capital markets access.

FitchRatings

# Treatment of Off Balance Sheet and Other Debt-Like Obligations

**For purchased power agreements, operating leases, tolling arrangements, and synthetic leases, Fitch policy varies from GAAP accounting rules in order to capture operating leverage.**

- Primary emphasis is identifying risk, and if appropriate, capitalizing a debt like obligation.
  - Two important concepts are:
    1. Whether an issuer has a high likelihood of recovering costs under the contract from ultimate consumers (or another counterparty).
    2. Whether the contract is in-the-money or out-of-the-money based on Fitch's Base Case and Low Gas Case projection models.

Fitch Ratings

# Treatment of Off Balance Sheet and Other Debt-Like Obligations

| Mark to Model Value | Low | High |
| --- | --- | --- |
| Out of the $$ | **High Risk**<br>Potential earnings and cash flow impact. | **Moderate Risk**<br>Certainty of recovery limits risk. |
| In the $$ | **Moderate Risk**<br>Need to monitor for change in value and counterparty credit risk. | **Low Risk**<br>Counterparty credit risk is still an issue. |

Likelihood of Cost Recovery

Fitch Ratings

# Treatment of Off Balance Sheet and Other Debt-Like Obligations

- **Power Purchase Agreements**
  - In cases where there is limited information, assume 30% of total payment is capacity and capitalize that amount.
  - Where sufficient information is available, the MTM value of the contract is determined based on Fitch's market forecast.
  - The amount capitalized is affected by amount of risk attributed to recovery:
    - Contractual offsets and counterparty credit quality.
    - Level of regulatory support and recovery mechanisms.
    - QF contracts are deemed to be relatively low risk.

Fitch Ratings

# Treatment of Off Balance Sheet and Other Debt-Like Obligations

- **Operating Leases**
  - Fitch policy dictates that operating leases should be capitalized using one of two primary methods – a multiple approach or a PV calculation of the minimum lease rent.
- **Tolling Agreements**
  - Power plant tolling arrangements are treated in the same manner as operating leases for the purchaser of the toll with the PV of the capacity payments capitalized.
- **Synthetic Leases**
  - If the lessor is an SPE, then the entire SPE is consolidated into the lessee.
  - If not, the lease obligation is valued based on the PV of payments plus residual value guarantee.

FitchRatings

# Treatment of Off Balance Sheet and Other Debt-Like Obligations

- **Non-Recourse Debt Obligations**
  - Non recourse debt obligations are evaluated in terms of the strategic relevance of the asset or business unit and the level of financial and legal separation and can be deconsolidated.
  - When a unit is determined to be "off credit" and debt is deconsolidated, all income and dividends from the unit must be excluded from projections.

Fitch Ratings

# Treatment of Off Balance Sheet and Other Debt-Like Obligations

- **Corporate Guarantees**
  - **Guarantees of Debt**
    - Guaranteed debt of non-consolidated entities is consolidated.
  - **Performance Guarantees** (currently under review)
    - Current Method: Nominal amount of guarantees times x% (e.g.,10% of nominal)
    - Proposed: Fitch is considering whether to apply the standard of FIN 45 not only to new performance guarantees issued after January 1, 2003, but also to pre-existing guarantees.
      - Will issuer's provide sufficient disclosure?
      - How long will it take for pre-existing guarantees to roll over?

# Hybrid Securities

- Fitch's evaluation of hybrid securities focuses on the flexibility the instrument provides –
  - Required payment of dividends or interest
  - Terms of ultimate repayment of principal
  - Priority in bankruptcy
- Each security can be analyzed and classified on an equity-debt continuum with "equity credit" based on established ranges in Fitch's hybrids criteria.
- Not affected by GAAP accounting treatment.
- See Exhibit D for further details.

Fitch Ratings

# Use of Fitch Energy Price Forecasts

- Fitch uses a model provided by an outside consultant to forecast market clearing prices of power in 5 main regions and 70 sub-regions.
  - The current base case forecast assumes long term gas prices of $3.50 (in constant 2003 dollars)
  - The current low gas case forecast assumes long term gas prices of $2.50 (in constant 2003 dollars)
- Financial Projections incorporate expected revenues from merchant assets based on energy price forecasts.

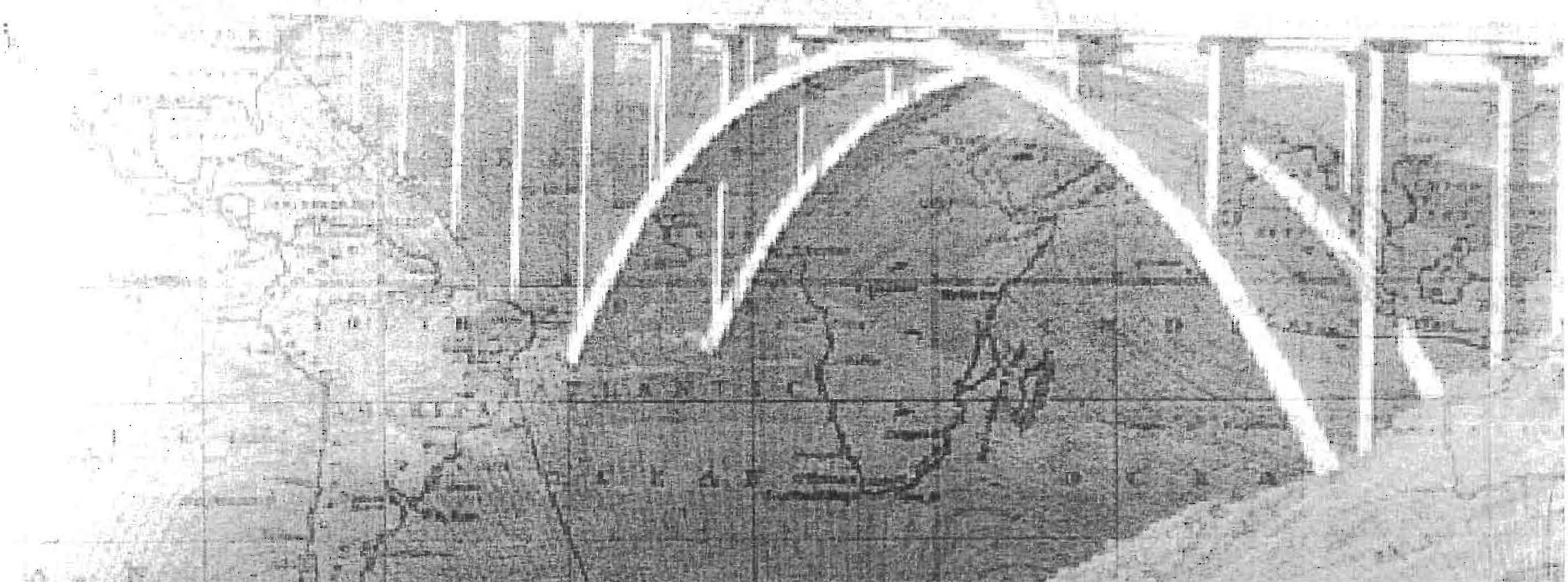
Fitch Ratings

# Schedule of Exhibits

| | |
|---|---|
| A | Financial Peer Study |
| B | Corporate Rating Criteria |
| C | Credit Update Report Guidelines |
| D | Hybrid Securities: Evaluating the Credit Impact |
| E | Rating Linkage Within US Utility Groups: Ring-Fencing Mechanisms |
| F | Operating Leases: Implications for Lessees' Credit |
| G | Synthetic Leasing |

FitchRatings

**www.fitchratings.com**



Fitch Ratings

# PROGRESS ENERGY FLORIDA'S HINES ENERGY COMPLEX UNIT 4

The following data represent the current cost and performance estimates for Progress Energy Florida's Hines Energy Complex Unit 4. The final actual cost of the project could be greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on PEF's existing Hines Energy Complex site in Polk County, Florida.
2. Planned Size: 517 MW (winter), 461 MW (summer). These values have been adjusted to include the impact of estimated degradation.
3. Commercial Operation of the facility is proposed to be December 1, 2007.
4. The primary fuel is natural gas. Distillate fuel oil will be used as a backup fuel source.
5. The estimated total direct cost is $221.5 million, including escalation, but excluding AFUDC. This estimate does not include transmission interconnection or required system upgrade costs.
6. The estimated annual levelized revenue requirement is $35.3 million over 25 years (2008$). This estimate reflects the costs associated with generation construction only and includes taxes and insurance. It does not include O&M or transmission interconnection or integration costs.
7. The estimated annual value of deferral of this unit is $56.40/kW-yr (2008$), which includes generation construction costs and fixed O&M.
8. The estimated annual fixed O&M is $1.29/kW-yr (2007$). The estimated variable O&M is $0.28/MWh (2007$). The estimated major maintenance costs are $2.71/MWh (2007$).
9. The estimated delivered fuel cost is $4.69/mmBtu (2007$), plus fixed transportation at $0.76/mmBtu.
10. The following are estimates for:

| | |
|---|---|
| Planned outage rate | 6% |
| Forced outage rate | 3% |
| Minimum load | 210 MW (winter) |
| Ramp Rate | 45 MW/minute from min. to full load |
| Minimum run time | 4 hours |
| Minimum down time | 6 hours |
| Capacity factor | 50% (annual average from TYSP) |
| Annual starts | 50-100 |

Capacity States and heat rates (based on HHV of fuel)

| Seasonal Capacity States and Net Heat Rates | | | | | |
|---|---|---|---|---|---|
| Capacity State (MW) | | Primary Fuel (Btu/kWh) | | Secondary Fuel (Btu/kWh) | |
| Winter | Summer | Winter | Summer | Winter | Summer |
| 210 | 184 | 7710 | 7863 | 8206 | 8287 |
| 517 | 461 | 7062 | 7079 | 7802 | 7753 |

All values include impact of estimated degradation.

11. The estimated transmission interconnection costs for this unit are $3.1 million, excluding AFUDC. The estimated transmission system integration costs for this unit are $26.9

million, excluding AFUDC.

12. Supplemental site certification as well as amendment to related environmental permits will be required for this unit. It is PEF's plan to comply with all environmental standards of Local, Regional, State and Federal governments.
13. The major financial assumptions in the development of these numbers were:

| | |
|---|---|
| Construction escalation: | 2.5% per year |
| O&M escalation: | 2.5 % per year |
| Fuel escalation: | Varies by year |
| Capital structure: | 48% debt @ 6.5%<br>52% equity @ 12% |
| Composite tax rate: | 38.58% |
| Discount rate: | 8.16% |

## Roeder, Dan

**From:** PEF 2007 RFP
**Sent:** Friday, March 05, 2004 1:43 PM
**To:** 'Antonell, Michael'
**Subject:** Progress Energy Florida 2007 RFP Short List Announcement

The purpose of this e-mail is two-fold. First, I am pleased to inform you that Reliant Energy is on the Short List of the Progress Energy Florida 2007 RFP. Other companies on the Short List are Calpine, Pasco Cogen, and Southern Power. Proposals placed on the Short List will be compared to PEF's Hines 4 unit in the Detailed Evaluation step of PEF's RFP process.

After reviewing your proposal during our Technical Evaluation, there are a number of items for which we need clarification or additional information. These items are contained in the attached document. We request answers to these questions so we may conclude our evaluation of your proposal during the Detailed Evaluation step. Our target for Final List announcement remains April 27, 2004.

FollowUp
ıestions_ReliantEner

To enable us to meet this schedule, I request you to provide responses to the questions no later than 10:00 AM on Monday, March 15, 2004. Depending on your responses to the attached questions, I may schedule a conference call to "close the loop" on any open issues. I may have some of our technical experts included on the call. In this case, I will give you a call ahead of time and let you know so you may have your technical experts there also.

The second purpose of this e-mail is to provide revised cost and operating characteristics for Hines 4.

- Based on analyses performed to develop our upcoming Ten Year Site Plan (TYSP), Hines 4 is expected to operate more than the 50% capacity factor indicated in last year's TYSP. The current projected average annual capacity factor in the preliminary TYSP is 67%. This changes the estimate of major maintenance costs to be $2.02/MWh (the expected costs in dollars remain the same; the denominator is greater, thus, lowering the $/MWh cost estimate).
- The estimated delivered fuel cost is $4.64/mmBtu, plus fixed transportation of $0.66/mmBtu.

Pursuant to Rule 25-22.082(14), PEF is providing the Bidders an opportunity to revise their bids. If you chose to revise your price proposal, please include it with your response that is due on March 15.

Thank you for your continued interest in the Progress Energy Florida 2007 RFP.

--Dan

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## Roeder, Dan

| | |
|---|---|
| **From:** | PEF 2007 RFP |
| **Sent:** | Friday, March 05, 2004 1:43 PM |
| **To:** | 'Williams, Andy' |
| **Subject:** | Progress Energy Florida 2007 RFP Short List Announcement |

The purpose of this e-mail is two-fold. First, I am pleased to inform you that Pasco Cogen is on the Short List of the Progress Energy Florida 2007 RFP. Other companies on the Short List are Calpine, Reliant Energy, and Southern Power. Proposals placed on the Short List will be compared to PEF's Hines 4 unit in the Detailed Evaluation step of PEF's RFP process.

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FollowUp
estions_PascoCogen

To enable us to meet this schedule, I request you to provide responses to the questions no later than 10:00 AM on Monday, March 15, 2004. Depending on your responses to the attached questions, I may schedule a conference call to "close the loop" on any open issues. I may have some of our technical experts included on the call. In this case, I will give you a call ahead of time and let you know so you may have your technical experts there also.

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Thank you for your continued interest in the Progress Energy Florida 2007 RFP.

--Dan

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Roeder, Dan

**From:** PEF 2007 RFP
**Sent:** Friday, March 05, 2004 1:43 PM
**To:** 'Mark Daley'
**Subject:** Progress Energy Florida 2007 RFP Short List Announcement

The purpose of this e-mail is two-fold. First, I am pleased to inform you that Calpine is on the Short List of the Progress Energy Florida 2007 RFP. Other companies on the Short List are Pasco Cogen, Reliant Energy, and Southern Power. Proposals placed on the Short List will be compared to PEF's Hines 4 unit in the Detailed Evaluation step of PEF's RFP process.

After reviewing your proposal during our Technical Evaluation, there are a number of items for which we need clarification or additional information. These items are contained in the attached document. We request answers to these questions so we may conclude our evaluation of your proposal during the Detailed Evaluation step. Our target for Final List announcement remains April 27, 2004.

FollowUp
iestions_Calpine.doc

To enable us to meet this schedule, I request you to provide responses to the questions no later than 10:00 AM on Monday, March 15, 2004. Depending on your responses to the attached questions, I may schedule a conference call to "close the loop" on any open issues. I may have some of our technical experts included on the call. In this case, I will give you a call ahead of time and let you know so you may have your technical experts there also.

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- The estimated delivered fuel cost is \$4.64/mmBtu, plus fixed transportation of \$0.66/mmBtu.

Pursuant to Rule 25-22.082(14), PEF is providing the Bidders an opportunity to revise their bids. If you chose to revise your price proposal, please include it with your response that is due on March 15.

Thank you for your continued interest in the Progress Energy Florida 2007 RFP.

--Dan

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## Roeder, Dan

**From:** PEF 2007 RFP
**Sent:** Friday, March 05, 2004 1:43 PM
**To:** 'Weaver, Murry'
**Subject:** Progress Energy Florida 2007 RFP Short List Announcement

The purpose of this e-mail is two-fold. First, I am pleased to inform you that Southern Power is on the Short List of the Progress Energy Florida 2007 RFP. Other companies on the Short List are Calpine, Reliant Energy, and Pasco Cogen. Proposals placed on the Short List will be compared to PEF's Hines 4 unit in the Detailed Evaluation step of PEF's RFP process.

After reviewing your proposal during our Technical Evaluation, there are a number of items for which we need clarification or additional information. These items are contained in the attached document. We request answers to these questions so we may conclude our evaluation of your proposal during the Detailed Evaluation step. Our target for Final List announcement remains April 27, 2004.

FollowUp
estions_SouthernPo

To enable us to meet this schedule, I request you to provide responses to the questions no later than 10:00 AM on Monday, March 15, 2004. Depending on your responses to the attached questions, I may schedule a conference call to "close the loop" on any open issues. I may have some of our technical experts included on the call. In this case, I will give you a call ahead of time and let you know so you may have your technical experts there also.

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- The estimated delivered fuel cost is $4.64/mmBtu, plus fixed transportation of $0.66/mmBtu.

Pursuant to Rule 25-22.082(14), PEF is providing the Bidders an opportunity to revise their bids. If you chose to revise your price proposal, please include it with your response that is due on March 15.

Thank you for your continued interest in the Progress Energy Florida 2007 RFP.

--Dan

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PEF_2007_RFP@pgnmail.com

Natural Gas ($/MMBtu)

| | High HH | Base HH | Low HH |
|---|---|---|---|
| Jan-04 | $ 8.84 | $ 7.16 | $ 5.85 |
| Feb-04 | $ 9.78 | $ 7.20 | $ 5.37 |
| Mar-04 | $ 9.79 | $ 6.89 | $ 4.95 |
| Apr-04 | $ 7.09 | $ 5.06 | $ 3.61 |
| May-04 | $ 6.78 | $ 4.87 | $ 3.50 |
| Jun-04 | $ 6.98 | $ 4.88 | $ 3.42 |
| Jul-04 | $ 7.15 | $ 4.90 | $ 3.36 |
| Aug-04 | $ 7.38 | $ 4.91 | $ 3.27 |
| Sep-04 | $ 7.58 | $ 4.91 | $ 3.18 |
| Oct-04 | $ 7.77 | $ 4.92 | $ 3.11 |
| Nov-04 | $ 9.24 | $ 6.08 | $ 4.14 |
| Dec-04 | $ 9.72 | $ 6.26 | $ 4.17 |
| Jan-05 | $ 10.20 | $ 6.40 | $ 4.17 |
| Feb-05 | $ 10.30 | $ 6.38 | $ 4.11 |
| Mar-05 | $ 9.97 | $ 6.20 | $ 4.02 |
| Apr-05 | $ 7.39 | $ 4.75 | $ 3.05 |
| May-05 | $ 7.29 | $ 4.66 | $ 2.98 |
| Jun-05 | $ 7.40 | $ 4.68 | $ 2.96 |
| Jul-05 | $ 7.57 | $ 4.71 | $ 2.93 |
| Aug-05 | $ 7.68 | $ 4.74 | $ 2.93 |
| Sep-05 | $ 7.83 | $ 4.75 | $ 2.88 |
| Oct-05 | $ 8.41 | $ 4.81 | $ 2.75 |
| Nov-05 | $ 9.06 | $ 5.02 | $ 2.78 |
| Dec-05 | $ 9.74 | $ 5.23 | $ 2.81 |
| 2006 | $ 7.72 | $ 4.62 | $ 2.73 |
| 2007 | $ 7.65 | $ 4.50 | $ 2.58 |
| 2008 | $ 7.67 | $ 4.50 | $ 2.57 |
| 2009 | $ 7.72 | $ 4.50 | $ 2.55 |
| 2010 | $ 7.81 | $ 4.50 | $ 2.50 |
| 2011 | $ 7.89 | $ 4.50 | $ 2.45 |
| 2012 | $ 8.08 | $ 4.60 | $ 2.51 |
| 2013 | $ 8.27 | $ 4.70 | $ 2.56 |
| 2014 | $ 8.46 | $ 4.80 | $ 2.61 |
| 2015 | $ 8.66 | $ 4.90 | $ 2.65 |
| 2016 | $ 8.86 | $ 5.02 | $ 2.74 |
| 2017 | $ 9.06 | $ 5.15 | $ 2.82 |
| 2018 | $ 9.27 | $ 5.28 | $ 2.91 |
| 2019 | $ 9.48 | $ 5.41 | $ 3.00 |
| 2020 | $ 9.69 | $ 5.54 | $ 3.09 |
| 2021 | $ 9.92 | $ 5.68 | $ 3.19 |
| 2022 | $ 10.14 | $ 5.82 | $ 3.29 |
| 2023 | $ 10.37 | $ 5.97 | $ 3.39 |

High & Low Base Cost are not the total costs. Please refer to the "Natural Gas Costs_0627.xls" for other adders.

**Prepared By:** Jay Nemeth
**Date:** 12/18/2003
**Organization:** Risk Analytics.



PEF 000056
DOCK. NO. 040817-EI

**No6 Oil, 3% ($/Bbl)**

| | High | Base | Low |
|---|---|---|---|
| Jan-04 | $ 33.33 | $ 24.43 | $ 21.69 |
| Feb-04 | $ 33.42 | $ 24.49 | $ 21.75 |
| Mar-04 | $ 33.13 | $ 24.29 | $ 21.56 |
| Apr-04 | $ 33.98 | $ 24.91 | $ 22.12 |
| May-04 | $ 33.59 | $ 24.62 | $ 21.86 |
| Jun-04 | $ 33.24 | $ 24.36 | $ 21.63 |
| Jul-04 | $ 33.25 | $ 24.37 | $ 21.64 |
| Aug-04 | $ 32.99 | $ 24.18 | $ 21.47 |
| Sep-04 | $ 32.77 | $ 24.02 | $ 21.33 |
| Oct-04 | $ 32.05 | $ 23.49 | $ 20.86 |
| Nov-04 | $ 31.89 | $ 23.38 | $ 20.75 |
| Dec-04 | $ 31.79 | $ 23.30 | $ 20.69 |
| Jan-05 | $ 34.77 | $ 23.30 | $ 19.67 |
| Feb-05 | $ 34.77 | $ 23.31 | $ 19.67 |
| Mar-05 | $ 34.37 | $ 23.03 | $ 19.44 |
| Apr-05 | $ 33.17 | $ 22.23 | $ 18.76 |
| May-05 | $ 32.79 | $ 21.98 | $ 18.55 |
| Jun-05 | $ 32.42 | $ 21.73 | $ 18.33 |
| Jul-05 | $ 34.90 | $ 23.39 | $ 19.74 |
| Aug-05 | $ 34.58 | $ 23.17 | $ 19.56 |
| Sep-05 | $ 34.34 | $ 23.02 | $ 19.42 |
| Oct-05 | $ 32.63 | $ 21.87 | $ 18.45 |
| Nov-05 | $ 32.51 | $ 21.79 | $ 18.38 |
| Dec-05 | $ 32.44 | $ 21.74 | $ 18.35 |
| 2006 | $ 34.31 | $ 18.46 | $ 12.78 |
| 2007 | $ 33.26 | $ 18.47 | $ 11.87 |
| 2008 | $ 34.37 | $ 20.29 | $ 12.20 |
| 2009 | $ 36.00 | $ 21.20 | $ 12.58 |
| 2010 | $ 35.89 | $ 21.56 | $ 12.18 |
| 2011 | $ 36.25 | $ 21.95 | $ 11.98 |
| 2012 | $ 37.09 | $ 22.34 | $ 12.22 |
| 2013 | $ 37.93 | $ 22.75 | $ 12.45 |
| 2014 | $ 38.78 | $ 23.16 | $ 12.67 |
| 2015 | $ 39.68 | $ 23.57 | $ 12.87 |
| 2016 | $ 40.58 | $ 24.00 | $ 13.24 |
| 2017 | $ 41.48 | $ 24.43 | $ 13.62 |
| 2018 | $ 42.40 | $ 24.87 | $ 14.01 |
| 2019 | $ 43.34 | $ 25.32 | $ 14.42 |
| 2020 | $ 44.30 | $ 25.77 | $ 14.83 |
| 2021 | $ 45.29 | $ 26.24 | $ 15.25 |
| 2022 | $ 46.30 | $ 26.71 | $ 15.69 |
| 2023 | $ 47.34 | $ 27.19 | $ 16.14 |

**No6 Oil, 3% ($/MMBtu)**

| | High | Base | Low |
|---|---|---|---|
| Jan-04 | $ 5.30 | $ 3.89 | $ 3.45 |
| Feb-04 | $ 5.32 | $ 3.90 | $ 3.46 |
| Mar-04 | $ 5.27 | $ 3.86 | $ 3.43 |
| Apr-04 | $ 5.41 | $ 3.96 | $ 3.52 |
| May-04 | $ 5.34 | $ 3.92 | $ 3.48 |
| Jun-04 | $ 5.29 | $ 3.87 | $ 3.44 |
| Jul-04 | $ 5.29 | $ 3.88 | $ 3.44 |
| Aug-04 | $ 5.25 | $ 3.85 | $ 3.41 |
| Sep-04 | $ 5.21 | $ 3.82 | $ 3.39 |
| Oct-04 | $ 5.10 | $ 3.74 | $ 3.32 |
| Nov-04 | $ 5.07 | $ 3.72 | $ 3.30 |
| Dec-04 | $ 5.06 | $ 3.71 | $ 3.29 |
| Jan-05 | $ 5.53 | $ 3.71 | $ 3.13 |
| Feb-05 | $ 5.53 | $ 3.71 | $ 3.13 |
| Mar-05 | $ 5.47 | $ 3.66 | $ 3.09 |
| Apr-05 | $ 5.28 | $ 3.54 | $ 2.98 |
| May-05 | $ 5.22 | $ 3.50 | $ 2.95 |
| Jun-05 | $ 5.16 | $ 3.46 | $ 2.92 |
| Jul-05 | $ 5.55 | $ 3.72 | $ 3.14 |
| Aug-05 | $ 5.50 | $ 3.69 | $ 3.11 |
| Sep-05 | $ 5.46 | $ 3.66 | $ 3.09 |
| Oct-05 | $ 5.19 | $ 3.48 | $ 2.93 |
| Nov-05 | $ 5.17 | $ 3.47 | $ 2.92 |
| Dec-05 | $ 5.16 | $ 3.46 | $ 2.92 |
| 2006 | $ 5.46 | $ 2.94 | $ 2.03 |
| 2007 | $ 5.29 | $ 2.94 | $ 1.89 |
| 2008 | $ 5.47 | $ 3.23 | $ 1.94 |
| 2009 | $ 5.73 | $ 3.37 | $ 2.00 |
| 2010 | $ 5.71 | $ 3.43 | $ 1.94 |
| 2011 | $ 5.77 | $ 3.49 | $ 1.91 |
| 2012 | $ 5.90 | $ 3.55 | $ 1.94 |
| 2013 | $ 6.03 | $ 3.62 | $ 1.98 |
| 2014 | $ 6.17 | $ 3.68 | $ 2.02 |
| 2015 | $ 6.31 | $ 3.75 | $ 2.05 |
| 2016 | $ 6.45 | $ 3.82 | $ 2.11 |
| 2017 | $ 6.60 | $ 3.89 | $ 2.17 |
| 2018 | $ 6.74 | $ 3.96 | $ 2.23 |
| 2019 | $ 6.89 | $ 4.03 | $ 2.29 |
| 2020 | $ 7.05 | $ 4.10 | $ 2.36 |
| 2021 | $ 7.20 | $ 4.17 | $ 2.43 |
| 2022 | $ 7.36 | $ 4.25 | $ 2.50 |
| 2023 | $ 7.53 | $ 4.32 | $ 2.57 |

**Prepared by:** Jay Nemeth
**Organization:** Risk Analytics
**Date:** 12/18/2003
**Manager:** Glen Snider

2004 - 2005 Monthly Base Case No6 based on market observations dated Dec. 5, 2003
2005 Monthly Base Case No6 monthly shape (seasonality) is modified to be the same as the 2004 seasonality
2006 - 2010 Annual Base Case No6 based on PIRA Energy Group forecast dated Sept. 9, 2003
2011 - 2023 Annual Base Case No6 uses a 1.8% annual escalation of the 2010 price, based on the rate of escalation in the Sept. '03 No6 price forecast
Low No6 forecast is based on applying the results of a regression of base gas and No6 prices to the 10th percentile gas forecast
High No6 forecast is based on applying the results of a regression of base gas and No6 prices to the 90th percentile gas forecast

| No6 Oil, 1% ($/Bbl) | High | Base | Low |
|---|---|---|---|
| Jan-04 | $ 37.06 | $ 27.16 | $ 24.12 |
| Feb-04 | $ 37.16 | $ 27.23 | $ 24.18 |
| Mar-04 | $ 36.83 | $ 27.00 | $ 23.97 |
| Apr-04 | $ 35.80 | $ 26.24 | $ 23.30 |
| May-04 | $ 35.38 | $ 25.93 | $ 23.03 |
| Jun-04 | $ 35.00 | $ 25.66 | $ 22.78 |
| Jul-04 | $ 37.68 | $ 27.62 | $ 24.52 |
| Aug-04 | $ 37.38 | $ 27.40 | $ 24.32 |
| Sep-04 | $ 37.13 | $ 27.22 | $ 24.16 |
| Oct-04 | $ 35.13 | $ 25.75 | $ 22.86 |
| Nov-04 | $ 34.95 | $ 25.62 | $ 22.75 |
| Dec-04 | $ 34.84 | $ 25.53 | $ 22.67 |
| Jan-05 | $ 38.68 | $ 25.92 | $ 21.87 |
| Feb-05 | $ 38.67 | $ 25.92 | $ 21.87 |
| Mar-05 | $ 38.22 | $ 25.61 | $ 21.62 |
| Apr-05 | $ 36.88 | $ 24.71 | $ 20.86 |
| May-05 | $ 36.45 | $ 24.43 | $ 20.62 |
| Jun-05 | $ 36.03 | $ 24.15 | $ 20.38 |
| Jul-05 | $ 38.78 | $ 25.99 | $ 21.94 |
| Aug-05 | $ 38.43 | $ 25.75 | $ 21.73 |
| Sep-05 | $ 38.16 | $ 25.57 | $ 21.58 |
| Oct-05 | $ 36.25 | $ 24.29 | $ 20.50 |
| Nov-05 | $ 36.11 | $ 24.20 | $ 20.43 |
| Dec-05 | $ 36.04 | $ 24.15 | $ 20.38 |
| 2006 | $ 43.03 | $ 23.15 | $ 16.03 |
| 2007 | $ 42.66 | $ 23.70 | $ 15.23 |
| 2008 | $ 42.78 | $ 25.25 | $ 15.18 |
| 2009 | $ 43.04 | $ 25.35 | $ 15.04 |
| 2010 | $ 43.53 | $ 26.15 | $ 14.78 |
| 2011 | $ 43.97 | $ 26.62 | $ 14.53 |
| 2012 | $ 44.98 | $ 27.10 | $ 14.82 |
| 2013 | $ 46.00 | $ 27.59 | $ 15.09 |
| 2014 | $ 47.04 | $ 28.08 | $ 15.37 |
| 2015 | $ 48.13 | $ 28.59 | $ 15.61 |
| 2016 | $ 49.21 | $ 29.10 | $ 16.05 |
| 2017 | $ 50.30 | $ 29.63 | $ 16.52 |
| 2018 | $ 51.42 | $ 30.16 | $ 16.99 |
| 2019 | $ 52.56 | $ 30.70 | $ 17.48 |
| 2020 | $ 53.73 | $ 31.26 | $ 17.99 |
| 2021 | $ 54.93 | $ 31.82 | $ 18.50 |
| 2022 | $ 56.15 | $ 32.39 | $ 19.03 |
| 2023 | $ 57.41 | $ 32.98 | $ 19.57 |

| No6 Oil, 1% ($/MMBtu) | High | Base | Low |
|---|---|---|---|
| Jan-04 | $ 5.89 | $ 4.32 | $ 3.84 |
| Feb-04 | $ 5.91 | $ 4.33 | $ 3.85 |
| Mar-04 | $ 5.86 | $ 4.29 | $ 3.81 |
| Apr-04 | $ 5.69 | $ 4.17 | $ 3.71 |
| May-04 | $ 5.63 | $ 4.12 | $ 3.66 |
| Jun-04 | $ 5.57 | $ 4.08 | $ 3.62 |
| Jul-04 | $ 5.99 | $ 4.39 | $ 3.90 |
| Aug-04 | $ 5.95 | $ 4.36 | $ 3.87 |
| Sep-04 | $ 5.91 | $ 4.33 | $ 3.84 |
| Oct-04 | $ 5.59 | $ 4.10 | $ 3.64 |
| Nov-04 | $ 5.56 | $ 4.08 | $ 3.62 |
| Dec-04 | $ 5.54 | $ 4.06 | $ 3.61 |
| Jan-05 | $ 6.15 | $ 4.12 | $ 3.48 |
| Feb-05 | $ 6.15 | $ 4.12 | $ 3.48 |
| Mar-05 | $ 6.08 | $ 4.07 | $ 3.44 |
| Apr-05 | $ 5.87 | $ 3.93 | $ 3.32 |
| May-05 | $ 5.80 | $ 3.89 | $ 3.28 |
| Jun-05 | $ 5.73 | $ 3.84 | $ 3.24 |
| Jul-05 | $ 6.17 | $ 4.13 | $ 3.49 |
| Aug-05 | $ 6.11 | $ 4.10 | $ 3.46 |
| Sep-05 | $ 6.07 | $ 4.07 | $ 3.43 |
| Oct-05 | $ 5.77 | $ 3.86 | $ 3.26 |
| Nov-05 | $ 5.74 | $ 3.85 | $ 3.25 |
| Dec-05 | $ 5.73 | $ 3.84 | $ 3.24 |
| 2006 | $ 6.85 | $ 3.68 | $ 2.55 |
| 2007 | $ 6.79 | $ 3.77 | $ 2.42 |
| 2008 | $ 6.80 | $ 4.02 | $ 2.41 |
| 2009 | $ 6.85 | $ 4.03 | $ 2.39 |
| 2010 | $ 6.92 | $ 4.16 | $ 2.35 |
| 2011 | $ 6.99 | $ 4.23 | $ 2.31 |
| 2012 | $ 7.15 | $ 4.31 | $ 2.36 |
| 2013 | $ 7.32 | $ 4.39 | $ 2.40 |
| 2014 | $ 7.48 | $ 4.47 | $ 2.44 |
| 2015 | $ 7.65 | $ 4.55 | $ 2.48 |
| 2016 | $ 7.83 | $ 4.63 | $ 2.55 |
| 2017 | $ 8.00 | $ 4.71 | $ 2.63 |
| 2018 | $ 8.18 | $ 4.80 | $ 2.70 |
| 2019 | $ 8.36 | $ 4.88 | $ 2.78 |
| 2020 | $ 8.55 | $ 4.97 | $ 2.86 |
| 2021 | $ 8.74 | $ 5.06 | $ 2.94 |
| 2022 | $ 8.93 | $ 5.15 | $ 3.03 |
| 2023 | $ 9.13 | $ 5.25 | $ 3.11 |

1.0% of Sulfur is equivalent to 1.1 pounds of Sulfur.

**Prepared by:** Jay Nemeth
**Organization:** Risk Analytics
**Date:** 12/18/2003
**Manager:** Glen Snider

2004 - 2005 Monthly Base Case No6 based on market observations dated Dec. 5, 2003
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Low No6 forecast is based on applying the results of a regression of base gas and No6 prices to the 10th percentile gas forecast
High No6 forecast is based on applying the results of a regression of base gas and No6 prices to the 90th percentile gas forecast

| No2 Oil, 0.5% (Cents/Gallon) | High | Base | Low |
|---|---|---|---|
| Jan-04 | 123.61 | 101.01 | 87.83 |
| Feb-04 | 134.85 | 101.59 | 82.17 |
| Mar-04 | 134.90 | 100.09 | 77.16 |
| Apr-04 | 102.65 | 81.88 | 61.08 |
| May-04 | 98.99 | 78.76 | 59.78 |
| Jun-04 | 101.35 | 77.01 | 58.85 |
| Jul-04 | 103.43 | 76.15 | 58.08 |
| Aug-04 | 106.16 | 76.36 | 57.10 |
| Sep-04 | 108.53 | 77.23 | 56.01 |
| Oct-04 | 110.86 | 78.10 | 55.15 |
| Nov-04 | 128.34 | 94.01 | 67.43 |
| Dec-04 | 134.15 | 94.79 | 67.86 |
| Jan-05 | 139.89 | 95.46 | 67.82 |
| Feb-05 | 141.07 | 95.44 | 67.06 |
| Mar-05 | 137.10 | 93.96 | 66.01 |
| Apr-05 | 106.25 | 76.08 | 54.48 |
| May-05 | 105.10 | 74.03 | 53.57 |
| Jun-05 | 106.40 | 73.35 | 53.40 |
| Jul-05 | 108.38 | 72.54 | 53.05 |
| Aug-05 | 109.76 | 72.73 | 53.00 |
| Sep-05 | 111.50 | 73.57 | 52.38 |
| Oct-05 | 118.48 | 74.40 | 50.89 |
| Nov-05 | 126.22 | 75.14 | 51.18 |
| Dec-05 | 134.41 | 75.89 | 51.56 |
| 2006 | 134.14 | 72.50 | 48.90 |
| 2007 | 132.97 | 73.30 | 46.37 |
| 2008 | 133.34 | 75.80 | 46.22 |
| 2009 | 134.17 | 78.20 | 45.78 |
| 2010 | 135.70 | 81.10 | 44.94 |
| 2011 | 137.10 | 82.56 | 44.18 |
| 2012 | 140.28 | 84.05 | 45.08 |
| 2013 | 143.52 | 85.56 | 45.95 |
| 2014 | 146.77 | 87.10 | 46.81 |
| 2015 | 150.21 | 88.67 | 47.57 |
| 2016 | 153.64 | 90.26 | 48.98 |
| 2017 | 157.09 | 91.89 | 50.44 |
| 2018 | 160.60 | 93.54 | 51.95 |
| 2019 | 164.21 | 95.22 | 53.49 |
| 2020 | 167.90 | 96.94 | 55.07 |
| 2021 | 171.68 | 98.68 | 56.70 |
| 2022 | 175.55 | 100.46 | 58.37 |
| 2023 | 179.52 | 102.27 | 60.09 |

| No2 Oil, 0.5% ($/MMBtu) | High | Base | Low |
|---|---|---|---|
| Jan-04 | $ 8.91 | $ 7.28 | $ 6.33 |
| Feb-04 | $ 9.72 | $ 7.32 | $ 5.92 |
| Mar-04 | $ 9.73 | $ 7.22 | $ 5.56 |
| Apr-04 | $ 7.40 | $ 5.90 | $ 4.40 |
| May-04 | $ 7.14 | $ 5.68 | $ 4.31 |
| Jun-04 | $ 7.31 | $ 5.55 | $ 4.24 |
| Jul-04 | $ 7.46 | $ 5.49 | $ 4.19 |
| Aug-04 | $ 7.65 | $ 5.51 | $ 4.12 |
| Sep-04 | $ 7.83 | $ 5.57 | $ 4.04 |
| Oct-04 | $ 7.99 | $ 5.63 | $ 3.98 |
| Nov-04 | $ 9.25 | $ 6.78 | $ 4.86 |
| Dec-04 | $ 9.67 | $ 6.83 | $ 4.89 |
| Jan-05 | $ 10.09 | $ 6.88 | $ 4.89 |
| Feb-05 | $ 10.17 | $ 6.88 | $ 4.84 |
| Mar-05 | $ 9.89 | $ 6.77 | $ 4.76 |
| Apr-05 | $ 7.66 | $ 5.49 | $ 3.93 |
| May-05 | $ 7.58 | $ 5.34 | $ 3.86 |
| Jun-05 | $ 7.67 | $ 5.29 | $ 3.85 |
| Jul-05 | $ 7.81 | $ 5.23 | $ 3.82 |
| Aug-05 | $ 7.91 | $ 5.24 | $ 3.82 |
| Sep-05 | $ 8.04 | $ 5.30 | $ 3.78 |
| Oct-05 | $ 8.54 | $ 5.36 | $ 3.67 |
| Nov-05 | $ 9.10 | $ 5.42 | $ 3.69 |
| Dec-05 | $ 9.69 | $ 5.47 | $ 3.72 |
| 2006 | $ 9.67 | $ 5.23 | $ 3.53 |
| 2007 | $ 9.59 | $ 5.29 | $ 3.34 |
| 2008 | $ 9.61 | $ 5.47 | $ 3.33 |
| 2009 | $ 9.67 | $ 5.64 | $ 3.30 |
| 2010 | $ 9.78 | $ 5.85 | $ 3.24 |
| 2011 | $ 9.89 | $ 5.95 | $ 3.19 |
| 2012 | $ 10.11 | $ 6.06 | $ 3.25 |
| 2013 | $ 10.35 | $ 6.17 | $ 3.31 |
| 2014 | $ 10.58 | $ 6.28 | $ 3.38 |
| 2015 | $ 10.83 | $ 6.39 | $ 3.43 |
| 2016 | $ 11.08 | $ 6.51 | $ 3.53 |
| 2017 | $ 11.33 | $ 6.63 | $ 3.64 |
| 2018 | $ 11.58 | $ 6.74 | $ 3.75 |
| 2019 | $ 11.84 | $ 6.87 | $ 3.86 |
| 2020 | $ 12.11 | $ 6.99 | $ 3.97 |
| 2021 | $ 12.38 | $ 7.12 | $ 4.09 |
| 2022 | $ 12.66 | $ 7.24 | $ 4.21 |
| 2023 | $ 12.94 | $ 7.37 | $ 4.33 |

**Prepared by:** Jay Nemeth
**Organization:** Risk Analytics
**Date:** 12/18/2003
**Manager:** Glen Snider

2004 - 2005 Monthly Base Case No2 based on market observations dated Dec. 5, 2003
2006 - 2010 Annual Base Case No2 based on PIRA Energy Group forecast dated Sept. 9, 2003
2011 - 2023 Annual Base Case No2 uses a 1.8% annual escalation of the 2010 price, based on the rate of escalation in the Sept. '03 No2 price forecast
Low No2 forecast is based on applying the results of a regression of base gas and No2 prices to the 10th percentile gas forecast
High No2 forecast is based on applying the results of a regression of base gas and No2 prices to the 90th percentile gas forecast
In consideration of the high price volatility and shortages of supply, $1.03/MMBtu was added to Jan 04-Mar 04 and $1.09 was added to Nov 04-Mar 05.

**No2 Oil, 0.05% (Cents/Gallon)**

| | High | Base | Low |
|---|---|---|---|
| Jan-04 | 124.99 | 102.13 | 88.81 |
| Feb-04 | 137.18 | 103.34 | 83.59 |
| Mar-04 | 137.93 | 102.33 | 78.89 |
| Apr-04 | 105.39 | 84.08 | 62.72 |
| May-04 | 101.83 | 81.02 | 61.50 |
| Jun-04 | 104.69 | 79.55 | 60.79 |
| Jul-04 | 106.90 | 78.71 | 60.02 |
| Aug-04 | 109.48 | 78.75 | 58.88 |
| Sep-04 | 111.83 | 79.58 | 57.72 |
| Oct-04 | 113.84 | 80.20 | 56.63 |
| Nov-04 | 130.92 | 95.90 | 68.78 |
| Dec-04 | 136.45 | 96.42 | 69.03 |
| Jan-05 | 141.45 | 96.52 | 68.58 |
| Feb-05 | 143.51 | 97.09 | 68.22 |
| Mar-05 | 140.18 | 96.07 | 67.50 |
| Apr-05 | 109.09 | 78.11 | 55.94 |
| May-05 | 108.12 | 76.15 | 55.10 |
| Jun-05 | 109.91 | 75.77 | 55.16 |
| Jul-05 | 112.02 | 74.97 | 54.82 |
| Aug-05 | 113.20 | 75.01 | 54.66 |
| Sep-05 | 114.90 | 75.81 | 53.97 |
| Oct-05 | 121.66 | 76.40 | 52.26 |
| Nov-05 | 128.75 | 76.65 | 52.21 |
| Dec-05 | 136.72 | 77.19 | 52.45 |
| 2006 | 141.69 | 76.58 | 51.65 |
| 2007 | 142.29 | 78.44 | 49.63 |
| 2008 | 142.34 | 80.92 | 49.35 |
| 2009 | 143.31 | 83.52 | 48.90 |
| 2010 | 144.59 | 86.42 | 47.89 |
| 2011 | 146.09 | 87.97 | 47.07 |
| 2012 | 149.48 | 89.56 | 48.03 |
| 2013 | 152.93 | 91.17 | 48.96 |
| 2014 | 156.40 | 92.81 | 49.88 |
| 2015 | 160.06 | 94.48 | 50.69 |
| 2016 | 163.72 | 96.18 | 52.19 |
| 2017 | 167.39 | 97.91 | 53.75 |
| 2018 | 171.14 | 99.68 | 55.35 |
| 2019 | 174.97 | 101.47 | 57.00 |
| 2020 | 178.91 | 103.30 | 58.69 |
| 2021 | 182.94 | 105.16 | 60.42 |
| 2022 | 187.07 | 107.05 | 62.20 |
| 2023 | 191.29 | 108.97 | 64.03 |

**No2 Oil, 0.05% ($/MMBtu)**

| | High | Base | Low |
|---|---|---|---|
| Jan-04 | $ 9.01 | $ 7.36 | $ 6.40 |
| Feb-04 | $ 9.89 | $ 7.45 | $ 6.03 |
| Mar-04 | $ 9.95 | $ 7.38 | $ 5.69 |
| Apr-04 | $ 7.60 | $ 6.06 | $ 4.52 |
| May-04 | $ 7.34 | $ 5.84 | $ 4.43 |
| Jun-04 | $ 7.55 | $ 5.74 | $ 4.38 |
| Jul-04 | $ 7.71 | $ 5.67 | $ 4.33 |
| Aug-04 | $ 7.89 | $ 5.68 | $ 4.25 |
| Sep-04 | $ 8.06 | $ 5.74 | $ 4.16 |
| Oct-04 | $ 8.21 | $ 5.78 | $ 4.08 |
| Nov-04 | $ 9.44 | $ 6.91 | $ 4.96 |
| Dec-04 | $ 9.84 | $ 6.95 | $ 4.98 |
| Jan-05 | $ 10.20 | $ 6.96 | $ 4.94 |
| Feb-05 | $ 10.35 | $ 7.00 | $ 4.92 |
| Mar-05 | $ 10.11 | $ 6.93 | $ 4.87 |
| Apr-05 | $ 7.87 | $ 5.63 | $ 4.03 |
| May-05 | $ 7.80 | $ 5.49 | $ 3.97 |
| Jun-05 | $ 7.93 | $ 5.46 | $ 3.98 |
| Jul-05 | $ 8.08 | $ 5.41 | $ 3.95 |
| Aug-05 | $ 8.16 | $ 5.41 | $ 3.94 |
| Sep-05 | $ 8.28 | $ 5.47 | $ 3.89 |
| Oct-05 | $ 8.77 | $ 5.51 | $ 3.77 |
| Nov-05 | $ 9.28 | $ 5.53 | $ 3.76 |
| Dec-05 | $ 9.86 | $ 5.57 | $ 3.78 |
| 2006 | $ 10.22 | $ 5.52 | $ 3.72 |
| 2007 | $ 10.26 | $ 5.66 | $ 3.58 |
| 2008 | $ 10.26 | $ 5.83 | $ 3.56 |
| 2009 | $ 10.33 | $ 6.02 | $ 3.53 |
| 2010 | $ 10.43 | $ 6.23 | $ 3.45 |
| 2011 | $ 10.53 | $ 6.34 | $ 3.39 |
| 2012 | $ 10.78 | $ 6.46 | $ 3.46 |
| 2013 | $ 11.03 | $ 6.57 | $ 3.53 |
| 2014 | $ 11.28 | $ 6.69 | $ 3.60 |
| 2015 | $ 11.54 | $ 6.81 | $ 3.65 |
| 2016 | $ 11.80 | $ 6.93 | $ 3.76 |
| 2017 | $ 12.07 | $ 7.06 | $ 3.88 |
| 2018 | $ 12.34 | $ 7.19 | $ 3.99 |
| 2019 | $ 12.62 | $ 7.32 | $ 4.11 |
| 2020 | $ 12.90 | $ 7.45 | $ 4.23 |
| 2021 | $ 13.19 | $ 7.58 | $ 4.36 |
| 2022 | $ 13.49 | $ 7.72 | $ 4.48 |
| 2023 | $ 13.79 | $ 7.86 | $ 4.62 |

**Prepared by:** Jay Nemeth
**Organization:** Risk Analytics
**Date:** 12/18/2003
**Manager:** Glen Snider

2004 - 2005 Monthly Base Case No2 based on market observations dated Dec. 5, 2003
2006 - 2010 Annual Base Case No2 based on PIRA Energy Group forecast dated Sept. 9, 2003
2011 - 2023 Annual Base Case No2 uses a 1.8% annual escalation of the 2010 price, based on the rate of escalation in the Sept. '03 No2 price forecast
Low No2 forecast is based on applying the results of a regression of base gas and No2 prices to the 10th percentile gas forecast
High No2 forecast is based on applying the results of a regression of base gas and No2 prices to the 90th percentile gas forecast
No2 .05% based on the relationship of No2 .05% and .5% in PIRA's short-term forecast dated Nov. 25, 2003 and PIRA's long-term forecast dated Sept. 9, 2003
In consideration of the high price volatility and shortages of supply, $1.04/MMBtu was added to Jan 04-Mar 04 and $1.11 was added to Nov 04-Mar 05.

## Murphy, Pam (CPL)

**From:** Nemeth, Jay
**Sent:** Thursday, December 18, 2003 3:30 PM
**To:** Baumann, Dana
**Cc:** Murphy, Pam (CP&L); Adams, Melanie; Williams, Dale D.; Nishtala, Subba; Snider, Glen; Ridgway, Jason; Trimble, John; Luhrs, Michelle
**Subject:** Gas and Oil Forecasts with 80% low/high bandwidth

Attached are the updated forecasts, per Dana's email request. We have changed from a one standard deviation (roughly a 16th and 84th percentile) low and high case to a 10th and 90th percentile case - resulting in an 80 percent bandwidth. The base remains unchanged, but as one would expect, the low case is lower and the high case is higher. This will make our forecasts consistent with prior submittals.

-Jay

Natural Gas 'osts_2003_1218.xl.    Oil (12-18-03).xls (148 KB)

-----Original Message-----
**From:** Baumann, Dana
**Sent:** Thursday, December 18, 2003 11:19 AM
**To:** Nemeth, Jay
**Cc:** Murphy, Pam (CP&L); Adams, Melanie; Williams, Dale D.; Nishtala, Subba; Snider, Glen; Ridgway, Jason; Trimble, John; Luhrs, Michelle
**Subject:** RE: Final: PMDb - Oil and Gas forecasts (no change to numbers)
**Importance:** High

Jay,

Per discussion between you and Ron Coats, please update the natural gas forecast to incorporate the 80% bandwidth for the high and low forecasts and submit by early this afternoon to Pam's group so they can update their forecasts and submit to me by tomorrow morning. We need to maintain this bandwidth to be consistent with prior submittals to the FPSC and to be consistent with the corporate load and energy forecast.

Thank you,

Dana

-----Original Message-----
**From:** Nemeth, Jay
**Sent:** Wednesday, December 17, 2003 10:28 AM
**To:** Nemeth, Jay; Murphy, Pam (CP&L); Adams, Melanie; Luhrs, Michelle; Williams, Dale D.; Nishtala, Subba; Trimble, John; Baumann, Dana; Snider, Glen; Ridgway, Jason
**Subject:** Final: PMDb - Oil and Gas forecasts (no change to numbers)

These forecasts are the same as what was sent on Dec. 11--the only difference is that I have added comments.

-Jay

<< File: Oil (12-11-03).xls >> << File: Natural Gas Costs_2003_1211.xls >>

-----Original Message-----
**From:** Nemeth, Jay
**Sent:** Thursday, December 11, 2003 6:52 PM
**To:** Nemeth, Jay; Murphy, Pam (CP&L); Adams, Melanie; Luhrs, Michelle; Williams, Dale D.; Nishtala, Subba; Trimble, John; Baumann, Dana; Snider, Glen; Ridgway, Jason

**Subject:** UPDATED: PMDb - Oil and Gas forecasts

The first iteration of forecast updates has been conducted today. After discussions with the commercial organization, a few modifications have been made. Attached are the revised forecasts.

The volatility in the natural gas market without near-term prospects for additional supply (i.e., LNG) has resulted in the addition to our forecast of $1/MMBtu for the remainder of the winter of 2004 and the winter of Nov '04-Mar '05. By nature of the fungibility of natural gas and distillate fuel oil and the high correlation of their prices, a similar addition was made to the winter distillate prices. The addition for the .5% heating oil forecast was $1.03/MMBtu for this winter and $1.09/MMBtu for next winter.

The other modification was to the residual forecasts. The prices for 2005 lacked any seasonality, missing the market observation that prices typically peak in the summer. To make this more representative of our view, the average of the year was maintained, but was shaped to be consistent with the 2004 shape.

Finally, after increasing the winter costs for the short-term Henry Hub prices, the regression analysis that calculated the relationship of distillate and Henry Hub using historic prices from 1994 to the present gave irregular results for the high distillate case. To correct this, a new regression analysis was performed that compared the short-term base forecasts of both distillate and Henry Hub. This gave much more intuitive results for the high case while maintaining appropriate low case results.

No changes were made to the long-term (2006-2023) forecasts.

My thanks to those who have offered suggestions. Please contact me if you have any questions.

<< File: Natural Gas Costs_2003_1211.xls >> << File: Oil (12-11-03).xls >>
-Jay

-----Original Message-----
**From:** Nemeth, Jay
**Sent:** Tuesday, December 09, 2003 5:31 PM
**To:** Murphy, Pam (CP&L); Adams, Melanie; Luhrs, Michelle; Williams, Dale D.; Nishtala, Subba; Trimble, John; Baumann, Dana; Snider, Glen
**Cc:** Ridgway, Jason
**Subject:** PMDb - Oil and Gas forecasts

Please find attached the short and long-term forecasts for natural gas, No. 2 and No. 6 fuel oils. I have reviewed all of the files that Dana attached in her initial request and have attempted to utilize the same spreadsheets with the same formats. The template for my Henry Hub forecast was 'Natural Gas Costs_2003_0731.xls'. I have removed the columns related to the Adder to Z3, added a column for my Base Case forecast and renamed the file 'Natural Gas Costs_2003_1209.xls'.

The template for my oil price forecasts was not an attachment in Dana's email -- I actually used a file provided by Stacy Chang called 'Oil (0730).xls'. I used the same template and renamed the file 'Oil (12-09-03).xls'.

Realizing that the numbers are the highest priority at this time, I am sending these forecasts without supporting notes. I will work on the supporting comments in parallel with the "bolt-on" work.

In lieu of comments in the spreadsheet, I will briefly summarize the methodology that was employed.

**Short Term**

The base short-term forecasts for each of the commodities was developed by using a methodology put forward in an EPRI study to convert forward prices to spot forecast prices by "putting risk back in" to the forward curve. The date of the forward curves that were used to develop the spot forecasts was 12-05-03.

The high and low short-term Henry Hub forecasts were developed by using the volatility of the forward prices to calculate prices one standard deviation above and one standard deviation below the expected (base) case.

Finally, historic cash price data (going back to 1994) was gathered from the EIA for oil and from Inside FERC for Henry Hub. A regression analysis was performed on this data to identify the relationships between Henry Hub and the two oil products. The results of these regressions were then applied to the high and low short-term Henry Hub forecasts to develop the high and low short-term oil forecasts.

**Long Term**

After comparing forecasts by CERA, PIRA and EVA, the forecasts by PIRA were selected as being the most consistent with our market view. The forecasts for oil ended in 2010 and the Henry Hub forecast ended in 2015. Analysis of the previous corporate forecasts showed that in the later years the forecasts escalated at a constant rate. The oil forecasts increased at a rate of 1.8% and the Henry Hub forecast increased at 2.5%. These same escalation rates were used to extend the forecasts beyond the years that the PIRA forecasts provided.

The methodology for developing the high and low long-term Henry Hub forecasts was similar to that of the short-term forecasts. The volatilities of the forward prices were used to calculate prices one standard deviation above and one standard deviation below the expected (base) case. The difference between the "high" spot-adjusted curve and the "base" spot-adjusted curve was calculated and that difference was added to the long-term PIRA forecast to produce our official high Henry Hub case. The same technique was used to calculate our official low Henry Hub case.

Another regression analysis was performed to identify the relationships of the long-term forecasts for Henry Hub and the oil products, using our base long-term forecasts. The results of these regressions were then applied to the high and low long-term Henry Hub forecasts to develop the high and low long-term oil forecasts.

I welcome any questions or comments as this process continues.

-Jay

<< File: Oil (12-09-03).xls >> << File: Natural Gas Costs_2003_1209.xls >>

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http://www.energypulse.net

# Puncturing Natural Gas Myths -- Part I

*11.21.03 Andrew Weissman, Publisher, EnergyBusinessWatch.com*




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Does the U.S. still face a severe natural gas supply crisis during the remainder of this decade?

If there is any remaining doubt regarding this issue, it should be thoroughly dispelled by the National Petroleum Council's recent Report to Secretary of Energy Spencer Abraham.

The Council's Report, entitled "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," presents the results of the most comprehensive assessment of supply and demand of natural gas in the North American market undertaken in many years. To date, it has received surprisingly little attention – despite Alan Greenspan's warning last May regarding the potential threat to the U.S. economy posed by tighter-than-expected natural gas supplies.

Anyone who reads the Council's Report carefully, however – and I would urge everyone who reads this article to do just that -- can't help but come away from the experience shaken. (The Report is available on the Council's web site at www.npc.org.)

The Council's last assessment of the U.S. market, completed in December of 1999, was one of the few government or privately-sponsored studies that offered any substantial basis for believing that it would be possible to significantly expand North American supplies of natural gas above 1999 levels. It also provided the basis for many of the assumptions used by the Energy Information Agency (EIA) in its subsequent annual forecasts of supply and demand in the U.S. market.

As such, it played an important role in justifying decisions by power plant developers to build more than $ 100 billion in new gas-fired generating units over the past four years – foregoing the opportunity to construct a more diversified portfolio that relied more heavily on coal-fired generation and renewable energy.

Soon after the Council's 1999 Study was published, however, production from some of the most important natural gas basins in the U.S. and Canada (particularly the Near Shelf region in the Gulf of Mexico and Canadian fields in Alberta) began to decline at an alarming rate. This in turn raised significant questions regarding the continued validity of many of the assumptions on which the 1999 Study was based.

As a result, in March of last year, Secretary of Energy Spencer Abraham asked the Council (an advisory group the sole purpose of which is to advise the Secretary on issues pertaining to supply and demand of petroleum and natural gas) to undertake a comprehensive new assessment of the North American market. To help improve the accuracy of this assessment, the Secretary and other participants provided substantially greater funding and stronger technical support than had been made available in 1999.

The Council's new Study, which reflects the results of 18 months of intensive effort, includes a comprehensive, region-by-region assessment of likely future production for every major basin in the U.S. and Canada. This assessment, in turn, is based upon intensive interaction with the producers in each basin, to attempt to develop realistic estimates of future production for each field.

The results of this reassessment are stunning and warrant urgent attention at the national level. They give notice of a potentially severe crisis during the next 10 years that will not be eliminated even if Congress immediately enacts the federal energy legislation about to be sent to the floor of both Houses.

In its new Study, the Council begins by noting that, by 2002 (i.e., less than 36 months after the 1999 Study was issued), North American production already had fallen 6 BCf/day below the Council's forecast for 2002.

The Council concludes, however, that this inability to achieve the production levels previously forecast by the Council will not be a one time event.

Instead, it reflects the inevitable result of the maturation and increasingly rapid aging of most major fields in the U.S. and Canada. This rapid aging has resulted in flat or declining production in many of the most important basins in both the U.S. and Canada and, as a practical matter, can not be reversed.

As a result, the Council concludes that, with each passing year, North American production is likely to fall increasingly further behind the Council's earlier projections.

The Council's new Report estimates that, by 2015, North American production from "traditional U.S. and Canadian sources of supply" (defined by the Council to include every basin south of the Arctic Circle) will fall an almost unfathomable 21 BCf/day short of the levels the Council had concluded would be necessary to meet the needs of the U.S. market when it issued its earlier Study less than four years ago.

This equates to a drop in expected production, compared to the Council's earlier estimate of expected production by 2015, of more than 7.5 Trillion Cubic Feet per year – i.e., a downward revision of more than 22% in less than 48 months.

In BTU equivalent terms, the effect of this steep reduction is to create a hole in expected U.S. energy supply equivalent to more than 1.5X the amount oil the U.S. currently imports from Saudi Arabia (which is currently averaging a little over 1.8 million barrels/day).

The Council bases this unprecedented downward revision in its earlier forecast on a combination of:

- A significant reduction in its estimate of reserves in the U.S. and Canada that are technically capable of being developed;
- A far more rapid than-expected drop-off in production from existing fields in both the U.S. and Canada; and
- A dramatic decline in the size of new wells in both the U.S. and Canada.

Based upon these factors, the Council concludes that even at prices as high as $ 8.00/MMBTU ($ 2002) there is only very limited potential to expand production in most major fields in the U.S. and Canada; production from many basins inevitably will decline.

While the Council's focus is principally on long-term supply and demand, the implications of its findings for the adequacy of natural gas supply in the North American market during the next 10 years are deeply disturbing.

Even if the proposed Alaskan natural gas pipeline ultimately goes forward, it will not be completed for at least a decade; further, as much as the additional supplies it brings are needed, if and when it goes into service, it still will offset less than 21.5% of the shortfall in production identified in the Council's Report.

Further, the Council's new estimates do not include any contingency factor to allow for the potential that its new estimates will prove to be too optimistic.

This, too, should give cause for significant concern.

As a result of the rapid aging of most U.S. and Canada fields, the Council already has been forced to reduce its estimate of future production levels by more than 22% in less than 48 months. Given the trend line, there obviously can be no guarantee that this year's downward revision will be its last.

Instead, if anything, given the continued declines in production that have been occurring during the past year (despite higher than expected prices and a high rate of drilling of new wells) further downward revisions in expected North American production may be likely to occur – with the potential that the decline rate could accelerate rapidly over the next several years.

The Council did find that, under some scenarios, assuming much higher prices than the Council previously had thought would be necessary, it might be possible after an extended period to achieve a modest increase production from the lower 48 states compared to this year's sharply reduced levels.

To do so, however, would: i) require prices well above $ 5.00/MMBTU in $ 2002; (ii) take several years to achieve; and (iii) require a series of policy changes and other heroic measures that are relatively unlikely to occur (e.g., opening up for development areas that currently are restricted for drilling, significant speed-up in deepwater drilling in the Gulf, etc.). Further – and just as significantly -- even if all of these conditions are met, the Council estimates that, at most, these efforts would be unlikely to expand U.S. production to a level more than 1.0 BCf/day higher than the levels of U.S. production achieved three years ago, before production began to rapidly decline. (During this same period, the Council expects production from Canada at best to be flat.)

This miniscule increase in U.S. production, even if achieved, will offset only a small portion (i.e., less than one year) of the growth in power sector demand for natural gas expected to occur over the same period.

The Council also concluded that assuming that: (i) construction of the proposed Alaskan pipeline goes forward on an all-out, fast track basis with no impediments to prompt completion; and (ii) a number of other significant policy changes are adopted (e.g., fast-track permitting for new LNG terminals), by some time during the next decade, the massive supply deficit identified in the Report can be partially offset by bringing natural gas from the Arctic Circle into the lower 48 states and by major increases in the amount of Liquefied Natural Gas (LNG) imported into the U.S.

In addressing these longer-term solutions, however, the Council's focus was primarily on long-term supply and demand. This focus on long-term solutions is consistent with the Council's mandate from Secretary Abraham, which was to examine supply and demand of natural gas through the year 2030.

In the interim, as the Council emphasizes in its Report, North American demand still is expected to grow at a rapid rate, due primarily to the expected increase in the amount of natural gas used to generate electricity in the U.S.

This expected increase is likely to be particularly steep starting in 2004 and continuing throughout the next 7 to 10 years, since natural gas-fired generating units are currently the only source of supply available to meet the incremental electricity needs of the U.S. economy during this period.

Even if the Alaskan pipeline is started immediately and LNG imports ultimately become one of the primary sources of energy supply for the U.S., therefore (as the Council's Report envisions), a huge gap still will remain between the maximum supplies that realistically are likely to be available to the U.S. market during the middle and later part of this decade and the projected needs of the U.S. economy over the next 7 to 10 years.

**A Decade of Crisis**

We believe that this near-term supply deficit is potentially the most serious problem facing the U.S. economy during the remainder of this decade.

A Study recently completed by our firm, to be released in December, attempts to quantify the size of this supply deficit and identifies steps that can be taken to respond to this deficit.

The Study concludes that, absent prompt implementation of the specific steps proposed in our study, for the U.S. economy to continue growing, it will be necessary to increase supplies of natural gas available to generate electricity by at least 3.39 TCf/year by 2010 and by at least 5.19 TCf/year by 2014:

Table 1
Increased Power Sector Consumption of Natural Gas

| Year | Expected Increase | Cumulative Total |
|---|---|---|
| 2004 | 0.250 – 0.300 TCf/year* | 0.250 TCf/year |
| 2005 | 0.462 TCf/year | 0.712 TCf/year |



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| | | |
|---|---|---|
| 2006 | 0.563 TCf/year | 1.275 TCf/year |
| 2007 | 0.522 TCf/year | 1.795 TCf/year |
| 2008 | 0.460 TCf/year | 2.257 TCf/year |
| 2009 | 0.568 TCf/year | 2.825 TCf/year |
| **2010** | **0.568 TCf/year** | **3.393 TCf/year** |
| 2011 | 0.353 TCf/year | 3.746 TCf/year |
| 2012 | 0.353 TCf/year | 4.099 TCf/year |
| 2013 | 0.546 TCf/year | 4.645 TCf/year |
| **2014** | **0.546 TCf/year** | **5.191 TCf/year** |

* This estimate assumes normal summer temperatures in both 2003 and 2004 and normal growth in the economy. Given the mild weather that occurred this past summer (discussed in the text below) and the recent high growth rate of the economy, a much larger year-over-year increase in power sector consumption of natural gas is nearly certain to be required over the next 12 months compared to this year.

Taking into account potential growth in residential and commercial demand for natural gas, the total increase in the amount of natural gas per year needed to meet the needs of the U.S. economy could be even greater - viz., as high as 5.3 TCf/year by 2010 and 6.4 TCf/year by 2014.

The National Petroleum Council Study demonstrates beyond a shadow of a doubt that the supplies required to meet these projected needs won't be available. Instead, absent aggressive steps to reduce the amounts of natural gas needed to meet the needs of the U.S. economy during this period, a massive shortfall is inevitable.

Indeed, in the very near term (i.e., between now and 2006 or 2007), it has become increasingly clear that there is not likely to be any net increase in the supplies of natural gas available to the U.S. market (i.e., zero growth in net supplies, after taking into account the net impact of flat or declining U.S. production, modest near-term increases in imports of LNG, declining imports from Canada and expanding exports to Mexico).

This is a startling prospect, since the increased supplies of natural gas needed to sustain the growth of the U.S. economy over the period between now and 2007, including likely increases in residential and commercial demand, could easily reach 1.5 to 2.0 TCf/year.

This is an unprecedented shortfall in supplies. And it is likely to last not just for one or two years. Instead, as the amount of natural gas needed to generate electricity continues to grow every, the deficits will continue to mount, since we are unlikely to be able to ramp up imports of LNG rapidly enough to keep pace with growing power sector and residential demand for natural gas until, at the earliest, the mid to later part of the next decade.

The basic contours of the crisis we're facing, therefore, are unmistakably clear.

Why then is there still no sense of urgency regarding the potential threat to the U.S. economy posed by this huge shortfall in expected supplies of natural gas over the next 7 to 10 years?

**Flaws in the Convention Wisdom**

Part of the reason there isn't a greater sense of urgency regarding the crisis we face clearly is that, even though severe price spikes have occurred in two out of the past three winters, the period in which the supply crunch is likely to be most severe - with the most extreme prices - has yet to occur (although it could begin as early as next year).

As a society, we're seldom very good about addressing serious problems in advance - even when the dimensions of the problem are crystal clear and go straight to the core of our economy.

A second reason is that the most powerful segments of the oil and gas industry, in their public advocacy efforts, have tended to focus primarily on supply options addressed to our long-term needs (e.g., the proposed Alaskan pipeline, expanded offshore drilling and steps to increase imports of LNG).

This, too, is understandable, since at this point in the maturation of the industry opportunities for development in the lower 48 States are limited. The most attractive opportunities for new development, therefore, typically involve more distant sources of supply that often require government approvals to go forward and will take many years to develop.

A third, equally important factor, however, is that (at least in my judgment) many of the best private forecasters and Wall Street equity analysts specializing in the oil and gas industry - bright people whose work often can be very helpful - aren't yet interpreting properly the sweeping changes that have occurred in the natural gas market and instead continue to publish every week analyzes of what is happening in the U.S. natural gas market that are far off the mark.

The result of the continued dissemination of these mistaken analyzes (however well intentioned) has been to perpetuate - and, over the past few months, perhaps even intensify - three pervasive myths regarding the natural gas market:

<u>Myth # 1</u>: The near universal belief that the larger-than-expected injections into underground storage that occurred this summer were due to large-scale reductions in industrial demand that occurred this spring and early this summer.

<u>Myth # 2</u>: The closely-linked belief that last summer's experience demonstrates that natural gas prices above $ 6.00/MMBTU are not sustainable and instead will quickly result in large reductions in industrial use - which in turn will rapidly bring prices back to more "normal" levels.

<u>Myth # 3</u>: The belief that, as long as the amount of working gas injected into underground storage exceeds 3,000 Billion Cubic Feet (BCf) (a benchmark that now has been substantially exceeded for this coming winter) reserves in storage are likely to be sufficient to meet winter needs and severe price spikes are unlikely to occur.

These three beliefs are the cornerstone of the how many observers still look at the natural gas market.

As recently as 1999 or even 2000, there still was a substantial basis for holding these views.

As we'll see momentarily, however, despite the frequency with which these claims are repeated, they clearly and demonstrably are no longer true today, in a market the fundamentals of which have irrevocably changed over the past 36 months.

Instead, all of the larger-than-expected injections into storage that occurred this summer can be explained based upon decreases in the amount of natural gas used to generate electricity compared to the same months last year, not fuel switching by industrial users or other industrial demand destruction as so many analysts contend.

Much of this reduction in the use of natural gas to generate electricity is weather related - and therefore not likely to be repeated.

Further - and just as importantly - over the next 12 months, as the population continues to grow and the economy continues to expand, the amount of natural gas consumed to generate electricity is nearly certain to continue to increase dramatically - and then to continue increasing every year for at least the next 7 to 10 years (i.e., the minimum lead-time necessary to build new coal-fired capacity and/or to ramp-up imports of LNG sufficiently to begin to offset the increased natural gas requirements of the power industry).

Contrary to the assertion that is often made, therefore, there was no structural change in the natural gas market this summer that "eliminated" or even materially reduced the likelihood of a natural gas crisis in future years.

Instead, to the contrary, as we'll discuss below, we dodged the bullet this summer far more narrowly than most of us realized at the time.

If temperatures this summer had been more like the summer of 2002 and/or the resurgence in the economy that began in August had begun just 60 or 90 days earlier, we might well have seen $ 8.00 to 10.00/MMBTU natural gas prices this summer (i.e., during the time of year when natural gas prices historically are at or near their lowest point for the year).

Further, while the sharp drop in the use of natural gas to generate electricity that has occurred over the past six months and the continued mild weather this fall have made it possible to build up larger storage reserves heading into this winter than might have been true under other circumstances, and thus reduced the risk of severe price spikes this winter, depending upon the severity of the weather this winter, before the winter is over, we still could see price spikes this winter that are just as severe as last winter, if not worse.

How could this be? How could the conventional wisdom be this far off? And how could so many well-intentioned analysts have missed almost entirely the huge reduction in power sector consumption of natural gas that occurred over the past several months?

And if the evidence of a long-term crisis is so overwhelming, why have natural gas prices softened significantly since they reached the $ 6.00/MMBTU level this past June?

Quite frankly, as we'll see, the issues involved are not subtle and are not difficult to assess fairly definitively. Instead, to the contrary, the relevant facts are obvious and indisputable.

**Why then do the three myths persist?**

At least part of the reason may be that all three myths have a certain seductive quality: they suggest that there is no crisis or, alternatively, that if there is it will "solve itself" painlessly, with higher prices quickly driving sufficient industrial demand out of the market to bring prices back down to levels consumers can tolerate.

This seductive quality, however, is as dangerous as it is appealing.

As long as the three myths continue to be treated as credible, we are likely to continue to delay taking the specific actions required to reduce the threat we face during the remainder of this decade as a result of drastically-lower-than-expected supplies of natural gas.

Delay, however, is a luxury we can not afford. The costs ultimately will be far too high: literally tens of billions of dollars of avoidable energy costs over the next 10 years, hundreds of thousands of lost jobs and the potential to seriously retard the growth of the U.S. economy.

It may be fairly important, therefore, to understand why each of these myths is false, since until we do we are likely to continue putting off actions that are essential to preserve the health of our economy over the next 10 years.

*This article is the first of three in a series.* Click here to go to Part II



## Readers Comments

| Date | Comment |
|---|---|
| Len Gould *11.22.03* | Man, this is EXACTly my worst fear. I've been watching BP's anual evaluations of world petroleum resource status for several years now (a group I have a lot of respect for), and their predictions match this exactly. I've got a brother who contract managed gas fields in northern Alberta for years, a nephew who's an engineer for TCPL, a friend who does wildcat gas well drilling in Alberta. This matches what I've been hearing anecdotally between the lines all along. My gut reaction is I believe this about 80 - 90% certainty. The '99 spike in supply was just a blip caused by the new TCPL north-south line into the US midwest, but they've already got pipes up into the Cdn artic. They're looking hard and not finding it easy.<br><br>So what now? What odds something like offshore gas hydrates could do it? Any other unconventional supplies? One group has proposed a bridge across the bering straight using the ice-bridge technology on the PEI - New Brunswick bridge . Looks like it should work, and Russia's got 2/3 the remaining world resources.<br><br>At US$10+ / MMBTU, my present house isn't woth a nickel in Canada. People will walk away from such inefficient homes. Others up here will freeze to death.<br><br>Any odds southern US would shut down their Air Conditioning to help out?<br><br>Looks like we'd better start figuring out how to replace gas electric gen with Coal / Wind / Nuclear right away. How does a Nat. Gas turbine operate on coal gassifier ouput? Let's start that one right away fast, then make it illegal to burn Nat. Gas for electric gen, buy out the investors, convert what can be to producer gas or water gas now. Before we have to start figuring out how to pump carbon monoxide into homes as heating fuel. Yech. |

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# Puncturing Natural Gas Myths -- Part II

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The Industrial Demand Destruction Myth

No myth has been repeated as persistently – or has as little foundation in fact – as the near-universal belief that the much higher-than-expected injections into underground storage that began in late May of this year are attributable to large scale industrial "demand destruction" that purportedly began this Spring and Summer in response to the run-up in natural gas prices that occurred at about the same time.

This myth stems in large part from analyzes published every week by private forecasters and by Wall Street equity analysts (among others), who week after week routinely assert that large scale shifts in industrial use of natural gas are occurring literally every week.

Over this past spring and summer, this "demand destruction" purportedly included both massive fuel switching and reduced utilization and/or outright shutdown of a large number of industrial facilities.

Some analysts asserted that, at its peak, the reduction in industrial use of natural gas that occurred since the end of last winter was as high as 3.5 to 4.0 BCf/day; others asserted that the shift in industrial consumption from one week to the next in some weeks was as much as 1.0 to 2.0 BCf/day.

Most analysts also routinely dismissed the notion that differences in weather between 2002 and 2003 could be sufficient to bring about significant differences in power sector consumption of natural gas. One of the Wall Street firms whose equity analysts we respect most, for example, attempted to specifically quantify the impact of weather on power sector consumption of natural gas and concluded that it was no more than 0.5 BCf/day.

There is only one small flaw in all of these assertions: no matter how many times they may be repeated or how many well respected analysts endorse these claims, based upon data published by EIA over the past two months, it can now be said definitively that they are flatly incorrect.

One of the frustrations we all have in trying to understand what is occurring in the natural gas market is that there is very little current year data available that can be considered reliable; almost all of the current year statistics published by EIA are preliminary estimates only. Some of these estimates are the output of relatively simplistic modeling efforts, which may or may not accurately reflect what is actually occurring in the real world; other estimates, even if they are based in part on actual data, still may be subject to huge after-the-fact adjustments at some later point in time.

There are two major exceptions, however, to this lack of timely and reliable current period data – i.e., EIA's final monthly underground storage numbers, published on a delayed basis in its Natural Gas Monthly Reports and its final figures for power plant consumption of fossil fuels, published in its Electric Power Monthly Reports.

Both sets of numbers are published two to three months after the end of a particular month. As a result, EIA has only recently published final figures for June and July; data for August has not yet been released.

Unlike most of the other current-period statistics issued by EIA, however, these figures are based upon actual readings at individual facilities and seldom are subsequently revised.

As a result, we now have a definitive set of numbers that can be used to compare the amount of working gas injected into underground storage and the use of natural gas to generate electricity during the first four months of this year's injection season with storage figures and fuel consumption data for the same four months in 2002.

These figures show that, in the period from April 1st through July 31st of this year, the total increase in working gas in underground storage was 344 BCf greater than in the same months in 2002:

Table 2
Increase in Working Gas in Underground Storage

| Month | '03 | '02 | Difference |
|---|---|---|---|
| April | 166 BCf | 141 BCf | + 25 BCf |
| May | 404 BCf | 309 BCf | + 95 BCf |
| June | 468 BCf | 340 BCf | +128 BCf |
| July | 327 BCf | 231 BCf | + 96 BCf |
| Total | 1,365 BCf | 1,021 BCf | +344 BCf |

(Note that, of this amount, 11 BCf consists of natural gas that was in underground storage prior to April of 2003, but was reclassified from "base gas" to "working gas" effective as of April of 2003, increasing the amount of working gas available for distribution into the market as of that date.)

During this same period, however, the total amount of natural gas used to generate electricity decreased by 375 BCf. In other words, **the decrease in the amount of natural gas used to generate electricity during this period in 2003 was greater than the total increase in the amount of natural gas injected into storage during the same period:**

Table 3
Decrease in Use of Natural Gas to Generate Electricity

| Month | '03 Use | '02 Use | Decrease |
|---|---|---|---|
| April | 365 BCf | 437 BCf | - 72 BCf |
| May | 417 BCf | 454 BCf | - 37 BCf |
| June | 452 BCf | 585 BCf | - 133 BCf |
| July | 646 BCf | 779 BCf | - 133 BCf |
| Total | 1,880 BCf | 2,255 BCf | -375 BCf |

**The decrease in the amount of natural gas used to generate electricity, therefore, during the period between April 1st, 2003 and July 31st, 2003, compared to the amount of natural gas used to generate electricity during the same four months in 2002, accounts for more than 100% of the increase in injections that occurred during the first four months of the injection season!**

Further, of this decrease in the amount of natural gas used to generate electricity, by far the largest share – i.e., just under 232 BCf (or 62%) – is attributable to a decline in total electric generation.

This decline in total electric generation in turn is attributable principally (although not by any means exclusively) to differences in weather between the two years – and particularly to milder summer temperatures in certain key cities in the eastern two thirds of the country during the first two months of the summer.

This difference in temperatures often eliminated or at least reduced significantly the need to run gas-fired generating units in areas like northern Illinois or the Mid-Atlantic states, which generated far larger quantities of electricity using gas-fired generating units in June of July of 2002 than they did this year.

Of the remaining decrease in the amount of natural gas used to generate electricity (viz., 143 BCf), 81 BCf, or 21.5%, is attributable to the efficiency effect from adding more efficient combined cycle units. The final 62 BCf (i.e., 16.5% of the total), is attributable to greater utilization of certain oil-fired units and to fuel switching from natural gas to residual fuel oil at a small number of plants.

In short, based upon publicly available, readily verifiable data, the notion that industrial demand destruction is the primary cause of the larger than expected injections into storage that occurred during the first several months of the injection season is, quite literally, nothing more than a myth.

Final data is not yet available for August, September or October of this year. During this period, however, injections this year increased by approximately 439 BCf compared to the same period in 2002 (i.e., 1,017 BCf this year vs. 578 BCf this year).

What accounts for this 439 BCf increase in injections over this three month period?

At least four major factors are at work:

1. First, when final figures are available, we expect that they will show that the use of natural gas to generate electricity was lower during this period in 2003 compared to the same months in 2002, just as they did in the period between April 1st through July 31st. We estimate that this decrease was at least 125 to 150 BCf for the three months combined --with a particularly steep decline in September (again attributable primarily to differences in weather between the two years);

2. Second, during this period in 2003, unlike 2002, there was no significant lost production due to shut-in of wells during Hurricanes. This increased the amount of natural gas available for injection into storage in late September and early October of this year compared to the same period in 2002 by approximately 85 BCf;

3. Third, to compound the impact of abnormally low air conditioning load in key urban areas in the eastern half of the U.S. during the summer, there was a sharp decrease in the number of gas-weighted Heating Degree Days in October of this year vs. October of 2002, with the number of gas-weighted Heating Degree Days declining by 73 HDD's. This in turn is likely to have reduced use of natural gas for space heating purposes during October of this year by as much as 100 to 125 BCf compared to October of 2002;

4. Finally, in addition to the direct impact of reduced heating load in October, the mild weather in mid to late October appears to have allowed the interstate pipelines to delay until early November a significant portion of the build-up in operating pressures in the interstate pipelines (i.e., increase in line-pack) that last year appears to have occurred primarily in the last two or three weeks of October. This may have freed up as much as 75 to 100 BCf for injection into storage in October of this year that was not available for injection into storage in October of last year since it was being used to increase line pack.

These estimates, of course, are preliminary in nature. Once again, however, they suggest that all or virtually all of the increase in injections that occurred this year can be explained based upon factors other than any change in industrial consumption compared to the same period last year:

Table 4

Net Change in Amounts Available for Injection

| | |
|---|---|
| Decreased use of natural gas To generate electricity | 125 – 150 BCf |
| Absence of Hurricane losses | 85 BCf |
| Significantly lower heating load In October | 100 – 125 BCf |
| Deferral of line pack until November | 75 – 100 BCf |
| Total | 385 – 460 BCf |

During the seven month period between April 1st and October 31st, injections this year increased by 783 BCf compared to the same seven months in 2002 (i.e., 344 BCf + 439 BCf = 783 BCf) – one of the largest year-over-year increases ever.

It is perfectly appropriate, therefore, to attempt to understand why an increase of this magnitude occurred.

It turns out, however, that this increase is due primarily to very good luck from a weather standpoint in key locations in the country - starting in the late spring, continuing during much of the summer air conditioning season and continuing again throughout most of the fall (including the absence of production losses due to Hurricanes).

This combination of circumstances has given us a far larger buffer going into the winter heating season than we had any right to expect when the injection season began this past April - or would have now if weather conditions in the northeastern quadrant of the U.S. over the past seven months had been more like conditions during the same months last year or if the resurgence in the economy that appears to have begun in August had begun just two or three months earlier.

As a result, at least to a degree, our exposure to severe price spikes this winter has been reduced - although, as we'll discuss later in the article, we're still not by any means entirely out of the woods, in terms of exposure to continued price spikes, despite the far-higher-than-expected injections into storage.

Contrary to the conventional wisdom, however, this increase in the amount of working gas in storage can be fully explained without attributing a single BCf of the increase to industrial "demand destruction" that occurred since the end of last winter.

Reassessing Industrial Demand

What then are the current realities of industrial demand in the U.S. market?

More specifically:

1. Has there in fact then been a reduction in industrial demand over the course of the past year? If so, how large has it been?
2. Just as significantly, when did this reduction in industrial demand occur? Had it already taken place prior to last winter (so that already was "built in" to the supply/demand balance last winter) or has it occurred since that time (in which case it could potentially reduce the pressure on the natural gas market this winter, compared to last year)?
3. Finally, if reduction in industrial demand is at most a minor factor explaining the larger-than-expected injections into storage, how could so many analysts have missed the primary cause (i.e., far lower use of natural gas to generate electricity than occurred last year)?

Each of these issues is addressed briefly below.

Net Decrease in Industrial Demand. There is no question that, during the three year period since Q4 of 2000, there has been a large reduction in industrial consumption of natural gas - perhaps on the order of 3.5 BCf/day total over the three year period (as contrasted with the past 12 months).

The smelter industry in the Pacific Northwest, for example, shutdown almost completely long ago and is unlikely ever to start back up. At least a dozen fertilizer plants have declared bankruptcy. Ethylene production has been cut back significantly. Some other chemical operations have been shifted overseas. Energy efficiency measures have been instituted at many facilities. And virtually every industrial boiler that is capable of burning residual fuel appears to have switched to fuel oil many months ago and has not switched back to natural gas.

Most this reduction, however, occurred either during the 2000/2001 winter heating season, when prices spiked to $ 10.00/MMBTU, or during the 12 months immediately thereafter, when the U.S. suffered its most severe manufacturing recession in 22 years (possibly in part as a direct result of the impact of higher natural gas prices on the manufacturing sector). Since that time, most of this lost consumption has never returned to the market.

It has no bearing, therefore, on the increase in injections between this year and last year, or on the potential difference in the supply/demand balance going into this winter vs. last winter, since it already had occurred before the 2002 injection season began and before last winter's heating season (and therefore had the same impact on the supply/demand balance in both this year's injection season and last year's).

To assess what to expect this winter, therefore, it is important to focus on reductions in industrial demand that have occurred during the past year.

Here, the evidence that there might have been a net reduction in industrial demand is far less persuasive than might be assumed. Instead, if there industrial consumption is currently any lower than it was one year ago, it appears that the difference is relatively small (i.e., in all likelihood, less than 1.0 BCf/day).

The potential reduction in industrial consumption can be divided into two categories: (i) fuel switching at industrial boilers that can burn either natural gas or fuel oil; and (ii) reduced consumption due to reduced operations, shutdown of facilities or switching to other products or manufacturing processes that do not require natural gas.

As noted earlier, most private forecasters and Wall Street analysts have been claiming for many months that fuel switching at industrial boilers has been a major factor accounting for the increase in injections into storage during this year's injection season.

While estimates vary from analyst to analyst, estimates of a reduction in natural gas use of 1.5 to 2.0 BCf/day have been common.

The new NPC Study, however, raises major questions regarding the validity of this claim.

As part of its work, the Council conducted a study of the remaining fuel switching capability at industrial boiler in the U.S.

This study concluded that, over the past several years, there has been a major reduction in the percentage of industrial boilers that are dual-fuel capable, from as high as 28%, in the 1994-98 timeframe, to no more than 5 to 10% today.

As a result, the Council concluded that, as a practical matter, the maximum remaining industrial fuel switching capability is no more than 200 BCf. The Council also concluded that the total could be as little as half this amount (i.e., 100 BCf or less of total switchable capacity).

If the Council's estimate is in the right ballpark, therefore, even if every dual fuel capable boiler switched to residual fuel oil or distillate, the total reduction in natural gas use would be no more than 0.33 to 0.67 BCf/day (i.e., at most 1/6th to 1/3rd of the levels that have been commonly suggested).

This is, of course, does not end the debate – on either side of the issue.

At least some decline in industrial consumption due to fuel switching clearly has occurred. And there are also other industrial uses that have clearly fallen off (e.g., a decline in total natural gas consumption by the fertilizer industry, at least compared to the early summer of 2002).

Many Wall Street analysts claim that the total reduction in industrial consumption of natural gas during the last year, including these other declines, could be as high as 3.5 to 4.0 BCf/day. (If this estimate is correct, it would account for more than 3/4th's of the increase in the size of the injections into storage during this year's injection season compared to last year.)

<u>Review of the July Injection Data</u>

A more careful review of the injection data for July, however (the last month for which we have definitive data) suggests that, as of July, the net decrease in industrial consumption of natural gas could well have been zero (taking into account all possible sources of decreases) and in any event almost certainly was no more than 1.0 BCf/day (i.e., less than 1/3rd of the level claimed by many analysts).

This should be seen as a shocking conclusion – i.e., if it's accurate, that there's only been a modest reduction in industrial consumption of natural gas during the last year and all of the claims regarding "industrial demand destruction," at least to a large degree, have been much ado over nothing.

Here's the reasoning process: as indicated in Table 2 above, what we know, definitively, from one of the few available data points that is reasonably certain to be correct, is that injections in July of 2003 were 96 BCf higher than in July of 2002 – i.e., an average increase of 3.1 BCf/day or 21.7 BCf/week. (Specifically, 327 BCf was injected into storage in July of 2003 vs. 231 BCf one year earlier.)

When first reported over the course of the summer, these higher injections were cited as proof positive that massive demand destruction was occurring in the industrial sector.

As a result, they were widely heralded as proof that the "market" would quickly correct any supply deficit, by driving large amounts of industrial out of the market in response to a relatively modest increase in price, demonstrating definitively that what the analysts had been saying all along was correct: that prices higher than the mid-$5.00/MMBTU range were not sustainable.

As indicated in Table 3 above, however, we also know, more or less as definitively, that the amount of natural gas used to generate electricity during this same time period decreased by 133 BCf (i.e., 646 BCf in July of this year vs. 779 BCf last year).

Further, while there were many factors at work in causing this decrease, a large chunk of this decrease was directly attributable to fairly massive differences in weather, not to a market response to higher prices for natural gas.

In the Midwest alone, for example, where I happened to grow up, natural gas consumption went down by 41.1 BCf (i.e., 1.32 BCf/day), for reasons that are attributable almost entirely to reductions in total load. A decline of more than 25 BCf that was principally weather-driven occurred in the Mid-Atlantic states, a 20 BCf + decline in the states along the Atlantic Coast north of Florida and a decline of 40 BCf along the Gulf Coast.

These were not subtle effects; we saw them happening all summer long, and reported them every week to subscribers to our weekly report.

They simply were missed by almost all of the analysts following the industry - even though they were the real story of what happened this summer.

For present purposes, however, the important point to note is that, now that the July fuel consumption data has been reported publicly, it is possible to quantify fairly precisely the reduction that occurred in the use of natural gas to generate electricity in July - viz., to be as precise as possible, 132.61 BCf (i.e., 646.150 BCf in 2003 vs. 778.760 in 2002).

This reduction in the use of natural gas to generate electricity, however, is 36.6 BCf greater than the increase in injections that occurred in July of 2003 vs. July of 2002 (i.e., 132.6 BCf – 96.0 BCf = 36.6 BCf).

This raises a fairly significant question: if the amount of natural gas used to generate electricity declined by 132.6 BCf (making 132.6 BCf of natural gas more available for injection into storage than had been available the year before) and there was also a significant decline in industrial consumption of natural gas, why didn't the amount of the injection increase by at least 132.6 BCf relative to the amount injected in July of 2002 and perhaps substantially more?

If industrial use, for example, actually had declined by an average of 3.5 BCf/day (i.e., 108.5 BCf over a 31 day month), presumably the net amount available for injection into storage, prior to taking into account any net reduction in supplies (which we'll address in a moment) should have increased by a total of more than 240 BCf (i.e., 132.6 BCf + 108.5 BCf = 241.1 BCf), or almost 8 BCf/day.

One can imagine any of a host of reasons why the reduction in consumption and the increase in injections might not match perfectly.

But they should track at least approximately. (For example, if the decline in industrial consumption actually had been in the range of 3.5 BCf/day, presumably the increase in the amount of natural gas injected into storage should have been in the range of at least 7.0 to 7.5/BCf/day – or 210 to 225 BCf for the month, even if it didn't quite reach the 8.0 BCf/day level.)

But they don't track – not just for July, but for any of the seven months of the injection season discussed above. And it's not even remotely close.

Instead, in July, rather than having an increase in injections well above the verifiable decline in use of natural gas to generate electricity, the increase in injections is actually 36.6 BCf less (i.e., - 1.18 BCf/day) – suggesting that it is at least possible that core industrial consumption of natural gas in July of 2003 actually was higher than in July of 2002.

And while the evidence doesn't necessarily suggest that industrial consumption increased in other months relative to the same month in 2002, the basic pattern still is the same: its difficult to look at the storage data and the data regarding actual fuel consumption to generate electricity and find evidence that there was any major year-over-year reduction in industrial consumption of natural gas over the period between April 1, 2003 and October 31, 2003.

Instead, the notion that massive demand destruction occurred during this period appears to be a romantic tale, told many times – and having huge financial consequences – but bearing no more relationship to what actually occurred than the tales of King Arthur's Court or countless other legends that have entertained us in the past.

Does that mean that there has been no net reduction in industrial use of natural gas over the past 12 months?

No. I didn't say quite that.

There certainly have been significant reductions in specific industries. The issue is only whether, in the aggregate, industrial consumption has increased or decreased.

Industrial consumption in July also may well have been higher than in June, in part because there was some softening of prices in June. It is possible, therefore – perhaps even likely -- that even if there was a net increase in industrial consumption in July of 2003 vs. July of 2002, there were small year-over-year decreases in April, May and/or June.

Further, even in July, it is possible that there could have been a small net decrease in industrial consumption compared to July of the prior year, for two reasons:

First, of the reduction that occurred in use of natural gas to generate electricity in July, approximately 16 BCf in July (or 0.5 BCf/day) occurred at Combined Heating & Power facilities, that produce both steam and electricity. (This decrease was much larger than in prior months; for the first six months of the year, the total decrease in natural gas use at industrial CHP facilities was only 29 BCf for the six months combined – i.e., an average of less than 5 BCf/month.)

One can debate forever whether the portion of the fuel at those facilities that is used to generate electricity should be classified as industrial use or electric use (different facilities arguably should be classified in different ways). If one chooses to categorize this 16 BCf as industrial use, however, than there arguably was at least a 16 BCf reduction at these facilities in July.

Second, to estimate the net change in industrial consumption, it also is necessary to estimate the change in net supplies delivered into the U.S. market during this time period and adjust the expected injections into storage accordingly.

This is a complex exercise. The bottom-line, however, in comparing July of 2003 to July of 2002, is as follows:

1. While U.S. production has been declining rapidly since 2001, the year-over-year comparison between July of 2003 and July of 2002 is better than in many other months. This is in part because both the Kern River expansion in the Rockies and the Canyon Express gathering system in the Gulf were in service in July of 2003 but not in July of 2002, mitigating some of the decline in production that otherwise would have occurred over this period.

   The most pessimistic assessments of production in the third quarter of this year generally have estimated a 2 to 3 % decline vs. the third quarter of last year. This in turn suggests that U.S. production may have declined by as much as 1.0 to 1.5 BCf/day (with further declines likely later in the year).

2. In addition, imports from Canada have declined and exports to Mexico have increased, adversely affecting the supply/demand balance in July of 2003 by an additional 1.0 – 1.2 BCf/day vs. July of 2002.

3. At the same time, imports of LNG (which were at a particularly low level in July of 2002) reached an all-time high in July of 2003. In July of 2003, there also was approximately 0.8 – 1.0 BCf/day of Natural Gas Liquids left in the gas stream that still was being extracted and sold as liquids (i.e., a petroleum product) in July of 2002. The net impact of these two factors was to increase pipeline receipts by approximately 2.0 to 2.2 BCf/day.

All-in, therefore, despite the decrease in U.S. production, the decline in imports from Canada and the increase in exports to Mexico, it is not clear that there was any decrease in the net supplies available to the U.S. market in July of 2003 vs. July of 2002 (i.e., U.S. production + increased supplies thru retention of liquids + imports – exports).

At a minimum (netting out the estimates listed above), if there was any net decrease in supplies, it appears to have been no more than 0.50 to 0.70 BCf/day (or a maximum of 21 BCf/month). And it could well have been less.

This presents a major problem for the proponents of the industrial demand destruction theory. Even using the high end of the range just noted, it suggests that a decline in supplies available to the U.S. market, if a decline in fact occurred, would have reduced the amount of natural gas available for injection into storage by no more than 21 BCf relative to the amounts available for injection into storage in July of 2002.

This still suggests that the amount actually injected into storage was smaller than would have been expected if no industrial demand destruction had occurred – specifically, by about 15.6 BCf (36.6 BCf - 21.0 BCf = 15. 6 BCf):

Table 5
Reconciliation of Injections into Storage in July of 2003 vs. July of 2002

| | |
|---|---|
| Increased amounts available due to use of less natural gas to generate electricity | 132.6 BCf |
| -- Maximum possible reduction in supplies | -- 21.0 BCf |
| Net Increase in Amounts Available for Injection | 111.6 BCf |
| -- Actual Increase in amount injected | 96.0 BCf |
| Unexplained shortfall in injections (most likely Due to increase in industrial consumption vs. '02) | 15.6 BCf |

This isn't necessarily dispositive of whether there was a slight increase or decrease in industrial consumption in July of 2003 as compared to July of 2002; there are too many factors that can cause injections or withdrawals from storage to swing up or down in any one month. The apparent 15.6 BCf increase in industrial consumption for the month, therefore, could be just "noise."

The overall pattern for the seven months, however, coupled with the specific figures for July, suggests very strongly that if there was any decrease in net industrial consumption in July of 2003 as compared to July of 2002, it was relatively small (i.e., in all likelihood, no more than 1.0 BCf/day, and probably less).

If July were the only month where this basic pattern exists, it would be reasonable to dismiss it as an anomaly.

But it is not. Instead, as noted earlier, it is possible to readily account for the size of the injections for all seven months without assuming any decrease in industrial consumption.

While this doesn't prove that no reductions occurred, it does strongly suggest that, to the extent reductions in industrial demand occurred during this year's injection season, they were only a small fraction of the levels that have previously been assumed.

Sanity Checks

In reaching a conclusion that is this much at variance with the conventional wisdom, one of course should ask whether it meets the sanity test – i.e., whether it fits with other available sources of information.

I think the answer is that it does, for at least two reasons:

- First (and I raise this point with some irony, since I have not been timid in my criticism of EIA when I thought specific criticisms were justified), I note that it is quite consistent with what EIA has been saying all along. EIA's most recent estimate, for example, is that core-industrial consumption of natural gas in July of 2003 (EIA labels it "non-CHP") was 465 BCf – nearly identical to its estimate for July of 2002 of 462 BCf (i.e., 3 BCf lower than in July of 2003).

  EIA's estimate that industrial consumption in July of 2003 may have increased slightly compared to consumption one year earlier reflects a slight change in trend from its estimates for earlier months; for months prior to July, EIA generally estimates that core industrial consumption was approximately 1.0 BCf/day less than in the same month in 2002, and an even larger decrease in April of 2003 (the one month in which EIA estimates that the decrease could have been as large as 2.0 BCf/day).

  It is consistent, however, with the overall position that the Agency has taken for almost two years in both its data collection and its modeling: that most of the decline in industrial consumption took place from 2000 to 2001, with only modest swings in industrial consumption since that time.



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EIA estimates that, in the aggregate, the total decrease in core industrial consumption for the first seven months of this year is only 139 BCf.

Notably, this is only 6 BCf greater than the decrease in the use of natural gas to generate electricity in July alone (and also occurred separately in June).

This doesn't mean that either my number or EIA's estimate are correct. It does tend to confirm, however, that the estimate I've presented isn't necessarily implausible – especially when put in the context of the NPC data suggesting that the maximum industrial fuel switching potential may be as little as 0.33 BCf/day.

- Second, while there is no question that some industries have been hurt badly by higher natural gas prices – and many others are in even greater peril going forward -- the extent of the lost load that already has occurred almost certainly has been exaggerated.

  While there is no question, for example, that the U.S. fertilizer industry has been hurt badly in recent years, and production of ammonia and urea may ultimately be destined to be shifted entirely offshore, reports of the industry's imminent demise tend to be greatly overstated.

  The U.S. remains one of the largest fertilizer producers in the world (as is Canada, which obviously has a similar cost structure). Recreating the infrastructure that is necessary to replicate that production elsewhere in the world is a process that will take many years (if it in fact occurs).

  While some U.S. producers in all likelihood have closed their doors permanently, and others ultimately may follow, much of this cutback in production began in the summer of 2002, at least partially in response to a temporary worldwide oversupply condition, which has now been largely worked off.

  Other cutbacks followed the normal seasonal pattern within the industry of performing annual maintenance and/or cutting back production late in the spring, immediately after the planting season has ended.

  Even at the point of greatest impact, the year-over-year reduction in fertilizer industry consumption of natural gas never exceeded 0.40 – 0.50 BCf/day and some of this lost demand has already returned to the market.

  Other, smaller reductions in consumption have occurred in other industries as well, particularly in other portions of the chemical industry. Overall revenues and employment in most of the potentially affected industries have remained reasonably stable since the end of the 2001 recession.

  Most of the impact of higher natural gas prices, therefore, may be in the form of lost opportunities for recovery and the potential for far more severe cutbacks down the road, and at least some of the lost consumption in these sectors has been offset by increased consumption by other industries (e.g., use of additional natural gas to process larger quantities of heavier crude oil at refineries, increased output of ethanol, etc.).

In the end, therefore, the available data is far more consistent with the notion that if there has been any reduction in industrial consumption of natural gas over the past 12 months, it has been modest in scale than with the claim that there has been massive industrial demand destruction over the past year.

Further, the entire decrease that has occurred – even with prices at or near $ 5.00/MMBTU all year long – has been small enough so that it quite literally can be totally offset by two or three hot weeks during the middle of the summer or a 10-day blast of cold air in the winter.

There has never been any well documented study or other properly substantiated evidence to support the demand destruction thesis.

While there has been a huge amount of industrial load lost since Q4 of 2000, and regrettably almost certainly will continue to be more industrial load lost over time, the notion that there has been massive industrial demand destruction over the course of the past year is in fact nothing more than a myth.

Every analysis of the natural gas market, therefore, that is centered around this claim is literally not worth the cost of the piece of paper it is written on.

This would be a serious matter even if all that were at stake were the valuation of E&P stocks and the pricing of commodities futures; hundreds of millions or even billions of dollars have changed hands based upon research reports and other analyzes that, to put it charitably, have been less than illuminating.

The real stakes, however, are much greater: we are faced with what could be the crisis of a lifetime, in the form of the potential for unprecedented increases in energy costs that could seriously compromise the health of the U.S. economy for much of the next decade.

Thus far, however, we have chosen not to take that threat seriously, and instead decided to trust in the validity of a seductive theory that, it turns out, may have little factual support.

It is important, therefore, that we begin to understand as quickly as possible what actually is occurring in the market.

<u>How Could the Primary Cause of the Larger than Expected Injections into Storage this Summer Have Been Missed by Most Analysts.</u> This leaves one obvious question: how could the highest priced private forecasters and many of the "best and brightest" of the Wall Street analysts have developed a picture of what has happened over the past 12 months that is so far off the mark?

The explanation appears to be surprisingly simple:

1. The practice historically has been for analysts to track week-to-week or month-to-month changes in injection levels, subtract out any changes that could be readily attributed to weather, and then assume that any remaining changes were attributable to increases or decreases in industrial consumption of natural gas.

   This may have made perfect sense 3 or 4 years ago, when: (i) total power sector consumption of natural gas was much smaller and much less subject to large fluctuations in the summer months (because of the states in which most gas-fired generation was located and where this generation fit in the dispatch order); (ii) industrial consumption was much larger (both in absolute terms and as a percentage of total consumption); (iii) the percentage of industrial boilers that could switch fuels was up to 5X larger than it is now; (iv) unlike the situation that exists currently, most dual-fuel capable boilers had not yet switched to fuel oil; and (v) there were a much larger number of industrial boilers that could - and often did - routinely switch back and forth between natural gas and fuel oil on a day-to-day basis based upon relatively modest swings in the prices of the two fuels.

   It does not necessarily make nearly as much sense now, however, when: (i) power sector use of natural gas plays a much more central role in driving total natural gas consumption for the year; (ii) power plant consumption of natural gas is much more likely to fluctuate by large amounts from one week to the next during the summer months; (iii) the number of dual-fuel capable industrial boilers is a small fraction of what it once was; and (iv) the vast majority of these boilers, if they had not already switched to fuel oil by early last winter, switched to fuel oil by no later than February of this year and never have switched back.

   Despite these sweeping changes, however, many analysts seem to have simply plugged week-to-week changes in reported injection levels into the same formulas that they had used in the past, and assumed that they could interpret the results in the same way that they had done 5 years ago, even though the pattern of usage within the natural gas market has fundamentally changed.

   This led one analyst after another to reach conclusions that bore no relationship to what actually has been occurring in the market.

   Since most analysts were using the same basic methodology, however, each reinforced the other's mistakes.

2. This problem was then greatly compounded by the fact that neither the high-priced private forecasters nor the Wall Street analysts appear to understand how to properly assess the impact of different weather conditions on power sector consumption of natural gas.

   For a variety of reasons, this topic is probably best left for another paper at another date.

In the interests of brevity, let me simply leave you with two simple rules:

• <u>Rule # 1</u>. Any time you see an analyst's report that contains a graphic purporting to show a correlation between the total number of Cooling Degree Days nationally and expected injections into storage, or makes any statement that attempts to predict injections or infer shifts in the supply/demand balance based upon changes in Cooling Degree Days nationally from one week or one year to the next, the analysis you are reading is mistaken and should be completed disregarded.

• Rule # 2. If you ever read a report that uses a concept called "Total Degree Days," that adds together Heating Degree Days and Cooling Degree Days, and treats the sum of these two numbers as if it were somehow a meaningful metric, that analysis is mistaken and should be completed disregarded as well.

By making these statements, I don't mean to be glib or to be disrespectful to people many of whom I in fact respect a great deal. (I confess, however, I may be making some effort to make sure I'm keeping your adrenaline flowing in an article that is admittedly quite long.)

There is a meaningful correlation between gas-weighted Heating Degree Days nationally and expected natural gas consumption (although the correlation is hardly perfect).

There is no correlation that is meaningful, however, between the total number of Cooling Degrees Days nationally and total natural gas consumption; nor can Cooling Degree Days and Heating Degree Days intelligently be added to one another (at least nationally) even though many analysts do just that.

Unlike gas-weighted Heating Degree Days (which by definition are linked to the number of gas-heated homes in a particular geographic area), Cooling Degree Days don't purport to measure anything correlates directly with natural gas consumption.

Instead, at most, they measure something that one would expect to correlate with total air conditioning demand (which is something quite different), and they don't even necessarily do that particularly well.

In most regions of the country, there is no linear correlation between the total number of Cooling Degree Days and expected consumption of natural gas to generate electricity.

Instead, what drives natural gas consumption is whether air conditioning load in a specific geographic market rises high enough so that, coupled with all other load that may exist at a particular point in time, total demand reaches a critical tipping point, at which it is no longer possible to serve all of the demand in that market with existing coal, nuclear and hydro generation.

Typically, if load is below that tipping point, only a few, discrete gas-fired units will operate (due to special circumstances pertaining to those units).

Once load reaches that tipping point, however, all or virtually all of the incremental demand above that point will be served by generating additional electricity using gas-fired generating units.

Further, once that tipping point is reached, the scale size of electric generating units is such that the amount of natural gas consumed can quickly become huge. In theory, for example, if it were very hot everywhere in the U.S. on the same day in late July (which occasionally happens, but rarely), power sector consumption of natural gas might increase by as much as 15 BCf per day (i.e., 105 BCf/week) compared to a typical day in May.

If the tipping point was roughly the same everywhere in the U.S. and if it were almost always surpassed during peak hours during the summer months, it might be possible to infer the amount of natural gas consumption by generators from the total number of Cooling Degree Days nationally (which is essentially what most analysts currently attempt to do).

But neither of these statements is true – at least for now.

Instead, the tipping point differs dramatically from region to region around the country and often within regions. As a result, the same number of Cooling Degree Days nationally can produce very different results, in terms of total natural gas consumption, depending upon where the hot weather is located.

In Texas, for example, during daytime in the summer, load is almost always above the tipping point and there almost always will be a large amount of load served using gas-fired capacity. Increases in temperature in Texas, therefore, will translate directly into increased consumption of natural gas.

By contrast, in Chicago, Atlanta or Philadelphia, however, that may or may not be the case.

Instead, if the temperature is mild enough, the tipping point either may never may reached or there be only a few megawatt


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hours (comparatively speaking) generated using gas-fired units. As a result, the amount natural gas consumed may be de minumus.

It is for this reason that it made all of the difference in the world this summer, in terms of natural gas consumption, that as of late July, there had been only 1 day in which the high temperature in Atlanta had been above 90 degrees, whereas in a normal year there would have been 33 days with temperatures above 90 degrees by the same date.

When temperatures never breach the mid to upper 80's, natural gas consumption in these regions may be very modest.

By contrast, if temperatures are in the upper 90's, natural gas consumption can quickly soar.

There are also still regions of the country where, even if temperatures are very hot, virtually all of the load can be served using coal-fired units, with very little need to use natural gas (e.g., portions of the Mountain States region and some of the Midwestern states and Plains states west of the Midwestern states).

As it happened, this summer, on more than one occasion, it was very hot in some of these regions, at the same time that temperatures were just below (or at most only modestly above) the tipping point in some of the largest population centers in the eastern half of the country.

This may have caused the total number of Cooling Degree Days nationally to look normal, but the consequences in terms of natural gas consumption were very different than they would have been if the air conditioning load happened to have been distributed in a different manner.

Power sector consumption of natural gas has only recently become the primary driving force shaping the demand side of the natural gas market.

It is not surprising, therefore, that very bright analysts who've spent their careers growing up in the gas patch environment might not yet recognize how power sector consumption should be evaluated.

As recently as three or four years ago, it may have been possible to intelligently assess the natural gas market without understanding the factors that are likely to cause significant increases or decreases in power sector consumption of natural gas over the course of the year.

But it is no longer possible now.

For the year as a whole this year, power sector consumption of natural gas is likely to be at least ½ of a Trillion Cubic Feet lower than last year.

This is the single most important development affecting the natural gas market this year.

And it likely to be the single most important development affecting the natural gas market next year as well. The effect of the unusual weather we had this summer is to set a very low baseline for comparison next year. And the growth in the economy that already has occurred over the past two to three months has already established a higher base for electricity production next summer.

The likelihood is very high, therefore, that next year power sector consumption of natural gas will grow by at least ½ of a Trillion Cubic Feet compared to this year, if the weather next summer is normal, and potentially more if it is not – setting the stage for intense upward pressure on the natural gas market by no later than the middle of next summer.

Most analysts, however, don't yet see the potential for this occurring, since they do not yet understand how dramatically power sector consumption of natural gas has shifted – even though it is having a far more powerful affect on the market than the relatively modest shifts that have occurred in industrial load.

Until analysts get that part of the equation right, their reports are likely to be just as far off the mark as they have been consistently throughout the past year.

It's for this reason only – and not out of any fundamental lack of respect for people who I in fact admire – that I recommend in all seriousness simply not reading any analyst's reports until he or she gets these issues right.

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# Puncturing Natural Gas Myths -- Part III

*12.3.03 Andrew Weissman, Publisher, EnergyBusinessWatch.com*

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**Myth that Prices Above $ 6.00 Are Not Sustainable**

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Once the real causes of this summer's higher-than-expected injections are better understood, it should be readily apparent that prices this summer could easily have soared far above the $ 6.00/MMBTU level reached early in June.

If temperatures this summer had been more like last year, or the surge in the economy that seems to have begun in mid-August had started a few weeks earlier, total power sector consumption of natural gas during the summer months easily could have been 200 BCf or more higher than the consumption that actually occurred.

In fact, the electricity production figures for the last two weeks of August this year show just how narrowly we dodged a bullet this summer, in terms of exposure to higher prices.

The current all-time record for electricity production in the U.S. was set last year, during the week ended August 2, 2002 (a week that was blistering hot in almost every region in the U.S) -- with total electricity production of over 90,000 GWhrs.

Notably, however, electricity production in the last weeks in August this year was almost as high, with total production of over 89,000 GWhrs the week ended August 23rd and 88,400 GWhrs the week ended August 30th – by a wide margin, the second and third weekly production figures in U.S. history.

Further, the near record levels of electricity production in both weeks were due primarily to the resurgence of the economy, not weather. (While temperatures in many regions during both weeks were hotter than normal for late August, they were well within the range that is typical during July and early August; electricity production nonetheless significantly exceeded prior highs for any week in U.S. history other than the week ended August 2, 2002.)

If the tax cuts that became effective this summer had gone into effect three months earlier, therefore, it is entirely plausible that electricity production (and therefore natural gas consumption) would have been comparable to last year all summer long even though temperatures this summer in many key cities were unusually mild.

If power sector consumption of natural gas this summer had been 200 BCf higher, however, Local Distribution Companies (LDC's) still would have had to have met the same PUC-mandated storage targets they met this summer – the main factor driving up spot market prices in the summer months. (The LDC's would have had no way of knowing that the weather this fall also would turn out to be unusually mild, reducing the need to inject natural gas into storage this summer.)

To meet the same storage targets, however, in a market in which generators consumed an additional 200 BCf of natural gas in June, July and August, the LDC's would have been required to bid up prices in the spot market high enough to drive out of the market an additional 200 BCf of industrial demand over a period of just 92 days (i.e., a reduction of almost 2.25 BCf/day).

This in turn would have required an additional 15 to 20% reduction in already pared-back industrial demand within a very compressed time frame.

No one knows the exact price that would have been necessary to drive out of the market such a large percentage of the remaining industrial demand in such a short time period; a series of fortunate circumstances spared us from finding out just how steep a price increase might have been required.

It is important to remember, however, that spot market prices in the Day Ahead market at Henry Hub averaged $ 5.27/MMBTU this summer.

Further, prices remained at record summer-month levels all summer long even though:

- A high percentage of all of the industrial boilers that could switch to fuel oil already had done so;
- The maximum amount of Natural Gas Liquids that can be left in the gas stream without damaging the pipelines already was being left in the gas stream;
- The fertilizer industry already was operating at significantly reduced capacity; and
- Many other price sensitive industrial users already had left the market.

Given these circumstances, therefore, there is every reason to assume that, if prices above $ 5.00/MMBTU all summer long had only the most minimal impact on industrial consumption, driving an additional 200 BCf of industrial demand out of the market (i.e., 15 to 20% of the remaining industrial load) in the space of less than 12 weeks, could easily have required prices at least in the $ 8.00 to 10.00/MMBTU range – and possibly much higher.

Rather than demonstrating that $ 6.00 prices are sustainable, therefore, this summer's experience, seen in its proper context, demonstrates how vulnerable we are to far higher than expected prices, even in non-winter months.

**The Myth that We Are No Longer Exposed to Price Spikes this Winter Because The Amount of Natural Gas in Storage Has Crossed the 3,000 BCf Threshold**

The last of the three myths that has so confused the market is the notion that, as long as end of Refill Season storage reaches the 3,000 BCf level, the amount of natural gas in storage should be considered to be adequate and we should not be concerned regarding the potential for price spikes during the winter months.

The notion that anyone would seriously take this position, after last winter's experience (let alone that it would become the conventional wisdom), quite frankly, perplexes me.

Let me confine myself, therefore, to a few simple points.

Even with the corrections the Climate Prediction Center made in its calculations of Heating Degree Days this summer, last winter was hardly a freakishly cold winter. Instead, during the heart of the withdrawal season (i.e., the period between November 1st and March 31st), the number of gas-weighted Heating Degree Days nationally was all of 35 HDD's (i.e., 0.9%) colder than historical norms:

Table 6
Heating Degree Days – 02/03 Winter Heating Season

| Month | Actual | Norm | Difference | % Difference |
|---|---|---|---|---|
| November | 589 HDD's | 580 HDD's | + 9 HDD's | + 1.6% |
| December | 841 HDD's | 874 HDD's | - 33 HDD's | - 3.8% |
| January | 992 HDD's | 980 HDD's | + 12 HDD's | + 1.2% |
| February | 856 HDD's | 785 HDD's | + 71 HDD's | + 9.0% |
| March | 616 HDD's | 640 HDD's | - 24 HDD's | - 3.8% |
| Total | 3,894 HDD's | 3,859 HDD's | + 35 HDD's | + 0.9% |

During this five month period, a total of 2,386 BCf was withdrawn from underground storage (i.e., 3,116 as of 10/31/02 – 730 BCf as of 3/31/03 = 2,386).

Further, approximately 56 BCf was withdrawn during the first two weeks in April, bringing the total withdrawal to 2,442 BCf.

It escapes me as to how anyone could review these figures and conclude that end of season storage of 3,000 BCf would be adequate.



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As a practical matter, temperatures that are within 35 HDD's of historical norms are about as close to a statistically normal winter as we're ever likely to see.

It is true, of course, that if this winter is exactly a statistically normal winter, which would mean 35 fewer HDD's. That in turn might well translate into 35 to 50 BCf less total consumption.

Even if it did, however, starting the season with only 3,000 BCf (3,172 BCf less than last year) would be nothing short of disastrous. Storage would be drawn down to an all-time record low. And even if we somehow made it through the winter without natural gas prices setting all-time record highs, we'd be entering the Refill Season with only about 600 BCf in storage - and therefore potentially setting ourselves up for an almost impossible task in attempting to Refill Storage next year, when base level electricity demand is likely to be much higher (in recent weeks its been up by about 5% on a year-over-year basis) and summer weather may not be as forgiving as it has been this year.

Further, and just as significantly, no rational planner would plan for the winter season on the assumption that winter temperatures necessarily will be exactly equal to historical norms.

To the contrary, there's every reason to assume that, over the next several years, there will be one or more winters that will be substantially colder than last year (including quite possibly this year).

The last substantially colder-than-normal winter, for example, was just three years ago – in the winter of 2000/2001.

That winter, like last winter, was not in any sense freakishly cold; instead, temperatures were within the range that a planner should anticipate might occur every few years.

The deviation from historical norms three years ago, however, was not 35 HDD's; it was 356 HDD's (i.e., 10X as great).

If the same basic temperature pattern were to be repeated this winter – and it is quite possible that it could be – this in turn would be likely to result in total natural gas consumption which is roughly 500 BCf greater than last winter.

Since the supply/demand balance this winter, if anything, is likely to be even worse than last winter, this in turn could necessitate a total withdrawal from storage in excess of 3,000 BCf – i.e., last year's 2,442 BCf + an additional 500 BCf to serve the increased space heating load + as much as another 100 to 250 BCf to account for continued deterioration in U.S. production, continued declines in imports from Mexico and the addition of approximately 1.0 million new gas-heated homes over the course of the past year.

Under this scenario, 3,000 BCf or even the close to 3,200 BCf we have in storage today won't be even remotely sufficient to cover our needs.

The fortunate set of circumstances that has occurred over the past several months has given us a somewhat larger buffer than we had any right to expect going into this winter.

But we are hardly out of the woods at this point.

Instead, unless the winter weather turns out to be far milder than currently expected this winter, the natural gas market this winter could easily be just as tight as last year – with the potential for it to become much worse if winter temperatures are more like winter weather three years ago.

The rejoinder that is usually given to these facts, to the extent that there is any, is to point to the fact that last winter was especially cold in the northeast – as if that were dispositive of the issue.

This observation, however, while accurate as far as it goes, is a red herring, for two reasons:

1. The whole purpose of using gas-weighted heating degree days is to properly weight the impact of differences in temperatures in different regions. At least to a significant degree, therefore, the impact of colder weather in the northeast is already properly taken into account by the use of this methodology.

2. The impact of colder temperatures in the northeast on total gas heating demand is much less than often is assumed. The largest heating load in the country is in the Midwest, which accounts for more than 40% of the total gas heating load in the country. Despite its large population, the gas heating load in the northeast is only about ½ this size. This



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lower-than-expected gas heating load in the northeast is a direct result of: (I) the moderating effect of the Atlantic ocean (which keeps winter temperatures far milder than in the Midwest – as I can personally testify to having grown up in Chicago); and (II) the significantly lower penetration rate for natural gas in the northeast than in the Midwest.

While temperatures in the Midwest were also above average last winter, the variance was only slightly greater than for the nation as a whole.

Thus, the colder-than-normal temperatures in the northeast were not nearly as important a driving factor last winter as the discussion sometimes suggests.

**What to Expect This Winter**

So what should we expect this winter?

Clearly, one of the main lessons we should be learning from our experience in recent years is that natural gas prices – which always have been highly volatile, and always have been highly sensitive to fluctuations in weather – have become even more volatile and even more weather sensitive in recent years and are destined to continue doing so in future years.

This is because a much greater percentage of our total natural gas load all year long is now weather-sensitive than was true in prior years. Over the past three years, a major shift has occurred in the distribution of natural gas use among user categories. Industrial use – which generally does not vary based upon weather – has declined dramatically.

This decline, as noted earlier, began in Q4 of 2000 and has been continuing ever since, with the lion's share occurring well before this year's Refill Season.

During this same period, however, use of natural gas for residential space heating has grown explosively, due to a combination of record new homebuilding, a high penetration rate for natural gas and aggressive conversion of a large number of existing homes to natural gas -- particularly in the northeast.

During this same period, total supplies available to the U.S. market also have been declining rapidly.

The end result is a market the total size of which is somewhat smaller than in 2000 (the all-time peak year), but in which a much higher percentage of total natural gas use during the year consists of temperature sensitive winter-heating load and, to a lesser degree (at least in 2003) power sector consumption of natural gas during the summer.

At the same time, shoulder--month consumption of natural gas has dropped dramatically, both in absolute terms and as a percentage of total natural gas consumption for the year as a whole.

As a result, when the weather is relatively mild during spring, fall, or early summer, as occurred this year, injections into storage will tend to be significantly higher than in the past, since non-weather driven demand for natural gas is at its lowest level in many years.

At the same time, however, once the cold weather kicks in the winter, far larger withdrawals are likely to occur than in the past, especially in weeks in which the weather is particularly cold – just as occurred last winter.

This is due to the combined effect of the significant increase that has occurred in total space heating load coupled with a sharp drop in the net supplies of natural gas available to the U.S. market -- the combined effect of which is to create an unprecedented gap between new pipeline receipts and current demand during weeks of peak demand.

It was the size of this gap (+ the end of a streak of abnormally mild winters) that led to last winter's all-time record withdrawals, not (as so many have claimed) the fact that winter temperatures were 35 HDD's above historical norms.

This winter, therefore, once the cold weather hits, we are just as vulnerable to 200 BCf/week + withdrawals as were last winter. Further, it won't take many withdrawals of this magnitude relatively early in the winter season to have a fairly profound impact on the dynamics of the natural gas market for the remainder of the winter.

The severity of the price spikes this winter, therefore, will depend largely on when the cold weather hits and just how far the temperature drops.

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We could get lucky; temperatures could stay mild enough so that, given the build-up in storage that has occurred, we could get through the winter without prices ever exceeding $ 6.00/MMBTU.

Or the pressure on the natural gas market could be just as severe as last winter, if not worse. It all depends on the weather.

Much will depend on what happens in December in particular. While it may seem like a distant memory at this point, in December of last year, there was still a modest el Nino effect – which is part of the reason that December temperatures were slightly below historical norms, as indicated in Table 6.

This year, there will not be any el Nino effect to keep us warm in December.

Temperatures still could prove to be mild.

There are also many forecasters, however, who believe that this December will be especially cold. If they are correct – and I want to make clear that I have no idea where their predictions will prove to be accurate – temperatures might rival December of 2000, when there were 1058 gas-weighted HDD's (vs. 841 HDD's in December of last year).

If this were to occur – and I want to underscore that I am not predicting that it will – it could easily lead to total natural gas consumption next month that is 300 BCf greater than in December of last year, and wipe out in three to four weeks any storage "surplus" compared to last winter that may have developed by the end of this month.

**Fundamentally Changed Market Dynamics**

A logical next question might be: how would the market be likely to react under this (entirely plausible) scenario that (at least conceivably) could play out over the next six weeks.

Here, I think the answer is that the market almost certainly would react explosively. This, at least in my judgment, is the real story of the past year, which has been lost in the hoopla over "demand destruction."

Specifically, I believe that, basic dynamics of the market have now fundamentally changed and that the likelihood of severe price spikes is now far greater than it was even last year, for three specific reasons:

1. The "slack in the system," in terms of available industrial load that can be reduced quickly has been drastically reduced. As noted, earlier, there is now far less industrial load available to decrement when supplies begin to tighten and prices begin to increase than there was just three years ago in Q4 of 2000, when the first of the recent severe price spikes occurred.

   Further, since the beginning of last winter, virtually every dual fuel capable industrial boiler that is allowed to burn fuel oil and had not already done so has switched to fuel oil and retention of Natural Gas Liquids (NGL's) in the gas stream had been increased to near maximum levels.

   In effect, therefore, industrial consumption already has been pared to the bone and there is virtually no remaining use that can be readily cut. Further, the remaining users already have repeatedly demonstrated their willingness to pay much higher-than-expected prices to continue using natural gas and it may take very high prices to drive them out of the market. (See also # 3 below.)

2. After last winter's experience, Local Distribution Companies (LDC's) are likely to be far more cautious in withdrawing natural gas from storage, especially during the first several months of the season. At the same time, after last winter's experience, in which – despite record prices before the end of the season -- the amount of natural gas in storage in the eastern half of the country was drawn down to perilously low levels, LDC's are likely to be very cautious in withdrawing natural gas from storage, especially during the first 60 to 90 days of the winter heating season, in order to minimize the risk that supplies of natural gas in storage will prove to be inadequate later in the winter.

   This could be an important factor tending to put a floor on natural gas prices during the early months of the winter, even if temperatures are mild.

   It also could significantly increase upward pressures if weather in December and early January turns out to be unusually cold, since natural gas in storage is likely to be far more "sticky" than it has been in the past.

3. Many industrial users already have locked in pricing and may be reluctant to reduce their consumption of natural gas no matter how high prices climb. Finally, after last winter's experience, a significant percentage of industrial users who are continuing to use natural gas have locked in pricing for this coming winter by purchasing futures contracts or implementing other hedging strategies. These industrial users are likely to be reluctant to disrupt their operations or default on delivery obligations to customers for the output of their facilities by cutting back on their use of natural gas, irrespective of the market price of natural gas.

   Even a very steep increase in natural gas prices, therefore, may only bring about a relatively small near-term reduction in industrial consumption of natural gas.

As a result, if the winter turns very cold, steep price increases are likely to be required in order to free-up even modest supply increments to meet the increased needs of residential and commercial customers.

**Potential Price Impacts of Changed Market Dynamics**

Many analysts have not yet picked up on this fundamental change in the underlying dynamics of the natural gas market.

It is important to recognize, however, how profoundly the market has changed in the space of just 36 months.

Three years ago, in Q4 of 2000, when cold weather hit in early December and supplies of natural gas began to tighten, there still will a major safety valve available, as there always had been in the past, to relieve the upward price pressure on the market: as soon as supplies began to tighten and prices began to increases, many industrial natural gas users still could – and did -- switch fuels; increased quantities of natural gas liquids still could be – and were -- left in the gas stream and a significant number of price sensitive users (e.g., smelters in the Pacific Northwest, fertilizer producers, etc.) still could – and sometimes did -- quickly shut down.

The combined impact of these actions, in prior years, was to quickly reduce demand and relieve upward pressure on the market price for natural gas.

As a result, in Q4 of 2000, when supplies tightened, while the spot market price of natural gas increased sharply, in the end it only quadrupled – peaking near $ 10.00/MMBTU in late December, and averaging well above in both December of 2000 and January of 2001.

In just 36 months, however, much has changed. There is much less industrial demand available to decrement. LDC's are likely to be far more cautious in pulling natural gas out of storage. And the industrial users who remain in the market are much more likely to have fully hedged their positions and therefore may not be as quick to cut back on their use of natural gas.

It is possible – although still by no means certain – that if the weather is mild enough this winter we will be able to avoid severe price spikes this winter.

Even if prices stay at reasonable levels this winter, however, all of the ingredients exist for a perfect storm again in the very near future – if not this winter, than potentially this summer and even more likely in the 2004/2005 winter heating season.

Given the underlying shifts that have occurred in the natural gas market, from this point forward, in any year in which an extended blast of cold weather occurs early in the winter season, or a severe hot spell occurs in the summer, it is likely to become necessary to bid prices to levels far above 2000/2001 peaks to drive even small amounts of industrial use out of the market.

Even if we dodge the bullet again this winter, therefore (as we were fortunate to do this summer), severe price spikes are virtually certain to occur in some (and perhaps most) future winters during the remainder of this decade.

The exposure to price spikes, however, is not the most severe problem we face.

Instead, our greatest challenge is to develop a strategy for continuing to meet the energy needs of the U.S. economy over the next decade despite the near-certainty of an unprecedented shortfall in supplies of natural gas.

We will attempt to begin addressing this issue in a report to be issued by our firm next month.

# Asia-Pacific Oil Market Forecast


## SUMMARY

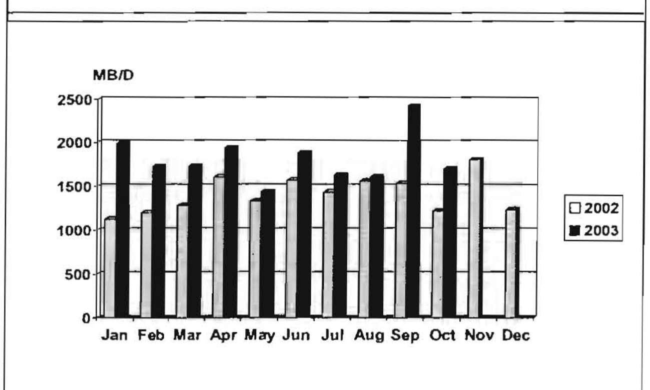
Exceptionally strong Asian economies are underpinning world oil markets, maintaining just enough pull on crude oil, in light of OPEC's recent quota action and growing Iraqi/non-OPEC supply, to keep inventories worldwide around the low levels prevalent over the past year. The resultant market strength has kept OPEC's basket price within the upper half of the price band and more recently above the band. PIRA expects prices to remain strong through January when seasonal factors will gradually begin to take prices lower and force OPEC to once again revisit the quota issue. Asian refining margins are expected to remain stable near current levels over the next six months, with fuel oil strength next year offsetting most of the expected seasonal decline in distillate values. Tapis values have begun to feel the pressure generated by the large influx of West African barrels to Asia as had been expected, and differentials versus Dubai are forecast to continue to weaken over the coming months.


## KEY MARKET FACTORS

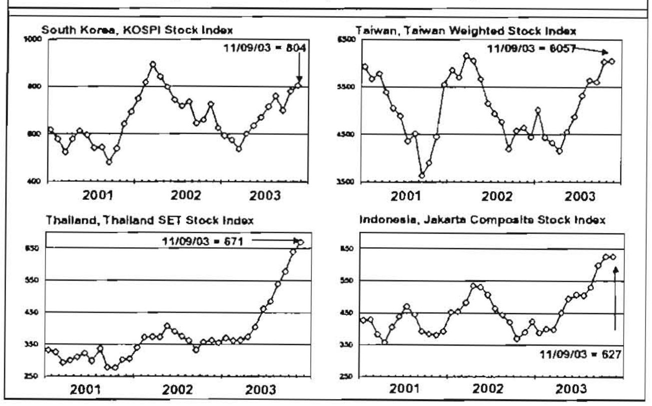
The past month has seen continued strong growth in Asia, particularly within the Chinese economy where strong economic growth has prompted PIRA to increase projected 2003 and 2004 demand growth by 150 MB/D and 130 MB/D respectively. Chinese crude oil imports have run consistently ahead of last year even during the SARS crisis, with September volumes reaching historically high levels and, as noted, contributing to a stronger worldwide crude oil market.

Other Asian economies are also contributing to the economic resurgence with stock markets around the region pointing to continued economic growth and increasing energy demand. Even the Japanese economy, which has been stagnant in recent years, showed solid

Chinese Crude Oil Imports




Asian Stock Markets on the Upswing
(End-of-Month, except the Latest Month)



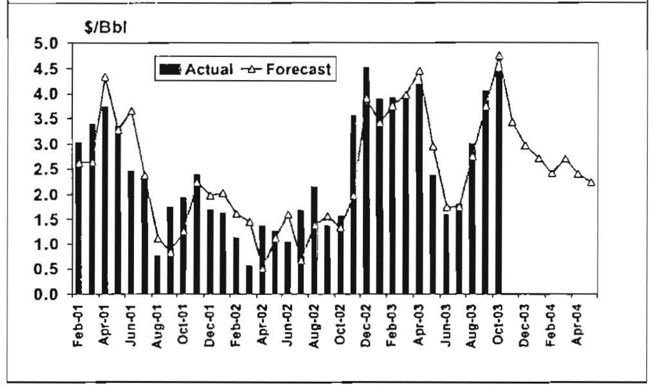
GDP growth during the third quarter. Anecdotal information is reminiscent of pre-"Asian Crisis" days in 1996 and during 2000 when Asian economies were the catalyst to surging oil demand growth.

## PRICE/MARGIN FORECAST

Over the past few weeks, the market has traded within a roughly $28-$32/Bbl range basis WTI that has reflected short-term supply/demand considerations, political unrest, and growing economic activity. PIRA has projected that strong oil prices will continue through January, with Dated Brent and Dubai expected to average $28.60/Bbl and $27.45/Bbl respectively over the November–January period. Prices should subsequently soften by a few dollars as winter demand eases and inventories start to rebuild. Note that this forecast assumes that OPEC cuts quota by a further 500 MB/D effective March in order to stabilize prices above the bottom of the OPEC price band.

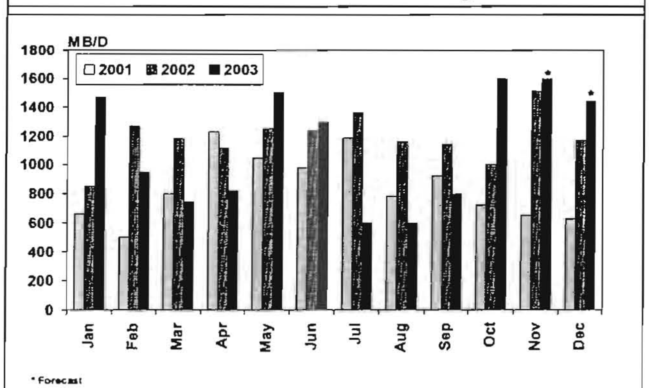
The Dated Brent-Dubai spread has narrowed over the past few months, facilitating large-scale movement of West African crude oil to Asia. Volumes are expected to peak in November and then gradually decline as winter demand eases. But the spread will remain narrow over 1Q03, encouraging continued high volume imports from the Atlantic Basin. As a result, PIRA expects the Tapis-Dubai spread to continue to remain at narrow levels over the next six months.

**Tapis - Dubai Differential**
(Actual Platt's Spot Differential And Forecast Differential)

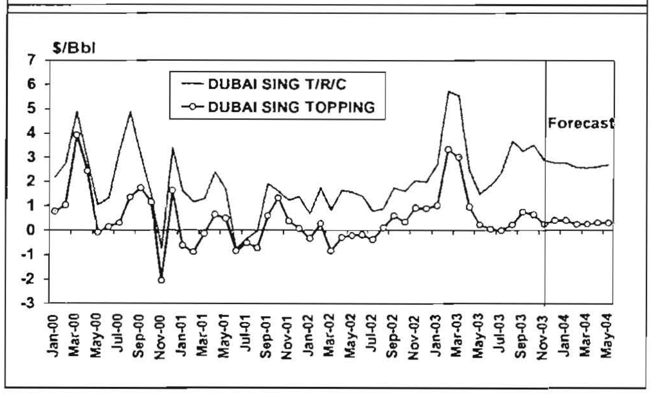



Singapore refining margins remain attractive, although they have declined somewhat from higher September/October levels. Going forward, margins should remain relatively stable over the coming months with cracking margins above $3.00/Bbl and simple topping margins remaining positive at around $0.50/Bbl. Strong naphtha prices in Asia that have opened the arb from Europe are currently supporting topping margins, while expected fuel oil strength will keep these margins positive during 1Q04. Asian margins have shown greater stability over the past few months than other regions and that should continue into the first quarter.

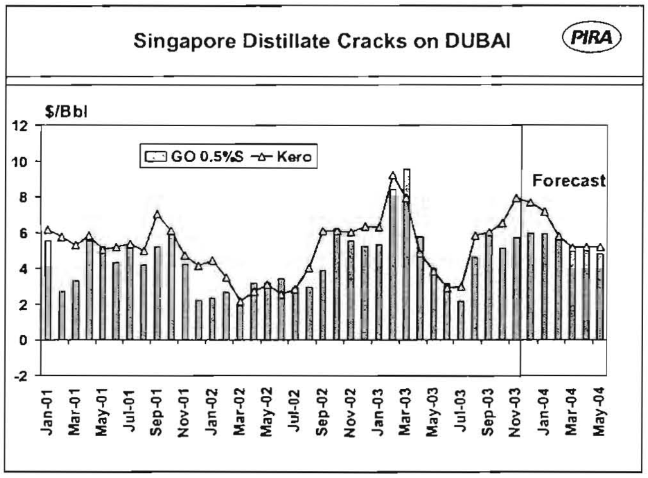
**Atlantic Basin Sweet Crude Going East**



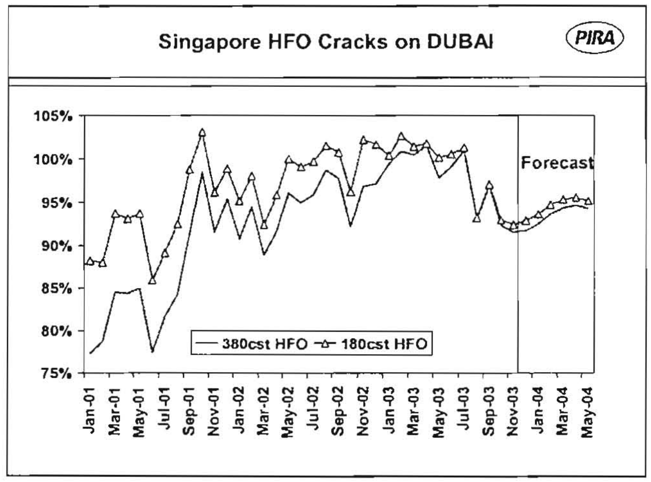

**Singapore Dubai Margins**



Distillate cracks are showing typical seasonal patterns, peaking now as colder weather sets into Northern Asia. Kerosene is expected to perform better than gasoil, despite relatively mild temperatures, due to surging aviation demand in China, Singapore and Indonesia. PIRA expects kerosene cracks to remain stable, unlike gasoil cracks, even as the heating season ends due to strong economic growth fueling robust aviation demand.




Singapore fuel oil cracks have weakened over the past two months as ample high sulfur supplies from the Mideast have been met by lower Chinese demand that resulted from year-end depletion of import quotas into China. Chinese inventories are currently being drawn, and with replenishment expected next year first quarter demand should be robust. PIRA expects HFO cracks to steadily gain value next year. Low sulfur fuel has remained strong on the back of power plant demand in South Korea and Japan, where continued nuclear generation problems have bolstered demand and supported prices.



# China Coal Newsletter

---Biweekly by AAA Minerals International

*Advanced Research, Assiduous Operation, Authentic Results*

Issue 2, Volume 1. Jan. 20, 2004

## Contents



For more information, please send us an E-mail at: coal@aaamineral.com

## Highlights

### A Snapshot of China's Coal Supply Shortfall

*Singapore, January 05, 2004* ---The pattern of Asian coal markets is changing drastically as a result of a shortage in coal supplies from China. China's inability to export as much coal as usual means the power companies are turning to more costly coal from Indonesia and Australia, or buying more fuel oil to produce electricity. This has had the effect of boosting their overhead costs. Suffering from a coal shortage due to a combination of large increases in domestic power demand, the closure of many small mines, transport logistic problems and mine safety issues, the spot price for Chinese coal as shot up by about 60%, or $15/ton free-on-board Qinhuangdao, to about $39/ton since August.

The situation may worsen in 2004, as experts predict that China will consume 2,091 billion kilowatt-hours of electricity in 2004. This is an increase of 11%, or 207 billion kilowatt-hours, more than 2003. The highest electrical load will be 65.42 million kilowatts. Shanghai, Jiangsu and Zhejiang will see a shortage of 1.09, 4.77 and 5.24 million kilowatts of electricity respectively, and more areas will have to limit power consumption. This will further boost the demand of coal and cause prices to rise, indicating a possible sharp reduction in coal supply for Asian markets in 2004.

### Largest Steaming Coal Enterprise Established in Shanxi

*Beijing, January 10, 2004 (CCIA)* ---The Datong Coalmine Group was established on December 21, 2003 in the city of Datong, Shanxi Province. This group, regarded as the largest steaming coal producer in China, represents the merger of more than ten province- and city-owned coalmines that are producing coal from the Datong-Pingwu Coalfield. This coalfield covers an area of 890 $km^2$ and has a total producing capacity of 80 Mt raw coal per year. The total assets of the group reaches 22 billion Yuan RMB, reported the China Coal Industry Association.

Mr Peng Jianxun, the director of the Datong Coalmine Group, said the coal sales of the group will be 80 Mt in 2004 and he predicts sales to be 100 Mt in 2006. Their customers include the North China Electricity Corporation, Zhejiang Electricity Corporation, Jiangsu Electricity Corporation, Guangdong Electricity Corporation, Shanghai Electricity Corporation and various overseas countries.

Shanxi Province will establish another large-scale anthracite producing enterprise in order to promote its coal resources and mining capacity, Mr. Jin Shanzhong, vice-governor of Shanxi Province, said during the opening ceremony of the Datong Coalmine Group.

### Coal Exports Decrease in Year 2004

*Beijing, January 10, 2004* ---The China National Coal Group, formerly known as the China National Coal Industry Import and Export Group said its exports dropped slightly last year as the company shifted a part of its supplies to markets at home during the fourth quarter of 2003 in order to meet





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the domestic shortfall. The company said its profits increased by 20% to 520 million Yuan (US$ 62.9 million) last year, thanks to coal production increases and coal price hikes, General Manager Mr. Jin said. China exported more than 90 million tons of coal last year, increasing by 7.3 percent year-on-year. However, as the largest of the four government authorized exporters, CNCG exported 45.2 million tons of coal last year, a decrease of 5 percent in comparison with 2002, because of the profitable domestic markets favored by increasing coal consumption in China. The surging demand has been attributed to rampant output growth of coal-consuming industries such as the power, steel and coal-chemical industries. This situation will likely continue in 2004 and the strategic shift of CNCG from being an enthusiastic exporter to focusing more on the domestic market may suggest a continued reduction of its coal exports in 2004.

Starting this year, the new tax rebate system may also discourage coal companies from increasing exports (ref. CC Newsletter Issue 1 for details). The China National Developing and Reforming Committee recently stated that China would not support coal exporting as before so as to alleviate the pressure of rapidly increasing demand at home. The export amount of coal in 2004 is supposed to be 80 million tons in 2004, reflecting a major change in coal exporting policy in China.

### Qinhuangdao Port Broke its Record in 2003

The Qinhuangdao Bureau of Port Administrations on January 9 released information showing they handled 125 million tons of coal in 2003, which makes it a major world port. As one of the largest energy ports in the world, Qinhuangdao Port is mainly responsible for transporting coal from northern China, the main coal producing region, to southern China and overseas counties. Its planned capacity is 90 Mtpa and its current coal handling amount is 50 % of the total of all the coastal ports in China. To increase its capacity, the port has invested 1.46 billion Yuan in 2003 to build a 100,000-ton navigational channel and will upgrade all the docks and other infrastructure facilities.

### Electricity Price Hike for the New Year

*Beijing, January 19, 2004*---Pressured by a nationwide power shortage, the government raised the electricity price at the beginning of the year. The price hike of 0.7 Fen RMB (0.08 US Cent) per kilowatts/hour (kwh) will affect production of most industrial sectors, said Zhang Guobao, vice-minister of the National Development and Reform Committee. He emphasized the fact that the rise in electricity prices is directly related to the shortage of coal and the increase in coal prices.

To release pressure caused by the shortage of electricity and the increasing demand of coal, China plans to build up to ten large-scale mining enterprises, each of which will be capable of producing over 50 million tons of raw coal annually, the China Coal Industry Association announced recently.

## Enterprise

### Yanzhou Coal Mining Company, Limited

Yanzhou Coal Mining Co., Ltd is located in the city of Yanzhou within the province of Shandong and was established on the 25th of September in 1997. The planned capacity of raw coal of its mines is 25 Mt per year and the total measured reserves are 3,778.68 Mt. Currently, this company owns five underground coalmines and six wash-plants, producing high-quality power and coking coal. The total number of employees was approximately 97,000 in 2003. The capital cost of Yanzhou Coal Mining Company Limited reaches 26 million Yuan RMB. The corporation's raw coal output was 40.81 Mt in 2002, making it the third greatest coal producer in China. The total washing-plant capacity for raw coal is 18.10 Mtpa. Since it has a favorable location, its thermal coal and metallurgical coal products are highly competitive, especially in eastern China.

The company successfully applies mechanized comprehensive caving methods and appropriate of mining equipment suitable for thick coal seam extraction, which has greatly enhanced productivity and mining safety. Consequently, Yanzhou Coal Mining Co. recently won the First Class National Scientific and Technological Award, and has become one of the key state enterprises and is listed as one of the top ten companies in terms of annual gross income in China.

## Review

### The National Coal Trade Fair 2004

From December 25th, 2003 to January 6th, 2004, the China National Developing and Reforming Committee, the Ministry of Railways, the Ministry of Transportation and Communications, the China Coal Industry Association and the state electricity authorities held the National Coal Trade Fair 2004 in Fuzhou (formerly Foochow), the provincial capital of Fujian Province. This trade fair was one of the most significant events for the coal industry of China. Tentatively, the total contracts signed between coal producers and consumers during the fair came to approximately 800 million tons of coals and 200 billion Yuan RMB. The coal amount ordered by the power industry was approximately 250 Mt and the amount ordered by the metallurgical and coking sectors was approximately 150 Mt. In the past, the coal amount ordered at the fair is more than 70% of the total coal-traded quantity of the following year. The annual contracted deals during the trade fair in 2001、2002 and 2003 were 350 million, 550 million, and 750 million tons respectively.

The debate regarding steaming coal prices remains a hot topic, which was raised during last year's fair held in Changsha, Hunan Province. This may reflect the problems caused by the conflict between the state-regulated electricity price and the open market coal price, or between the systems of planned versus market economies. To resolve the problems, the China National Developing and Reforming Committee suggested raising the price of coal and electricity slightly. From January 1st, 2004, the price of coal for power generation will be allowed to have a markup of up to 12 Yuan/ton (including tax) on the price base of 2003 and the state regulated electricity prices will raise to 0.7 Fen RMB (0.08 US Cent) correspondingly. This measure promoted deals between the power industry and coal companies and may relieve the current shortfall of the steaming coal in some degree.

During the coal trade fair, the China National Developing and Reforming Department stated that the Chinese government will put controls on the exportation of raw coal; it will especially reduce the coke export amount so as to alleviate the pressure of the rapidly increasing coal demands of China. The coal export amount is planned to be 80 million tons in 2004, which may suggest a significant reduction of coal exports in comparison with previous years.

It has been widely regarded that the outcome of the National Coal Trade Fair is a reflection of the developing trends of the basic industrial sectors of China and of the national economy. This fair is held annually at end of the year and is the second largest domestic trade fair for raw stuff and material exchange and trade. It should be mentioned that the National Coal Trade Fair has already lasted 50 years and was originally created by the government as a nationwide meeting of coal producers and consumers in order to plan coal production and allotment. This makes the fair a product of the planned economic system. Before opening the price of coal in 1993, coal production and sales of the coal mines were assigned by the government at a regulated price. The coal mines had to supply coal to their assigned consumers and did not have the right to sell coal to other customers. Coal output, transport, supply and prices for the coming year were all determined and planned by the government, the producers and the consumers at the meeting. Since 1993, part of the coal prices have gradually opened to the market, but the price of coal supplied to the electric industry was still controlled until 2002. In most cases, the market coal price is 30 to 70 Yuan/t higher than that of state-assigned coal, which was regulated by the State Planning Committee. On other hand, the price of electivity is still regulated by the government and most state-owned power stations and companies could not stand the market prices. As a result, the state-owned power stations and companies could not get 40% of their supplying contracts at the state-regulated price during the Coal Trade Fair 2003. This is the main cause of the coal supply shortfall occurring in most power companies of northern and eastern China since late 2003.

With the further opening of coal prices, the government-controlled coal trade fair has to face more challenges and its function may have to change in the near future, for example, international coal trades may also became a main event of this fair.

(By Xia Qing of AAA Minerals Intern.)

## Opportunity

### Looking for Investment and Cooperation

**Project:** New mine of Yushuwan
**Mine background:** The mining district is located in the Yushen coalfield with an area of 117 km². The total Grade A reserves is 1.8 Bt. The main minable seam, #2-2, is of lower ash, lower sulphur and low phosphate contents, but high heating value.

Exploration and feasibility studies are completed and the mine plan has been submitted to the proper authorities for final approval. The current planned capacity of the mine is 8Mt/year and future plans will reach 20 to 30Mt/year.

**Location:** North of Yulin City, Shaanxi Province
**Investment:** The total investment is 876.47 Million Yuan and 109.56 Yuan/ton for the first stage.
**Main customer:** Its coal products can be supplied to the major metallurgic enterprises and power stations of southern and south-western China, and for exports. A railway goes through the area.
**Return:** The annual yield is 17.21% and the investment return within 6.25 per year, based on Chinese standard.
**Contact:** info@aaaminerals.com

## Statistics

### Energy production mix of Jan. to Nov. 2003 with comparison to 2002

Unit: Mt

| | Total | Coal | Crude oil | Fire-Power (Bkwh) | Coke |
|---|---|---|---|---|---|
| Jan.-Nov. 2003 | 1,209.16 | 1423.24 | 154.68 | 139.56 | 125.25 |
| Growth rate (%) | 13.2 | 17.7 | 1.3 | 15.5 | 20.57 |

### Raw coal output in 2003 by ownership

Unit: Mt

| Ownership | Output | Comparing with 2002 | |
|---|---|---|---|
| | | Cumulative | Rate (%) |
| Total | 1,60 8.10 | 214.75 | 16% |
| State-owned coalmine | 808.16 | 96.5 4 | 14% |
| Local coalmine | 262.81 | 19.3 6 | 7% |
| Township coalmine | 517.16 | 98.8 5 | 24% |

### Coal exports from Jan. to Nov. 2003

Unit: Kt

| Coal type | November | Cumulation |
|---|---|---|
| Anthracite 442. | 35 | 6,418.94 |
| Bituminite subtotal | 5,939.71 | 77,898.6 |
| Coking coal | 699.02 | 11,876.9 |
| Other Bituminite | 5,240.68 | 66,021.70 |
| Other Ranks | 1.08 | 30.26 |
| Total 6,38 | 3.14 | 84,347.8 |

### Coal imports from Jan. to Nov. 2003

Unit: Kt

| Coal type | November | Cumulation |
|---|---|---|
| Anthracite | 395.79 | 3,074.87 |
| Bituminite subtotal | 384.81 | 6,439.13 |
| Coking coal | 155.42 | 1,922.73 |
| Other Bituminite | 229.38 | 4,516.40 |
| Other Ranks | 0.2 | 146.04 |
| Total | 780.81 | 9,660.04 |

### Output of coal-consuming industries in 2003 and their comparison with 2002

Unit: Mt

| Type | December | | January to December | |
|---|---|---|---|---|
| | Output (Mt) | Increase % | Cumulative (Mt) | Increase (%) |
| Steel | 20.16 | 20.89 | 220.11 | 21.15 |
| Iron | 18.88 | 25.74 | 202.31 | 19.65 |
| Coke | 13.33 | 22.02 | 138.79 | 20.75 |
| Iron ore | 26.47 | 29.05 | 261.09 | 13.83 |
| Ferroalloy | 61.31 | 28.91 | 634.06 | 34.05 |

### Coal prices of the main markets on January 14th, 2004

Unit: ton/Yuan

| Region | Coal Rank | FOR Price | FOB Price |
|---|---|---|---|
| Huaibei | Soft coal | | 280 |
| Qinghuangdao | Complex coal | | 290 |
| Changchun | Electric coal | 210 | |
| Xuzhou | Soft coal | | 310 |
| Wuhai of Mongonia | Lump coal of anthracite | 390 | |
| Jiexiu | Main coking coal | 460 | |
| Shuicheng | Coking coal | 380 | |

### Coal price at Qinhuangdao Port on January 6th, 2004

Unit: ton/Yuan

| Coal Type | | FOR Price | FOB Price | Reference* Price |
|---|---|---|---|---|
| Mixed coal of Datong | >6,000 Kcal | 268-290 | 274-295 | 290-320 |
| Mixed coal of Shanxi | >5,500 Kcal | 260-275 | 264-280 | 280-295 |
| Mixed coal of Kailuan | >4,800 Kcal | 235-248 | 243-248 | 252-265 |
| Mixed coal of Shenhua Group | >5,800 Kcal | | | >270 |

Reference Price*: The reference price means the price made by coal producer.

### Coke prices of the main markets on January 13th, 2004

Unit: ton/Yuan

| Province | Price | Province | Price |
|---|---|---|---|
| Shanxi | 900 | Anhui | 1,150 |
| Hebei | 1,220 | Yunnan | 900 |
| Shandong | 1,280 | Zhejiang | 1,250 |
| Henan | 1,200 | Guizhou | 970 |
| Jiangsu | 1,220 | Shanghai | 1,060 |

## AAA Minerals International

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## AUGUST 2004 VS. AUGUST BUDGET - BILLING MONTH BASIS

| CLASS OF BUSINESS | WEATHER NORMALIZED BILLED MWH SALES | | | | NUMBER OF CUSTOMERS Adj. for Event-Driven Billing | | | | WEATHER & CUSTOMER NORMALIZED BILLED KWH SALES PER CUSTOMER | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | AUG'04 Actual | Forecast | Change | % DIFF | AUG'04 Actual | Forecast | Change | % DIFF | AUG'04 Actual | Forecast | Change | % DIFF |
| RESIDENTIAL | 2,044,463 | 2,048,751 | -4,288 | -0.21% | 1,365,744 | 1,353,772 | 11,972 | 0.88% | 1,497 | 1,513 | -16 | -1.06% |
| COMMERCIAL | 1,135,839 | 1,146,702 | -10,863 | -0.95% | 159,272 | 157,125 | 2,147 | 1.37% | 7,131 | 7,298 | -167 | -2.29% |
| INDUSTRIAL | 346,762 | 346,807 | -45 | -0.01% | 2,741 | 2,625 | 116 | 4.42% | 126,509 | 132,117 | -5,608 | -4.24% |
| ST & HIGHWAY | 2,310 | 2,359 | -49 | -2.07% | 1,843 | 1,900 | -57 | -3.00% | 1,254 | 1,242 | 12 | 0.97% |
| PUBLIC AUTHORITY | 276,372 | 275,122 | 1,250 | 0.45% | 20,543 | 20,310 | 233 | 1.15% | 13,453 | 13,546 | -93 | -0.69% |
| **TOTAL RETAIL** | 3,805,747 | 3,819,741 | -13,994 | -0.37% | 1,550,143 | 1,535,732 | 14,411 | 0.94% | 2,455 | 2,487 | -32 | -1.29% |
| Provision For Refund | | | | | | | | | | | | |
| REA | 123,292 | 92,249 | 31,043 | 33.65% | 8 | 5 | 3 | 60.00% | | | | |
| Oth Whol (w/Ref $ or Interchg MWh | 351,166 | 141,556 | 209,610 | 148.08% | 18 | 15 | 3 | 20.00% | | | | |
| **WHOLESALE (Not W/N)** | 474,458 | 233,805 | 240,653 | 102.93% | 26 | 20 | 6 | 30.00% | | | | |
| TOTAL SYSTEM | 4,280,204 | 4,053,546 | 226,658 | 5.59% | 1,550,169 | 1,535,752 | 14,417 | 0.94% | | | | |

## YEAR TO DATE AUGUST 2004 VS. BUDGET - BILLING MONTH BASIS

| CLASS OF BUSINESS | WEATHER NORMALIZED BILLED MWH SALES | | | | NUMBER OF CUSTOMERS Adj. for Event-Driven Billing | | | | WEATHER NORMALIZED BILLED KWH SALES PER CUSTOMER | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | YTD'04 Actual | Forecast | Change | % Diff | YTD'04 Actual | Forecast | Change | % Diff | YTD'04 Actual | Forecast | Change | % Diff |
| RESIDENTIAL | 12,979,875 | 13,041,750 | -61,875 | -0.47% | 1,360,260 | 1,355,701 | 4,559 | 0.34% | 9,542 | 9,620 | -78 | -0.81% |
| COMMERCIAL | 7,778,362 | 7,903,890 | -125,528 | -1.59% | 157,690 | 156,400 | 1,290 | 0.83% | 49,327 | 50,537 | -1,210 | -2.39% |
| INDUSTRIAL | 2,756,191 | 2,753,425 | 2,766 | 0.10% | 2,734 | 2,625 | 109 | 4.14% | 1,008,209 | 1,048,924 | -40,715 | -3.88% |
| ST & HIGHWAY | 18,677 | 19,270 | -593 | -3.08% | 1,865 | 1,900 | -35 | -1.86% | 10,016 | 10,142 | -126 | -1.24% |
| PUBLIC AUTHORITY | 1,969,579 | 1,987,621 | -18,042 | -0.91% | 20,416 | 20,142 | 274 | 1.36% | 96,472 | 98,682 | -2,210 | -2.24% |
| **TOTAL RETAIL** | 25,502,684 | 25,705,956 | -203,272 | -0.79% | 1,542,964 | 1,536,767 | 6,197 | 0.40% | 16,528 | 16,727 | -199 | -1.19% |
| Provision For Refund | | | | | | | | | | | | |
| REA | 718,883 | 628,982 | 89,901 | 14.29% | 6 | 5 | 1 | 12.50% | | | | |
| Oth Whol (w/Ref $ or Interchg MWh | 2,623,407 | 1,320,266 | 1,303,141 | 98.70% | 18 | 16 | 3 | 17.60% | | | | |
| **WHOLESALE (Not W/N)** | 3,342,290 | 1,949,248 | 1,393,042 | 71.47% | 24 | 21 | 3 | 16.36% | | | | |
| TOTAL SYSTEM | 28,844,975 | 27,655,204 | 1,189,771 | 4.30% | 1,542,988 | 1,536,788 | 6,200 | 0.40% | | | | |

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# CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
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NO. 040817-EI EXHIBIT NO. 3
COMPANY/ F.P.S.C. Staff
WITNESS: Specified Conf. Responses to Staff Discov
DATE: 11-03-04

**Exhibit ___ (SSW-1)**

**Progress Energy Florida Corporation Need Determination Study for Hines Unit 4**

(Filed Separately)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040817-EI EXHIBIT NO 4
COMPANY/ Progress Energy
WITNESS. Samuel S. Waters
DATE 11-03-04

**Exhibit ___ (SSW-2)**

***Forecast of Winter Demand and Reserves With and Without Hines 4***

| | Net Firm Demand (MW) | Resources Without Hines 4 (MW) | Reserves Without Hines 4 (MW) | Reserve Margin w/o Hines 4 (%) | Reserves With Hines 4 (MW) | Reserve Margin With Hines 4 (%) |
|---|---|---|---|---|---|---|
| 2004/05 | 8,903 | 10,666 | 1,763 | 20% | 1,763 | 20% |
| 2005/06 | 9,153 | 11,218 | 2,065 | 23% | 2,065 | 23% |
| 2006/07 | 9,595 | 11,734 | 2,139 | 22% | 2,139 | 22% |
| 2007/08 | 9,737 | 11,561 | 1,824 | 19% | 2,341 | 24% |
| 2008/09 | 9,891 | 11,452 | 1,561 | 16% | 2,078 | 21% |

Notes:

Average load growth (2004/05 – 2008/09) = 247 MW/Year.

Resources include the addition of Hines 3 in December 2005 and purchased capacity starting in December 2006.

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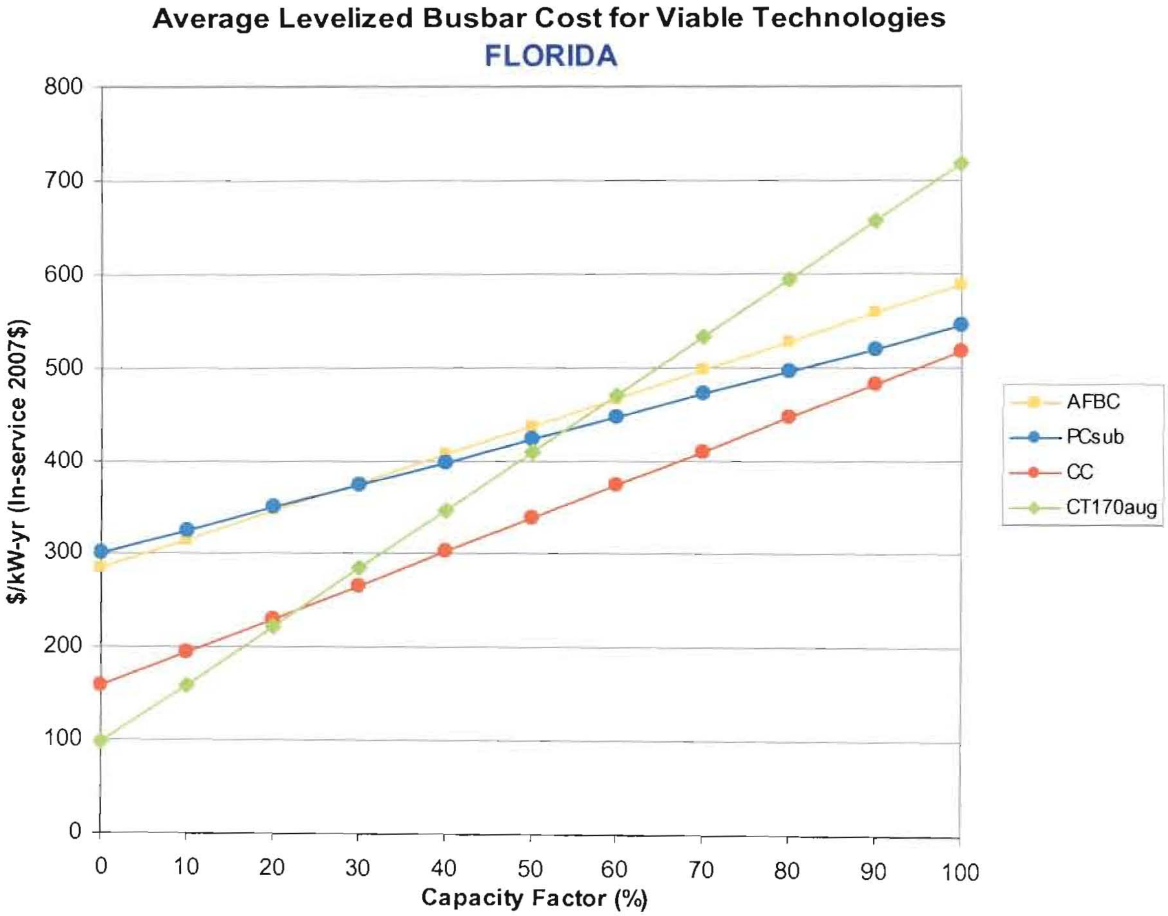
**Exhibit ___ (SSW-3)**




*Based on average of summer and winter.*

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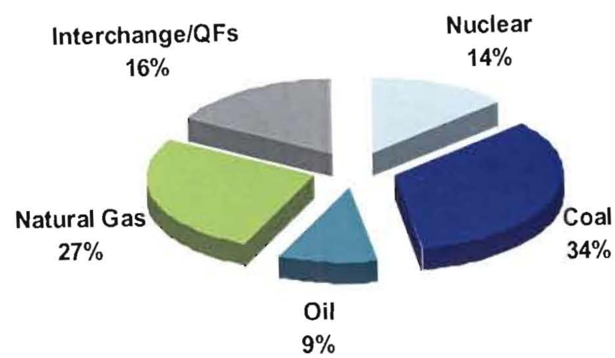
Exhibit ___ (SSW-4)

## Progress Energy Florida 2008 System Energy Mix




Source: Progress Energy Florida Ten-Year Site Plan, April, 2004, Schedule 6.2

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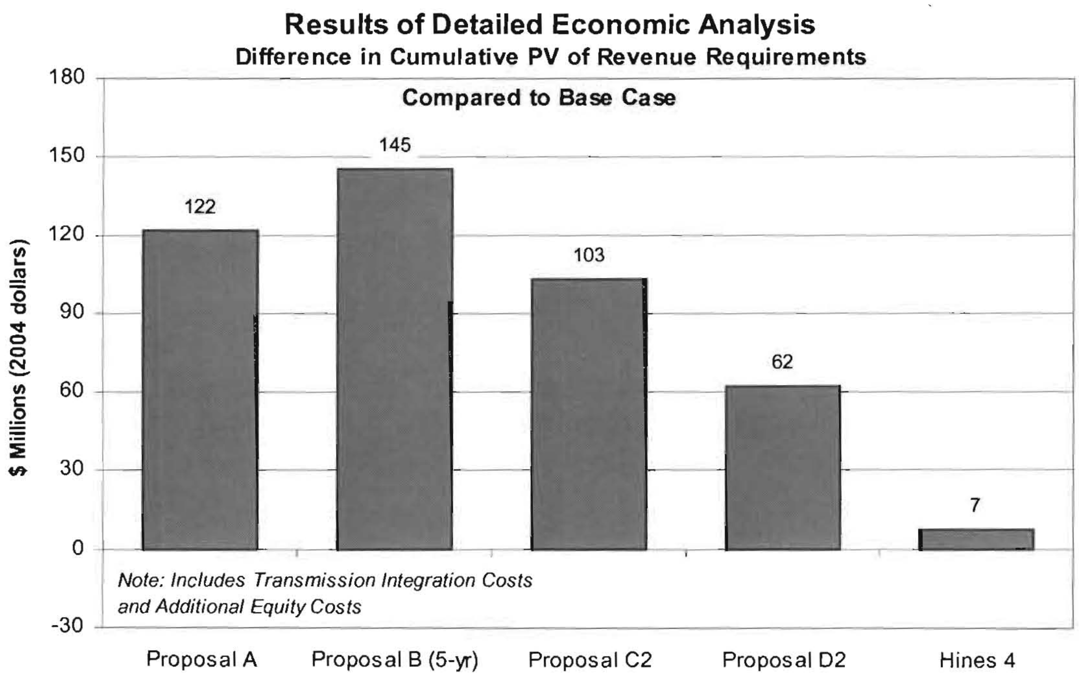
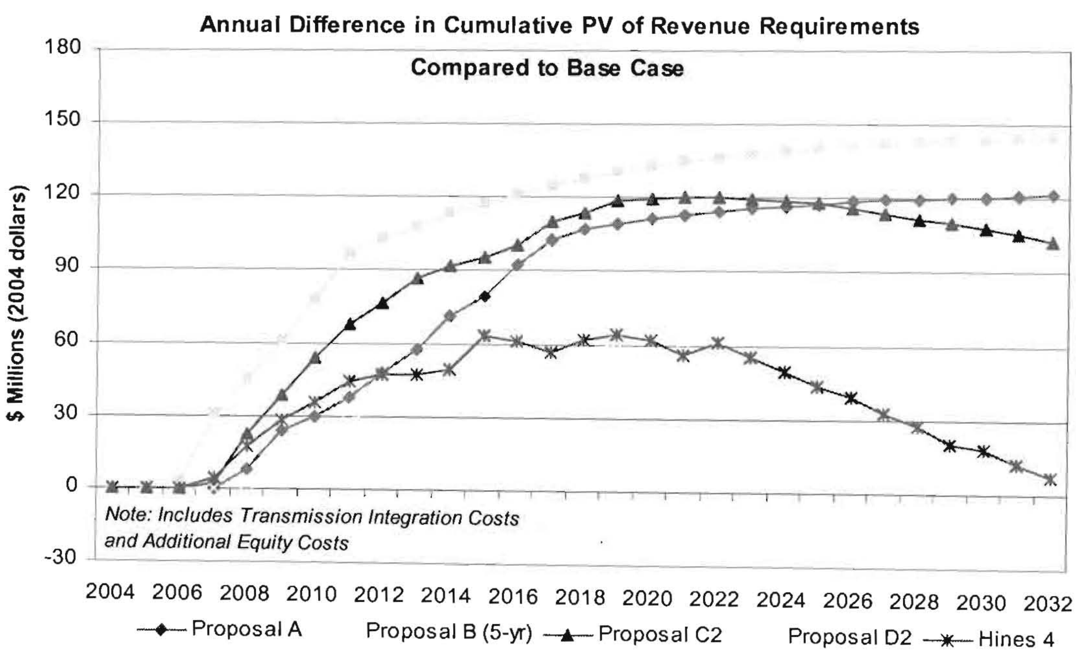
Exhibit ___ (DJR-1)

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WITNESS. Daniel J. Roeder (DJR-1)
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Exhibit ___ **(DJR-2)**

## RFP Evaluation Process

**Receipt of Proposals**

↓

**Step 1**
**Screening for Threshold Requirements**

↓

**Step 2**
**Segregation of Bids**

↓

**Step 3**
**Economic Evaluation**

↓

**Step 4**
**Technical Evaluation**
**(Minimum Evaluation Requirements and Technical Criteria)**

↓

**Step 5**
**Selection of Short List**

↓

**Step 6**
**Detailed Evaluation**

↓

**Step 7**
**Selection of Final List**

↓

**Contract Negotiations**

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Exhibit ___ **(DJR-3)**

## Summary of Proposals

| Proposal | Location (County) | Winter Capacity (MW) | Proposal Type | Term (yrs) | Technology | Primary Fuel |
|---|---|---|---|---|---|---|
| A | Indian River | 252 | New Unit | 10 | Combined-cycle | Natural gas |
| B | Brevard | 571-582 | Existing Unit | 5–10* | Fossil steam | No. 6 oil |
| C1 | Orange | 515 | New Unit | 25 | Combined-cycle | Natural gas |
| C2 | Orange | 632 | New Unit | 25 | Combined-cycle | Natural gas |
| C3 | Orange | 514 | New Unit | 25 | Combined-cycle | Natural gas |
| D1 | Pasco | 111 | Existing Unit | 15 | Combined-cycle | Natural gas |
| D2 | Pasco | 13-124 | Existing/New | 15 | Combined-cycle | Natural gas |

* Note: All proposals started December, 2007 except Proposal B, which started December, 2006

**List of Bidders**

Calpine
Pasco Cogen
Reliant Energy
Southern Power

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Exhibit ___ **(DJR-4)**

# Threshold Requirements

**A. General Requirements**

- The proposal is received on time.
- The offer is reasonable and bona fide.
- Complete and credible answers are provided to all questions.
- The proposal submittal fee is included.
- The pricing schedules are properly specified.
- The proper price indices are used.
- Power must be available for delivery under the contract by December 1, 2007.
- The proposed term is for a minimum of one (1) year if the project does not require a Need Determination and 10 years if a Need Determination is required. The proposed term is less than the maximum of 25 years.
- For New Unit Proposals located in Florida, the output of the unit(s) is sufficiently committed to Progress Energy Florida (or other utilities serving retail customers).

**B. Operating Performance Thresholds**

- If the project is located in PEF's control area, the Bidder will be required:
  - to operate the project to conform with PEF's ***Voltage Control*** requirements.
  - to operate the project to conform with PEF's ***Frequency Control*** requirements.
- New and Existing Unit Proposals must be ***Fully Dispatchable*** and install ***Automatic Generator Control*** that is tied into PEF's Energy Control Center.
- The Bidder must be willing to ***coordinate the project's maintenance scheduling*** with PEF.
- Proposals should have a project size less than or equal to approximately 500 MW.
- System Power Proposals must be ***Fully Schedulable*** (i.e., operate according to a day-ahead schedule but with schedule changes subject to normal utility practices).

**C. Contractual Thresholds**

- Bidders must agree to each of the Key Terms and Conditions identified in Attachment A.
  - OR -
- If Bidder has any objections to the Key Terms and Conditions, the Bidder must:
  - Identify the language which is objectionable;
  - Provide revised language.

**D. Site Control Thresholds [New and Existing Unit Proposals]**

- Identification of the site location on a USGS map.
- At a minimum, a Letter of Intent to negotiate a lease for the full contract term or term necessary for financing (whichever is greater), or to purchase the site **[New Unit Proposals]**. A copy of the title and legal description of the property is required for **Existing Unit Proposals**.

**E. Transmission Threshold**

- If the project is located outside of PEF's control area, the Bidder must provide a transmission plan for wheeling services from those utilities which would be required to wheel the project's power to PEF and provide evidence that the host utility is willing to grant PEF the right to dispatch the output of New and Existing Unit Proposals or the right to schedule power from System Power Proposals.
- If the project is located inside of PEF's control area, the Bidder must complete a Network Resource System Impact Study data request (Schedule 7 of the Response Package).

Exhibit ___ **(DJR-5)**

## Results of Threshold Screening

**Meets Requirements?**

| | | | **Bidder** | A | B | C1 | C2 | C3 | D1 | D2 |
|---|---|---|---|---|---|---|---|---|---|---|
| **A.** | **General Requirements** | | | | | | | | | |
| | • | The proposal is received on time. | | Y | Y | Y | Y | Y | Y | Y |
| | • | The offer is reasonable and bona fide. | | Y | Y | Y | Y | Y | Y | Y |
| | • | Complete and credible answers are provided to all questions. | | N/Y | N/Y | N/Y | N/Y | N/Y | N/Y | N/Y |
| | • | The proposal submittal fee is included. | | Y | Y | Y | Y | Y | Y | Y |
| | • | The pricing schedules are properly specified. | | N/Y | N/Y | N/Y | N/Y | N/Y | N/Y | N/Y |
| | • | The proper price indices are used. | | -- | -- | N/Y | N/Y | N/Y | N/Y | N/Y |
| | • | Power must be available for delivery under the contract by December 1, 2007. | | Y | Y | Y | Y | Y | N | Y |
| | • | The proposed term is for a minimum of one (1) year if the project does not require a Need Determination and 10 years if a Need Determination is required. The proposed term is less than the maximum of 25 years. | | Y | Y | Y | Y | Y | Y | Y |
| | • | For New Unit Proposals located in Florida, the output of the unit(s) is sufficiently committed to Progress Energy Florida (or other utilities serving retail customers). | | Y | Y | Y | Y | Y | Y | Y |
| **B.** | **Operating Performance Thresholds** | | | | | | | | | |
| | • | If the project is located in PEF's control area, the Bidder will be required: | | | | | | | | |
| | | – to operate the project to conform with PEF's ***Voltage Control*** requirements. | | -- | -- | Y | Y | Y | Y | Y |
| | | – to operate the project to conform with PEF's ***Frequency*** Control requirements. | | -- | -- | Y | Y | Y | Y | Y |
| | • | New and Existing Unit Proposals must be Fully Dispatchable and install Automatic Generator Control that is tied into PEF's Energy Control Center. | | -- | -- | Y | Y | Y | Y | Y |
| | • | The Bidder must be willing to coordinate the project's maintenance scheduling with PEF. | | Y | Y | Y | Y | Y | Y | Y |
| | • | Proposals should have a project size less than or equal to approximately 500 MW. | | Y | Y | Y | Y | Y | Y | Y |
| | • | System Power Proposals must be Fully Schedulable (i.e., operate according to a day-ahead schedule but with schedule changes subject to normal utility practices). | | Y | Y | Y | Y | Y | Y | Y |
| **C.** | **Contractual Thresholds** | | | | | | | | | |
| | • | Bidders must agree to each of the Key Terms and Conditions identified in Attachment A. | | -- | -- | -- | -- | -- | -- | -- |
| | | - OR - | | | | | | | | |
| | • | If Bidder has any objections to the Key Terms and Conditions, the Bidder must: | | | | | | | | |
| | | • Identify the language which is objectionable; | | Y | Y | Y | Y | Y | Y | Y |
| | | • Provide revised language. | | Y | Y | Y | Y | Y | Y | Y |
| **D.** | **Site Control Thresholds [New and Existing Unit Proposals]** | | | | | | | | | |
| | • | Identification of the site location on a USGS map. | | Y | Y | Y | Y | Y | Y | Y |
| | • | At a minimum, a Letter of Intent to negotiate a lease for the full contract term or term necessary for financing (whichever is greater), or to purchase the site... | | N/Y | Y | Y | Y | Y | N/Y | N/Y |
| **E.** | **Transmission Threshold** | | | | | | | | | |
| | • | If the project is located outside of PEF's control area, the Bidder must provide a transmission plan for wheeling services... | | N/Y | N/Y | -- | -- | -- | -- | -- |
| | • | If the project is located inside of PEF's control area, the Bidder must complete a Network Resource System Impact Study data request (Schedule 7 of the Response Package). | | -- | -- | Y* | Y* | Y* | Y | Y |

* Clarification/additional information needed (and later received)

-- Not applicable to this type of proposal

N/Y Initially did not pass threshold. Later provided information to pass threshold.

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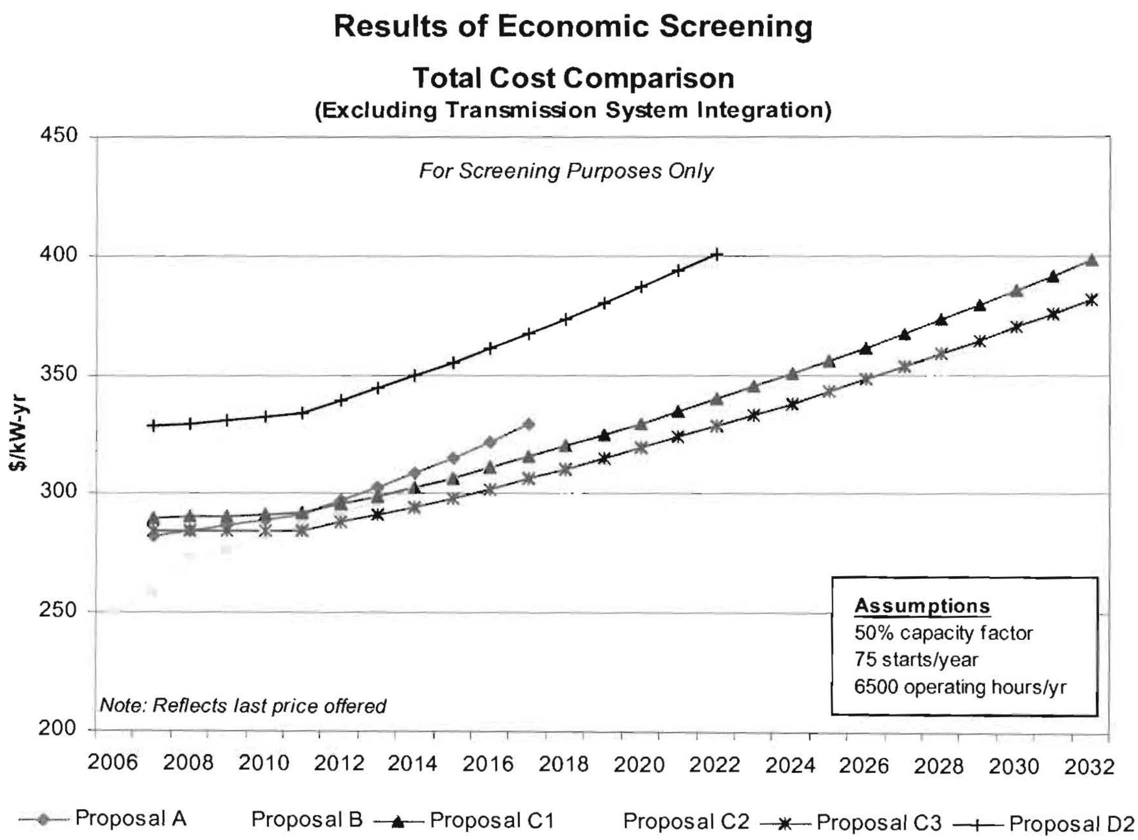
Exhibit ___ **(DJR-6)**

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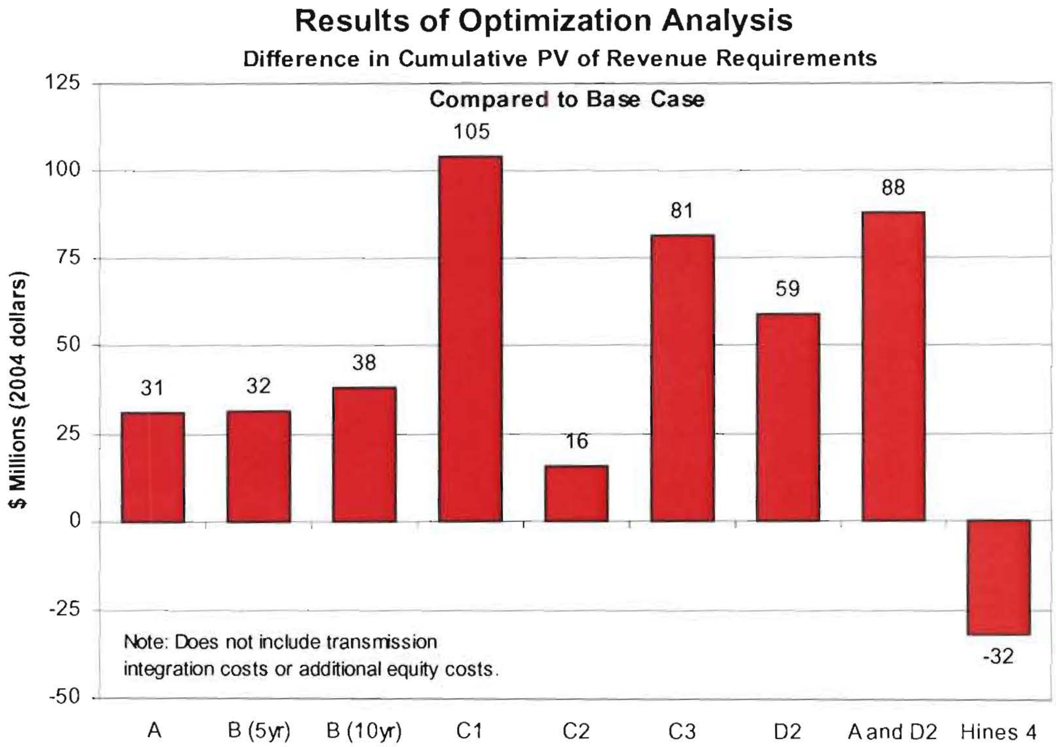
WITNESS: Daniel J. Roeder (DJR-6)
DATE: 11-03-04

Exhibit ___ **(DJR-7)**

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COMPANY/ Progress Energy FL
WITNESS: Daniel J. Roeder (DJR-7)
DATE: 11-03-04

Exhibit ___ **(DJR-8)**

## Minimum Evaluation Requirements

A. **Environmental**
- Preliminary environmental analysis performed and submitted to PEF [New Unit Proposals].
- Reasonable schedule for securing permits presented and evidence provided that permits are likely to be secured [New Unit Proposals].

B. **Engineering and Design**
- The project technology will be able to achieve the operating targets specified by the Bidder [New Unit and Existing Unit Proposals].
- Operation and Maintenance Plan provided which indicates that the project will be operated and maintained in a manner adequate to allow the project to satisfy its contractual commitments [New Unit and Existing Unit Proposals].

C. **Fuel Supply and Transportation Plan**
- Preliminary fuel supply plan provided which describes the Bidder's plan for securing fuel supply and transportation for delivery to the project. The plan shall provide a description of the fuel delivery system to the site, the terms and conditions of any existing or proposed fuel supply and transportation arrangements, and the status of such arrangements [New Unit and Existing Unit Proposals].

D. **Project Financial Viability**
- For New Unit Proposals, evidence provided that demonstrates the project is financially viable [New Unit Proposals].
- Demonstration that the Bidder has sufficient credit standing and financial resources to satisfy its contractual commitments [All Proposals].

E. **Project Management Plan**
- For a New Unit Proposal, critical path diagram and schedule for the project provided which specify the items on the critical path and demonstrate the project would achieve commercial operation by December 1, 2007 [New Unit Proposals].

Exhibit ___ **(DJR-9)**

## Technical Criteria

| Development Feasibility | Project Value | Operational Quality |
|---|---|---|
| Permitting Certainty (N) | Acceptance of Key Terms and Conditions (N,E,S) | Minimum Load (N, E) |
| Financial Viability (N,E,S) | Fuel Supply and Transportation Reliability (N,E) | Start Time (N, E) |
| Commercial Operation Date Certainty (N) | Reliability Impact (N,E,S) | Ramp Rate (N, E) |
| Bidder Experience (N,E,S) | Flexibility Provisions (N,E,S) | Maximum Starts/Year (N, E) |
| | | Minimum Run-Time Constraint (N, E) |
| | | Minimum Down-Time Constraint (N, E) |
| | | Annual Operating Hour Limit (N, E) |

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Exhibit ___ **(DJR-10)**

## Final Results of Technical Evaluation

| | Minimum Evaluation Requirements | A | B | C | D | Hines 4 |
|---|---|---|---|---|---|---|
| A1 | Preliminary environmental analysis is performed and submitted to PEF | Go | N/A | Go | N/A | Go |
| A2 | Reasonable schedule for securing permits presented and evidence provided that permits are likely to be secured | Go | N/A | Go | N/A | Go |
| B1 | The project technology will be able to achieve the operating targets specified by the Bidder | Go | Go | Go | Go | Go |
| B2 | O&M Plan provided that indicates that the project will be operated and maintained adequate to allow the project to satisfy its contractual commitments | Go | Go | Go | Go | Go |
| C | Fuel Supply and Transportation Plan provided for securing fuel supply and transportation for delivery to the project | Go | Go | Go | Go | Go |
| D1 | For New Unit Proposals, evidence provided that demonstrates the project is financially viable | Go | N/A | Go | Go | Go |
| D2 | Demonstration that the Bidder has sufficient credit standing and financial resources to satisfy its contractual commitments | Go | Go | Go | Go | Go |
| E | For a New Unit proposal, critical path diagram and schedule provided demonstrating the project would achieve commercial operation by 12/1/07 | Go | N/A | Go | Go | Go |
| | **Technical Criteria** | | | | | |
| | ***Development Feasibility*** | | | | | |
| 1 | Permitting Certainty | 2 | N/A | 2 | N/A | 1 |
| 2 | Financial Viability | 5 | 4 | 2 | 3 | 1 |
| 3 | Commercial Operation Date Certainty | 3 | N/A | 3 | 1 | 2 |
| 4 | Bidder Experience | 3 | 5 | 4 | 1 | 2 |
| | ***Project Value*** | | | | | |
| 5 | Acceptance of Key Terms & Conditions | 4 | 1 | 3 | 2 | N/A |
| 6 | Fuel Supply and Transportation Reliability | 5 | 2 | 2 | 4 | 1 |
| 7 | Reliability Impact | 4 | 5 | 2 | 1 | 2 |
| 8 | Flexibility Provisions | N/A | N/A | N/A | N/A | N/A |
| | ***Operational Quality*** | | | | | |
| 9 | Minimum Load | 3 | 1 | 4 | 2 | 5 |
| 10 | Start Time | 3 | 5 | 4 | 1 | 2 |
| 11 | Ramp rate | 2 | 4 | 3 | 5 | 1 |
| 12 | Maximum Starts/Year | 1 | 5 | 1 | 1 | 1 |
| 13 | Minimum Run-Time | 5 | 3 | 4 | 1 | 2 |
| 14 | Minimum Down Time | 2 | 5 | 3 | 1 | 3 |
| 15 | Annual Operating Limit | 1 | 5 | 1 | 1 | 1 |

Exhibit ___ (**DJR-11**)

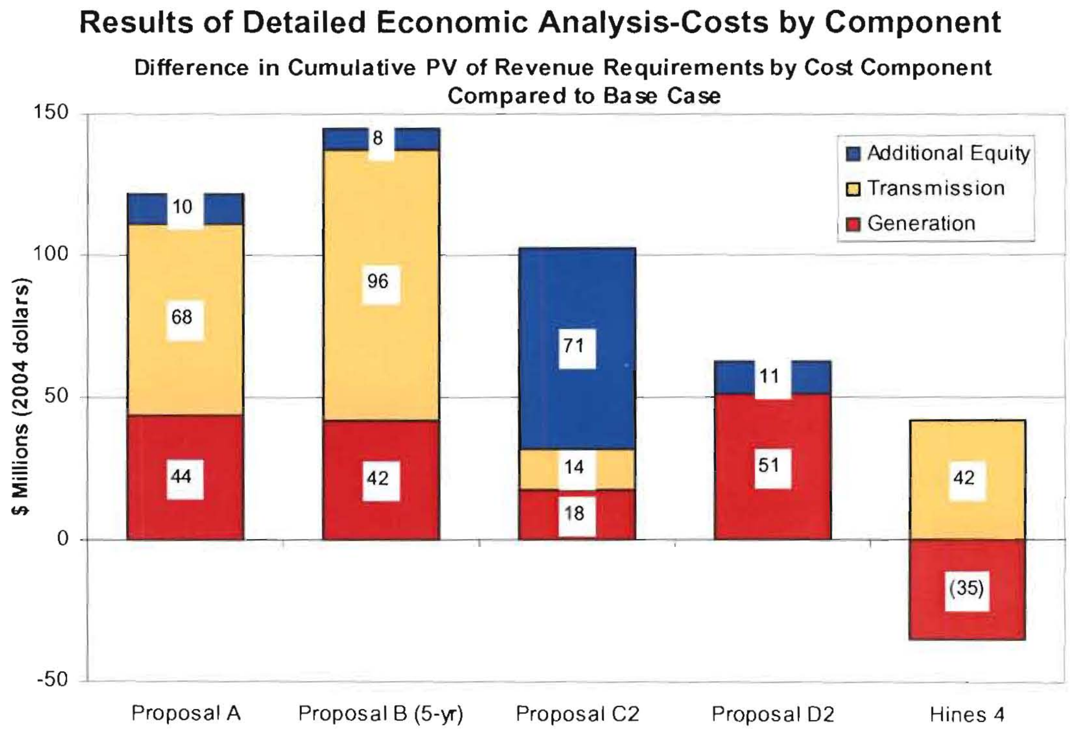


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**Exhibit___ (PRM-1)**

**Natural Gas Forecasts Compared to Other Industry Forecasts**

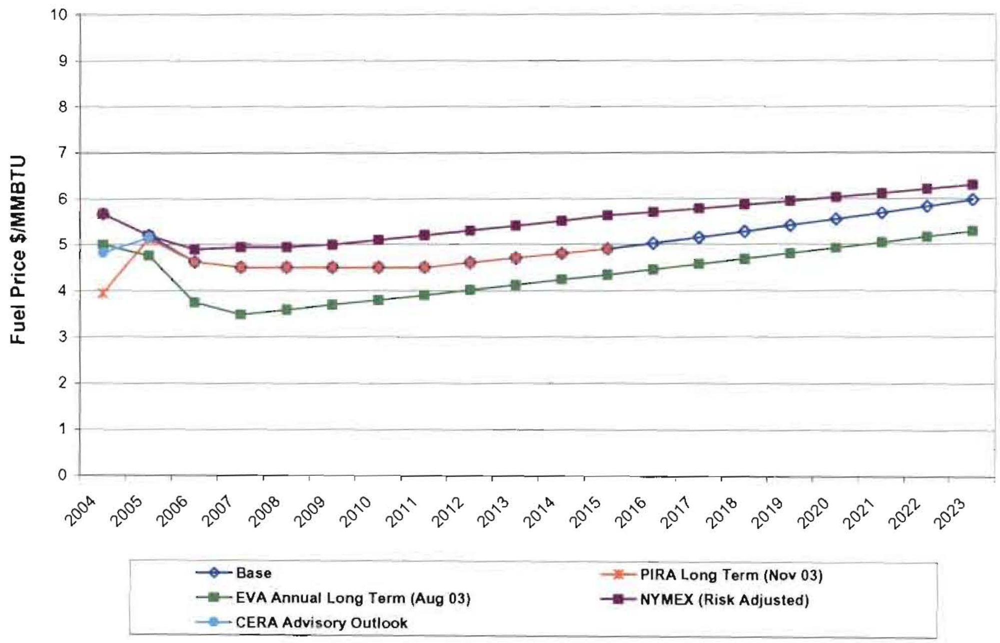


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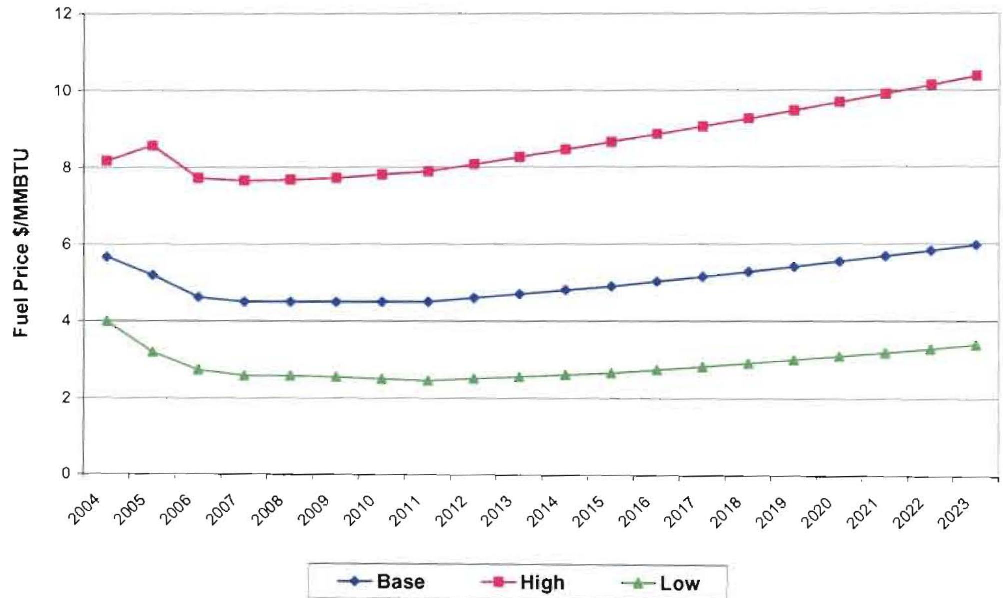
**Exhibit___ (PRM-2)**

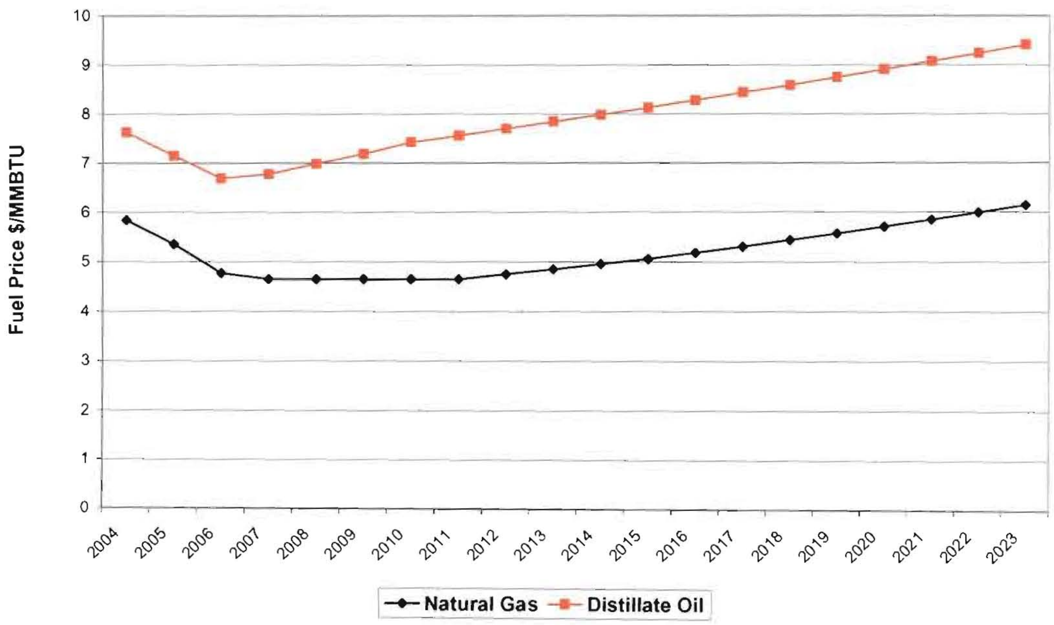
**Base, High and Low Case Natural Gas Forecasts**




Henry Hub basis

Exhibit___ (PRM-3)

**Fuel Price Forecast for Hines**




Variable Transportation Included

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**Exhibit___ (JMR-1)**

**Hines Energy Complex Map**

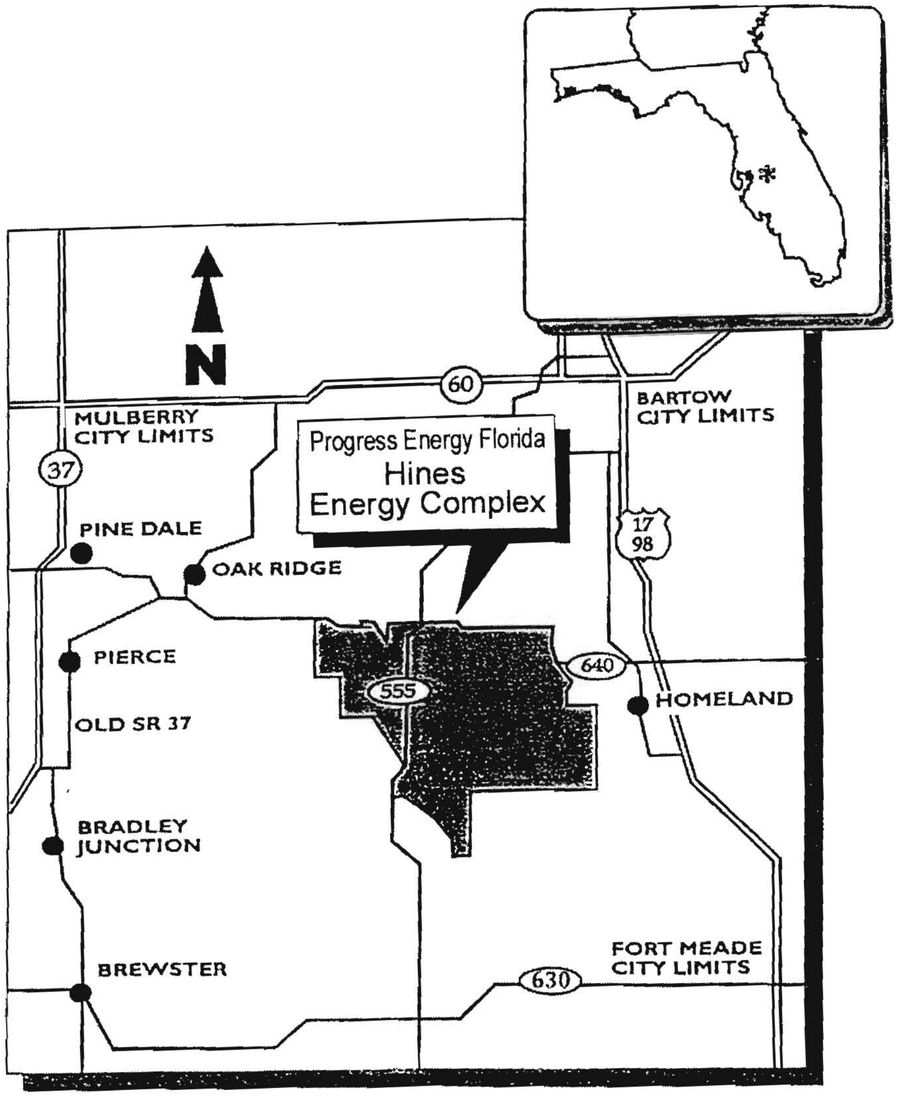


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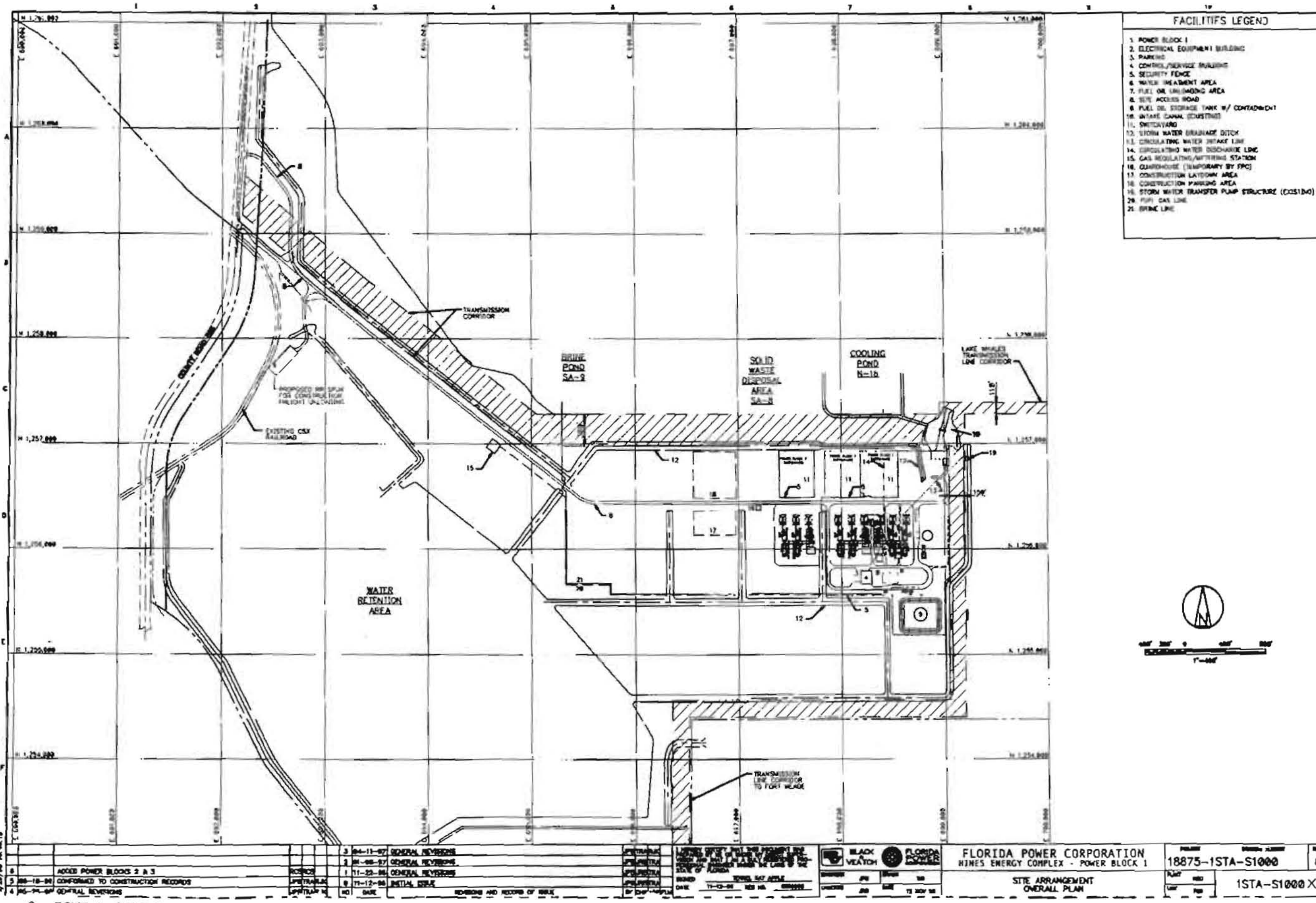
**Exhibit___ (JMR-2)**

**Site Arrangement – Overall Plan**




*ref: ISTA-S100x*

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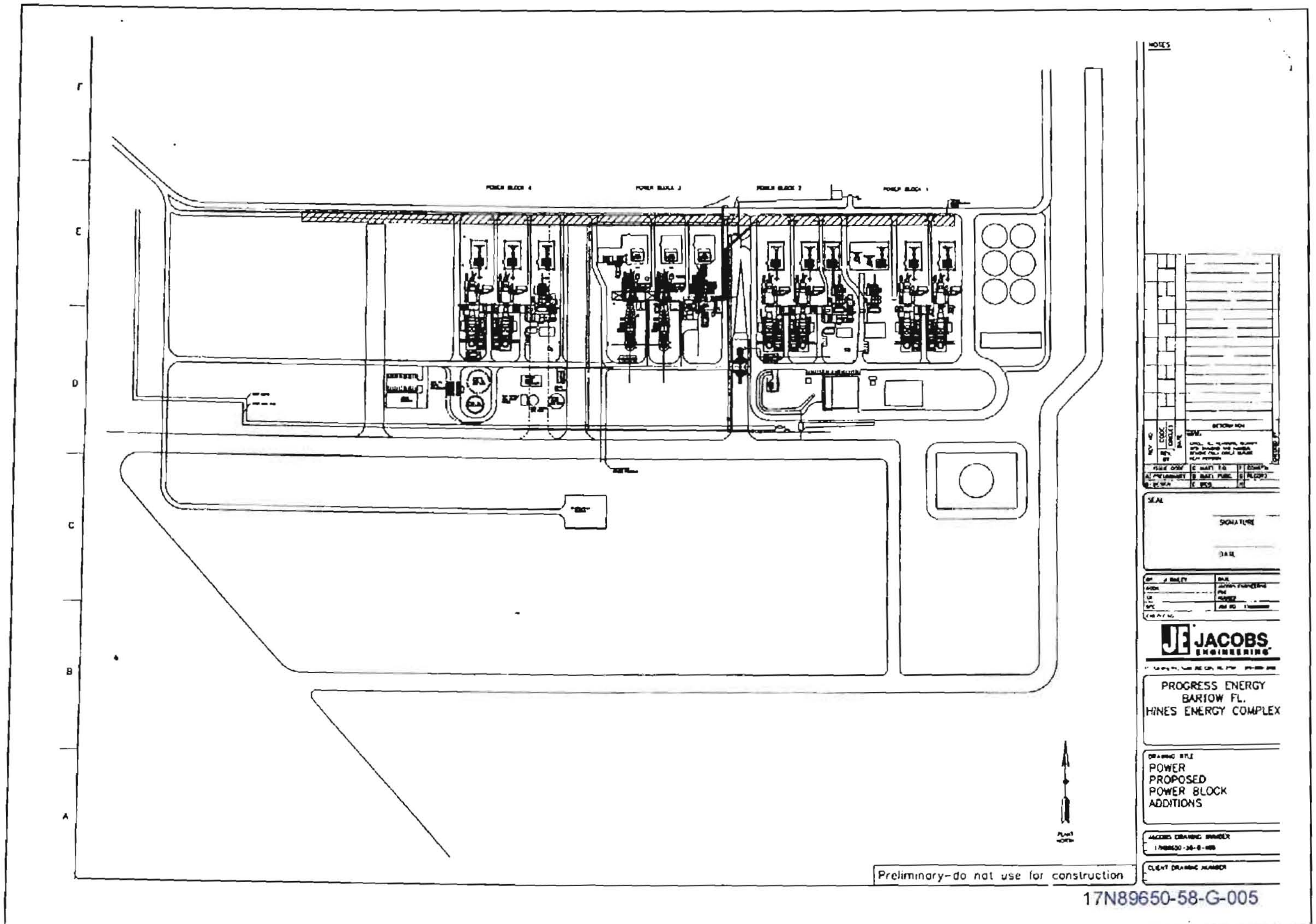
**Exhibit___ (JMR-3)**

**Site Arrangement -- Power Block Area**

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WITNESS. John M. Robinson (JMR-3)
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Exhibit___ (JMR-4)

Typical Combined Cycle Schematic

(2-on-1)

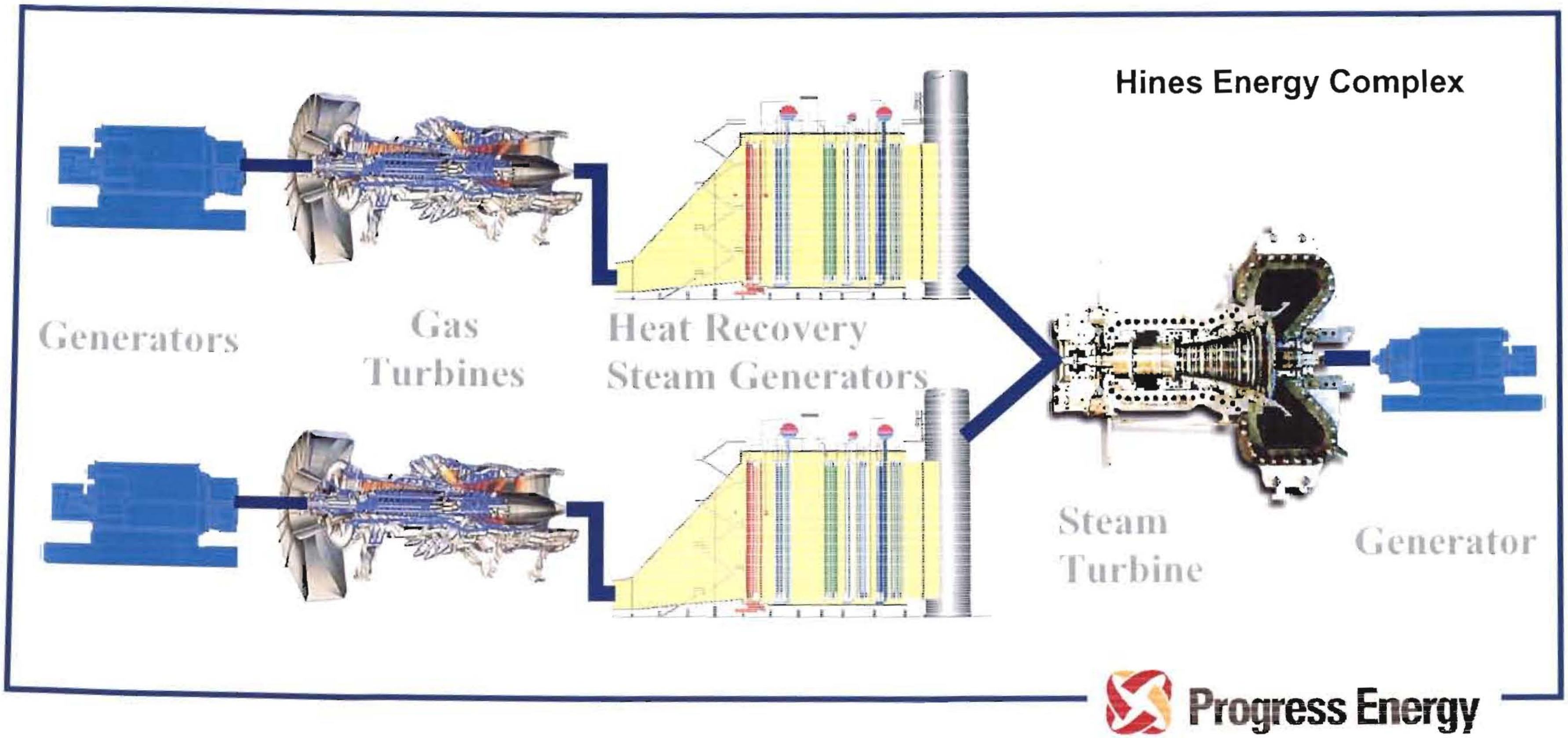

**Exhibit___ (JMR-5)**

**Projected Cost Estimate for Hines Unit 4**

**($ Thousands)**

| | |
|---|---|
| EPC Contractor and Equipment Contracts | $188,450 |
| Contingency | 4,289 |
| Licensing, Permits and Site Certificates | 500 |
| PEF Internal Costs | 28,280 |
| **Total Project Cost – Excluding Transmission** | **$221,519** |
| AFUDC | 27,014 |
| **Total Installed Cost – Excluding Transmission** | **$248,533** |
| | |
| | |
| | |

Exhibit___ (JMR-6)

Project Schedule for Hines 4

| | |
|---|---|
| Award Purchase Order Contracts for Major Equipment | February 28, 2005 |
| Award EPC Contract | February 28, 2005 |
| Supplemental Site Certification Approval | September 30, 2005 |
| Begin Construction | January 2, 2006 |
| Construction Complete | November 1, 2007 |
| Commercial Operation | December 1, 2007 |

**Exhibit CGB-1**

***"Buy versus Build": Debt Aspects of Purchased-Power Agreements. May 8, 2003, S&P***

STANDARD & POOR'S | RATINGSDIRECT

Return to Regular Format

# Research:

## "Buy Versus Build": Debt Aspects of Purchased-Power Agreements

**Publication date:** 08-May-2003

**Credit Analyst:** Jeffrey Wolinsky, CFA, New York (1) 212-438-2117; Dimitri Nikas, New York (1) 212-438-7807; Anthony Flintoff, London (44) 20-7826-3874; Laurie Conheady, Melbourne (61) 3-9631-2036

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery--and thus release from the payment obligation--is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

### Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

## Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

## Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build--i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%--10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios.

Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

## Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (11 plus 48). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

**Table 1 ABC Utility Co. Adjustment to Capital Structure**

| | Original capital structure | | Adjusted capital structure | |
|---|---|---|---|---|
| | $ | % | $ | % |
| Debt | 1,400 | 54 | 1,400 | 48 |
| Adjustment to debt | - | - | 327 | 11 |
| Preferred stock | 200 | 8 | 200 | 7 |
| Common equity | 1,000 | 38 | 1,000 | 34 |
| Total capitalization | 2,600 | 100 | 2,927 | 100 |

**Table 2 ABC Utility Co. Adjustment to Pretax Interest Coverage**

| | | Original pretax interest coverage (x) | | Adjusted pretax interest coverage (x) | |
|---|---|---|---|---|---|
| Net income | 120 | | | | |
| Income taxes | 65 | 300 | | (300+33) | |
| Interest expense | 115 | 115 | = 2.6x | (115+33) | = 2.3x |
| Pretax available | 300 | | | | |

## Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means.