BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060220-EC

In the Matter of

PETITION FOR DETERMINATION OF NEED FOR SEMINOLE GENERATING STATION UNIT 3 ELECTRICAL POWER PLANT IN PUTNAM COUNTY, BY SEMINOLE ELECTRIC COOPERATIVE, INC.

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER J. TERRY DEASON COMMISSIONER ISILIO ARRIAGA COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. TEW
DATE:	Wednesday, June 7, 2006
TIME:	Commenced at 9:50 a.m. Concluded at 12:35 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, RPR, CRR Official FPSC Reporter (850) 413-6734

DOCUMENT NUMBER-DATE
04984 JUN-9 06
FPSC-COMMISSION CLERK

PARTICIPATING:

CHARLES A. GUYTON, ESQUIRE, and ELIZABETH C. DALEY, ESQUIRE, Squire, Sanders & Dempsey, LLP, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1804, appearing on behalf of Seminole Electric Cooperative, Inc.

MARTHA CARTER BROWN, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

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CHAIRMAN EDGAR: Thank you all for your patience. I will call this hearing to order and ask staff to read the notice.

MS. BROWN: By notice issued March 29th, 2006, this time and place was set for an administrative hearing in Docket Number 060220-EC: Petition for determination of need for Seminole Generating Station Unit 3 electrical power plant in Putnam County, by Seminole Electric Cooperative, Inc. The purpose of the hearing is set out in the notice.

CHAIRMAN EDGAR: Thank you. And next I will take appearances from the attorneys representing parties in this case.

MR. GUYTON: Charles A. Guyton and Elizabeth C. Daley appearing on behalf of Seminole Electric Cooperative, Inc., with the law firm of Squires, Sanders & Dempsey, LLP.

CHAIRMAN EDGAR: Thank you.

MS. BROWN: And Martha Carter Brown on behalf of the Commission.

CHAIRMAN EDGAR: Thank you. Ms. Brown, are there preliminary matters?

MS. BROWN: There are a couple, at least one, Commissioner, having to do with a late-filed petition to intervene by the Sierra Club. It was filed on Friday evening after the clerk's office closed and was logged in as filed the

following Monday pursuant to the Uniform Rules of Administrative Procedure. That puts it past the deadline for filing petitions to intervene five days before the hearing.

Furthermore, the petition did not include a certificate of service and was not served on the parties to the hearing or on staff's attorneys. Seminole has filed an objection to this petition to intervene yesterday afternoon. They object to the intervening on several grounds, the first of which being the failure to comply with the Administrative Procedure Rules. They also object on standing grounds.

We recommend that the petition be denied. The lateness of the filing and the failure to serve the parties creates hardship for the participants. We recommend denial, but we want to note that we have told the Sierra Club that they'll have the opportunity to present public testimony, and they have indicated that they will take advantage of that. That's our main preliminary matter. We suggest that you deny the petition.

CHAIRMAN EDGAR: Okay. I haven't seen anybody -- Ms. Brown, is there anybody here to speak on behalf of the petition?

MS. BROWN: No.

CHAIRMAN EDGAR: No? Mr. Guyton, do you have --

MR. GUYTON: Madam Chairman, Commissioners, we think this issue is appropriately framed by staff. It is infirm for

a variety of reasons which I will not go into in length, but I'll be glad to entertain questions, if there are any.

CHAIRMAN EDGAR: Thank you. Then for the reasons that have been described by our staff, it is my decision to deny the petition to intervene, recognizing, again, as Ms. Brown stated, that there will be the opportunity here in a few moments to take public testimony on the issues that are before us.

Ms. Brown, are there other matters?

MS. BROWN: There are several individuals who have asked to provide public testimony in the public testimony part of the proceeding. In the formal part of the proceeding all of the issues identified in the prehearing order have been stipulated, and we have an agreement with Seminole to request that all of the witnesses have been excused and that we enter the formal evidentiary record testimony and exhibits and then move to the public testimony, and from there we can determine whether the Commission wants to make a bench decision in the case. So I guess we can proceed to that.

CHAIRMAN EDGAR: Okay. Well, then let's get the record in order.

MS. BROWN: All right. We ask that all prefiled testimony as revised and identified in the prehearing order be inserted into the record as though read. The parties have waived cross-examination.

CHAIRMAN EDGAR: The prefiled testimony as revised will be inserted into the record as though read.

MS. BROWN: All the formal exhibits are stipulated as indicated on the comprehensive exhibit list. We would like to mark that list itself as Exhibit 1, and all other exhibits on the list should be numbered as indicated there and moved into the record.

CHAIRMAN EDGAR: The exhibit list will be marked as you have described and the exhibits will be entered into the record.

(Exhibits 1 through 36 marked for identification and admitted into the record.)

MS. BROWN: I would note that on that list we can keep track of any exhibits that public witnesses would like to provide for the Commission.

CHAIRMAN EDGAR: If there are additional exhibits to come forward, we will add them -- we will number, label them and add them to the exhibit list.

060220-EE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF TIMOTHY S. WOODBURY

DOCKET NO. 06____-EU

MARCH 10, 2006

Q. Please state your name and business address.

A. My name is Timothy S. Woodbury. My business address is 16313 North Dale Mabry Highway, Tampa Florida 33688-2000.

Q. By whom are you employed and what is your position?

A. I am employed by Seminole Electric Cooperative, Inc. (Seminole) as Senior Vice President and Chief Strategic Officer.

Q. Please describe your duties and responsibilities in that position.

A. My responsibilities include managerial oversight of activities related to strategic planning, rate design and development, power supply planning, power marketing, load forecasting, regulatory affairs, and purchased power acquisition and contract administration.

Q. Please describe your educational background and business experience.

A. I have over twenty-eight years of experience in the electric utility industry. Prior to my employment at Seminole in August 1979, I was employed as an economist by

Duke Power Company working in the areas of both rates and load forecasting. I have a Bachelor of Science in Financial Management and a Master of Arts in Economics from Clemson University.

Q. Have you previously testified before this Commission?

A. Yes. I have provided written testimony and testified on behalf of Seminole before both the Florida Public Service Commission (Commission or FPSC) and the Federal Energy Regulatory Commission (FERC) in a number of different regulatory proceedings concerning a variety of issues relating to my areas of responsibility. Most recently, I testified in FPSC Docket No. 001748 relating to the determination of need for the Osprey Energy Center.

Q. What is the purpose of your testimony?

A. In my testimony, I will describe Seminole and its Members and provide an overview of the case supporting Seminole's request for a determination of need for Seminole Generating Station Unit 3 (SGS Unit 3), a proposed 750 MW supercritical pulverized coal unit. I will also introduce Seminole's witnesses and the Need Study sponsored by these witnesses. Finally, I will address the adverse consequences that will occur if SGS Unit 3 is not granted an affirmative determination of need.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I sponsor the following six exhibits, which are attached to my testimony:

Exhibit TSW-1 – Seminole's Member Distribution Cooperatives

Exhibit TSW-2 – Seminole's 2006 Generation Resources

Exhibit TSW-3 – Seminole's Power Purchase Contracts With Renewable Resources

Exhibit TSW-4 – Seminole's Power Purchase Contracts

Exhibit TSW-5 – Seminole's Interconnections

Exhibit TSW-6 – Seminole's Reliance Upon Natural Gas Generation

Q. Are you sponsoring any part of the Need Study in this proceeding?

A. Yes. I sponsor Sections I, II, III and X and co-sponsor Section IX. I also sponsor Appendices A and B to the Need Study.

I. SEMINOLE REQUESTS A DETERMINATION OF NEED FOR SGS UNIT 3.

Q. Please summarize the relief Seminole requests in this proceeding.

A. Seminole asks the Commission for an affirmative determination of need for SGS Unit 3. SGS Unit 3 is a 750 MW supercritical pulverized coal unit. It is anticipated that SGS Unit 3 will go into commercial operation in May 2012 and will be fueled by a combination of coal and petroleum coke. SGS Unit 3 will be constructed on an existing Seminole generation site, sharing common facilities currently serving SGS Units 1 and 2, two pulverized coal units located in Putnam County, Florida. The projected cost of SGS Unit 3, which is developed in more detail in the testimony of Mr. Klover and Mr. Opalinski, will be approximately $1.4 billion. The project will

be financed by loans guaranteed by the Rural Utilities Service (RUS) in conjunction with any financing available to Seminole through the issuance of pollution control bonds. As Mr. Mahaffey addresses in detail, SGS Unit 3 is, by a wide margin, the most cost-effective option available to meet the reliability and economic needs of Seminole and its Members.

Seminole asks the Commission to find, based on the evidence submitted, that SGS Unit 3 satisfies all the legal requirements for an affirmative determination of need. Such an affirmative determination of need would then be used by Seminole in its Siting Application under the Florida Electric Power Plant Siting Act (Siting Act), which is currently pending.

II. SEMINOLE'S WITNESSES

Q. Please summarize Seminole's direct case.

A. In support of its request for an affirmative determination of need for SGS Unit 3, Seminole has filed a detailed Petition setting forth its need for SGS Unit 3 and addressing how SGS Unit 3 satisfies the statutory criteria for a determination of need. Seminole has also filed a detailed Need Study, with supporting appendices, setting forth Seminole's need for SGS Unit 3. Seminole is also filing extensive direct testimony supporting the need for SGS Unit 3 and showing that SGS Unit 3 meets the criteria to be considered in assessing a determination of need.

Q. Please introduce Seminole's witnesses and the areas they address in their testimony.

A. Seminole is sponsoring the direct testimony and exhibits of seven witnesses. The names and areas of responsibility for each of the other six witnesses are as follows:

Michael Opalinski, Seminole's Vice President of Technical Services, describes SGS Unit 3, including its site, technology, related facilities, operating assumptions and estimated total cost. He also addresses Seminole's experience in the construction and operation of pulverized coal units.

Richard Klover, the Burns & McDonnell Project Manager for SGS Unit 3, provides a detailed description of SGS Unit 3, the technologies incorporated in its design and its estimated design cost. Mr. Klover also presents the feasibility studies and technology assessment prepared by Burns & McDonnell for Seminole, including its assessment of other generation technologies, and addresses the experience of Burns & McDonnell.

Wm. Jack Reid, Seminole's Director of Fuel Supply, presents the fuel supply and transportation plans for SGS Unit 3 as well as the fuel forecasts used in the analyses that examined the various options for meeting Seminole's base load capacity need in 2012.

William (Bill) Lawton, Seminole's Staff Economist, presents the Member load forecast used in the identification of SGS Unit 3 as the most cost-effective alternative available to meet the reliability and economic needs of Seminole and its Members. He also addresses why there is not sufficient conservation and DSM available to avoid SGS Unit 3.

Trudy Novak, Seminole's Director of Pricing & Bulk Power Contracts, addresses Seminole's experience in conducting capacity solicitations to meet forecasted needs, the April 2004 Request for Proposals (RFP) Seminole conducted to address its 2009/2012 need for base load capacity, the bids Seminole received in response to its RFP, the technical and commercial screening of such bids in conformance with the requirements of the RFP, and other purchased power options considered by Seminole.

Lane Mahaffey, Seminole's Director of Corporate Planning, addresses Seminole's power supply planning process, the reliability and need assessment Seminole performed to identify its 2012 need for base load capacity, Seminole's economic evaluation of self-built and purchased power options, the risk assessment performed for Seminole comparing the relative risk of coal-fired and gas-fired options, why SGS Unit 3 is the best, most cost-effective option to meet the reliability and economic needs of Seminole and its Members, and the adverse consequences if SGS Unit 3 is not granted an affirmative determination of need.

Each of Seminole's witnesses sponsors portions of the Need Study and Need Study Appendices. The portions they sponsor are addressed in each witness' testimony.

III. SEMINOLE AND ITS MEMBERS

Q. Please describe Seminole and its Members.

A. Seminole is a not-for-profit rural electric cooperative organized under Chapter 425, Florida Statutes. Seminole is a generation and transmission cooperative that only makes wholesale sales; it does not make retail sales.

Seminole's ten Members are also rural electric cooperatives organized under Chapter 425, Florida Statutes, and each serves retail end use consumers in Florida. The Members of Seminole are: Central Florida Electric Cooperative, Inc., Clay Electric Cooperative, Inc., Glades Electric Cooperative, Inc., Lee County Electric Cooperative, Inc., Peace River Electric Cooperative, Inc., Sumter Electric Cooperative, Inc., Suwannee Valley Electric Cooperative, Inc., Talquin Electric Cooperative, Inc., Tri-County Electric Cooperative, Inc., and Withlacoochee River Electric Cooperative, Inc. The areas in which Seminole's Members serve are shown in Exhibit TSW-1.

Q. Please describe the governance of Seminole.

A. Seminole is owned and governed by its Members. Each of its ten Members has two voting representatives and one alternate representative on Seminole's Board of

Trustees (Board). The General Manager of Seminole serves at the pleasure of the Board.

Seminole employs a comprehensive strategic planning process with Board involvement. All major strategic policy decisions, such as building new generation and entering into purchased power contracts, are made by the Seminole Board. Seminole is not involved in the management of its Member systems.

Q. **Please describe Seminole's purpose.**

A. Seminole exists to provide reliable electric service at competitive rates to its Members. Seminole was organized in 1948, but remained relatively inactive until shortly after the 1973 oil embargo. In 1974, Seminole's Board determined that Seminole should develop independent power supplies for its Members. In 1975, each Member entered into a long term "All Requirements" contract with Seminole for the purchase of wholesale power (Wholesale Power Contract). These Wholesale Power Contracts require each Member to purchase from Seminole all of its power requirements for distribution within the State of Florida not otherwise supplied under pre-existing contracts. Four of Seminole's Members then had, and continue to have, pre-existing contracts with the Southeastern Power Administration (SEPA) for a combined 26 MW of capacity.

Q. Do the terms of the Wholesale Power Contracts affect Seminole's need for capacity?

A. Yes. The Wholesale Power Contracts establish Seminole's obligations regarding electric service to its Members. The Wholesale Power Contracts, as originally executed, had an initial term of forty-five years (i.e., until July 30, 2020), and provided that any party could terminate the agreement effective any time after the initial term with a three year written notice. In 2004, amendments to the Wholesale Power Contracts were executed between Seminole and seven of Seminole's ten Members, representing approximately 55% of Seminole's current load, extending the term of those Wholesale Power Contracts by an additional 25 years, through 2045. The amended Wholesale Power Contracts may not be terminated prior to the end of the extended term (i.e., December 31, 2045). These amended Wholesale Power Contracts have been approved by the RUS.

Q. What is the status of discussions with the remaining three Members regarding Wholesale Power Contract extensions?

A. Discussions continue between Seminole and its three remaining Members. These discussions could result in similar contract term extensions for some or all of these Members. Indeed, two of those three Members have committed to extend their respective Wholesale Power Contracts through the year 2045 in exchange for Seminole agreeing to provide an option for Members to purchase a portion of their capacity and energy requirements after the year 2020 from power suppliers other than Seminole. A Member exercising such an option would still be obligated to pay its

allocated share of the fixed costs associated with any power supply resource that would otherwise be left stranded by the Member's having executed the option. The parties are currently working on an amendment to effectuate such a result. The amendment will be subject to RUS approval.

Q. Does this uncertainty regarding whether the three remaining Members will participate in Seminole after the year 2020 affect Seminole's need for SGS Unit 3 beginning in 2012?

A. No. Even in the most conservative post-2020 Member load scenario (i.e., none of the three remaining Members extending the Wholesale Power Contract), SGS Unit 3 is the most cost-effective alternative for meeting Seminole's base load requirements beginning in 2012. This result will be demonstrated by Mr. Mahaffey, who will describe how Seminole's economic studies were based on the most conservative load scenario wherein only seven Members remain under contract after 2020.

Q. Please summarize Seminole's recent and projected growth.

A. As is addressed in detail in Mr. Lawton's testimony, the Seminole system has experienced, and is forecast to continue to experience, some of the fastest growth in the State of Florida. In 2004, Seminole's Members had 805,085 member/consumers who used 15,348 GWh of energy and who placed a coincident system peak demand on the Seminole system of 3,364 MW. Seminole's highest peak demand on record occurred on February 14, 2006 at 4,113 MW (estimated). Over the past five years, the collective member/consumers of Seminole's Members have grown by 3.1% per

year and are projected to grow by 2.8% per year over the next ten years. The energy consumption for these member/consumers grew by 5.2% per year over the last five years and is projected to grow by 4.1% per year over the next ten years. The coincident winter peak demand on Seminole's system has grown by 3.8% per year over the last five years and is projected to grow by 4.1% per year over the next ten years. These historic and forecasted energy and peak demand values reflect the impact of conservation and DSM programs offered by Seminole's Members.

Q. How does Seminole meet the power supply needs of its Members and their member/consumers?

A. Seminole meets the power supply needs of its Members and their member/consumers with Seminole-owned generation in combination with purchased power contracts with independent power producers, investor-owned and municipal utilities, and renewable energy providers. Over half of Seminole's Members' capacity requirements are currently supplied through purchased power agreements, as is shown graphically on Exhibit TSW-2.

Q. Please describe the generating units Seminole owns to meet the requirements of its Members and their member/consumers.

A. Seminole's existing owned generating resources are located at three generating sites. Seminole Generating Station Units 1 & 2 are 650 MW class pulverized coal units located in Putnam County near Palatka, Florida. SGS Unit 1 began commercial operation on February 1, 1984. SGS Unit 2 began commercial operation on

December 31, 1984. Payne Creek Generating Station is a 500 MW class gas combined cycle unit located in Hardee County, Florida. It began commercial operation on January 1, 2002. The Payne Creek Generating Station is also the site for a scheduled addition of approximately 300 MW of peaking capacity (five gas turbines scheduled for commercial operation in December 2006). Seminole also owns a 15 MW share of Progress Energy Florida's (PEF) Crystal River 3 nuclear generating unit, which is operated by PEF. More detailed information regarding Seminole's existing owned generating resources is presented in Appendix A of the Need Study.

Q. Please summarize the purchased power contracts Seminole has with renewable resources.

A. Seminole has contracts to purchase firm capacity and energy from three renewable resource facilities: Lee County's Resource Recovery Facility, DG Telogia Power, LLC., and Bio-Energy Partners. These purchases currently total approximately 54 MW. Seminole has focused upon procurement of renewable resources that are cost-competitive and that provide a reliable source of supply of capacity and energy. A summary of these firm capacity and energy agreements with renewable resource facilities is presented in Exhibit TSW-3.

Q. What other purchased power contracts does Seminole have?

A. In addition to the three contracts for purchases from renewable resources, Seminole has contracts for the purchase of firm capacity from PEF, Oleander Power Project, Limited Partnership, Reliant Energy Florida, LLC., Calpine Construction Finance

Company, L.P., Hardee Power Partners Limited, and the City of Gainesville. Seminole also has agreements in place to purchase excess capacity from load management generation of its Members. A summary of Seminole's long-term firm capacity purchases is shown on Exhibit TSW-4.

Q. Please describe the transmission facilities and transmission service agreements Seminole employs to serve its Members and their member/consumers.

A. Seminole owns approximately 278 circuit miles of 230 kV transmission lines and fourteen 69 kV lines totaling 140 miles in length. In addition, Seminole receives firm transmission service from Florida Power & Light Company (FPL) and PEF. These transmission service agreements give Seminole the contractual right to deliver capacity and energy from Seminole's power supply resources over the FPL and PEF transmission systems for the purpose of serving Member load requirements.

Q. Please describe the interconnections that Seminole has with other operating systems within Florida.

A. Seminole has fifteen 230 kV transmission interconnections with the following utilities: FPL, PEF, Tampa Electric Company (TECO), Hardee Power Partners Limited, JEA, Lee County Electric Cooperative, and The City of Ocala. Each of those interconnection points is identified on Exhibit TSW-5.

Q Please summarize Seminole's unmet capacity need for 2012.

A. As explained in detail by Mr. Mahaffey, Seminole determined, based upon its forecasted load, reliability criteria and committed resources, that it needed over 1200 MW of additional capacity resources by 2012. Of this amount, Seminole determined that 750 MW should be base load capacity, and that such capacity should be coal generation. This additional base load capacity is necessary by 2012 not only to meet system reliability criteria, but also for Members to be able to provide adequate electricity at a reasonable cost to their member/consumers. In addition, Seminole and its Members need SGS Unit 3 to avoid an undue reliance upon gas-fired generation in 2012 and beyond.

Q. Which utilities in Florida would be primarily affected by the addition of SGS Unit 3?

A. It is the collective need of Seminole's Members for which Seminole plans and which justifies the need for SGS Unit 3. While there may be times when energy or capacity from SGS Unit 3 is sold to other electric utilities, it is envisioned that the unit will be used almost exclusively to provide energy and capacity to serve Seminole's Members' needs. Consequently, the utilities primarily affected by SGS Unit 3 are Seminole and its Members.

IV. SEMINOLE'S CONSIDERATION OF ALTERNATIVES TO SGS UNIT 3

Q. What process did Seminole follow in assessing alternatives that could meet its base load capacity needs in 2012?

A. As is addressed in detail in the testimony and exhibits of Mr. Mahaffey and Ms. Novak, Seminole used an extensive and vigorous process to identify and assess alternatives, both outside purchases and self-build options, that might be used to meet Seminole's need for base load capacity. Seminole's need for base load capacity exists after consideration of conservation and DSM captured in the load forecasts of Seminole and its Members.

Once Seminole's need for base load capacity in 2012 was established, Seminole first assessed the best means of meeting that need with self-build alternatives. As discussed by Mr. Opalinski and Mr. Mahaffey, those analyses showed that the best self-build option was a coal unit.

As discussed in detail by Ms. Novak, Seminole then issued an RFP seeking alternatives from wholesale providers of power – independent power producers, co-generators and other electric utilities. Seminole's use of an RFP was consistent with its well-established practice of using this approach for soliciting cost-effective and reliable capacity alternatives to self-build generation. Seminole has issued a number of such RFPs going as far back as 1988. Several of these RFPs have resulted in definitive purchased power agreements being awarded. At the present time, over

half of Seminole's resources are represented by purchased power contracts. This is shown graphically on Exhibit TSW-2.

Ultimately, after extensive efforts to identify purchased power options and further assess the relative risks of adding either coal-fired or gas-fired units to its system, Seminole concluded that the best, most cost-effective option available to Seminole to meet the needs of its Members and their member/consumers was for Seminole to build SGS Unit 3. This is addressed in detail in Mr. Mahaffey's testimony.

Q. Was the process Seminole followed to identify alternative resources and ultimately to choose SGS Unit 3 a fair process?

A. Yes. The process was fair both to potential suppliers and to Seminole's Members. From the perspective of potential suppliers, Seminole's RFP was not overly prescriptive in its terms. Therefore, the bidders were provided the opportunity to propose creative solutions to addressing Seminole's needs. Seminole broadly published its RFP. Seminole addressed bidder inquiries. The economic analyses performed were fair, with bidders being given an opportunity to improve their bids.

Seminole's evaluation of alternatives was also fair to Seminole's Members and their member/consumers. The best evidence of the fairness to Members and their member/consumers is that the process captured the alternative which is most cost-effective. While strategic considerations, such as dependence on natural gas, were not determinative (by themselves) in reaching a decision in this case due to the

significant economic disparity between SGS Unit 3 and Seminole's other options, the process was also fair to the Members and their member/consumers because it accommodated consideration of such factors.

V. SGS UNIT 3 MEETS THE STATUTORY NEED CRITERIA

Q. Mr. Woodbury, are you familiar with the criteria set forth in Section 403.519, Florida Statutes, that the Commission is to consider in a determination of need proceeding?

A. Yes. As a non-lawyer who has prior experience with the need determination process, I am familiar with the determination of need criteria.

Q. Is SGS Unit 3 needed by Seminole, its Members and their members/consumers for purposes of system reliability?

A. Yes. As developed in detail in Mr. Mahaffey's testimony, there is clearly a need for additional capacity on Seminole's system in 2012. Seminole's total need for additional capacity by 2012 was approximately 1200 MW, 750 MW of which is best served by base load generation. Seminole's need for base load generating capacity by 2012 is driven primarily by the expiration of existing purchased power contracts and load growth on Seminole's system. Absent the addition of SGS Unit 3 by the summer season of 2012, Seminole will not meet its minimum reliability criteria. If Seminole does not meet its minimum reliability criteria, its Members and their member/consumers will not receive the level of service reliability they require. In practical terms, this means an unacceptable level of service interruptions.

Q. Is SGS Unit 3 needed by Seminole, its Members and their member/consumers for reasons other than reliability?

A. Yes. As addressed in greater detail by Mr. Mahaffey, Seminole and its Members need SGS Unit 3 in 2012 for at least two reasons other than maintaining system reliability. First, SGS Unit 3 is needed for its economic value to Seminole, its Members and their member/consumers as a base load resource. Seminole and its Members need it to be able to provide adequate electricity at a reasonable cost. SGS Unit 3 is by far the most cost-effective alternative available to meet Seminole's and its Members' base load capacity requirements. It is anticipated to save Seminole and its Members approximately $500 million on a cumulative present worth revenue requirements (PWRR) basis compared to the next least costly alternative available to Seminole. This means that as a result of the addition of SGS Unit 3, Seminole and its Members will be able to charge lower rates than they otherwise would have to charge if any other identified alternative were selected. Second, SGS Unit 3 will help to mitigate fuel price volatility in member/consumer rates by reducing Seminole's reliance on gas-fired generation.

Q Is SGS Unit 3 the most cost-effective alternative to meet Seminole's need for base load generation in 2012?

A. Yes. As I noted above, this option is, by a wide margin, the most economical alternative available to Seminole and its Members.

Q. Is there reasonably achievable, cost-effective conservation and DSM available to mitigate the need for SGS Unit 3?

A. No. This question is addressed in detail in the Need Study and by Mr. Lawton in his testimony. As the Commission has previously found, Seminole provides price signals to its Members that are properly designed to provide incentives to lower on-peak demand, and Seminole's Members offer their end use customers a variety of conservation and DSM measures (Order No. PSC-01-0421-FOF-EC). Seminole's need for additional capacity captures the impact of conservation and DSM implemented by Seminole's Members by reflecting the impact of such measures in the load forecast. Seminole is not subject to Commission conservation and DSM goal setting and plan approval. However, even if it were, there is no reasonable scenario in which sufficient conservation and DSM could be added to the Seminole system to avoid the need for SGS Unit 3. Moreover, the 750 MW represented by SGS Unit 3 does not satisfy all of the incremental need by Seminole and its Members by 2012, and DSM is not well suited to avoiding the base load capacity that SGS Unit 3 would provide.

VI. ADVERSE CONSEQUENCES IF SGS UNIT 3 IS NOT APPROVED

Q. Please address the adverse consequences Seminole, its Members and their member/consumers would face if the Commission did not grant an affirmative determination of need for SGS Unit 3.

A. There are at least three significant adverse consequences which would flow to Seminole, its Members and their member/consumers from the Commission failing to grant a determination of need for SGS Unit 3.

First, Seminole, its Members and their member/consumers would face a less reliable system if SGS Unit 3 were not added. The capacity represented by SGS Unit 3 is essential to Seminole's ability to meet its reliability criteria in 2012. As a practical matter, given the timing of the Commission's decision on a determination of need for SGS Unit 3, there is not another coal-based option available that could feasibly meet Seminole's 2012 base load capacity need. Therefore, any alternative would have to be gas-fired, and Seminole believes that any new gas-fired alternative, whether self-build or supplying power through a purchased power agreement, would be not only more costly, but also less reliable than SGS Unit 3, given the greater potential for weather-related fuel supply and transportation constraints on gas deliveries into Florida.

Second, denial of a determination of need for SGS Unit 3 would result in significant additional costs for Seminole, its Members and their member/consumers. SGS Unit 3 is by far the most cost-effective alternative available to meet Seminole's 2012 base

load capacity need, providing savings of approximately $500 million. If SGS Unit 3 does not go into service, Seminole will be forced to find more expensive alternatives. This would have the effect of increasing the rates of both Seminole and its Members from what they would be if SGS Unit 3 been built.

Third, if SGS Unit 3 is not added to Seminole's system, then the Seminole system will face an undue reliance upon natural gas-fired generation. As shown on Exhibit TSW-6, at present 37% of the energy provided by Seminole is generated by natural gas. With the addition of SGS Unit 3 in 2012, that percentage will become 29% by 2013. If SGS Unit 3 were replaced by gas-fired alternatives, the only alternatives feasible at this point, Seminole's percentage of generation from natural gas in 2013 would rise to 52%. Seminole believes this would be an unwarranted reliance upon natural gas to meet its total system energy requirements.

Natural gas has experienced a significant and sustained rise in cost in the past few years. This cost increase has been passed on to end users, increasing the overall cost of energy. In addition to this adverse cost impact, natural gas supply, which was once seemingly assured in Florida, has become less certain, as is evidenced by the natural gas supply interruptions experienced during this last hurricane season. Because of natural gas' sustained cost increases and its less certain availability and reliability, Seminole believes that it should not construct additional gas-fired generation to meet this base load capacity need beginning in 2012. While there are no hard and fast rules governing what constitutes an optimal fuel mix, Seminole believes that additional

gas-fired generation to meet this base load need in 2012 would put the Seminole system in a position of having an undue reliance upon natural gas and thereby expose it to undue risks that would be counter to the interests of its Members and their member/consumers.

Q. Are there any other adverse consequences associated with a potential denial of a determination of need for SGS Unit 3?

Yes. The failure to add SGS Unit 3 would have adverse consequences upon Putnam County, Florida. As Mr. Opalinski discusses, the construction of SGS Unit 3 will add some 1,500 construction positions through 2012 and approximately 50 permanent positions in Putnam County, Florida. Of course, there will be secondary and tertiary economic benefits in and around Putnam County with the addition of these positions. Also, the tax base for the County and local governments will increase by a substantial margin. All of these significant economic benefits to Putnam County would be lost if Seminole were not granted a determination of need for SGS Unit 3.

Q. Does this conclude your direct testimony?

A. Yes, it does.

060220-EC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF MICHAEL P. OPALINSKI

DOCKET NO. 06____-EU

MARCH 10, 2006

Q. Please state your name, occupation and business address.

A. My Name is Michael P. Opalinski, and I am employed by Seminole Electric Cooperative (Seminole) as Vice President of Technical Services. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

Q. Please describe your duties and responsibilities.

A. In my position I am responsible for the Fuels and Transmission Services Departments and the Generation Engineering and Environmental Affairs Sections. The Fuels Department is responsible for the purchase and delivery of all fuels for Seminole's electric generating facilities. The Transmission Services Department is responsible for the planning, construction and maintenance of transmission lines and substations. The Generation Engineering Section is responsible for the design and construction of major capital projects at Seminole's operating facilities and new generating projects, including the development of feasibility and economic studies for new self-build projects. The Environmental Affairs Section is responsible for compliance of Seminole's generating and transmission facilities with existing regulatory permits and requirements, site selection of new generating and transmission facilities, and

securing necessary permits for all new projects, including the development of permitting feasibility analyses and the preparation and processing of permit applications.

Q. Please describe your educational background and business experience.

A. I graduated with a Bachelor of Science degree in Biology and Chemistry from Florida Southern College in 1970. After receiving my degree, I was employed by the City of Lakeland, Florida Electric and Water Department as a Chemist at the Larsen and McIntosh Power Plants. After serving as an officer in the United States Air Force, I returned to the City of Lakeland in 1974 to develop its environmental compliance program and manage environmental permitting for the McIntosh Unit 3 coal, oil and municipal refuse project.

In 1980, I began my career as the Environmental Manager for Seminole Electric Cooperative and was responsible for permit compliance during the construction and operation of Units 1 and 2 at the Seminole Generating Station (SGS). I was also responsible for site selection and permitting of new generation and transmission projects, which included Seminole's Taylor Project, a 1200 MW coal fired facility that was cancelled in 1983, the 572 MW Payne Creek Generating Station combined cycle unit in Hardee County, the 310 MW Payne Creek Peaking Project currently under construction, and numerous 230 kV transmission projects. Finally, I was responsible for the conversion project to produce wallboard grade synthetic gypsum

from the SGS desulfurization waste and the business arrangement with Lafarge Gypsum to construct a wallboard manufacturing facility at the SGS.

In 2002, I was promoted to Director of Environmental and Engineering Services with the added responsibility of managing the Generation Engineering Section. In this position, I oversaw the technical and economic evaluations which led to the construction of the Payne Creek Peaking Project utilizing fast start aero-derivative combustion turbine technology. In 2004, I was promoted to my current position.

Q. Have you testified before this Commission previously?

A. Yes. I testified on behalf of Seminole in Docket No. 880309-EC (Determination of Need for Hardee Power Station Units 1 and 2) and Docket No. 931212-EC (Determination of Need for Hardee Power Station Unit 3).

Q. What is the purpose of your testimony?

A. My testimony addresses the proposed Seminole Generating Station Unit 3 (SGS Unit 3), for which Seminole is seeking a determination of need in this proceeding. Specifically, my testimony will:

- describe the technical evaluation process that led to Seminole's selection of SGS Unit 3, a 750 MW (net) supercritical pulverized coal-fired unit, as its self-build alternative;
- describe the SGS site;
- describe the existing SGS Units 1 and 2;

- present a technical overview of the proposed SGS Unit 3;
- describe the environmental compliance measures planned for SGS Unit 3;
- describe the cost, schedule and economic benefits of SGS-3; and
- describe Seminole's experience in permitting, building and operating power plants.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit MPO-1 – Site Location Map – Putnam County
- Exhibit MPO-2 – Site Arrangement with SGS Unit 3
- Exhibit MPO-3 – SGS Unit 3 Project Capital Cost Components

Q. Are you sponsoring any portions of the Need Study document?

A. Yes. I sponsor Sections IV.A, IV.B, IV.D, IV.F, IV.G, IV.I and IV.J and co-sponsor Section IV.C of the Need Study.

I. TECHNICAL EVALUATION PROCESS

Q. How did Seminole determine what would be the most appropriate self-build generating alternative?

A. Seminole commissioned Burns & McDonnell, a consulting engineering firm with extensive experience in both evaluating and managing the construction of coal-fired power plants, to conduct a feasibility study to identify the best suited self-build alternatives for Seminole and the cost of those alternatives. Seminole requested that

Burns & McDonnell evaluate the site and water supply requirements, capital costs, operating and maintenance costs, performance, and schedule for a pulverized coal unit (sub-critical or super-critical steam cycle) or a natural gas combined cycle unit, and to make a determination if development of integrated gasification with combined cycle (IGCC) had reached commercial status.

Seminole did not recommend that circulating fluidized bed (CFB) boiler technology be included in the Burns & McDonnell alternatives assessment. At the time of the assessment, the largest operating CFB unit was approximately 300 MW, so multiple units would have been necessary to obtain the needed output. In addition, Seminole determined that its fuel delivery system would not allow it to take advantage of burning multiple lower ranked fuels; that emissions from a CFB were essentially comparable to a state of the art pulverized coal unit utilizing Best Available Control Technology; that wallboard grade gypsum could not be produced from a CFB unit; and that the Seminole site could not accommodate the on-site disposal of the significant amounts of combustion by-products generated.

Burns & McDonnell completed its initial feasibility study in August 2004. It identified a pulverized coal unit as the best base load alternative for Seminole, with a substantially lower overall cost than a gas-fired combined cycle unit. The study also concluded that integrated gasification with combined cycle (IGCC) technology was not yet ready for unsubsidized commercial operation and probably would remain in

that status for a few more years, until the technology has been more extensively demonstrated through several projects that are proposed or underway.

As discussed by Mr. Mahaffey, at the time of the initial feasibility study, Seminole envisioned a need for at least 600 MW of base load capacity in the 2009 – 2012 time frame. Subsequent to that feasibility study and during the evaluation of proposals submitted in response to Seminole's RFP, Seminole determined that its base load capacity need would be on the order of 750 MW by 2012. Seminole requested that Burns & McDonnell update its feasibility study to determine the economics of a 750 MW unit and whether such a unit could be constructed and permitted in a timely fashion. The updated study concluded that a 750 MW self-build unit was feasible and, due to economies of scale, the overall cost of the up-sized unit was lower (on a $ per MWh basis) than either the 600 MW coal-fired unit or a gas-fired combined cycle unit

The Burns & McDonnell studies are discussed in greater detail in the testimony of Seminole witness Richard Klover.

Q. How did Seminole use Burns & McDonnell's input in making its technical evaluation of the self-build alternative?

A. Seminole benefited greatly from Burns & McDonnell's technical expertise, but ultimately the decision on what would be the self-build alternative properly rested with Seminole and its staff. For example, Seminole relied heavily on Burns &

McDonnell to identify the relative economics of a pulverized coal-fired unit versus a gas-fired combined cycle unit and to evaluate the maturity of IGCC technology. Using that information and its own analyses, Seminole made the ultimate decision that a pulverized coal-fired unit was the most cost-effective, technologically mature self-build alternative.

Similarly, Seminole looked to Burns & McDonnell to identify the relative merits of using subcritical or supercritical design for the boiler of its pulverized coal self-build alternative. As Mr. Klover describes in his testimony, Burns & McDonnell advised that supercritical design is inherently more efficient and, therefore, has lower air emissions for a given level of electric output than a subcritical design. There were operational and reliability concerns with the early generations of supercritical design, but Burns & McDonnell reported that those concerns have been addressed in current supercritical designs. Burns & McDonnell found that most of the more recent coal-fired units in Japan and Europe use supercritical design. Burns & McDonnell expressed a concern over potential reliability issues resulting from burning high-sulfur coal and pet coke in supercritical boilers, but noted that it has been advised by the boiler manufacturer for one of its projects that this reliability issue can be effectively addressed with the selection of proper boiler tube material and enhanced preventive maintenance practices and inspections. Using this information, Seminole ultimately selected the more efficient, lower emission option of supercritical design. Burns & McDonnell has endorsed this decision.

II. THE SEMINOLE GENERATING STATION

Q. Please describe the Seminole Generating Station.

A. The SGS is a 1,922 acre site located in northeast Putnam County, approximately five miles north of the City of Palatka. My Exhibit MPO-1 is a map showing the location of the SGS.

The SGS currently accommodates two 650 MW class pulverized coal units (SGS Units 1 and 2). SGS Unit 1 began commercial operation in February 1984, and SGS Unit 2 began commercial operation in December 1984. The existing site contains all the facilities necessary for the operation of the existing units, including coal unloading and storage facilities, pollution control equipment and solid waste disposal areas for flyash and other solid waste materials. Both units are equipped with electrostatic precipitators and wet flue gas desulfurization systems for particulate and sulfur dioxide removal. Flue gas desulfurization waste is processed into wall board grade synthetic gypsum and conveyed to a wall board facility located on a parcel of land adjacent to the SGS.

Q. Please address Seminole's plans for the location of SGS Unit 3.

A. My Exhibit MPO-2 is a Site Map showing the preliminary site arrangement of SGS Unit 3. The design of SGS Unit 3 will use existing site facilities to the maximum extent possible. As a project at an existing site, SGS Unit 3 avoids not only the cost of developing a new site, but also the costs of numerous facilities already at the SGS that will be co-used by SGS Unit 3. Additionally, the use of the existing site avoids

the need to add new transmission lines and associated electric substations for SGS Unit 3.

Q. What are the existing facilities at the SGS that SGS Unit 3 will be designed to share?

A. Preliminary evaluations have identified the following existing site facilities that can be utilized either as currently designed or with minimal modification:

Coal delivery, unloading and storage - The existing facility has a coal handling system consisting of a spur railroad line off the CSXT rail system, a rotary car dumper, stock-out system and 52 acre lined coal storage area. The existing units currently receive approximately one unit train (8,000 -11,000 tons of coal per train) per day. The addition of SGS Unit 3 will require Seminole to increase the number of unit trains to an average of 1.6 per day. The existing rotary car dumper has adequate capacity to accommodate this increase. The existing coal handling system at SGS, while adequate for addition of the third unit, will be expanded by adding an additional stacker-reclaimer and related conveyor systems to facilitate material handling, fuel blending and reliability.

Potable water supply - The existing potable water system has sufficient capacity to provide water for drinking fountains and washroom facilities at SGS Unit 3.

Cooling and Service Water Supply - Makeup water to the existing unit cooling tower and service water systems is supplied from the St. Johns River. The addition of SGS Unit 3 will increase intake flow by approximately 30%. No changes to the river intake structure, which is already equipped with fine mesh screen technology, will be required. An additional pipe from the river intake structure to SGS Unit 3 will be required.

Cooling Water Discharge - The existing permitted wastewater discharge line has sufficient capacity to accommodate the increased discharge of cooling tower blowdown from SGS Unit 3.

Limestone Handling - The current limestone unloading facility has sufficient capacity to accommodate the increase in limestone required for SGS Unit 3 flue gas desulfurization system.

Plant Egress/Ingress - The existing plant entrance off of U.S. Highway 17 will continue to be utilized for existing facility traffic, as well as all SGS Unit 3 construction traffic. To accommodate peak construction traffic and maintain an adequate level of service, a traffic signal and additional approach lane will be constructed on U.S. Highway 17 at the plant entrance. Also, the plant entrance road will be widened.

III. OVERVIEW OF SGS UNIT 3

Q. Please briefly describe the design of SGS Unit 3.

A. SGS Unit 3 will be a pulverized coal, balanced draft unit employing supercritical steam pressure and temperature with a mechanical draft cooling tower for condenser cooling water. The primary advantages of supercritical steam cycles over subcritical steam cycles are improved plant efficiency due to elevated operating pressure and temperature, lower emissions and lower fuel consumption. Although the unit will be designed to operate as a base load unit, one of the design advantages of the planned sliding pressure supercritical boiler is that it simplifies cycling the unit to accommodate load flow fluctuations required by the electrical system demand. Mr. Klover's testimony describes the design of SGS Unit 3 in greater detail.

Q. What fuels will SGS Unit 3 be designed to burn?

A. SGS Unit 3 will be designed to burn 100% bituminous coal as a well as a blend of bituminous coal and up to 30% petroleum coke. That is the same fuel mix capability as SGS Units 1 and 2.

Q What will be the water sources for SGS Unit 3?

A. As I previously stated, SGS Unit 3 will be able to rely on the existing SGS water sources. The potable water system will rely on existing plant wells. The water supply for steam cycle makeup will also be from the existing plant wells and will be treated in a demineralizer. The water supply for cooling tower makeup will be from the St. Johns River, and cooling tower blowdown will be discharged to the St. John's River.

The addition of SGS Unit 3 will increase intake flow from the river by approximately 30%. However, cooling water discharge levels from SGS Unit 3 will be offset partially by reductions in process waste water discharge. No changes to the river intake structure, which is already equipped with fine mesh screen technology, will be required. However, an additional pipe from the river intake structure to SGS Unit 3 will be needed.

IV. SGS UNIT 3 ENVIRONMENTAL COMPLIANCE

Q. What pollution control measures will be employed in the design and operation of SGS Unit 3?

A. As I have noted previously, the supercritical design at SGS Unit 3 is more efficient and has lower emissions rates than a subcritical design. In addition, SGS Unit 3 will employ state-of-the-art emission control equipment to further reduce emissions, including:

- Low NO_x Burners and Staged Combustion / Overfire Air (OFA) for NO_x control.
- Selective Catalytic Reduction (SCR) for NO_x control.
- Electrostatic Precipitator (ESP) for particulate (PM) control.
- Wet Flue Gas Desulfurization (WFGD) for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.
- Mercury removal through application of the above technologies.

As a result of the emission control equipment that will be installed at SGS Unit 3 and emission-reduction measures that are planned for SGS Units 1 and 2 independent of

Unit 3's construction, the combined NO_x, SO2 and mercury emissions from all three units will be less than the current emissions from Units 1 and 2.

Most process wastewater streams will be treated and recycled as make-up water to the wet scrubber. Blowdown from the wet scrubber will be treated in a new zero liquid discharge system consisting of brine concentrators and a spray dryer system. Site runoff will be integrated into the site drainage system which will be expanded to accommodate Unit 3. Sanitary discharge will be to a sanitary treatment system.

Coal combustion by-products not sold for reuse will be disposed of in the permitted on-site landfill or an offsite permitted landfill. A monitoring well system is currently in place to monitor ground water quality adjacent to the landfill area and around the SGS property. The ground water monitoring system will be modified as necessary to evaluate the impact of SGS Unit 3.

Q. Does Seminole plan to reuse by-products from SGS Unit 3 as it does for SGS Units 1 and 2?

A. Yes. Coal combustion by-products produced as a result of the addition of Unit 3 will be sold for reuse to the maximum extent possible. The waste products from the flue gas desulfurization unit (wet scrubber) will be treated to produce commercial-grade gypsum for use in the manufacture of wallboard. As noted earlier, there is a wallboard facility located on a parcel of land adjacent to the SGS. Bottom ash and flyash can be used to produce concrete block, high quality concrete and cement.

Q. Should Seminole be able to acquire the necessary environmental approvals for SGS Unit 3?

A. Yes. SGS Unit 3 has been designed to comply with all applicable environmental requirements, and Seminole expects to receive all necessary approvals well in advance of the planned in-service date for SGS Unit 3.

V. SGS UNIT 3 TRANSMISSION REQUIREMENTS

Q. How does Seminole transmit electric service to its Members?

A. Seminole serves the vast majority of its Member load through the transmission systems of Florida Power & Light Company (FPL) and Progress Energy Florida (PEF). Seminole receives firm transmission service from FPL under FPL's Open Access Transmission Tariff and from PEF under a "1983 Agreement" between Seminole and PEF. The transmission service agreements give Seminole the contractual right to serve Member load in the FPL and PEF transmission control areas from Seminole's designated generating resources. In addition to its arrangements with FPL and PEF, Seminole serves approximately 10% of its Member load through its own transmission facilities.

Q. What transmission system improvements will be necessitated by the addition of SGS Unit 3?

A. When transmission service for a new capacity resource is requested under Seminole's network arrangements, the new designated resource must receive approval from FPL

and PEF to become a Seminole Network Resource. As a condition of this approval, Seminole performed a Transmission System Impact Study for the SGS Unit 3 project.

The Transmission System Impact Study included a short circuit, steady-state load flow and stability analysis. The short circuit analysis indicated that all seventeen (17) 230 kV circuit breakers at the SGS Switchyard needed to be upgraded to a Fault Interrupting Capability of 63 kA. The steady-state load flow analysis indicated that four (4) 230 kV circuit breakers at the Silver Springs North Switchyard and four (4) 230 kV circuit breakers at the SGS Switchyard needed to be upgraded to a continuous rating of 3000 amps. Also, four (4) FPL controlled 230 kV circuit breakers, two located at FPL's Rice Substation and two located at Seminole's SGS Switchyard, that are operated normally open need to be operated normally closed. The stability analysis indicated that all seventeen (17) 230 kV circuit breakers at the SGS Switchyard need to be upgraded to two cycle operation. The stability analysis also indicated that the four (4) FPL controlled 230 kV circuit breakers, two located at FPL's Rice substation and two located at Seminole's SGS Switchyard, that are operated normally open need to be operated normally closed.

On May 25, 2005, Seminole received written notification from FPL confirming the results of Seminole's SGS Unit 3 transmission study, agreeing to change the four (4) 230 kV FPL circuit breakers (two at SGS and two at FPL Rice) from normally open operation to normally closed operation, and confirming that SGS Unit 3 will be

designated as a Seminole Network Resource to serve Seminole Member load integrated within the FPL transmission system.

On September 6, 2005, Seminole received written notification from PEF confirming the results of Seminole's SGS Unit 3 transmission study, and accepting Seminole's SGS Unit 3 as a Seminole Network Resource to serve Seminole Member load integrated within the PEF transmission system.

No new transmission lines will be needed to integrate the output from SGS 3 into the Florida Grid. The estimated costs to replace the seventeen 230 kV breakers at the SGS switchyard is $4,250,000, and the cost to replace the four (4) 230 kV breakers at the Silver Springs North Switchyard is $600,000.

VI. CAPITAL COST, SCHEDULE AND IMPACT ON THE ECONOMY

Q. What is the estimated total capital cost for the SGS Unit 3 project?

A. The estimated total capital cost for the SGS Unit 3 project is approximately $1.4 billion in 2012 dollars. In its February 2005 feasibility study for a 750 MW coal-fired unit, Burns & McDonnell projected the direct plant construction costs to be approximately $1.1 billion. The remainder of the $1.4 billion total is comprised of the 230 kV transmission breaker upgrades discussed above, spare parts, testing, interest during construction, risk insurance, and Seminole labor and overhead. My Exhibit MPO-3 provides additional detail as to the components of this cost estimate.

Q. What is the estimated in-service date for SGS Unit 3?

A. The projected commercial operation date for SGS Unit 3 is May 2012. That date assumes a construction duration of 42 months, with construction beginning in October 2008. The estimated construction duration is based on the range of construction times for other similarly sized coal units at existing facilities. More detailed construction milestones are addressed in Mr. Klover's testimony.

Q. What economic benefits are anticipated in Putnam County due to the construction and operation of SGS Unit 3?

A. The construction of SGS Unit 3 will require up to a maximum of 1,500 positions during construction and 50 additional permanent positions to the existing SGS operating staff in Putnam County, Florida. There will be secondary and tertiary economic benefits in and around Putnam County with the addition of these positions. The additional personnel will spend portions of their income with local businesses, which will grow as a result of this increased business. That, in turn, will improve the local tax base. Also significant will be SGS Unit 3's contribution to the property tax base for Putnam County and local governments.

VII. SEMINOLE'S EXPERIENCE WITH PERMITTING, CONSTRUCTING AND OPERATING POWER PLANTS

Q. Please address Seminole's prior experience with the construction of power plants.

A. Seminole has extensive experience with power plant construction. Seminole has previously overseen the construction of the coal fired SGS Units 1 and 2 as well as the Payne Creek Generating Station combined cycle unit, and it is currently overseeing construction of the Payne Creek Peaking Project. SGS Units 1 and 2 were designed and constructed under a multiple-contract approach, with the engineering firm of Burns & Roe retained to complete the engineering and perform construction management. Seminole was responsible for the procurement of equipment and construction contracts for SGS Units 1 and 2. This project was completed within the prescribed schedule and budget.

The Payne Creek combined cycle unit was constructed under a turnkey arrangement, where Seminole selected a consortium consisting of Siemens Westinghouse and Overland Constructors, a construction subsidiary of Black and Veatch Engineering Company, to be responsible for all aspects of construction. This project was also completed within the prescribed schedule and within 2% of the budget.

The Payne Creek Peaking Project is currently being constructed under the same multiple-contract approach used with SGS Units 1 and 2, with Engineering Services,

Inc. providing engineering and construction management support. This project is currently on schedule and within budget.

Seminole plans to use the multiple-contract approach for SGS Unit 3, because of its proven success for SGS Units 1 and 2 and the Payne Creek Peaking Project. Burns & McDonnell has been retained to provide engineering and construction management support for SGS Unit 3. Mr. Klover's testimony describes Burns & McDonnell's extensive experience in these roles.

Q. How does the operating performance of Seminole's coal-fired generation compare to that of other utilities?

A. The operating performance of Seminole's coal-fired generating units compares quite favorably to the performance of other units of comparable size, fuel and equipment as to availability, heat rate, starting capability and most importantly, electrical energy cost. Seminole participates in a benchmarking program that compares the operation of Seminole's coal fired and combined cycle units with comparable units in a national study group. For SGS Units 1 and 2, the operating and maintenance costs, overall availability, heat rate, and forced outage rate compare favorably with the benchmarking group.

Q. What experience does Seminole have in permitting power plants?

A. Seminole has considerable experience permitting power plants. We have successfully permitted SGS Units 1 and 2, both coal-fired, as well as the Payne Creek Generating

Station combined cycle unit and the Payne Creek Peaking Project, a 310 MW facility utilizing aero-derivative combustion turbine technology.

Q. Should the Commission feel confident in Seminole's ability to timely and effectively permit, construct and operate SGS Unit 3?

A. Yes. As I have just explained, Seminole has extensive prior experience with permitting, building and operating power plants, including coal-fired units. In addition, Seminole has brought a wealth of outside expertise to bear on the selection, permitting and construction of SGS Unit 3. As I have described earlier, Seminole engaged Burns & McDonnell to assist in both the evaluation of its self-build alternative and then, once that alternative was chosen, to provide detailed design, procurement, construction management and startup services to Seminole for SGS Unit 3. As part of the evaluation process, Seminole engaged R. W. Beck to perform a risk assessment of the economic comparison between self-build coal-fired and gas-fired units, which confirmed that Seminole's conclusion about the favorable economics of the coal-fired unit is robust under a wide range of scenarios. Finally, Seminole has engaged Hopping Green & Sams LLP and Golder and Associates, two firms with well-recognized Florida and national environmental expertise, to assist in securing site certification and the necessary environmental permits.

Q. Does this conclude your testimony?

A. Yes.

060220-EC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF RICHARD KLOVER

DOCKET NO. 06____-EU

MARCH 10, 2006

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

A. My name is Richard Klover. My business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q. By whom are you employed and what is your position?

A. I am employed by Burns & McDonnell Engineering Company, Inc. as Senior Project Manager in the Energy Division.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for managing the evaluation, design, procurement, construction management, and startup and testing of power generation facilities.

Q. Please describe your educational background and business experience.

A. I graduated from Kansas State University with a Bachelor of Science Degree in Mechanical Engineering in 1987. I have 18 years of experience in the evaluation, design and construction of power generation projects. I have been involved with several large coal fired projects, including serving as the on-site startup engineer for

two units and project manager for two others. In addition, I have been involved in the development and evaluation of numerous coal fired projects. A more detailed description of my experience is in my Exhibit RAK-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe Burns & McDonnell's experience and role in the evaluation, design, procurement, construction, startup and testing of SGS Unit 3, to describe the feasibility studies and the technology assessment study that Burns & McDonnell performed to assist Seminole in deciding to build SGS Unit 3, and to describe the construction schedule for SGS Unit 3. In addition, I will provide a brief description of the operational characteristics of SGS Unit 3.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

Exhibit RAK-1	Summary of Richard Klover's Experience
Exhibit RAK-2	Summary of Burns & McDonnell Steam Electric Power Station Experience
Exhibit RAK-3	Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study, dated August 2004
Exhibit RAK-4	Seminole Generating Station 750 MW (Net) Solid Fuel Fired Unit Feasibility Study, dated February 2005
Exhibit RAK-5	Seminole Generating Station Technology Assessment Study dated March 2005

Exhibit RAK-6	SGS Unit 3 Steam Cycle
Exhibit RAK-7	SGS Unit 3 Fact Sheet
Exhibit RAK-8	SGS Unit 3 Expected Construction Schedule

Q. Are you sponsoring any part of the Need Study in this proceeding?

A. Yes. I sponsor Section IV.H and co-sponsor Section IV.C of the Need Study.

I. BURNS & MCDONNELL'S EXPERIENCE

Q. Please describe Burns & McDonnell's experience and capabilities with respect to the evaluation, design and construction of coal fired power plants.

A. Burns & McDonnell currently employs over 2,000 people. Over the last 30 years, Burns & McDonnell has been involved in over 10 gigawatts (i.e., 10,000 MW) of coal fired generation in varying capacities. Burns & McDonnell is currently involved in over 5 gigawatts of new supercritical coal fired generation projects. Burns & McDonnell's most recent pulverized coal design experience was for Hawthorn 5, a 550 MW unit for Kansas City Power & Light. A detailed summary of Burns & McDonnell's experience with coal fired generation is contained in my Exhibit RAK-2.

Q. What is Burns & McDonnell's experience with cooperatives and RUS financed projects?

A. Burns & McDonnell has been serving electric cooperatives since the 1930s. We have provided services to over 25 electric cooperatives and have been involved in over

II. FEASIBILITY STUDIES AND TECHNOLOGY ASSESSMENT

Q. What was the purpose of the feasibility and technology assessment studies that Burns & McDonnell performed for Seminole?

A. When Seminole decided that it would solicit bids for the purchase of needed capacity in the 2012 time frame, it first had to evaluate carefully what would be the most appropriate self-build alternative. As part of that evaluation process, Seminole asked Burns & McDonnell to bring its experience to bear on assisting Seminole in selecting the appropriate technology and providing a detailed, screening level evaluation of the cost of building and operating the preferred alternative. This request initially led to the preparation of the August 2004 Feasibility Study.

After Seminole had decided to self build, it considered whether it would be better served by building a 750 MW (net) unit rather than building a 600 MW (net) unit and purchasing 150 MW of capacity as it originally explored. Burns & McDonnell was asked to update the August 2004 Feasibility Study for the larger unit size, which led to the preparation of the February 2005 Feasibility Study. Finally, because there are multiple, complex and competing considerations involved in the selection of pulverized coal boiler technology, Burns & McDonnell was asked to perform the Technology Assessment, which addressed the relative merits of supercritical and subcritical boiler technology for SGS Unit 3.

Q. Please briefly describe the August 2004 Feasibility Study and the conclusions that it reaches.

A. The August 2004 Feasibility Study presents the results of pro forma economic analyses of three alternative self-build projects: a new brownfield 600 MW (net) subcritical solid fuel generating unit; a new brownfield 600 MW (net) supercritical solid fuel generating unit; and a new greenfield 500 MW (net) gas fired combined cycle unit. Burns & McDonnell also provided an assessment of a 600 MW (net) integrated gasification combined cycle ("IGCC") plant and recommended that the technology not be considered for new generation at this time due to insufficient operational experience and information on the cost and reliability of the technology. The pro forma economic analysis compared the 20-year levelized busbar cost for the three viable alternatives and found that the cost for the supercritical unit was the lowest at $52.77/MWh, followed closely by the subcritical unit at $52.97/MWh, with the combined cycle unit considerably more expensive at $75.48/MWh.

To develop the economic analysis, the August 2004 Feasibility Study focused on a detailed, screening level identification of the necessary components, and the cost, performance and environmental impacts, for supercritical and subcritical units. The study concluded that both types of units were feasible. It further advised that Seminole needed to begin preliminary engineering in 2005 in order to meet the 2012 planned in-service date and that Seminole could benefit economically by increasing the size of the unit because of economies of scale. The study did not recommend that

Seminole choose either supercritical or subcritical technology, but Appendix A to the August 2004 Feasibility Study provided Seminole with a brief comparison of the technologies and their operating histories, performance, environmental impacts and economics.

Q. Why did Burns & McDonnell conclude that IGCC is not yet a sufficiently proven technology?

A. Appendix C to the August 2004 Feasibility Study contains a detailed assessment of the IGCC technology. Burns & McDonnell saw two principal areas of concern with the current generation of IGCC technology. The first was unit availability. Burns & McDonnell identified several issues that have prevented IGCC units from achieving acceptable availability levels: fouling within the synthetic gas cooler; design of the pressurized coal feeding system; molten slag removal from the pressurized gasifier; limited durability of the gas clean-up equipment; and solid particulate carryover to the combustion turbines, resulting in accelerated erosion of their internals. The second area of concern related to the limited operational flexibility of IGCC plants, which have longer cold start-up times than conventional pulverized coal units, on the order of ten times as long. IGCC plants also have limited ability to load-follow.

Q. Please briefly describe the February 2005 Feasibility Study.

A. As I stated earlier, this study was essentially an update of the August 2004 Feasibility Study to address Seminole's interest in increasing the output of the SGS Unit 3

project from 600 MW (net) to 750 MW (net). The study concluded that both the supercritical and subcritical units were feasible and would be substantially more economically sized at 750 MW than at 600 MW (the 20-year levelized busbar cost declined from $51.84/MWh to $48.85/MWh for the supercritical unit, and from $52.08/MWh to $49.15/MWh for the subcritical unit.) Both remained far preferable to a conventional gas fired combined cycle unit.

The February 2005 Feasibility Study also addressed in more detail the relative merits of supercritical vs. subcritical technology. It concluded that supercritical technology would be more fuel efficient and hence have lower air emissions and, because of the lower emissions, would face fewer permitting hurdles than subcritical technology. The study pointed out, however, that there is limited experience in operating supercritical units at elevated steam cycle temperatures on a fuel mix containing high sulfur coals and up to 30% pet coke as Seminole intends to burn and thus concluded that the subcritical technology would be preferable from an experience and operational reliability standpoint.

Q. What is the difference between supercritical and subcritical technology?

A. In supercritical technology, the steam that drives the turbine generator is generated at pressures high enough that water converts directly to steam without two phase fluid existing. Supercritical technology is thus designed for once-through steam generation in the boiler, whereas subcritical technology employs a steam drum to separate steam

from the water before the steam is superheated and flows to the turbine generator. A supercritical steam cycle provides improved plant efficiency but tends to have slightly higher initial capital costs and more operating complexities.

Q. What was the purpose of the Technology Assessment?

A. Seminole was attracted to the benefits of the supercritical technology but concerned about the operational reliability issues raised in the February 2005 Feasibility Study. Therefore, it asked Burns & McDonnell to dig deeper into the available operational history on supercritical technology and provide more detailed advice on the two technologies.

Q. Please briefly describe the results of the Technology Assessment.

A. Burns & McDonnell found that, while the operational reliability of the early supercritical plants in the U.S. (i.e., those built in the 1950's and 1960's) had been less than expected, plants built later in Asia and in Western Europe had been redesigned to overcome most of those limitations. The impact of these improvements on operational reliability is captured in Figure 2.2 of the Technology Assessment, which plots the equivalent forced outage rate (EFOR) for supercritical units and subcritical units over the period from 1982 to 1997. Figure 2.2 shows that the EFOR for supercritical units was significantly higher than for subcritical units in the early 1980's, but has converged to the point that the EFOR for the two technologies is essentially identical in 1997.

As a result of these operational improvements, supercritical technology has become strongly favored in Asia and Europe. For example, the majority of fossil fired power plants built in Japan since 1967 that are larger than 500 MW use supercritical technology. Similarly, of the 20,000 MW of coal fired capacity installed in Europe between 1995 and 2000, approximately 85% uses supercritical technology. The main area of remaining concern over the operational reliability of supercritical coal-fired units relates to the use of corrosive (i.e., high sulfur) coal and pet coke as fuels. Supercritical boilers are more susceptible to corrosion damage from those fuels than subcritical boilers. The most recent designs of supercritical boilers are intended to address this issue, however, and Burns & McDonnell is involved in a project where the manufacturer of the supercritical boiler has stated that availability comparable to subcritical boilers can be achieved even with corrosive fuels by increasing preventive maintenance and inspections of the boiler water walls, superheater and reheater.

Q. As you are aware, Seminole ultimately chose supercritical technology for SGS Unit 3. Do you believe that this was a reasonable choice?

A. Yes. As is evident in the Technology Assessment, there are pros and cons to both supercritical and subcritical technologies. However, Seminole is certainly in the mainstream of a worldwide trend toward using the current generation of supercritical technology, which has addressed the operational reliability concerns of earlier generations of supercritical units while retaining the economic and environmental advantages that supercritical technology can offer.

III. UNIT CHARACTERISTICS

Q. Please describe the coal fired technology that will be used for SGS Unit 3.

A. SGS Unit 3 will utilize a supercritical pulverized coal boiler that will supply high pressure steam at a nominal 3700 psi and 1050 degrees F to the high pressure steam turbine and will supply hot reheat steam at 1050 degrees F to the intermediate steam turbine. SGS Unit 3 will be designed to burn high sulfur bituminous coal in combination with petcoke and will utilize the following state of the art emission controls:

- Low NO_x Burners and Staged Combustion / Overfire Air (OFA) for NO_x control.
- Selective Catalytic Reduction (SCR) for NO_x control.
- Electrostatic Precipitator (ESP) for particulate (PM) control.
- Wet Flue Gas Desulfurization (WFGD) for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.
- Mercury removal through application of the above technologies

Q. Please describe the steam cycle for SGS Unit 3.

A. SGS Unit 3 will utilize the steam cycle depicted in Exhibit RAK-6. Condensate pumps will take condensate from the condenser and pump the water through four low pressure feedwater heaters to the deaerator. The boiler feed pumps take suction from the deaerator and pump the water through three high pressure feedwater heaters to the boiler. The boiler feedwater enters the boiler through the economizer to recover heat from the combustion gases exiting the boiler. Downstream of the economizer, the

heated feedwater is directed to the water wall circuits enclosing the furnace. After passing through the lower and then the upper radiant walls, the fluid passes through the convection enclosure circuits to become steam, and then is superheated in the superheater section of the boiler.

The steam then exits the boiler to the high-pressure (HP) section of the steam turbine at an inlet temperature of 1,050°F. As the steam energy is converted to shaft power in the HP section of the steam turbine, its temperature and pressure are reduced.

The cooled and lower pressure steam exits the HP section and returns to the reheater section of the boiler, where the steam temperature is raised back up to the expected intermediate-pressure (IP) turbine inlet temperature of 1,050°F. This step is called reheat, and it is used to increase the efficiency of the steam cycle. The steam then returns to the IP section of the steam turbine where again the steam energy is further converted to shaft power as its temperature and pressure drops. From the IP section, the steam is directed to the low-pressure (LP) section of the steam turbine, where the steam further expands to convert additional energy to the turbine shaft power that drives the electric generator. Steam exhausts from the LP section of the steam turbine to the condenser, where the steam is condensed back to liquid phase water. Cooling water from the condenser is circulated through a mechanical draft cooling tower before returning to the condenser.

Q. What are the expected operational performance parameters of SGS Unit 3?

A. The projected net plant heat rate for SGS Unit 3 is 9,000 Btu/kWh at average ambient conditions of 71° F dry bulb temperature and a relative humidity of 80%. SGS Unit 3 will also be designed to operate with the top feedwater heater out of service, which can provide approximately 33 MW of additional capacity at average ambient conditions. Additional information on the expected operational performance for SGS Unit 3 is contained in the fact sheet that is my Exhibit RAK-7.

IV. PROJECT COST AND SCHEDULE

Q. Has Burns & McDonnell estimated the capital cost of SGS Unit 3?

A. Yes. As part of the February 2005 Feasibility Study, we estimated the cost of building a 750 MW pulverized coal project adjacent to the existing units at the Seminole Generating Station. Table 5-1 of Exhibit RAK-5 shows the estimated cost of each principal component of the project and the total estimated capital cost of approximately $1,200,000,000 in 2012 dollars (excluding interest during construction, and certain other owner's costs to be incurred by Seminole). This estimate reflects cost escalation of certain major cost components at the rate of 2.5% per year to the mid-point of the construction schedule in 2010, which serves as a proxy for the average escalation on plant components that will be purchased at various times throughout the construction schedule.

Q. What is the proposed project schedule for SGS Unit 3?

A. Seminole will commence construction upon receipt of the necessary federal and state certifications and/or permits. The expected construction duration for SGS Unit 3 is approximately 42 months and is comparable to other coal fired projects of similar size. This means that, in order to achieve the planned commercial operation date of May 2012, construction needs to commence on or before October 2008. A summary of the construction milestone dates is shown in Exhibit RAK-8.

Q. Do you believe that this schedule is reasonable and achievable?

A. Yes, it is.

Q. Does this conclude your testimony?

A. Yes.

060220-EC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF WM. JACK REID

DOCKET NO. 06____-EU

March 10, 2006

Q. Please state your name, occupation and business address.

A. My name is William Jack Reid. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Director of Fuel Supply. My business address is 16313 N. Dale Mabry Highway, Tampa, Florida 33618.

Q. Please describe your duties and responsibilities as Director of Fuel Supply.

A. I am responsible for management and planning of fossil fuels at Seminole's generating facilities and at those purchased power facilities for which Seminole has fuel supply responsibilities. In this role, I am responsible for the availability, reliability and transportation of fossil fuels, the optimization of the fossil fuel supply chain cost, the maintenance of adequate fossil fuel inventories, and the evaluation of alternative fossil fuel supply opportunities. My responsibilities also include fuel price risk management, the administration of Seminole's natural gas price hedging program, and shared responsibility for fuel procurement (with Seminole's Supply Management Department).

Q. Please summarize your background and experience.

A. I have 30 years experience in the electric utility industry, with 24 years in power generation fuel management. I have substantial experience in preparing fuel price forecasts, generation resource budgets, strategic fuel plans and operation plans, all of which are used to make major corporate decisions.

Much of this experience was gained in my former positions with Kansas Gas and Electric Company (KG&E), which later became Western Resources Inc. (WR). I started at KG&E in June 1976 in its generation group, where my responsibilities included engineering, generation planning and fuel planning. In 1983, I was promoted to Fossil Fuels Manager for KG&E. In April 1992, following the merger that created WR, I was promoted to Director of Fuel Supply for WR. In those positions, I spent nearly a decade coordinating the supply and transportation of fuels.

I joined Seminole in my current position as its Director of Fuel Supply on February 1, 2002. I am Seminole's designated member to the National Coal Transportation Association and was recently seated as a member of the Board of Directors of this organization. I also represent Seminole on, and serve as chair of, the Florida Reliability Coordinating Council (FRCC) Gas Electricity Interdependency Task Force.

Q. Have you previously testified before the Commission?

A. No. However, I have testified and been accepted as an expert witness on fuel supply, transportation and forecasting in various electric and natural gas proceedings before the Kansas Corporation Commission. I have also presented testimony before several federal agencies on behalf of KG&E and WR.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to introduce and describe the Seminole fuel price forecasts used in the evaluations that led to the selection of SGS Unit 3, explain Seminole's fuel procurement strategy related to the Seminole Generating Station (SGS), and address the supply of fuels for SGS Unit 3.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I have prepared and attached to my testimony the following Exhibits:

Exhibit WJR-1, August 2003 Fuel Price Forecast

Exhibit WJR-2, April 2004 Fuel Price Forecast

Exhibit WJR-3, December 2004 Fuel Price Forecast

Exhibit WJR-4, August 2005 Fuel Price Forecast

Exhibit WJR-5, June 2005 Global Insights Report

Exhibit WJR-6, July 2005 Pace Global Energy Services Report

Q. Are you sponsoring any portion of Seminole's Need Study in this docket?

A. Yes, I am co-sponsoring portions of Sections IV and VI of Seminole's Need Study, and I am sponsoring Appendices C and F to the Need Study.

I. SEMINOLE'S FUEL PRICE FORECASTS

Q. Please describe Seminole's fuel price forecast methodology.

A. Seminole first prepares a forecast of fuel supply (commodity) and fuel transportation prices for fuel purchases under Seminole's existing contracts. These internally generated forecasts start with known prices and rates for contract fuels and their related transportation prices. Over the current contract term, prices are escalated based on underlying contractual pricing formulae.

For fuel supply requirements not currently covered by contract, Seminole uses long term spot market prices (i.e., long term spot market prices are used for all such long term fuel requirements, including the significant portion of such future fuel supply which will likely be under contract in future years). Most spot market prices are provided by an independent forecasting consultant, Global Insights. To address short-term price volatility, Seminole periodically updates the early years of its forecast by using other sources of price information (e.g., NYMEX pricing for natural gas and oil and recent bid prices for coal and pet coke). In the analyses undertaken to assess Seminole's 2012 need, Seminole's use of these short term price adjustments had minimal impact, because by the time of the in service date

of the options being considered, 2012, the fuel forecasts used only long term pricing provided by Global Insights.

Seminole develops internally the projections of fuel transportation costs (including related services) that are not presently covered by contract. Fuel transportation includes costs paid directly to transporters (railroads, pipelines, trucking companies, etc.) plus the costs for related services required to deliver fuels to Seminole (i.e., railcars, import terminal services). When a contract renewal is required, Seminole analyzes market conditions and historic price increases to insure that future costs reflect and provide for such events.

Q. Does Seminole consider fuel price volatility in the future planning of its operations?

A. Yes. Seminole utilizes sensitivity analyses to assure that its plans are resilient to market shifts and robust relative to fuel price uncertainty. As described further in Mr. Mahaffey's testimony, Seminole has used a combination of qualitative and quantitative techniques to assess the risks associated with fuel price uncertainty. Seminole also seeks to maintain a diverse fuel supply portfolio, which combines long-term and short-term commitments as a hedge against market uncertainty.

Q. What fuel price forecasts have been used by Seminole in its economic assessments related to SGS Unit 3?

A. Seminole has relied primarily on a long term fuel price forecast. During the time period in which Seminole assessed its need for base load capacity and evaluated alternative resources (2003 – 2005), Seminole updated its long term fuel price forecast to reflect new information provided by Global Insight, the independent forecasting consultant retained by Seminole. This periodic updating of fuel price assumptions is part of Seminole's normal practice of updating key variables to ensure that its economic models are current.

During the period in which Seminole's 2012 base load capacity need was assessed, Seminole updated its fuel forecasts three times. The four fuel forecasts Seminole used are included as Exhibits WJR-1, WJR-2, WJR-3 and WJR-4.

Exhibit WJR-1 is Seminole's August 2003 fuel price forecast based upon a March 2003 updated forecast by Global Insights. This forecast was used by Seminole in estimating Seminole's base load needs at the time Seminole formulated its April 2004 RFP.

Exhibit WJR-2 is Seminole's April 2004 fuel price forecast based upon a December 2003 updated forecast by Global Insights. This fuel forecast was used in economic screening of self-build and purchased power alternatives in the RFP evaluation.

Exhibit WJR-3 is Seminole's December 2004 fuel price forecast based upon an October 2004 updated forecast by Global Insights. This fuel price forecast was used in Seminole's initial present worth revenue requirements analyses in early 2005 which were used as the underlying base case for the R.W. Beck risk assessment.

Exhibit WJR-4 is Seminole's August 2005 fuel price forecast based upon a June 2005 updated forecast by Global Insights. This fuel price forecast was used in Seminole's final economic results underlying the need application and is Seminole's most recent fuel forecast (as of the time of Seminole's need filing). It is a delivered price forecast for various fuels used on Seminole's system and covers the 25 year period from 2006 through 2030.

Exhibit WJR-5 is Global Insights' written report associated with its June 2005 fuel price forecast depicted in Exhibit WJR-4. This report contains background information and the rationale underlying the June 2005 fuel price forecast.

Q. Please address Seminole's current forecast of delivered natural gas prices.

A. Seminole forecasts the delivered natural gas prices for both pipeline systems serving Florida: the Florida Gas Transmission (FGT) and Gulfstream Natural Gas (GS) systems. The natural gas price starts at $ 9.11 /MMBtu for GS and at $9.25/MMBtu for FGT in 2005. The difference in cost between the pipelines relates to the amount of fuel reimbursement required for the pipelines' compressor

operations. The forecast anticipates that delivered natural gas prices will decline from current levels until 2010, when they will begin to rise again.

Because the near term commodity price of natural gas for 2005 through 2009 was heavily impacted by the 2005 hurricanes (this is captured by the use of NYMEX pricing rather than Global Insights longer term forecast), any comparison of a near term price to a future price is not representative of the future market expectations for price increases. A valid comparison can, however, be made between the 2010 and 2030 prices. In 2010, natural gas prices delivered on the GS and FGT pipelines respectively are $6.16 and $6.25/MMBtu and increase to $9.91 and $10.08/MMBtu in nominal dollars (i.e., no adjustment to remove the effects of inflation) in the year 2030. Over this 20 year period the nominal gas price grows at an average annual rate of 2.4% per year.

Q. Please address Seminole's current forecast for delivered distillate oil.

A. As with natural gas, the near term market prices for distillate oil (diesel) have been impacted by recent events and do not provide appropriate comparisons to future prices. However, the 2010 and 2030 prices provide a good indication of long term growth in prices, excluding impacts from recent events. The diesel price starts at $10.86/MMBtu in 2010 and increases to $14.37/MMBtu in nominal dollars in the year 2030. Over this 20 year time period the nominal diesel price grows at an average rate of 1.4% per year.

Q. Please address Seminole's current forecast of delivered coal and petroleum coke prices.

A. Traditionally, the main source of coal for SGS comes from the Illinois Basin, and this coal's delivered prices range from $2.16/MMBtu in 2005 to $3.35/MMBtu in 2030, which represents a nominal coal price growth at an average rate of 1.8% per year for the 25 year period.

The delivered price for petcoke starts at $1.77/MMBtu in 2005 and increases to $3.12/MMBtu for 2030, which represents a nominal petcoke price growth at an average rate of 2.3% per year for the 25 year period.

Consistent with recent experience, the near term prices for solid fuels are not forecast to be as volatile as prices for natural gas and diesel. Also, as the forecast shows, over the entire 25 year term coal enjoys significant price advantages relative to natural gas. Thus, while gas combined cycle technology had for a number of years served as the technology of choice for base load capacity, sustained gas price increases for the last several years as well as a forecast of high sustained gas prices and a significant differential between the cost of gas and coal suggest that coal would be a preferable fuel for a base load technology.

Q. Are the fuel price forecasts used by Seminole in its resource planning analyses that led to the selection of SGS Unit 3 reasonable?

A. Yes. Seminole used the same fuel price forecast methodology in developing each of the four fuel price forecasts used in the resource planning analyses that led to the selection of SGS Unit 3. That methodology is a reasonable methodology that accounts for both fuel and transportation costs that are under contract and those that are not under contract. For commodity prices not under contract, Seminole uses forecasts from a reputable independent forecasting consultant, and Seminole has updated those forecasts as circumstances warranted. Each of the forecasts used in Seminole's resource planning analyses was reasonable for that purpose at the time it was made, and the most recent of those forecasts continues to be used by Seminole for planning purposes today.

II. FUEL PROCUREMENT AND TRANSPORTATION STRATEGY

Q. How much fuel will be required to operate the Seminole Generating Station after completion of SGS Unit 3?

A. SGS is expected to burn over 6 million tons of solid fuel per year once SGS Unit 3 becomes operational.

Q. What fuels will be used by the SGS Unit 3?

A. As explained by Mr. Opalinski, Seminole plans to burn coal in combination with as much as 30% petcoke in SGS Unit 3. This is the same mix currently employed in SGS Units 1 and 2. Similar to SGS Units 1 and 2, distillate oil will be utilized

as a start up and flame stabilization fuel. Distillate oil use at SGS (for unit startup and flame stabilization purposes) has amounted to only a very small portion of SGS total fuel requirements (i.e., approximately 0.3% of total mmBtu).

Q. Please explain Seminole's strategy for procuring solid fuel for SGS Units 1 and 2 and the new SGS Unit 3.

A Seminole's primary objective is to achieve a balanced portfolio of long term and shorter term opportunity (spot market) commodity supply arrangements. Seminole will develop complimentary transportation arrangements.

Seminole is currently operating under long term coal supply arrangements with Alliance Coal, LLC to supply 2,750,000 tons of coal a year through the year 2012, with an option to extend 4 years through 2016. The Alliance contracts and other long term contracts act as a physical hedge to mitigate fuel availability and price risk, providing reliable supply and stable pricing with quarterly price adjustments tied to industry indices. Currently, Alliance provides approximately 70% of Seminole's annual coal requirements from multiple mines in Kentucky and Illinois. Seminole intends that in future years a significant portion of its solid fuel supply will continue to be met through long term supply contracts. Seminole's remaining annual requirements for solid fuels (coal and/or petroleum coke) which exceed the long term contract supply will be secured through spot market agreements for specified quantities for periods typically ranging from 1 to 18 months.

Seminole routinely reviews the short and long term market for opportunities and researches other alternative fuel sources such as petroleum coke and other non traditional fuel types to obtain the lowest delivered cost of fuel at the quality parameters required. Petroleum coke is an opportunity fuel from both domestic and international refineries that can be delivered directly to SGS by rail from domestic sources and/or by rail through terminal facilities located along the U.S. coast.

III. FUEL AVAILABILITY FOR SGS UNIT 3

Q: Has any independent evaluation of fuel availability been undertaken?

A. Yes. Seminole requested Pace Global Energy Services ("Pace Global") to provide an independent review of the long term supply availability of solid fuels (petcoke and coal) for the Seminole Generating Station. Pace Global's report found that "the supply of solid fuel from domestic and foreign sources will be adequate over the study period (present through the year 2040) to meet the requirements of Seminole's existing and new generation." The report also states that "over the period 2005-2040, adequate supplies of petroleum coke will be available from domestic and foreign suppliers to meet the partial or full fuel demand requirements of new solid-fuel-fired generation in Florida."

In light of Pace Global's findings, Seminole envisions a flexible solid fuel supply strategy to maintain reliable and economical sources of solid fuel from domestic and foreign sources of supply. Seminole intends to continue to use petroleum coke

as a supplemental fuel when it is economical and meets environmental requirements. The Pace Global Report is included as Exhibit WJR-6.

Q. What is Seminole's current arrangement for transporting solid fuel to SGS?

A. Seminole currently transports all solid fuels to SGS by way of CSX rail. CSX provides for the transportation of coal from the major eastern U.S. supply regions of Illinois Basin, Central Appalachia and North Appalachia and provides for coal imports through terminals accessed by CSX at Mobile, Alabama, Charleston, South Carolina, and Port St. Joe, Florida. Seminole is working with CSX to add other terminals (e.g., Tampa, Florida), to the CSX Contracts.

CSX transportation is provided under a long term rail transportation contract, which runs through December 31, 2008.

Q. What are Seminole's coal transportation alternatives for meeting its long term needs for SGS Units 1, 2, and 3?

A. Seminole will negotiate for an extension or renewal of the contract with CSX for service beginning in 2009. Such an extension or renewal would meet Seminole's long term fuel supply objectives. CSX has confirmed that the additional transportation capacity required for SGS Unit 3 is available, and that CSX requires 1-2 years advance notice to ramp up equipment and crew levels to accommodate the additional tonnage. Such future rail rates are subject to negotiation and/or resolution before the Surface Transportation Board.

In addition to its CSX relationship, Seminole is also looking at other rail, as well as water, delivery alternatives. For example, Seminole is presently researching the potential use of the Norfolk Southern Railroad, which could provide alternative rail access to east coast international coal terminals, as well as to coal supply from mines in Virginia, Kentucky and Indiana. While this and other alternatives are still being developed, if implemented they would give Seminole additional fuel supply and transportation alternatives.

Q. When does Seminole plan on entering into the long term fuel and transportation contracts required to support SGS Unit 3?

A. Seminole will begin a formal process for solid fuel supply acquisition upon receipt of its environmental permits. Before December 31, 2008, Seminole will be required to complete the negotiations for an extension or renewal of its existing CSX contract, or make other transportation arrangements. The resulting contract(s) are anticipated to include the arrangements for the transportation of solid fuel for SGS Unit 3, which is currently expected to begin inventory build up during 2011.

Q. In your opinion, will SGS Unit 3 have a reliable supply of fuel?

A. Yes, I am confident there will be reliable sources of fuel for SGS and reliable transportation for that fuel. This conclusion is based on my own experience as well as the Pace Global fuel supply assessment commissioned by Seminole and on Seminole's assessment of its transportation options for that fuel. Seminole will

continue to maintain a balanced portfolio of long term and short term supply so as to maintain flexibility, minimize the delivered cost of fuel, and address any emergency situations that could affect supplies to SGS.

Q. Does this conclude your testimony?

A. Yes.

060220-E

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF WILLIAM T. LAWTON

DOCKET NO. 06____-EU

MARCH 10, 2006

Q. Please state your name and business address.

A. My name is William T. Lawton. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33688-2000.

Q. By whom are you employed and what is your position?

A. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Staff Economist.

Q. Please describe your duties and responsibilities as Staff Economist.

A. The two primary responsibilities of my present position are to develop long term forecasts of electric demand and energy for Seminole and its member cooperatives (Members) and to conduct appliance saturation surveys of the Members' residential consumers. Both are joint efforts between Seminole and its Members.

Q. Please describe your educational background and business experience.

A. I have over 15 years of experience in electric demand and energy forecasting. My electric utility forecasting experience includes work at Kentucky Utilities Company

as a Financial Analyst and at Seminole as a Corporate Planning Analyst and Staff Economist. I received a Bachelor of Arts degree with honors in Economics from Michigan State University and a Master of Arts degree in Economics from the University of Detroit.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe Seminole's load forecasting methodology, the results of Seminole's two most recent long term load forecasts, and the demand side management (DSM) and conservation activity of Seminole's Members.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit WTL-1, which is a map of Seminole's Members' service territories, and Exhibit WTL-2, which is Seminole's History and Forecast of Energy and Demand.

Q. Are you sponsoring any part of the Need Study in this proceeding?

A. Yes. I am co-sponsoring Sections V, VI, VIII, as well as Appendices D and L.

Q. Please describe the existing service territory of Seminole's Members.

A. The Members' service area is primarily rural and extends approximately 400 miles from the northern border to the southwestern part of Florida. Seminole's Members provide electricity to over 800,000 consumers, serving a population of over 1.6 million people in 46 counties. This service territory encompasses a variety of

geographic and weather conditions as well as a diverse mix of economic activity and demographic characteristics.

Q. Please describe the existing consumer base of Seminole's Members.

A. The Members' consumer mix is 90 percent residential, 9 percent commercial/ industrial, and 1 percent other. Residential consumers represent 70 percent of total energy sales, with commercial/industrial consumers representing 28 percent, and other consumers representing 2 percent. Commercial/industrial energy sales are primarily to small to medium sized retail businesses. Industrial sales, primarily small manufacturing and mining, represent only a small portion of total energy sales. Other consumers consist of irrigation, street and highway lighting, public buildings, and sales for resale.

Q. What have been Seminole's recent energy sales and peak demands?

A. Seminole provided 15,348 GWh of energy to its Members in 2004. This represents an increase of 3.7 percent from 2003 and an average annual compound growth rate (AAGR) of 5.2 percent over the past 5 years. The 2003/2004 winter peak of 3,365 MW and the 2004/2005 winter peak of 3,776 MW were both lower than the 2002/2003 winter peak of 3,982 MW due to milder winters. Seminole's highest peak demand on record occurred on February 14, 2006 at 4113 MW (estimated). The volatility in winter demands over the past four years illustrates the weather sensitive nature of Seminole's winter peak demand. Seminole's summer peak shows much

more stable growth and reached 3,448 MW in 2005, representing an increase of 11.6 percent over 2004 and an AAGR of 6.1 percent over the past 5 years.

Q. How does Seminole's consumer growth compare to the State of Florida as a whole.

A. Historically, Seminole's Members' residential consumer growth has consistently exceeded the State of Florida as a whole. Since 2000, residential consumer growth has averaged 3.4 percent annually for Seminole's Members, compared with 2.5 percent for Florida as a whole. This growth is driven by the expansion of urban areas into the Members' service territories, which is replacing farmland with housing developments. This trend is expected to continue; therefore, the Members' consumer growth rate is projected to remain higher than the consumer growth rate for Florida as a whole.

Q. Please summarize Seminole's load forecast methodology.

A. Seminole's Staff uses econometric and end-use modeling techniques to forecast the number of consumers, energy, and monthly peak demands for each of its Members. These models were developed by Staff to run on Seminole's mainframe computer. Individual Member model results are aggregated to derive the Seminole forecast.

Q. Please describe Seminole's process to forecast energy sales.

A. The Seminole energy sales forecast is the sum of the forecasts of Members' energy purchases from Seminole. Seminole's Staff follows a four step process to develop an

energy forecast for each of its Member systems. First, forecasts of consumers by revenue class are developed using econometric models. Second, forecasts of energy usage per consumer by revenue class are derived using a combination of econometric and end-use methods. Third, sales by revenue class are derived by multiplying the number of consumers times the energy usage per consumer for each revenue class. Fourth, Member energy purchases from Seminole are calculated by summing the revenue class energy forecasts and then multiplying the sums by an adjustment factor (representing losses and billing cycle differences).

Average annual consumers are forecast for the Members' residential and commercial/industrial revenue classes using econometric models. Population is the primary explanatory variable in the models. Forecasts of annual consumers are converted to monthly forecasts using an algorithm derived by Seminole Staff.

Monthly usage per consumer is forecast for the Members' residential and commercial/industrial revenue classes using econometric end-use models. Heating and cooling degree days, space conditioning equipment saturations, the real price of electricity, real per capita income, and total non-farm employment are the primary explanatory variables in the models.

Member energy purchases from Seminole are a two step calculation. First energy sales by revenue class are summed to derive total retail energy sales. Second, total retail energy sales are multiplied by an adjustment factor, which is the historical

average of the ratio of Member energy purchases from Seminole to the Member's total retail energy sales.

Q. Please describe Seminole's process for forecasting peak demands.

A. The Seminole peak demand forecast is derived after the Member monthly peak demands and hourly load forecasts have been created. The Seminole peak demand forecast represents the maximum demand on Seminole in each month after summing the Members' hourly load forecasts. The Seminole Staff follows a four step process to develop a monthly peak demand forecast for each of its Members and the subsequent peak demand forecast for Seminole.

First, monthly load factors are forecast using winter (November – March) and summer (April – October) season econometric models. Cooling and heating degree variables, space conditioning equipment saturations, and weekend variables are the primary explanatory variables. Second, monthly demands are forecast by combining the load factor forecast with the energy purchases from Seminole. Third, hourly demands are created using an algorithm containing the following inputs: normal monthly hourly profiles, maximum and minimum monthly demands, and energy. Fourth, Seminole peak demands are derived by summing the Members' hourly loads and identifying the monthly coincident maximum demands.

Q. Please summarize the key assumptions used in the load forecast.

A. Demographic, economic, end-use, and weather data are the four assumption categories behind Seminole's forecasts. The main demographic and economic data are population, income, non-farm employment, and the price of electricity. County population projections are produced by the Bureau for Business and Economic Research (BEBR) at the University of Florida. County real per capita income and total non-farm employment projections are produced by Moody's Economy.com. Monthly real price of electricity is calculated by Staff from revenue and energy data provided by its Members. End-use information is obtained from Seminole's Residential Consumer Survey. Information on housing characteristics, demographic composition, and appliance saturations has been collected for each Member system since 1980. Weather information is produced by the National Oceanic and Atmospheric Administration. Seminole uses 25 year averages of five weather stations in and around the Members' service areas as representative of normal weather.

Q. Please describe Seminole's current consumer, energy, and seasonal peak demand forecast.

A. Seminole's Members are expected to continue to experience strong growth in the number of consumers, increasing at an AAGR of 2.8 percent over the next ten years and reaching 1,087,362 consumers in 2015. Consumer growth for the following five years (i.e., 2016-2020) is projected to slow down, increasing at an AAGR of 2.0 percent and reaching 1,199,628 consumers in 2020.

As shown on the first page of Exhibit WTL-2, Seminole's energy sales are projected to increase at an AAGR of 4.1 percent over the next ten years, reaching 24,021,037 MWH in energy sales in 2015. Energy sales for the following five years will increase at a slower AAGR of 3.4 percent, reaching 28,390,424 MWH in 2020.

As shown on page 3 of Exhibit WTL-2, Seminole's summer peak demand is forecast to increase at an AAGR of 3.9 percent over the next ten years, reaching 4,802 MW in 2015. The summer peak for the following five years will increase at a slower AAGR of 3.1 percent, reaching 5,603 MW in 2020. As shown on page 2 of Exhibit WTL-2, Seminole's winter peak demand is projected to increase at an AAGR of 4.1 percent over the next ten years, reaching 6,089 MW in 2015. The winter peak demand for the following five years will increase at a slower AAGR of 3.3 percent, reaching 7,173 MW in 2020.

Q. How does Seminole's current load forecast compare to its prior forecast?

A. Seminole's current forecast is relatively consistent with its prior forecast, as depicted in Exhibit WTL-2 (shown as the "2005 LFS" and the "2003 LFS" respectively). The current forecast shows a lower AAGR over the 2006–2020 period. This is a reflection of a consumer forecast with a higher AAGR; offset by a lower AAGR in energy usage per household over this time period. The current forecast is more reliable for planning purposes because it incorporates the most recent population and economic projections, and it has two additional years of history.

Q. Is Seminole's most recent load forecast reasonable for planning purposes?

A. Yes. Seminole's most recent load forecast, which is detailed in Appendix D of the Need Study, is based on generally accepted forecast methodologies and reasonable assumptions and is consistent with historical experience. Seminole, its Members, and the Rural Utilities Service (RUS) have consistently relied on Seminole's forecasts as the basis for power supply planning, rate development, and financial planning.

Q. Does the RUS approve Seminole's load forecasts?

A. Yes. Consistent with RUS rules, Seminole must update its load forecast at least every two years, and each forecast must be approved by the RUS. Each of the two forecasts Seminole used during the planning cycle associated with meeting its need for base load capacity has been approved by the RUS.

Q. Does Seminole offer any DSM or Conservation programs to end-use consumers?

A. No. As a Generation and Transmission cooperative, Seminole provides wholesale power to its Members and does not serve end-use consumers.

Q. Does Seminole promote the use of DSM or conservation in other ways?

A. Yes. Through its rate structure, which has been approved by its Members, Seminole provides its Members price signals that reflect Seminole's cost of supplying power in aggregate. Each Member may use this price signal to evaluate the cost-effectiveness of DSM and conservation measures for its own circumstances. In addition, Seminole's rate structure bases Seminole's billing to its Members on their demand at

the time of Seminole's peak, not the individual peaks of each Member. This encourages Members to concentrate their load management efforts on controlling Seminole's overall system peak rather than their separate peaks. As discussed by Mr. Woodbury, the Commission has previously found that Seminole provides price signals to its Members that are properly designed to provide incentives to lower on-peak demand.

Q. Do any of Seminole's Members have Commission-approved DSM and/or conservation programs?

A. No. Neither Seminole nor its Members have Commission approved DSM goals, programs or plans like investor owned and large municipal utilities.

Q. Do Seminole's Members nonetheless offer DSM programs?

A. Yes. Seminole's Members currently have 237 MW of DSM in the form of load control switches, voltage control, and distributed generation. Load control switches account for 69 MW, voltage control for 71 MW, and load management generation for 97 MW of the total 237 MW of DSM.

Q. Do Seminole's Members also offer conservation programs?

A. Yes. A number of Seminole's Members offer a variety of conservation programs. These conservation programs include: energy audits, energy surveys, consumer awareness, low interest energy loans, lighting conversion, Good Cents Homes, and making available for purchase high efficiency electric water heaters. Seminole

monitors the types of programs offered by the Members, but the design and implementation of DSM and conservation programs are within the management discretion of each Member.

Q. Does Seminole's load forecast reflect the effects of DSM and conservation programs?

A. Yes. Seminole's load forecast methodology captures the historic effect of the Members' residential and commercial DSM and conservation programs. In aggregate our Members are not projecting to increase their DSM capabilities over the forecast period, so reliance on historical effects is appropriate. For conservation however, forecasted energy and demand reflect not only the historic aggregate conservation impacts on Seminole's system, but also incremental conservation at the same rate of adoption.

Q. Is there a sufficient amount of reasonably achievable additional DSM and conservation to mitigate the need for SGS Unit 3?

A. No. Due to a combination of load growth and expiring purchase power contracts Seminole's total resource need in 2012 is 1261 MW, which is significantly greater than the SGS Unit 3 750 MW capacity rating. Because the need is so large, because DSM tends to avoid peaking rather than base load capacity, and given the structure of the Seminole system, it does not appear reasonable that enough cost-effective reductions from DSM or conservation programs could be achieved by 2012 to eliminate the need for SGS Unit 3.

Q. Does this conclude your testimony?

A. Yes.

060220-EC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF TRUDY S. NOVAK

DOCKET NO. 06_____ EU

MARCH 10, 2006

Q. Please state your name and business address.

A. My name is Trudy S. Novak, and my business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

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

A. I am the Director of Pricing and Bulk Power Contracts at Seminole Electric Cooperative, Inc. (Seminole).

Q. Please describe your duties and responsibilities in that position.

A. The responsibilities of my present position include: overseeing the development and issuance of all of Seminole's requests for proposals for purchased power alternatives to meet Seminole's power supply requirements; direct participation in the negotiation and administration of Seminole's purchased power, transmission and interconnection arrangements with other utilities; coordination and direction of my department's activities in the areas of development, design and administration of Seminole's wholesale rates for sales of electricity; evaluation of wholesale filings by Seminole's power and transmission suppliers in the areas of cost of service and rate design, and

the provision of technical support during negotiations and/or hearings; and the coordination and direction of Seminole's power marketing activities.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science degree with honors in General Business and Management from the University of Maryland in 1978 and became a Certified Public Accountant in the State of Maryland in 1980. I was employed by Seminole in May 1982 as a Rate Analyst II. In February 1984, I was promoted to a Senior Rate Analyst. I have held several supervisory roles in the rates and bulk power contracts area since June 1986, and I have been the Director of Pricing and Bulk Power Contracts since January 2000.

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

A. Yes, I submitted testimony before the Florida Public Service Commission (FPSC) in FPSC Docket No. 981827-EC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe: 1) Seminole's experience in purchased power capacity solicitations, 2) Seminole's Request for Proposals ("RFP") process which was utilized in soliciting purchased power alternatives to meet Seminole's base load capacity requirements beginning in the 2009-2012 time frame; 3) the purchased power offerings considered by Seminole; and 4) Seminole's commercial and technical screening of bids.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring three exhibits, TSN-1 through TSN-3, which are attached to my testimony.

Exhibit TSN-1 is a history of Seminole's formal RFPs.

Exhibit TSN-2 is the list of potential bidders to whom Seminole directly provided a copy of its RFP.

Exhibit TSN-3 is a summary of the responses Seminole received to Seminole's RFP issued in April 2004.

Q. Are you sponsoring any part of the Need Study in this proceeding?

A. Yes. I am co-sponsoring Sections VII and VIII, and I sponsor Appendices H and I.

I. SEMINOLE'S EXPERIENCE IN PURCHASED POWER CAPACITY SOLICITATIONS

Q. Please describe Seminole's philosophy in using purchased power RFPs.

A. Seminole firmly believes that a competitive bidding process is an essential element of meeting the power supply needs of our ten Members at the lowest possible cost. Seminole has, since 1988, consistently utilized an all-source competitive bidding process in every circumstance when Seminole has considered the option of building its own generation facilities. As Seminole's primary mission is to provide reliable, competitively priced wholesale power to it Members, Seminole's key objective in every RFP is to insure that we have chosen the best power supply alternative, taking into consideration economics and strategic objectives (such as diversity of fuel supply

and reliability).

In addition, Seminole strongly believes that it is critical to maintain a balanced and diversified generation portfolio that includes owned generating units as well as both long and short term purchased power arrangements with differing technologies and fuel types. As such, Seminole has executed purchased power agreements with entities such as Progress Energy Florida, Oleander Power Project, Limited Partnership (a subsidiary of Southern Power Company), Reliant Energy Florida, LLC (a subsidiary of Reliant Energy, Inc.), Calpine Construction Finance Company, L.P. (a subsidiary of Calpine Corporation), Hardee Power Partners Limited (a subsidiary of Invenergy LLC), Lee County Florida, Bio-Energy Partners, and DG Telogia Power, LLC. These purchased power arrangements serve the entire power supply spectrum, including base load, intermediate and peaking capacity needs. In 2006, Seminole's purchased power resources comprise approximately 60% of Seminole's total generating capacity. Mr. Woodbury describes these purchased power resources more fully in his direct testimony.

Q. Please describe Seminole's previous experience with RFPs.

A. Seminole was the first wholesale power supplier in Florida to use a competitive bidding process to fulfill its power supply needs. Seminole's first RFP was issued in 1988 and resulted in the execution of a purchased power agreement with Hardee Power Partners ("HPP") for capacity and energy from Hardee Power Station and Tampa Electric Company's Big Bend Unit 4. Since 1988, Seminole has issued seven

additional formal RFPs as well as an RFP soliciting renewable resources. In aggregate, Seminole's formal competitive bidding program has resulted in seven purchased power arrangements and three self-build projects (including the current decision to build SGS Unit 3). Exhibit TSN-1 provides a summary of Seminole's major RFP issuances and awards for the period 1988 through 2004. As shown on Exhibit TSN-1, as a result of its RFPs, Seminole has executed purchase power agreements with both investor owned utilities (IOUs) and independent power producers (IPPs). These agreements currently provide more than 2,371 MW of capacity with various terms and technology.

Q. Does Seminole restrict its consideration of purchased power alternatives to the issuance of formal RFPs?

A. No. Seminole enters into purchased power commitments outside of the formal RFP process when such commitments are clearly in Seminole's best interest, taking into consideration economics and strategic considerations. In some cases, these arrangements result from unsolicited offerings from potential counterparties. In other cases, Seminole's formal RFPs become a preface for discussions relating to generating capacity needs outside of the needs specified in the then-current RFP. In addition, Seminole's common practice in all of its formal RFPs is to reserve its rights to make purchased power commitments outside the RFP which result from: 1) negotiated amendments with its current power suppliers, 2) negotiated arrangements with parties with which Seminole was engaged in negotiations prior to the issuance of the RFP, and 3) negotiated arrangements for small power resources (e.g., 50 MW or

less).

Q. Please describe Seminole's experience in contracting for small power resources.

A. During the last several years, Seminole has been committed to seeking cost-effective contractual arrangements with third party power suppliers from small base load power resources, especially when such resources provide renewable energy. Seminole currently has three purchased power agreements from renewable energy resources with varying terms and fuel supply. The energy from these renewable resources serves 2-3% of Seminole's annual energy requirements. These agreements are discussed more fully in Mr. Woodbury's testimony.

II. SEMINOLE'S APRIL 2004 REQUEST FOR FIRM BASE LOAD CAPACITY

Q. Please describe Seminole's RFP issued in April 2004.

A. On April 19, 2004 Seminole issued an "all-source" RFP (Request for Firm Base Load Capacity, RFP No. BL 2012) seeking capacity offerings to meet up to 600 MW of Seminole's base load capacity and energy needs beginning as early as the summer of 2009 but no later than December 2012 with terms from one to twenty years. All proposals were due back to Seminole by September 1, 2004. The April 2004 RFP and the addenda to the RFP are provided in Appendix H of the Need Study.

Q. What do you mean by an "all source" RFP?

A. Seminole's April 2004 RFP was open to all parties, including, but not limited to: IPPs, IOUs, exempt wholesale generators, power marketers, qualifying facilities

("QFs"), and renewable energy providers, etc. As described above, renewable energy providers are typically small base load resources and as such, had the option of bidding on the RFP or negotiating separately in parallel with the process.

Q. Please describe more fully Seminole's identified power supply need in its April 2004 RFP.

A. As explained more fully in Mr. Mahaffey's testimony, in early 2004 Seminole had determined that it had a significant requirement for additional capacity beginning in the 2009 – 2012 time frame, with at least 600 MW expected to operate as a base load resource. Since much of Seminole's capacity need in the targeted time frame would be base load and therefore energy-intensive, Seminole's April 2004 RFP expressed a preference for responses which could provide fuel price stability. The RFP suggested a preference for either coal fired generation or alternatively non-coal capacity resources structured to provide long term energy price stability.

Q. Please describe the key components of Seminole's April 2004 RFP.

A. Seminole's April 2004 RFP was developed by in-house staff from a template largely based on the previously issued Seminole RFPs. The April 2004 RFP detailed a variety of information for potential bidders. It included sections on items such as purpose, a description of Seminole and its system, means of communicating with Seminole staff for questions (via fax or e-mail), a summary schedule, procedures for providing a response to Seminole with bid forms, and information on how the response would be evaluated. The April 2004 RFP is Appendix H to the Need Study.

Seminole's RFPs are purposely designed to be flexible, with a minimum of detail and requirements. The goal is to allow potential bidders as much flexibility as possible to develop proposals to meet Seminole's identified need(s). For example, in the April 2004 RFP, Seminole offered flexibility to the bidders in regards to the term of the purchase power agreement as well as the type of technology proposed. In addition, in the April 2004 RFP Seminole stated it would consider market energy offerings as long as the bidder provided adequate firm and verifiable backup capacity.

Q. Please describe the process by which the April 2004 RFP was issued to potential market counterparties.

A. Seminole makes all of its formal RFPs available to the wholesale market in three ways. These are: 1) a general press release on an electronically distributed news release service; 2) posting of the RFP on Seminole's public website; and 3) an e-mail with the RFP attached which is sent directly to potential counterparties known to Seminole (Seminole sent its April 2004 RFP to over forty such counterparties). Seminole maintains an ongoing list of potential counterparties that have been involved in previous Seminole RFPs, have expressed an interest in responding to Seminole RFPs, or with which Seminole has a significant relationship in regards to wholesale energy including current or prior purchase power agreements. Seminole used all three vehicles to generate awareness of and solicit responses to the April 2004 RFP. The press release utilized to announce the April 2004 RFP is provided in Appendix I of the Need Study, and the contact list for the direct mailing is provided in Exhibit TSN-2.

Q. Did Seminole hold any pre bid or bidder conferences for the April 2004 RFP?

A. No. Seminole has held pre bid conferences on previous RFPs but has found this tool to be of little incremental value. Consequently, these conferences were not held for the April 2004 RFP. Seminole did provide a business contact for any questions that might arise and encouraged all potential bidders to pose questions. Any critical information that resulted from these inquiries was communicated to all potential bidders via a posting on Seminole's public website as well as e-mailed directly to all the potential bidders on our contact list.

Q. Did Seminole receive any questions from potential bidders on the April 2004 RFP?

A. Yes. Seminole received several questions from potential bidders. Seminole deemed these questions and responses to be of interest to all potential bidders and as such responded to these questions in the form of three Addenda to the April 2004 RFP. The Addenda are included as part of the RFP in Appendix H of the Need Study. As mentioned previously, these Addenda were e-mailed directly to all potential bidders on our contact list and posted on Seminole's public website.

III. PURCHASED POWER OFFERINGS IN RESPONSE TO SEMINOLE'S APRIL 2004 RFP.

Q. Did Seminole receive any bids in response to its April 2004 RFP?

A. Yes. On September 1, 2004, Seminole received a total of fourteen different proposals from five bidders. In Seminole's view, the number of responses was deemed to be

fairly strong in light of the future timeframe and the base load capacity need. The bidders were IPPs and IOUs with capacity amounts ranging from 100 MW to 750 MW and terms ranging from ten to forty years.

Q. What generation technologies were offered to Seminole?

A. The technologies offered to Seminole in response to the RFP were pulverized coal and gas combined cycle. Seminole was offered capacity from three proposed new pulverized coal units, one located within Florida, one in Southwest Georgia, and one in Kentucky. Seminole was offered capacity from both existing and new gas combined cycle units, all located in Florida. The proposals are displayed in summary fashion in Exhibit TSN-3.

Q. Please describe the screening process Seminole followed upon receipt of the bids.

A. Seminole initially reviewed the offers for completeness and responsiveness. On September 16, 2004 each bidder was forwarded a list of clarifying questions via e-mail to ensure that the responses were being interpreted correctly.

Q. What technical evaluation was done by Seminole on the received proposals?

A. Seminole reviewed the offerings involving construction of new capacity to determine if the proposed equipment was technically viable and whether the performance data seemed reasonable.

Q. Were any of the proposals eliminated from further consideration as a result of the technical evaluation?

A. No. Since all of the proposals for new construction were based upon proven technology (i.e., gas combined cycle and pulverized coal), none of the bids were excluded from further consideration as a result of this technical screening.

Q. What was the next step in Seminole's RFP evaluation?

A. As Mr. Mahaffey explains in his testimony, his group performed an initial economic evaluation comparing the purchased power offerings with the costs associated with Seminole's self build alternatives. The results of this initial economic evaluation revealed a significant economic advantage for the self build coal-based alternative over any of the purchased power alternatives submitted in response to the April 2004 RFP.

Q. What did Seminole do upon the completion of this initial economic evaluation?

A. In an effort to ensure that all possibilities to find an economic purchased power alternative were investigated, on October 28, 2004, two bidders submitting pulverized coal-based offers (the two lowest cost bidders) were asked to refresh and revise their pricing and other applicable terms and conditions by November 10, 2004. Only one of the bidders chose to refresh its pricing, and as Mr. Mahaffey explains in his testimony, the initial economic analysis was updated using this new pricing information.

Q. Did Seminole compile a short list of bidders from the received responses?

A. No. Based upon the results of Seminole's updated economic evaluation, which is described by Mr. Mahaffey, a recommendation to eliminate from further consideration all the purchased power proposals submitted in response to the April 2004 RFP was approved by Seminole's Board of Trustees in December 2004.

Q. Please summarize Seminole's overall view of the April 2004 RFP process and results.

A. The April 2004 RFP was a success. The process worked, resulting in Seminole choosing the lowest cost, most reliable option for Seminole, its Members and their member/consumers. Seminole received an adequate number of responses to the April 2004 RFP to assure Seminole that the self build option in this case was the most cost-effective alternative for Seminole. I would also note that, although Seminole eliminated all of the purchased power alternatives in response to the April 2004 RFP from further consideration for this 2012 base load capacity need, Seminole did continue discussions with two of the bidders to potentially meet other, more intermediate type needs in the 2009 through 2012 time frame.

Q. Did Seminole obtain any feedback from any of the bidders relating to Seminole's RFP process?

A. Seminole did not receive criticism from any of the bidders or potential bidders in the RFP process. In fact, one potential bidder personally told me that Seminole's RFPs and the process followed for making power supply decisions is a model that should be

followed by others.

Q. Does that conclude your testimony?

A. Yes.

060220-EC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF LANE MAHAFFEY

DOCKET NO. 06____-EU

MARCH 10, 2006

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

A. My name is Lane Mahaffey. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33688-2000.

Q. By whom are you employed and what is your position?

A. I am employed by Seminole Electric Cooperative, Inc. (Seminole) as Director of Corporate Planning in the Strategic Services Division.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for overseeing the development and implementation of Seminole's long term strategic plan, developing and updating long-term electrical load forecasts, and planning adequate, reliable and economic generation resources to meet the requirements of Seminole's member cooperatives (Members).

Q. Please describe your educational background and business experience.

A. I graduated from the University of South Florida with a Bachelor of Science Degree in Electrical Engineering in 1976. I began work for Florida Power Corporation (now

Progress Energy Florida), first as a cooperative student and upon graduation as a System Performance Engineer in the production (power plant) testing department. In 1979, I began work for the City of Vero Beach, Florida as Results Engineer in the Vero Beach Municipal Power Plant. In that capacity, I was responsible for overall plant efficiency and supervised the system operations department (system control center) and the plant electrical and instrument shops. In 1982, I joined Seminole as Supervisor of System Operations with responsibility for the system control center operation. In 1984, I was promoted to Manager of System Operations with similar responsibilities. In 1993, I was promoted to Director of Operations with responsibility for the System Operations Department and the Fuels Department. In 1996, I was named Director of Strategic Planning and Market Analysis (strategic planning, load forecasting, and market analysis responsibilities), and later Director of Strategic Planning and Marketing (strategic planning, load forecasting, and energy marketing). In 2002, I was named Director of Corporate Planning.

Q. What is the purpose of your testimony?

A. My testimony addresses the need of Seminole, its Members and their member/consumers for SGS Unit 3, the most cost-effective alternative available to meet their need for reliable and adequate electricity at a reasonable cost in 2012 and beyond. My testimony has six primary elements. First, I describe Seminole's generation planning process. Second, I review Seminole's reliability criteria that are used in determining capacity need. Third, I describe Seminole's evaluation of self-build and purchased power alternatives that led to the decision to add SGS Unit 3.

Fourth, I describe Seminole's assessment of risk associated with this capacity decision. Fifth, I discuss the recommendation by Seminole's Staff to our Board of Trustees to proceed with SGS Unit 3 and the Board's subsequent approval. Sixth, I describe Seminole's and Peninsular Florida's need for SGS 3 and the adverse consequences to Seminole and its Members in the event the proposed project is not constructed.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the five exhibits listed below, which are attached to my testimony.

Exhibit LTM-1 Seminole Capacity Need Without SGS Unit 3

Exhibit LTM-2 Seminole Power Supply Resource Requirements

Exhibit LTM-3 Summary of Bus Bar Costs

Exhibit LTM-4 Present Worth Revenue Requirements (PWRR) Results

Exhibit LTM-5 Cumulative and Annual PWRR Results

Q. Are you sponsoring any part of the Need Study in this proceeding?

A. Yes. I am co-sponsoring Sections V, VI, VII, and IX of the Need Study document. I am also sponsoring Need Study Appendices E, G, and K.

I. SEMINOLE'S GENERATION RESOURCE PLANNING PROCESS

Q. What is the objective of Seminole's generation resource planning process?

A. The fundamental objective of Seminole's planning process is to provide a portfolio of generation resources that ensures reliable wholesale electric service at a competitive cost. Underlying this fundamental objective is a strong belief that, over the long term, a reliable and competitive generation portfolio must be based on a diverse generation and fuel mix to provide price stability.

Q. Please provide an overview of Seminole's generation resource planning process.

A. The load forecast is a starting point. As Mr. Lawton describes in more detail, Seminole works with its ten Members to develop individual forecasts, which roll up into an aggregate Seminole load forecast. Once the load forecast is developed, Seminole assesses the amount of capacity needed to meet the load forecast plus additional capacity necessary to meet Seminole's reliability criteria.

After determination of the total generating capacity need and any resulting capacity deficiency, Seminole further analyzes the capacity need in order to determine the type of capacity addition which would contribute optimally to the overall generation mix (i.e., base, intermediate, or peaking). This is done using a combination of analytical techniques involving load duration curve analysis, bus bar cost analysis, and/or iterative production costing runs.

Next, Seminole must evaluate its alternatives to meet the identified capacity need. One or more self-build alternatives are developed. This is typically done by an independent engineering consulting firm. Then, Seminole solicits competitive bids for purchased power via a request for proposals (RFP). Seminole may also be involved in continuing negotiations with other parties or existing suppliers.

The self-build alternative(s) are evaluated against purchased power alternatives and, ultimately, a recommendation is made to Seminole's Board as to what individual resources (or combination of resources) should be pursued.

Q. Please describe Seminole's generation portfolio and address whether the above described planning process has been effective in meeting Seminole's planning objectives.

A. Seminole's generation portfolio currently consists of approximately 60% purchased power. This is the result of an aggressive competitive bidding program wherein Seminole strives to ensure that its decisions among power supply alternatives are based on the best available market information in comparison to self-build alternatives which are viable at that time. Over the past two decades, the wholesale market in Florida has produced competitive pricing from independent power producers eager to enter the Florida market. Seminole has also been able to negotiate favorable purchased power arrangements with investor-owned and municipal utility partners. These market conditions have allowed Seminole to contract for a significant portion of its power supply resources from a range of purchased power resources, in

combination with self-build projects. The resulting resource mix has provided competitive and reliable wholesale power to Seminole's Members, while allowing Seminole the flexibility to replace these resources with other sources of supply in response to major market trends (e.g., high natural gas prices).

II. SEMINOLE'S GENERATING CAPACITY NEED IN 2012

Q. Please describe Seminole's reliability criteria and related reserves.

A. The total amount of generating capacity and reserves required by Seminole is affected by Seminole's load forecast and a set of reliability criteria. Reserves serve two primary purposes: to provide replacement power during generator outages and to address load forecast uncertainty.

Seminole has two principal reliability criteria: (1) a minimum reserve margin of 15% during the peak season, and (2) a 1% Equivalent Unserved Energy (EUE) limitation. Both criteria help maintain the reliability of Seminole's power supply to its Members and limit Seminole's need to rely on emergency reserve purchases from interconnected neighboring systems.

Q. Please describe in general terms the load forecast which Seminole uses as the basis for its capacity need.

A. Seminole provides firm bulk power supply (at wholesale) to its ten Members which serve retail consumers in Peninsular Florida. Seminole's Members are described in detail in the Need Study document and in Mr. Woodbury's testimony. Seminole

serves these ten Members under long term wholesale power contracts. The original contracts were for 45 years, extending through July 2020. Seven of Seminole's ten Members have extended their contracts an additional 25 years (through 2045). Seminole has reached agreement with two of the remaining three Members (Clay Electric Cooperative and Suwannee Valley Electric Cooperative) to extend their contracts through 2045, contingent upon certain contract amendment terms which are still under development. Thus, Seminole is planning on serving nine of the ten Members through 2045, with the responsibility for serving the tenth Member still unresolved. However, since the extended wholesale power contracts are currently only finalized with seven of ten Members, Seminole has based its capacity need and economic assessments for this determination of need on serving only the seven Members that have already signed contract extensions.

Q. Please describe Seminole's capacity needs in future years and explain how SGS Unit 3 will meet a portion of those needs.

A. Seminole's need assessment process demonstrated that, in order to meet Seminole's established reliability criteria, over 1200 MW of additional capacity will be needed in 2012. This capacity need results from the scheduled expiration of purchased power contracts (i.e., 546 MW Oleander Power Project, L.P., 360 MW Calpine Construction Finance Company, L.P., and 55 MW Lee County, Florida), planned annual adjustments in Seminole's PEF Partial Requirements contract, plus expected load growth. By 2015, the capacity need will increase to over 4600 MW. The increased capacity needed by 2015 results from the combined effect of the changes mentioned

previously, plus the scheduled expiration of additional purchased power contracts (i.e., 356 MW Hardee Power Partners, Limited, 364 MW Reliant Energy Florida, LLC, 450 MW Progress Energy Florida System Intermediate, Progress Energy Florida Partial Requirements), and additional load growth.

Since Seminole's cumulative need for capacity in 2012 exceeded 1200 MW and increased significantly thereafter, SGS Unit 3 alone only meets a portion of Seminole's projected load and reserve requirements. Seminole's total additional capacity needs based on serving seven Members after 2020 (i.e., consistent with the basis of the economic justification) are summarized in tabular format in Exhibit LTM-1. A graphical overview of Seminole's overall resource portfolio is included as Exhibit LTM-2. Page 1 of Exhibit LTM-2 shows Seminole's capacity needs with only seven Members served after July 2020, representing the Member load commitment assumption which underlies Seminole's economic case. Page 2 of Exhibit LTM-2 shows Seminole's capacity needs with nine Members served after 2020 (for reference only).

Q. Is SGS Unit 3 needed for reliability or for economic reasons?

A. Both. As noted above, SGS Unit 3 fulfills a portion of Seminole's reliability need in 2012 and beyond. Thus, SGS Unit 3 is clearly needed for reliability. At the same time, the selection of SGS Unit 3 to serve as a base load resource, as opposed to alternative types of capacity resources, is motivated by economics. So SGS Unit 3 is needed both to maintain reliability and to provide electricity at a reasonable cost.

Q. Describe how Seminole determined that a portion of its 2012 capacity needs should be met with a "base load" resource.

A. Most electric utilities, including Seminole, employ a mix of generation which includes resources generally characterized as base, intermediate, and peaking. Base load resources are those resources which typically operate around the clock to serve consumer demands. Intermediate resources are typically cycled on during the daytime hours and off during the lower demand nighttime hours. Peaking resources typically operate only during peak hours of the day, mostly during peak seasons, and occasionally provide reserve (backup) capacity for short periods to replace base and intermediate capacity during outages.

Seminole uses a combination of analytical techniques to determine how much of its total capacity need in future years should be met with each type of resource. Load duration curve techniques provide a rough estimate of an optimal system generation mix. These curves allow a determination of the amount of capacity on a system which will operate above a specified capacity factor. In order to use a load duration curve approach for determining base load capacity need, first an estimate is made of the typical operating profile for base load resources in terms of an annual capacity factor. Such an estimate could be made by analyzing bus bar costs (i.e., the total cost to operate a base load generating technology on a $ per MWh basis). Seminole used this approach to estimate the amount of base load capacity it needed in advance of its competitive bid for purchased power. However, these load duration curve techniques only provide an initial estimate. The detailed economic analyses comparing one

alternative against another is the real determinant of the most economic resource(s) and/or resource combination and how large the MW commitment for a selected type of resource should be at a particular time.

Q. How much base load capacity does Seminole need?

A. Seminole originally estimated a need for up to 600 MW of base load capacity as early as 2009. Ultimately, as load forecasts and fuel price forecasts were updated, and as specific self-build and purchased power alternatives were studied, Seminole concluded that 750 MW of base load capacity should be added in the 2012 time frame.

III. EVALUATION OF SELF-BUILD VERSUS PURCHASED POWER ALTERNATIVES

Q. Please describe how Seminole developed its self-build alternatives.

A. As described more fully in Mr. Klover's testimony, in August 2004, Burns & McDonnell completed a feasibility study assessing Seminole's self-build alternatives to provide base load capacity. The feasibility study concluded that a third 600 MW (nominal) pulverized coal unit at the Seminole Generating Station was the best and most economic self-build alternative. This feasibility study provided the expected costs of construction and the schedule associated with achieving commercial operation for the prospective coal unit. Burns & McDonnell also provided costs for a gas combined cycle unit and a cost comparison which concluded that a coal unit was the lower cost alternative.

Q. What other generation technologies did Burns & McDonnell consider to meet Seminole's need for base load capacity?

A. In addition to the recommended pulverized coal technology and gas combined cycle technology, the Burns & McDonnell study addressed integrated coal gasification with combined cycle (IGCC). As discussed in Mr. Klover's testimony, Burns and McDonnell determined that IGCC technology remains relatively unproven in commercial scale electric applications, and that the reliability and cost risks are too high at the present time (i.e., until these technologies have been further developed by others).

Q. Did Seminole consider any other technologies as a self-build alternative?

A. Yes. Seminole staff considered circulating fluidized bed (CFB) technology. As discussed further by Mr. Opalinski, Seminole concluded, based on industry information available at the time, that large scale CFB projects would be more costly than a pulverized coal project and would not provide any offsetting benefits. Consequently, Seminole did not ask Burns & McDonnell to consider CFB technology. Seminole was also a joint participant in a feasibility study for a separate jointly owned coal fired unit with several Florida municipalities (i.e., 150 MW share of a 600-800 MW unit). This feasibility study was conducted by a separate independent engineering consulting firm which had made similar conclusions to Burns & McDonnell on the feasibility of pulverized coal technology. Therefore, Seminole ultimately had three self-build alternatives for serving portions of its base

were excluded from further consideration as a result of either the administrative or the technical screening. All of the bidders were contacted on September 16, 2004 for clarification of the specific terms and conditions of their offers, including pricing and unit characteristics. In order to insure that all possibilities to find a purchased power alternative had been investigated, on October 28, 2004, the bidders with the lowest cost proposals were asked to refresh and revise their pricing and other applicable terms and conditions by November 10, 2004. The RFP process is described in greater detail in Ms. Novak's testimony.

Economic screening of the purchased power proposals was accomplished by comparing "bus bar costs." Bus bar costs are a representation of the all-in cost for each alternative divided by the energy produced. The bus bar cost (in $ per MWh) for each alternative was calculated for each of three different operational scenarios (i.e., all proposals, including the three self-build alternatives, were evaluated at 70%, 80% and 90% capacity factors, representing the base load operation range). The analysis included all fixed and variable costs, including fuel expense. Fuel costs and other applicable assumptions which were not specifically tied down by the RFP proposals were standardized for consistency in the evaluation. The bid-to-bid comparisons (and associated ranking) were done on a levelized $/MWh basis, calculated over a twenty-year period, on a nominal and present worth basis.

Q. Please describe the generation alternatives that were evaluated using Seminole's bus bar cost comparison.

A. As further described in Ms. Novak's testimony, Seminole evaluated three self-build alternatives and fourteen purchased power alternatives. The three self-build alternatives were a pulverized coal unit at Seminole's existing coal site, a participation share in a jointly-owned pulverized coal unit, and a greenfield gas combined cycle unit. The purchased power alternatives included purchased capacity and energy from three greenfield pulverized coal units (one in Florida and two out-of-state), three greenfield gas combined cycle units (with nine proposals reflecting unit configuration alternatives and pricing options), and one existing gas combined cycle unit (with two unit configuration alternatives). The proposal from the existing gas combined cycle unit was at a significantly higher cost than the other alternatives, and for this reason, only the best of two configuration alternatives was carried forward in the bus bar cost comparison.

Q. Describe the results of Seminole's economic screening evaluation.

A. The bus bar cost comparison revealed a significant economic advantage of coal-based alternatives over gas-based alternatives, and further, that self-build alternatives for both coal and gas were significantly favorable relative to the purchased alternatives resulting from the RFP process. The results of this screening process are included as Exhibit LTM-3.

Q. What action did Seminole take upon completion of the economic screening described above?

A. At the December 2004 meeting of Seminole's Board of Trustees, staff presented its economic assessment of self-build and purchased power options. Staff concluded that the economic favorability of a self-build coal unit (Seminole's lowest cost self-build alternative) over any of the purchased power alternatives was so significant that further negotiations would not yield a change in the rankings. On this basis, staff recommended, and the Board approved, discontinuing negotiations with the RFP bidders related to their base load proposals.

The Seminole Board also directed staff to continue background activities associated with a pulverized coal unit. Staff also reported to the Board that a consulting firm had been engaged to assist with a risk assessment of the economic evaluation of alternatives. The risk assessment would compare the economic risks of a coal-based scenario and an alternative all-gas scenario utilizing gas combined cycle technology, as both generation technologies were described in the Burns & McDonnell study.

IV. EVALUATION AMONG THE SELF-BUILD ALTERNATIVES

Q. Describe how Seminole proceeded in its evaluation of the self-build alternatives.

A. As described above, Seminole initially used a "bus bar cost" comparison in determining that its self-build coal unit alternatives (specifically a pulverized coal unit at Seminole's Palatka site and a prospective 150 MW share of a separate coal unit) were its most economic alternatives. As a further test of the validity of these

results, staff proceeded with a risk assessment of the prospective coal strategy versus an all-gas strategy (both self-build). The risk assessment would initially involve further evaluation of these alternatives on a present worth revenue requirements basis.

A self-build 600 MW coal unit (lowest cost option) in combination with the 150 MW joint coal unit participation (next lowest cost option) was compared to an all-gas scenario based around the self-build gas combined cycle technology and costs from the Burns & McDonnell study. The comparative results from these two competing cases were then subjected to a probability-based risk assessment.

As noted above, a consulting firm (R.W. Beck) had been commissioned to develop the analytical tools necessary for Seminole to perform detailed risk analysis of power supply alternatives, and to assist with the risk analysis of the coal vs. gas scenarios. These analytical tools assign probability distribution functions (PDFs) around selected variables, and using various probability techniques, including Monte Carlo simulations, evaluate the aggregate risk of the variables in combination, as opposed to traditional scenario analysis which looks at one variable at a time.

The approach used in the risk analysis included (i) preparing market data inputs (such as gas prices and coal prices), environmental cost inputs, inputs on future generation costs by type of plant (including capital costs, operating costs, etc.) and load forecast inputs; (ii) defining the variability of major inputs that could impact power supply

decisions ("risk" variables); and (iii) preparing PDFs that describe the uncertainty of each risk variable.

Based on the PDFs defined for each risk variable, the assessment process used stochastic modeling and statistical analysis techniques to analyze how (in aggregate) these risks could impact Seminole's projected annual power costs. The results of the risk assessment included a projection of the potential range (with a certain confidence level) and expected outcome of annual power costs and average Member rates under the two options (coal and gas) being evaluated.

Q. Briefly describe the results of the risk assessment.

A. The present worth revenue requirements analysis which served as the underlying base case for the risk assessment yielded a projected savings of $476 million (2005 dollars) for the studied coal strategy versus an all-gas strategy. The risk assessment concluded there was an 80% probability that the coal strategy would yield lower costs over the study period than the all-gas strategy. The results of the present worth revenue requirement savings analysis and the risk assessment were reviewed with Seminole's Board at its February 2005 meeting. The final report of Seminole's Risk Assessment of Base Load Options is included as Appendix K to the Need Study.

Q. After its decision to proceed with a self-build coal project, Seminole chose a 750 MW unit instead of its original 600 MW unit in combination with the 150 MW coal unit participation. Describe the circumstances which led to Seminole's decision.

A. In early 2005, as the purchase power proposals and self-build options were being evaluated, refined cost estimates for the joint coal project were received which had increased significantly from prior estimates. In addition, the anticipated in-service date for the joint unit, which was originally in 2009, was now 2011 or 2012. Further, a purchased power option Seminole had negotiated with the joint participants (i.e., a purchased power structure instead of equity ownership) was deemed infeasible by the other participants due to financing difficulties. In consideration of the higher costs, the later commercial operation date, and the loss of the purchased power option for the joint project, Seminole decided to re-evaluate its own self-build alternative to assess the viability of a larger unit.

Burns & McDonnell was commissioned to update its feasibility study. The updated study indicated that a 750 MW (nominal) unit at Seminole Generating Station was technically feasible and could be permitted on the site. An economic analysis of the larger unit showed that the incremental 150 MW of capacity in the self-build unit could be constructed and operated at a significantly lower cost than the 150 MW share of the planned joint unit. The decision was made to discontinue further participation in the joint unit project.

V. SEMINOLE BOARD'S APPROVAL OF THE SGS UNIT 3 PROJECT

Q. What was the recommendation of Seminole's staff to the Board regarding SGS Unit 3, and what was the result?

A. At the March 2005 meeting of the Board of Trustees, staff reviewed the chronology of planning activities for base load capacity since 2003. Technical staff also reviewed a technology study performed by Burns & McDonnell relating to SGS 3 unit design details. Staff recommended, and the Board approved, proceeding with the planning, permitting, and construction of SGS Unit 3 as a 750 MW supercritical pulverized coal unit, for commercial operation in May 2012.

VI. UPDATED ECONOMIC ANALYSIS

Q. Has Seminole updated its assessment since the March 2005 project approval?

A. Yes. During the summer of 2005, staff updated its economic assessment. A new load forecast was approved by Seminole's Board in July 2005, and the fuel price forecast was updated in August 2005. Due to revisions of these and other input assumptions, staff updated its economic comparisons.

Q. Please describe Seminole's updated economic assessment.

A. Seminole performed two separate analyses: (1) a present worth revenue requirements comparison for a 750 MW pulverized coal unit versus an all-gas scenario, using updated costs for the coal unit and updated load and fuel forecasts; and (2) a case study using a present worth revenue requirements analysis and the December 2004 base case assumptions, which compared the original self-build alternatives, the best

purchased power scenario, and the 750 MW pulverized coal unit. The economic comparisons in (2) were designed to provide a bridge between the original decision to eliminate all purchased power alternatives and Seminole's updated plan to proceed with a more economical 750 MW unit as opposed to a 600 MW unit. The updated coal versus gas analysis in (1) revealed a projected present worth revenue requirement savings of $498 million (2005 dollars). The bridge analysis in (2) revealed cumulative present worth revenue requirement savings as follows:

- $123 million savings for a 750 MW SGS Unit 3 versus a 600 MW SGS Unit 3 in combination with the 150 MW joint coal unit participation option.
- $600 million savings for a 750 MW SGS Unit 3 versus an all gas case built around an equivalent amount of gas combined cycle.
- $684 million savings for a 750 MW SGS Unit 3 versus a 600 MW Invenergy coal unit (best purchased power offer) in combination with the 150 MW joint coal unit participation option.

A summary of the results of Seminole's updated analyses as described above is included as Exhibit LTM-4. The annual detail for Seminole's updated economic results comparing SGS Unit 3 to an alternative all-gas scenario is included as Exhibit LTM-5.

VII. ADVERSE CONSEQUENCES IF SGS 3 IS NOT CONSTRUCTED

Q. What will be the projected impact on the reliability of service to Seminole's Members and their member/consumers if SGS Unit 3 is not constructed to meet the identified capacity needs in 2012?

A. Approximately half of Seminole's generation portfolio consists of purchased power contracts. The expiration of some of these contracts in the time frame of the proposed unit addition combined with projected growth in our Member service areas left a deficiency of over 1200 MW in total capacity need by the summer of 2012. The proposed unit addition satisfies a significant portion of this total need. If SGS Unit 3 were not constructed timely, and in the absence of other alternative capacity additions, Seminole would not meet its planning reliability criteria. That would leave our Members and their member/consumers without reliable wholesale service and would result in an unacceptably high risk of service interruptions.

Q. What will be the projected economic impact on Seminole's Members and their member/consumers if the SGS Unit 3 project is not constructed to meet the identified capacity needs in 2012?

A. Seminole's election to build a 750 MW coal unit, as opposed to a purchased power contract or building another type of unit (e.g., gas combined cycle, combustion turbine, etc.), was based on economic studies which demonstrated that the recommended unit will provide the lowest cost base load power for our Members' consumers. In the event SGS Unit 3 is not constructed timely, the economic studies which support this need application show that Seminole's Members and their

member/consumers would be significantly harmed through higher costs and greater price uncertainty. The additional cost Seminole and its Members and their retail member/consumers would incur is essentially the loss of $498 million of expected savings attributable to SGS Unit 3.

Q. What other consequences will there be to Seminole and its Members and their member/consumers if SGS Unit 3 is not constructed as planned?

A. In 2006, Seminole will rely on natural gas for 37% of its system energy requirements. By 2013, the first full year of operation of SGS Unit 3, Seminole's reliance on natural gas will have decreased to approximately 29%. In the absence of SGS Unit 3, the resulting level of reliance on natural gas to meet Seminole's system energy requirements would be approximately 52%, imposing unacceptable risks associated with price uncertainty and weather-related fuel availability. Such fuel-related risks threaten Seminole's reliability of service, and the increased price uncertainty would flow through to Seminole's wholesale rates and the retail rates of Seminole's Members.

VIII. PENINSULAR FLORIDA'S CAPACITY NEED

Q. Is Seminole's need for SGS Unit 3 consistent with Peninsular Florida's capacity need?

A. Yes. By the year 2014, Peninsular Florida utilities report that in aggregate, they will require over 18,000 MW of new generating capacity (i.e., based on the July 2005 issue of the FRCC Regional Load and Resource Plan). Seminole and its ten Members

are, in aggregate, among the fastest growing electric systems in Peninsular Florida, and Seminole's needs are a significant portion of the statewide need for generating capacity. The addition of a 750 MW unit at Seminole's existing SGS site will contribute to meeting the statewide need for power.

Similarly, the aggregate reliance of Peninsular Florida on natural gas for electric energy will have increased from 32% in 2005 to 46% in 2011. By 2013, currently announced coal additions (including SGS Unit 3) will have increased solid fuel's energy share and, correspondingly, decreased the portion served by natural gas by approximately 2% (reducing the state's reliance on natural gas from 46% to approximately 44%). Even with coal additions by Seminole and others in the 2012 time frame, natural gas is projected to increase to 44% of Peninsular Florida's energy needs by 2013.

Q. Please summarize your testimony.

A. Seminole needs a significant amount of additional generating capacity by the year 2012, and a portion of such capacity should operate as a base load resource. These needs are due primarily to expiring purchased power contracts and load growth. An engineering consultant's study recommended a modern pulverized coal unit as the best self-build option. A competitive bidding process provided purchased power alternatives for comparison to the self-build option(s). A rigorous analytical evaluation demonstrated that a 750 MW pulverized coal unit, SGS Unit 3, was the most economical alternative to meet Seminole's base load requirements in 2012. A

risk assessment provided additional assurance that a coal unit is the most economical alternative under a range of alternative scenarios. Seminole's Board of Trustees, consisting of Trustees from Seminole's Members (wholesale customers), reviewed the economic studies described above and directed Seminole to proceed with planning activities necessary to construct SGS Unit 3.

Seminole requests a favorable finding from the Commission on Seminole's application for a determination of need for SGS Unit 3. An adverse finding would jeopardize Seminole's ability to provide reliable service to Seminole's Members and their member/consumers, would significantly increase the future costs of Seminole's wholesale electric service, and would create an unacceptable level of reliance on natural gas generation.

Q. Does this conclude your testimony?

A. Yes.

MS. BROWN: Well, then I guess we're ready to hear public testimony. I have -- go ahead.

CHAIRMAN EDGAR: I was just going to say, as Ms. Brown described earlier, there is a sign-up sheet. Anybody who would like to give public testimony to the Commission in this matter, if you have not yet, please sign up on the sheet. All, all of those who come before us to speak will need to be sworn in, we will do that as a group here in a moment, and then Ms. Brown will call in order from the sign-up sheet. I'll ask you to come forward and come and sit right over here to my right. As you have been sworn, there will be the opportunity for questions to be asked of you after you have given us your statement.

And so with that, for those who would like to come and give testimony before the Commission in this matter, please stand and I will swear you in as a group.

(Witnesses collectively sworn.)

CHAIRMAN EDGAR: Thank you.

Ms. Brown, we're ready for the first person.

MS. BROWN: Gary Lloyd.

GARY LLOYD

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

MR. LLOYD: Good morning, Commissioners. I

appreciate the opportunity to speak. I'm Gary Lloyd of Tallahassee.

I believe that this proposal as written should be denied. It needs further exploration and there are many factors that need to be considered.

The pollutants to the human health for asthma, emphysema, respiratory infections are really not written into this. I understand that it is still being -- the last I heard, they're using a so-called supercritical boiler. The best estimate I could get from any source on the reduction of pollutants was 6 percent from the use of this boiler. Most people and authorities said 5 percent. That isn't very much.

We have to remember that coal is the biggest polluter of all, and particularly for carbon dioxide, which is the main --

MR. GUYTON: Madam Chairman, excuse me. Mr. Lloyd, I apologize.

MR. LLOYD: Yeah.

MR. GUYTON: I just want to pose an objection to the scope of this testimony. Environmental matters are not appropriate matters for consideration by this Commission under your prehearing notice as well as prior precedent before this Commission.

I just -- I don't want to have a continuous objection to things of that nature, but I do want to make sure that we

note that for the record.

CHAIRMAN EDGAR: Mr. Guyton, your objection is noted for the record. And I do reiterate, as you have described, that in the notice for this proceeding it does specifically state that the Commission will only consider matters relating to the need for the proposed plant, and that other environmental matters will be addressed by DOAH and the Department of Environmental Protection and other entities through other phases of this review process. And, Mr. Lloyd, you may proceed. Mr. Lloyd.

MR. LLOYD: Yes.

MR. URSE: Excuse me, Mr. Lloyd. Chairman Edgar, I'd like to have a moment to respond to your ruling and Attorney Guyton. My name is Steve Urse, and I'm a citizen here in Tallahassee. And I've been working with a group called the Big Bend Climate Action Team that's been concerned about global warming, the effects of carbon dioxide, and indeed on the cost to society, those costs being caused by increased sea level rise, increased and intense storms, including hurricanes. And so I think it's important, since what you say here is that the guidelines are a cost-effective means of meeting capacity needs, that when you are considering a coal plant, you must consider all the costs of the coal plant, not just what it costs to build it and not just the fuel costs, but you need to consider other costs that are incumbent upon it. And some of

these costs are going to be costs for CO2 and carbon allowances that are going to be coming along that if indeed this coal plant is built in 2012, that they'll be paying -- and they're enacted by 2012, they're going to be paying those costs for 30 years. Were those costs taken into consideration?

CHAIRMAN EDGAR: Mr. Urse, Mr. Urse, were you sworn?

MR. URSE: Yes.

CHAIRMAN EDGAR: Is, is this your testimony before the Commission?

MR. URSE: No, this is not my testimony. What I heard --

CHAIRMAN EDGAR: Okay. Mr. Urse, Mr. Urse.

MR. URSE: Yes.

CHAIRMAN EDGAR: Have you signed up to speak?

MR. URSE: I have. But your --

CHAIRMAN EDGAR: Okay. Mr. Urse --

MR. URSE: Yes.

CHAIRMAN EDGAR: -- I would like to proceed in the order as I described and let Mr. Lloyd have the opportunity to continue to address the Commission, and you will be called in order and we will look forward to hearing from you at that time. But I would like to proceed in the order that we had, please.

MR. URSE: What I would like to say in response to that --

CHAIRMAN EDGAR: Mr. Urse, Mr. Urse.

MR. URSE: -- Chairman Edgar, is that your ruling right now is going to affect the testimony of all the participants.

CHAIRMAN EDGAR: Mr. Urse, I noted Mr. Guyton's objection for the record and I have asked Mr. Lloyd to proceed with his comments.

MR. URSE: So you noted it and did not rule.

CHAIRMAN EDGAR: That is correct.

MR. URSE: Thank you. And my apologies for interrupting the proceeding, but I thought it was important to clarify it.

CHAIRMAN EDGAR: Thank you, Mr. Urse. We will call you in order.

Mr. Lloyd, you're recognized.

MR. LLOYD: I would like for the Commission to ask Seminole Electric to consider other alternatives that are fast growing such as investigation of biomass, solar power and wind. They say we can't have wind in Florida. We can have offshore wind, and that is being looked at on the Atlantic Coast north of Daytona.

Solar, I've heard objections that we were too cloudy and that I guess we couldn't call ourselves the Sunshine State anymore, but I don't think we have that much cloud that we can't benefit with solar energy.

These, these sources are declining in cost and they are improving in efficiency. And coal is the 100-year-old type of thing at least. And I think as the rest of the world is moving forward, Florida should think about that too.

The demand side is another important issue. It's the question of the need for this much power. Have we really fully utilized the emphasis on reducing demand through such things as efficiency in housing and in appliances, tiered rates to encourage conservation in the kilowatt hours used, the time of use to encourage conservation, net metering? All of these things could reduce the demand. Florida is growing and somewhere along the way all it is is just getting more and more power, and somewhere in this the demand side needs to be an integral part of any decision on the amount of the need. So I ask you to consider these things because, as written, I do not feel it should be moving forward. Thanks a lot.

CHAIRMAN EDGAR: Thank you. Mr. Lloyd, just a moment. Commissioners, any questions for Mr. Lloyd? No?

Mr. Guyton?

MR. GUYTON: Just a few, Madam Chairman.

CHAIRMAN EDGAR: Mr. Lloyd, Mr. Guyton has the opportunity to pose a few questions to you.

CROSS EXAMINATION

BY MR. GUYTON:

Q Mr. Lloyd, you're not testifying as an expert here

this morning, are you?

A Well, I don't know. I'm testifying as someone who has studied the matters over the last few years. I don't have any fame as an expert witness, no.

Q All right.

A But I'm just basing it on, on my interest and my studies.

Q Are you an expert, for instance, in biomass technology and the cost of it?

A I would not classify myself, no, as an expert because I think you'd have to really devote more time on it than that, and particularly focusing on that.

Q Have you done an examination of the, the, the tiered rates, time of use offering or net metering that may be offered by Seminole's member cooperatives?

A Have I been told that?

Q No. Have you done any study of it?

A Yes. I have just -- I have made contact with six utilities, four munis and two investor-owned, and all six --

Q I'm sorry. I asked you if you had done any study of Seminole's members' time of use to your rates or net metering.

A No, I have not.

MR. GUYTON: All right. That's all I have. Thank you.

CHAIRMAN EDGAR: Thank you. Thank you, Mr. Lloyd.

Ms. Brown.

MS. BROWN: The next public witness is Rob Brinkman.

ROBERT W. BRINKMAN

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

MR. BRINKMAN: Good morning, Madam Chair and Commissioners. I have been sworn.

My name is Robert W. Brinkman, and I am currently serving as the chair of the Suwannee St. Johns group of the Sierra Club, which comprises 14 counties of North Central Florida, all of which are part of the service area of member cooperatives of the Seminole Electric Cooperative.

I also chair the Alachua County Environmental Protection Advisory Committee appointed by the Alachua County Commission to advise it on environmental matters. I serve on the Gainesville Energy Advisory Committee that is appointed by the Gainesville City Commission to advise it on matters related to energy policy.

Finally, I am vice chair of the Citizens Advisory Committee to the Gainesville Metropolitan Transportation Planning Organization.

Having said all that, I want to note that I am speaking on my own behalf. I want to emphasize that point. The above comments were just to give you an introduction to me.

Governor Jeb Bush in August of 2001 stated, "The cheapest, easiest and fastest kilowatt we generate is the one we save through efficiencies. There is a consensus on conservation and efficiency, so let us start there." Indeed, not only is saving energy more cost-effective than generation, it has less negative environmental and health impacts. Further, the public is finally realizing that even if coal and other fossil fuels could meet our energy needs, continuing to increase the atmospheric concentration of greenhouse gases released by burning these fossil fuels will have catastrophic consequences for the climate. These will disproportionately impact those people living in coastal --

MR. GUYTON: I'm going to object and move to strike the last remark as being beyond the scope of this proceeding.

CHAIRMAN EDGAR: I'm going to allow Mr. Brinkman to proceed.

MR. BRINKMAN: Thank you very much.

Further, continued -- let me pick up my point here. This will disproportionately impact those people living in coastal communities worldwide. Yet this is a needs determination hearing, as has just been noted by the attorney, and Seminole Electric Cooperative represents that their customers need more electrical energy. But can they or the rest of Floridians afford it? I refer not only to the direct economic costs, which are naturally of concern to the Florida

Public Service Commission, but to the cost of more intense hurricanes, of rising sea levels and the disruption of economic activity that result from both of these and other adverse consequences of climate change.

But since the Commission may not consider these issues relevant or proper, I return to the strict sense of need determination in terms of future electric demand. Will the state continue to grow at forecasted rates? One often quoted statistic is that 1,000 people move to Florida daily. Yet according to an article in the Orlando Sentinel of June 5th, 2006, 400 people a day are now leaving the state daily. They leave seeking less traffic and congestion and in part, in some cases to avoid hurricanes and other extreme weather that Florida is uniquely vulnerable to.

Seminole Electric Cooperative represents that a 750 megawatt coal plant is the best choice for additional baseload capacity. However, will coal continue to be the cheapest fuel? The supply, while substantial, is nevertheless a dwindling, nonrenewable resource which has led to higher prices evident in the last few years. Transportation of coal by rail has become increasingly congested in the last few years, causing delays in supplying some plants and clearly demonstrating that the rail system is extremely vulnerable to supply disruption.

Florida has an abundant supply of renewable fuels such as biomass, solar and perhaps wind. Biomass particularly

is becoming cost competitive with coal and, being a renewable resource, biomass will exhibit long-term price stability. Furthermore, biomass and other renewable resources keep capital in Florida rather than exporting billions of dollars a year to other states or countries.

Recently Progress Energy signed a purchased power agreement for the 130 -- 135 megawatt capacity of a biomass plant to be situated amidst a 15,000-acre plantation that will supply all the fuel for the plant. On Page 11 of the direct testimony filed by William T. Lawton on behalf of Seminole Electric Cooperative, in Lines 7 through 13 he states that Seminole Electric Cooperative member co-ops have no plans to increase their DSM capabilities over the forecast period. I must say I was astounded when I read that. No plans to increase their DSM capabilities. Yet later on the same page, Lines 21 through 23, he states that "it does not appear reasonable that enough cost-effective reductions from DSM or conservation programs could be achieved by 2012 to eliminate the need for Seminole Generating System Unit 3." How can it appear reasonable to state that DSM or conservation programs cannot meet the need when no attempt is even being made to meet the need by increasing your capabilities?

I assume that the member co-ops that do have some form of conservation or DSM programs, and it is my understanding that not all of them do, are using the Rate

Impact Measure Test and not the Total Resource Cost Test or the Participant Test. According to previous testimony before the Florida Public Service Commission in July of 2004, and I'm referring specifically here to Page 45 of this document prepared by GDS Associates on behalf of the Alliance to Save Energy and the Southern Alliance for Clean Energy. And I quote from that testimony, "Unlike the Rate Impact Measure Test, the TRC Test places demand-side and supply-side options on a level playing field. If it is less expensive to save a kilowatt hour with DSM than to generate a kilowatt hour on the supply side, then the DSM option is the least cost option and should be selected. Using the TRC Test allows us to compare the cost of DSM options with the cost of planned supply-side options such as generation, transmission and distribution facilities. The TRC Test allows DSM resources to be part of integrated planning, while the RIM Test does not allow DSM resources to be adequately integrated into the planning process."

It appears, based on the testimony of Mr. Lawton, that DSM resources have not been fully integrated into the planning process. Therefore, I respectfully submit that neither the Seminole Electric Cooperative, the Sierra Club or even the Florida Public Service Commission could possibly categorically state that the forecasted need cannot be met without additional generation. We haven't gotten there yet. We need to look at it more. We need to try harder.

I have also submitted electronically to the Commission a filing before the Florida, excuse me, the North Carolina Utilities Commission by the Alliance to Save Energy. It describes how the Georgia Public Service Commission ordered the creation of a DSM working group to cooperatively provide recommendations on DSM integration into the IRP process. If Florida is to meet the energy challenges it now faces, all electric utilities in Florida must work together with affected stakeholders to develop similar policy recommendations to ensure that all cost-effective and economically achievable energy efficiency, DSM and conservation programs are compared on an equal basis to supply-side options.

I respectfully request that the Florida Public Service Commission continue this matter before it and order the creation of a working group to provide an agreed basis for screening and implementing DSM programs employing the RIM Test, the TRC Test and the Participant Test together in order to balance economic efficiency, fairness and equity. Thank you for your attention to my concerns.

CHAIRMAN EDGAR: Thank you, Mr. Brinkman.

Commissioners? Commissioner Arriaga.

COMMISSIONER ARRIAGA: I don't have a question for the witness. I do have a question for a staff member. Is that possible at this time?

CHAIRMAN EDGAR: It is.

COMMISSIONER ARRIAGA: I'd like to ask a question for Mr. Ballinger.

Mr. Ballinger, as I hear the testimony that was just presented to the Commission, there were some issues concerning biomass. Are you -- do you know how much, how many megawatts are produced in the state from all the biomass sources existing today?

MR. BALLINGER: Currently produced?

COMMISSIONER ARRIAGA: Yes. What I'm trying to get at, Mr. Ballinger --

MR. BALLINGER: Yeah. I understand. We've gone through this with the standard offer of contracts. I'm trying to recall it. I want to say 500 megawatts, and most of it is from municipal solid waste facilities.

COMMISSIONER ARRIAGA: So if we took all the biomass produced in the state, we would not be able to meet the requirements that Seminole has in front of the Commission today.

MR. BALLINGER: Correct. And I would add that a couple of years ago the PSC in conjunction with the Department of Environmental Protection did an assessment of potential renewable resources, and I believe we found there was only a potential for an additional 250, 300 megawatts of biomass type renewables.

COMMISSIONER ARRIAGA: One second question would

be -- may I? Thank you.

When you were studying the need request presented by Seminole, I'm sure you probably went through the issue of demand-side management programs.

MR. BALLINGER: Correct.

COMMISSIONER ARRIAGA: Do I understand correctly that DSM programs are only applied at the retail level? In other words, can Seminole actually control DSM programs of the end-user of the electricity?

MR. BALLINGER: No. It's their member distribution cooperatives who actually offer the DSM programs.

COMMISSIONER ARRIAGA: Okay. Thank you so much.

MR. BALLINGER: Uh-huh.

CHAIRMAN EDGAR: Commissioner Deason and then Commissioner Carter for questions.

COMMISSIONER DEASON: Yes. Mr. Brinkman, I'm looking at your prefiled testimony and I appreciate you putting it in this format. I say prefiled -- at least it was written and I guess it was prefiled.

MR. BRINKMAN: Yes. I e-mailed last night.

COMMISSIONER DEASON: Yes. On the second page, you refer to the recently announced Progress Energy purchase of 135 megawatts of capacity from a biomass plant; correct?

MR. BRINKMAN: That's right.

COMMISSIONER DEASON: And you mention in there that

there's going to be a 15,000-acre plantation that will supply the fuel.

MR. BRINKMAN: Yes.

COMMISSIONER DEASON: I'm just trying to get an appreciation of the scale involved here.

If we assume, and I know that it is an issue before us, but if we assume that something in the order of 750 megawatts is, in fact, needed by Seminole, for that much capacity to be provided by a biomass facility similar to the Progress Energy arrangement, wouldn't it take something in excess of 80,000 acres devoted to the production of the fuel?

MR. BRINKMAN: It would take roughly six times -- yeah. Eighty, 90,000 acres. That's correct. I mean, your math is correct.

COMMISSIONER DEASON: Do you -- yeah. Do you know if there is that much plantable land available in Florida to grow that much biomass? Do you have any idea, at least in the area that you're familiar with in North Central Florida?

MR. BRINKMAN: No, not -- well, besides North Central Florida, I think one area which is ripe for such development is a lot of the mining lands in Central Florida which have been pretty well ruined by the phosphate mining activities that have occurred on them.

And I would note that one issue I have, now that you've brought it up, is that Seminole is concentrating all of

its baseload capacity in one location, Palatka, which is on the edge of its service territory, so to speak. It is certainly not centrally located. And I think it would benefit the system greatly to distribute its baseload generation capacity throughout its service territory, thereby reducing line losses.

COMMISSIONER DEASON: Thank you.

CHAIRMAN EDGAR: Commissioner Carter.

MR. BRINKMAN: Madam Chair, if I may.

CHAIRMAN EDGAR: Mr. Brinkman.

MR. BRINKMAN: I would like to respond to the point the Commissioner raised with staff. I do not have any figures for the State of Florida, but I think the Commission may be interested to know that the United States as an aggregate has 10 gigawatts of biomass-fired capacity, and, in fact, the United States has more biomass-fired capacity than any other country on earth.

CHAIRMAN EDGAR: Mr. Guyton, questions?

MR. GUYTON: Just a few, Madam Chairman.

CROSS EXAMINATION

BY MR. GUYTON:

Q Mr. Brinkman, have you been trained, have experience in transmission planning?

A I am not an expert. I do not hold any degrees as such in it. I would characterize myself as a student. And as you may have noted in the positions I'm currently serving on in

Gainesville, I have been following our own local power plant issues in Gainesville that you may be familiar with and have learned quite a bit over the last few years. But, no, I am not an expert in the matter.

Q All right. Have you ever had occasion to formulate a utility or conservation DSM plan?

A I have participated in the review of conservation and DSM plans as a member --

Q I'm sorry. I asked if you had ever formulated them.

A No, not formulated them. That is the responsibility of the utility.

Q Okay. Have you ever performed an assessment of the technical potential of DSM and conservation for any Seminole member cooperatives?

A No.

Q An assessment of achievable potential for DSM and conservation for any of the Seminole member cooperatives?

A Not for any members of the Seminole cooperative.

Q Ever done a cost-effectiveness analysis of conservation programs for the Seminole member cooperatives?

A No, I haven't.

Q Okay. Do you know what Seminole's capacity need is in 2012?

A I believe it's stated as being about 1,200 megawatt hours -- megawatts.

Q Okay. Demand-side management measures such as interruptible rates and load management, customer-owned generation, typically they're dispatchable, are they not?

A In some cases, yes.

Q Yeah. And typically they're used to shave peak, are they not?

A They are.

Q Okay. So their operation is more akin to a peaking unit rather than a baseload unit; correct?

A That's true.

Q So they're not employed around the clock like a baseload coal unit.

A Well, that's true on the face of it. But one popular program involves the placement of electronic programmable thermostats in customers' homes that are controllable by the utility, and there has been a lot of evidence to show that the placement by the utility of that programmable thermostat allows the customer to save energy year-round.

Q Back to the question that I asked about demand-side management measures as opposed to conservation measures, there are indeed limits on the number of times and the duration of interruptions under such programs, are there not?

A Certainly if you don't want to run all your customers out of the program.

MR. GUYTON: All right. Madam Chairman, I, I don't

have anymore questions, but I do want to object to Mr. Brinkman's attempt to incorporate into his testimony extensive documents that he submitted along with his prefiled testimony. There are two: One is something out of a North Carolina Utilities Commission, and the second is the final report of a Georgia DSM working group. These are documents that he graciously admits that he had no hand in preparing, they are not properly authenticated, there is no opportunity for Seminole to exercise its fundamental right of cross-examination of the authors of these and, indeed, they're hearsay. And while hearsay evidence is admissible, it can only be used for corroboration, and there's nothing for them to corroborate. So we will not object to Mr. Brinkman's prefiled testimony that he's given here today, but we would have an objection to the inclusion of these documents as part of his testimony.

CHAIRMAN EDGAR: Ms. Brown.

MS. BROWN: Mr. Guyton raises good points from the staff's perspective. We recommend that you admit this into the record and give it the weight it's due.

MR. BRINKMAN: Madam Chair, if I may in regard to those documents that Mr. Guyton raised. I realize that technically I can't substantiate their authorship or anything, but I basically provided them to give the Commission an example of what could be done, what I think it should do. It's more

just as background, as information, background information for the Commissioners.

CHAIRMAN EDGAR: Thank you, Mr. Brinkman. And, again, Mr. Guyton, I, I recognize your objection and the points that you have raised; however, I am going to allow as Ms. Brown has described. So we will need to give it a number, which is 37 on my list.

Ms. Brown, will one number suffice for labeling this as, kind of as a package, or do we need to do it separately?

MS. BROWN: No. I think we could do it as a package. We will identify it as the Public Testimony of Rob Brinkman, and give it the short title "Testimony Provided in North Carolina and Georgia."

CHAIRMAN EDGAR: Thank you. So noted. This will be Exhibit Number 37.

(Exhibit 37 marked for identification and admitted into the record.)

CHAIRMAN EDGAR: Thank you. And, Ms. Brown, if you would, call the next person on the list.

MS. BROWN: Yes, Madam Chairman.

Susan Caplowe.

SUSAN CAPLOWE

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

MS. CAPLOWE: Good morning, and thank you very much for, Commissioner Edgar -- Chairwoman, should I say, Edgar, allowing us to continue and all the other Commissioners.

My name is Susan Caplowe, and I'm a resident here in Tallahassee, Florida. And I just wanted to read a couple things for you regarding the coal-burning power plants and some health impacts, although I know we've already heard that episode. But anyway, from the Florida Medical Association, they did a Resolution regarding --

MR. GUYTON: Madam Chairman, I apologize, but I -- for purposes of the record, I have to make the objection. I'd just object to the testimony addressing environmental or health impacts in the scope of a need case. I apologize for the interruption.

CHAIRMAN EDGAR: That's okay, Mr. Guyton. I understand, and your objection is noted. And I will allow Ms. Caplowe to proceed.

MS. CAPLOWE: Thank you very much.

Whereas -- just a couple of these.

"Whereas, coal-burning power plants emit significant quantities of mercury, a potent toxin that attacks the human nervous system; nitrogen and sulfur oxides that produce smog; particulates that are especially dangerous to children and the elderly; and carbon dioxide that is linked to global warming; and, whereas, air pollution increases both asthma attacks and

deaths due to heart and lung disease, with considerable financial and human cost to Floridians; and each year in Florida, pollution from power plants triggers an estimated 28,000 asthma attacks and 2,100 heart attacks while causing 180 deaths in individuals with lung cancer."

In another document, the New England Journal of Medicine went through, did a study, and their conclusion was, "There is consistent evidence that the levels of fine particulate matter in the air are associated with the risk of death from all causes and from cardiovascular and respiratory illnesses. These findings strengthen the rationale for controlling the levels of respirable particles in outdoor air."

I want to add that the state has fish consumption warnings for lakes, rivers and streams due to mercury. The Idaho Legislature recently passed a moratorium on coal plants. The Governor of Michigan recently did an executive order mandating a reduction of mercury emissions by 90 percent in the year, I believe, 2012.

And I have for you, if you want, copies of the New England Journal of Medicine, the Florida Medical Association Resolution. And I don't know if any of you were able to get the Time issue "Special Report on Global Warming. Be Worried. Be Very Worried." It was quite informative. Should I bring them up to you or here or to Martha Brown?

CHAIRMAN EDGAR: Ms. Brown.

MS. BROWN: I think if Ms. Caplowe provides a copy of those to the court reporter, we can identify these as Exhibit 38, public testimony of Susan Caplowe, newspaper articles regarding environmental questions.

MS. CAPLOWE: And the medical resolutions.

MS. BROWN: Medical resolutions. All right.

MS. CAPLOWE: Thank you.

(Exhibit 38 marked for identification.)

CHAIRMAN EDGAR: Ms. Caplowe, just a moment. Commissioners, any questions? No?

Mr. Guyton.

CROSS EXAMINATION

BY MR. GUYTON:

Q Good morning, Ms. Caplowe.

A Good morning.

Q You, you read from a medical resolution and the New England Journal of Medicine. You didn't prepare either of those documents from which you read, did you?

A No, sir. I got these from Dr. Saff.

Q And you don't have personal knowledge of the matters contained therein, do you?

A No, sir. Dr. Saff does.

Q All right.

A He couldn't be here today.

MR. GUYTON: That's all I have, Madam Chairman.

CHAIRMAN EDGAR: Thank you, Mr. Guyton. Thank you, Ms. Caplowe.

MS. CAPLOWE: Thank you.

CHAIRMAN EDGAR: Ms. Brown. Mr. Guyton.

MR. GUYTON: If -- Seminole would -- it hasn't been moved. I assume it will be. Seminole would lodge an objection to Exhibit 38 on the grounds that it's not authenticated, we've not had an opportunity to cross-examine the authors, it contains hearsay material. And the order on -- or the prehearing notice indicated that public testimony, but not exhibits, would be taken.

CHAIRMAN EDGAR: Okay. And, Mr. Guyton, your, your points are recognized, and we can go ahead and, and move it in as evidence as labeled and as described a few moments ago.

(Exhibit 38 admitted into the record.)

And, Ms. Brown, the next witness.

MS. BROWN: The next witness is Dan Hendrickson.

DAN HENDRICKSON

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

MR. HENDRICKSON: Good morning. My name is Dan Hendrickson. I also wish to thank y'all for giving us this opportunity. We've been looking forward to today for the last month or two. We assumed that there would be a little bit more

back and forth and discussion of some of the issues among the parties. But since there aren't any parties, then this is our -- we understand this is sort of our opportunity. So we sure thank you that, that -- you know, I'm thanking you. I'm a volunteer here today. I live in Tallahassee, Florida. I took off work and I'm, you know, taking vacation time, so I'm actually paying for being here today. And it's similar to some of the hearings we had with the City of Tallahassee, and at that time -- I know Mr. Guyton is feeling like he expected this to be a little bit less contentious today because the parties had stipulated and all, but we did not put out an all call to everybody that came to the City of Tallahassee hearings to see how many people we could bring in today. So I wanted to assure you of that. But we did want to make sure that we at least had an opportunity to express to you things, and we're not sure about -- I'm not sure about the process. I just know when I was reading through some of the documents, and I read what seems like hundreds of pages here, and then I found out in the last day or two that there's still yet more documents because there were references to things on the Internet that we couldn't access. I wasn't able to read and see some of those documents. So if I state a couple of things today that, in fact, are in the evidence somewhere else, then please, you know, pardon my omissions on that.

We do have a feeling, and the reason that I know that

I'm here and that some others had wished they could have come here if it hadn't been during the day, that what y'all decide today is not just about the Seminole plant. That, in fact, there may be some precedent for the policy issues that, in fact, were debated just last month and over the last couple of months in the Capitol. These policy issues about the future, uses of the various energy sources are going to be ongoing. And I'm personally now a City of Tallahassee resident, as I stated, but I've been a Talquin customer. And y'all know, those of you from Tallahassee, that people here move back and forth. One residence -- they may be a member of one of your co-ops under Seminole, and then the next thing you know they're a customer using the practices and advantages of getting electricity from the City of Tallahassee. A lot of my friends are served by Talquin and have some of the same energy habits, however, as people who live in Tallahassee. So we're asking you to not look at this quite as isolated as actually having the one docket, and we know that that's what's technically before you, but we hope that a number of the issues can be looked at a little more broadly.

I also lived many years in the Southern Appalachian coal fields, and during that time I was working alongside many coal mining families for more than a dozen years. I was a journalist and I also was a mine safety instructor. And some of the most vivid memories for me are with people who were

dying as I sat up all night long in rocking chairs and living rooms with men wheezing from the decades of working in the coal mines, many of whom had to retire by their 40s and within a few years of retirement had died. Those, the black lung effects, of course, are different in degree from what happens with coal when you don't get it in the workplace, but nevertheless it's some of the same wheezing that our kids and grandkids and the next generations may be subjected to. And we really think -- and from my experience I want to do everything we can to decrease the use of coal. It's just, again, as a volunteer, but I just think that the additional costs of coal, if they were not looked into, and so far I haven't found in the documents I've read over that you have factored in those costs, that you please keep the docket open long enough to do that.

In those same coal mining communities there are a number of creeks where the water is yellow from the sulfuric acid. There are thousands of miles of creeks just in East Kentucky alone where all life is gone because of the coal mining runoff and the effects of coal mining; there are no fish anymore. Everything has changed in the areas of the coal mining. And this is predating the Mountain Top Mining that one of the other witnesses may be talking about today.

On a lighter note -- lighter for a minute anyway. Those of y'all who have -- you know, we all a couple of years ago saw that movie "Day After Tomorrow." If you haven't gone

back and watched it again after Katrina, I encourage you to do that. Because some of those images that we just assumed were Hollywood fantasy, the big flood, the surge, were some of the same images that then we saw last summer on some of the news coverage from Katrina. The first indicators of the problems, and that was, if you recall in the movie, the temperatures that were on the buoys floating out in the oceans, is another evidence now. Recently we've seen on some web sites where every hour these temperatures are fed into the computers for records of history as to the temperatures of the water in both the Atlantic and the Gulf Coast waters off of Florida as well as other states, and the increase in those temperatures is dramatically increasing over the years. 1996 just seems like not too long ago for most of us, but since 1996 a number of those temperatures now have gone up more than a degree. In some areas, particularly in the Atlantic, it's even higher than in the Gulf; apparently some of those on an average of up to two, two and a half degrees warmer than they were just ten years ago. And then the records are available for the ten years before that that show this upward trend in the warming of the Gulf's oceans. And while I'm not an expert here either, Mr. Guyton, but the general consensus from the communities and the scientific communities is that the global warming obviously is causing the increase in both the frequency and the severity of the hurricanes and the storms.

So I guess I could even provide a list to those web sites, if that's not available in the other documents, in terms of the global warming, the longer term trends. Now nobody is going to sue Seminole over global warming or over the effects of a specific hurricane, so it's not directly on point except that when you factor in: should we continue doing coal?

The assessment needs to include the environmental costs. And while I understand, again, the finality and the limits of a docket, just as recently as last week some of the documents that you all passed last week in an uncontested hearing -- and I'll cite from the OUC proceeding. It was Page 13. When I read this -- and I had to read it two or three times because it was something that I didn't see in the docket that's before you today and yet it's right on some of the same points. On Page 13 of the witness Myron Rollins, I think he was the last one that was presented to y'all in testimony, he stated that in their analysis they did the forecast for emission allowances, Black & Veatch did, for the OUC plant. They reflected the cost to reduce the emissions of SO2 and NOX by a ton a year. The forecasts were not projected in that particular time for mercury because they assumed that mercury is not going to be required to be decreased, which is an incredible assumption given the fact that mercury contamination in this state is as bad or near, maybe even worse than most other states.

Some of the informal studies by people who are being tested, even though it's the hair test, show an average of 30 percent of people are showing signs of mercury ingestion, which means contamination in excess of the limits that are recommended and allowed, you know, the maximum limits by EPA. Those of us who are more cynical about the hair tests, that they may not be quite as valid as they think, we would argue that it's more than 30 percent of Floridians probably have a higher range of mercury in our bodies than the EPA even admits is safe.

At any rate, back to Page 13, he says, "These costs," and that's of SO2 and NO2 -- NOX, and I assume he did it also with carbon, though I haven't found that, "These costs were incorporated into the fuel prices for both existing and candidate units." In other words, all the other variations that you heard they considered in the economic analysis based on the emission rates of those units that they're preparing and that last week you approved, or at least tentatively, for the Orlando area.

So what I'm asking is if that hasn't been done here, that we would hope that, that despite the need for some kind of finality at some point, we think the finality is not just based upon your decision and actually signing and sealing an order, but we think the public policy debate is going to continue to go on.

It could be that next week's hurricane becomes the 100th monkey that then says -- that the public says, enough, you know, we're at least not going to be responsible in Florida in contributing more coal-burning carbon dioxide into the air that contributes more to these hurricanes. If the public feels that way, then sooner or later the public officials are going to as well, the elected officials. So we just encourage -- I don't know what the motion to reconsider that was in some of the documents would entail, but we would just encourage y'all to please go slow on this, to understand that the issues are going to have long-lasting effects, and that even one more coal plant may be too many for Florida, let alone the several that we think may follow on today's decision.

CHAIRMAN EDGAR: Thank you, Mr. Hendrickson.

Commissioners? Mr. Guyton. Oh, excuse me, Mr. Guyton. Commissioner Deason.

COMMISSIONER DEASON: Mr. Hendrickson, you referenced the OUC case.

MR. HENDRICKSON: Yes, sir.

COMMISSIONER DEASON: And that there was, there was an analysis done on some costs that you, that you think are absent for this case, but you're not absolutely sure, but you have not seen it in this case; correct?

MR. HENDRICKSON: Correct. I saw the service, you know, the certificate of service was available to us on the

Web, but I'm not sure what some of those documents were that were given to you all.

COMMISSIONER DEASON: Okay. And could you describe again for me, please, what, what costs were analyzed in the OUC case that you referenced, what specific costs?

MR. HENDRICKSON: In here, the ones that I just read --

COMMISSIONER DEASON: Yes.

MR. HENDRICKSON: -- from that Page 13 was SO2 and NOX.

COMMISSIONER DEASON: SO2 and NOX? So in the OUC case there was an estimate done. In comparing the various generating technologies and alternatives, there were assumptions made about the cost of SO2 and NOX that were factored into that analysis.

MR. HENDRICKSON: Yes, sir. And I assume carbon dioxide because I saw it referenced in another witness maybe 50 pages earlier talking about the -- and they make declarative statements about the need for the carbon dioxide scrubbers and that those need to be -- and, again, these were Black & Veatch people I guess out of Kansas that were making those statements in those documents that were available on the web site.

COMMISSIONER DEASON: Okay. Thank you.

Madam Chairman, I just would ask for our staff to, to, now or later, depending on our course of action, as to

Web, but I'm not sure what some of those documents were that were given to you all.

COMMISSIONER DEASON: Okay. And could you describe again for me, please, what, what costs were analyzed in the OUC case that you referenced, what specific costs?

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COMMISSIONER DEASON: Okay. Thank you.

Madam Chairman, I just would ask for our staff to, to, now or later, depending on our course of action, as to

whether there -- in the Seminole case, if there was like analysis done on SO2 and NOX and possibly CO2 as well.

MR. COLSON: Is that a question? According to --

COMMISSIONER DEASON: I'm sorry. If they can answer it now, fine. I'm not necessarily looking for an answer right now, but at some point in this proceeding I'd like an answer to that question.

MR. COLSON: Okay.

CHAIRMAN EDGAR: Mr. Guyton.

MR. GUYTON: Mr. Hendrickson has acknowledged that he's not an expert. I'm going to move to strike one remark that he made that the Commission consider the costs of environmental compliance that goes beyond existing permitted standards; in other words, the Commission should consider environmental externalities over and above the cost of environmental compliance that Seminole has captured. And I move to strike that because the Commission has ruled as a matter of law in two earlier need determination cases that indeed it cannot and should not consider environmental externalities in the, actually in three cases. In the Martin expansion project and in the Fort Lauderdale repowering, the Commission said, and I quote, "We are of the opinion that the Commission cannot and should not consider these types of environmental and natural resource costs in making need determinations pursuant to the Power Plant Siting Act."

Similar language is found in the Cypress Energy proceeding as well.

Those are matters as a matter of law the Commission has previously addressed that are not appropriately considered in a determination of need proceeding, and, therefore, I think the testimony here goes, goes beyond the Commission's jurisdiction and should be stricken. Not in its entirety, just his remarks about the additional environmental costs.

CHAIRMAN EDGAR: I understand, Mr. Guyton. I am going to allow Mr. Hendrickson's statements to remain in the record, and recognize that the Commission certainly can and will take notice of previous decisions.

Mr. Guyton, did you have any questions for Mr. Hendrickson?

MR. GUYTON: I'm sorry. I don't. Thank you, Mr. Hendrickson.

CHAIRMAN EDGAR: Okay. I just wanted to make sure that we didn't move too quickly. Okay. Mr. Hendrickson, thank you very much.

MR. HENDRICKSON: Ms. Brown?

MS. BROWN: No questions.

CHAIRMAN EDGAR: Okay. And, Ms. Brown, you can call the next person on the list.

MS. BROWN: Yes. The next person on the list is Ben Fusaro.

BEN FUSARO

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

CHAIRMAN EDGAR: And, sir, could you repeat your name for me?

MR. FUSARO: Yes. Ben Fusaro, 203 Ridgeland Drive, Tallahassee. Thank you for this opportunity. I'm going to assume, assume this power plant needs to be built. I'm not going to get into conservation or upstream costs. We're talking about the decision to build a coal-fired power plant, and the cost of fossil fuels is one of the determining factors.

The cost of oil, gas and coal are all interrelated. The costs associated with CO2 is far cheaper when you -- excuse me. The costs associated with CO2 is the same for these various fuels. But when you talk about particulates, PM-10, Page 14 in your document, the cost of coal is far greater than the cost of gas. The assumption here is that in 2012 and later that the cost of coal will be less than the cost of natural gas.

I just want to point out that the Department of Energy is doing research and development on methane hydrate. Methane hydrate is a potential source of natural gas which dwarfs anything in the ground today, and there is a program to exploit domestic methane hydrate.

The second point I'd like to make is that in Germany in World War II and in South Africa oil was made from coal. The trouble with this process is it's inefficient, which means it's costly. However, a break-even point is about $35 a barrel for oil. I doubt if we'll ever see $35 a barrel again.

Montana is seriously thinking -- Montana has a great deal of coal, is seriously thinking of going to production on a large scale to turn coal into oil. All of this is going to increase the cost of coal. The methane hydrate will decrease if it, if it can be produced, and we're talking about 2012 plus, will decrease the cost of natural gas. So I think I've satisfied the counsel and I stuck to cost. There is no reason to believe that the cost of coal will be less than the cost of natural gas in 2012 plus.

CHAIRMAN EDGAR: Thank you.

Commissioner Carter.

COMMISSIONER CARTER: Thank you, Madam Chairman.

Mr. -- could you tell me your name again?

MR. FUSARO: Yes. Fusaro.

COMMISSIONER CARTER: F-U-S-A-R-O; am I close?

MR. FUSARO: Yes.

COMMISSIONER CARTER: Tell me a little more about this methane -- is methane hydrate, is that what --

MR. FUSARO: Hydrate.

COMMISSIONER CARTER: What is that?

MR. FUSARO: Well, it looks like kind of a slush. It's not very impressive. It looks like what we up from the north call slush. But it actually burns because there are water molecules with CH4, methane, natural gas, enclosed within it.

And the -- let me see if I remember, I didn't write down these figures, but I think right now domestically there are a couple of sources, mainly the ocean and Antarctica, along the east coast and the Antarctica the size of, I think it's twice the size of Rhode Island, which has enough methane to replace -- let me think about this a minute. It's enough methane, I think the figure was, to keep us going in terms of natural gas for 70 years at the 1989, that's the figure that was given, 1989 level of use. It's enormous. It's simply staggering the amount of CH4 that's in these -- that's in methane hydrate. And although -- I mean, it sounds like pie in the sky, the idea that you're going to get this slush and get gas out of it, but we know what modern technology is like: It's gone today but it's here tomorrow. So we don't know what can come out of the DOE research and development.

COMMISSIONER CARTER: Permission for follow-up.

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: Is there any current refinery facilities or current available supply of this, I mean, in --

MR. FUSARO: No, it's not -- not now. Not now. But

it's a source. And as energy gets tighter, there's more and more consumption of energy, there's more and more China and India, their use of energy is increasing. China doesn't want to die in mercury, which is what will happen to them at the rate they're going with their use of coal, so they have a demand for oil. Demand for oil, demand for coal, demand for gas that are all related. And as far as I know, CH4 is the largest source right now of energy, potential energy.

COMMISSIONER CARTER: Thank you. Madam Chairman, if I could beg your indulgence for one last question.

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: What's the break point? I noticed you mentioned earlier in your discussion about the price per barrel being $30 a barrel.

MR. FUSARO: $35.

COMMISSIONER CARTER: $35?

MR. FUSARO: Yes.

COMMISSIONER CARTER: So that's the break point?

MR. FUSARO: Yes. Where it's worth -- okay. This shifts back to the making oil from coal.

COMMISSIONER CARTER: Okay. I'm not -- I wanted to stay with the methane.

MR. FUSARO: Okay. This is not the methane. Yeah.

COMMISSIONER CARTER: What's the price point per -- excuse me, Madam Chairman.

What's the price point per barrel?

MR. FUSARO: Well, they don't know. They don't know yet. But it's whatever it would cost -- since it's in R&D, that means we taxpayers -- I don't think they look at it that way. Right now they're spending money to see what can be done. So I don't think they're at the break-even point yet. But they could be in a few years just because the source is so massive, the source of methane is so massive. And it's so much better than if you're going to have power plants, which I'm not convinced that we need all these power plants, but if we're going to have power plants, at least gas is much cleaner than coal. It still produces CO2, all fossil fuels produce CO2, but at least it's much cleaner than coal and could be cheaper. I think it will be cheaper.

COMMISSIONER CARTER: Thank you, Madam Chair.

CHAIRMAN EDGAR: Thank you.

Commissioners? Mr. Guyton?

MR. GUYTON: Just a few questions, Madam Chairman.

CROSS EXAMINATION

BY MR. GUYTON:

Q Mr. Fusaro, did I get that right, your last name, the pronunciation?

A That's right. That's good enough.

Q Thank you. You spoke of a World War II conversion of coal to oil and a break point of $35. How many commercial

applications are there of conversion of coal to oil in the United States?

A I don't know if there are any operating right now. But Montana is certainly serious about going into it because of the break-even of $35 per barrel.

Q All right. Have you prepared a fuel forecast?

A For what?

Q For --

A For the United States?

Q For an electric utility. Have you ever examined and priced out the potential costs of fuel for an electric utility?

A Well, yes, I've done this in a certain sense. I worked with H. T. Odom, who's a systems ecologist, in 1981. And what you do is -- this is going to get a little afield. What you do is take the GDP, the gross domestic product, and you take the total energy input into the U.S. And what you do is get a cost -- what you do is get a correlation between dollars and energy, Btu, calories, whatever you want. In other words, given a dollar, you can tell how many BTUs that's going to buy. You can also associate that with each fuel, oil, gas, actually any fuel. So I have done that. But, no, I haven't done the accounting for a particular firm or --

Q Okay. And have you had occasion to examine the fuel forecast that Seminole has developed and relied upon in this case?

A I have not.

MR. GUYTON: Okay. That's all I have. Thank you.

CHAIRMAN EDGAR: Thank you. Thank you, Mr. Fusaro.

MR. FUSARO: Thank you.

CHAIRMAN EDGAR: Ms. Brown.

MS. BROWN: The next witness on the list is Steve Urse.

STEVE URSE

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

MR. URSE: Madam Chairwoman, Commissioners, again, I'm Steve Urse. And I'm a citizen here in Tallahassee who has for the last year been working on energy issues or actually a little bit more than a year on energy issues as part of the Big Bend Climate Action Team. And we have been working with the City of Tallahassee meeting at least monthly with their electric planning staff to specifically work on clean energy and integrating as much clean energy into the integrated resource plan as possible. And we've also been working then with energy services, the people that implement energy efficiencies, and we've been working -- and they also deal with purchased power. And so under purchased power, certainly one of the things they're pursuing now in an aggressive way is looking at biomass. And we applaud the City of Tallahassee for

taking a really aggressive approach in terms of investigating clean energy, both in the generation side and on the efficiency side.

Specifically -- so then what I'm going to address today are some, in the docket paperwork that was prepared essentially some items on Page 5 and 6 and kind of relate the approach that the City of Tallahassee has taken and that we would hopefully encourage not only Seminole Electric and their members to take, but indeed all utilities that are going to come in front of the Public Service Commission in the, in the near future, whether this is the most rigorous process to determine the most cost-effective means of meeting its capacity needs and, of course, to provide adequate electricity at a reasonable cost and to avoid an undue reliance upon natural gas. When we, as part of our climate action team, were trying to help the City with meeting its energy needs, one of the things that we concluded at that time, perhaps wrongfully, that even though natural gas was a fossil fuel, it was a better bridge to a clean energy future than coal.

So one of the things I mentioned briefly before that's been covered far better by other speakers, in terms of cost-effectiveness, did Seminole Electric really consider all the costs when they were developing this recommendation and this choice of coal? And the one that was raised before by me and better explained by others is the CO2 and carbon

allowances.

And I just want to mention that the City of Tallahassee has a main consultant, Black & Veatch, whom you're familiar with, and they're doing the models and the algorithms and those sort of things, base case, environmental sensitivities, risk analysis and so on. But what happened last July, and you may have read about this in the paper, when the City Commission considered to go forward and they made the first step of entering into the contract with the Taylor Energy Center -- which is kind of ironic because the reason that the City of Tallahassee got an opportunity was because Seminole Electric had pulled out of that project. So anyway they decided to go forth, but it's not a done deal because indeed they're still in the middle of the integrated resource process and that now the decision point after more meetings, two more meetings in June, a meeting in July, the Commissioners will have another public hearing in August, on August 23rd, and then the City Commission will vote on August 30th.

So with that in mind, in the meantime what the City of Tallahassee did -- at the time they authorized $250,000 for clean energy consultants, and they hired during that time period three: Navigant Consulting, Sterling Planet and a company up in Massachusetts called Synapse, I believe it's Synapse Economics. And much to the City's credit, Synapse Economics is a, a consulting firm that's typically hired by

environmentalists. And their goal -- and they haven't issued a report that I have seen yet, but their goal is to, after Navigant has done their reports, after Sterling Planet has done their reports, then Synapse, working with the team and the City of Tallahassee electric planning staff, are then going to figure the best way to integrate clean energy into their process.

Tallahassee has a peak peak of about 600; it's a summer peaking utility. I noticed Seminole Electric had a peak peak of a little over 4,200 in February '06, I guess categorizing them as a winter peaking facility. Those kind of things are important because of some of the findings that the consultants have made in terms of what they could, what they could do.

So on Page 6 -- well, let me just say one more thing on, on generation and considering all the costs and Seminole's need. Tallahassee believed they had a need last July and they reported to the public that they needed about 556 megawatts. After a few months they had another consultant out of Chicago who looked at repowering their natural gas plant, and indeed they've then, because they said that was so cost-effective and they were going to be able to save about $25 million a year in fuel costs. And I think Gary Brinkworth is in the audience, so if I misstate something, I'd encourage him to come up and report on it. But anyway they decided after this repowering

that then they only needed 282 megawatts by 2025 and they did not need 150 megawatts by 2012 as they initially thought, but indeed they didn't need the 150 megawatts until 2016, so giving the City of Tallahassee lots of time to implement clean energy and renewables.

So back in the stipulated Issue 4, are there any conservation measures taken by or reasonably available to Seminole Electric which might mitigate the need for the proposed power plant? Their position is no. Seminole does not offer conservation or DSM programs directly to retail customers, and Seminole and its members do not have Commission-approved goals and plans pursuant to FEECA. Of course, one would wonder why they don't.

The PSC is promoting conservation and efficiency. This one, of course, that's in the, was in the front, "Conserve Your World," deals with homes. It would also be good to add one for public buildings, businesses and industry. And in addition, the posters, and these are good, mostly Department of Energy, but one of the things I like is over here in the corner, "Energy Efficiency and Renewable Energy, a Good Deal for Everyone." A little hand with the world in it; "You have the Power." And, of course, efficient technologies, solar and biofuels are mentioned.

Now the -- so here's what Navigant did. They were essentially focusing on DSM measures potential and DSM measure

characterization. So in December they had issued a report. Following is a status report on the two main research tasks in the current study reviewing the appropriateness of assumptions used in screening DSM measures for the City, and, two, assessing the methods used in other jurisdictions for screening DSM measures and selecting measures and programs to implement.

I guess one of our concerns is what Black & Veatch had done was they checked with Florida Power & Light and a couple of other utilities in Florida, and so we then asked the question, well, is that everything? Why didn't they check with the more innovative utilities like Austin, Sacramento, Pacific Gas & Electric and so on? So we encourage that.

And indeed this is kind of interesting. One of their summaries on Page 5 -- because remember Black & Veatch had looked at Florida Power & Light. So what Navigant does is they call Florida Power & Light and they say, this data source which we had hoped could provide both high quality and geographically appropriate data has proven less robust than expected. FP&L indicated to NCI, Navigant Consultants, via a telephone discussion that most of its measured characterizations are based on the SRC statewide study conducted in the early '90s, quite a long time ago, supplemented with baseline changes caused by changes in the Florida Building Code and certain impact evaluation findings. So that was interesting. And then they indeed found a lot more DSM measures when they started

looking around and they started evaluating. So the City of Tallahassee and its consultant are evaluating hundreds of DSM measures, including a lot of -- a number of the new ones, say 20 or so from those out-of-state utilities.

They did a white paper on DSM cost-effectiveness, screening and spending levels and encouraged things like green building programs, more efficiency and the like. They then more recently assessed the maximum DSM potential for the City of Tallahassee. And it said, "This memorandum summarizes the results of our high level assessment to determine the extent to which Tallahassee could achieve 150 megawatts of load reduction by the year 2025 through DSM." And they concluded that it was obtainable, it would take an aggressive approach, lots of staff, lots of money on programs and the like.

There -- and I only have a chart on this. So they broke out -- actually they estimated 137 megawatts by 2026 and then they divided it up into the different components.

Sterling Planet was given a mission, it was kind of interesting: Can you come up with a plan to develop 100 megawatts of clean energy by 2016 that you would be willing to assign a cost to and then take on the project of implementing it? And interestingly enough, they came up with some of the conclusions that the Big Bend Climate Action Team did, which was biomass, because Leon County and the surrounding area has lots of biomass. And we've been promoting the kind of

biomass that has a fuel stock that is clean, as clean as possible, clean and it's not going to adversely impact the forest. So that's the kind that we've been promoting. And certainly would not require any exotic invasives to have as a fuel stock. So they came up with what Sterling Planet was willing to do on biomass. And I know Commissioner Deason was asking some questions about this. They were willing to by 2016 come up with a couple of biomass plants, each 20 megawatts. One would essentially be focused on waste wood. The other would be using some kind of a fuel stock that you would grow. So the other 60 -- and there were 2.5 megawatts of solar water heating. And they were kind of building on and taking from the City of Lakeland. You know that good program that Jeff Curry developed down there where the City of Lakeland owns some solar thermal units and then they charge their utility customer, I mean, their customers money and so they make some revenue for the utility. So a win-win for both the customer and the utility. So interestingly enough, if solar thermal were -- that's only 2.5 megawatts, but that's a summer peaking. And as you know, if you're a winter peeking, and most hot water is used in the winter, you can essentially double the kind of effect. So about 5 megawatts for a winter peaking unit. And that's, of course, with, remember, Tallahassee having a peak peak of 600 and Seminole Electric having a peak peak of 4,200. So in terms of -- and their energy efficiency did not

necessarily overlap with Navigant in that they had some direct load control of 25 megawatts that Navigant wasn't considering. So those, those were the, the reports. And on the biomass front -- well, that's on the efficiency.

You've got to commend the City of Tallahassee because, as you may have read, if you all are customers, that they promoted this programmable thermostat program. 100 -- I mean, 1,000 programmable thermostats to customers that they're implementing now. They just finished the second week. I think they've already -- and they were short weeks. They've already installed 180. And they're doing some energy efficiency audits and tweaking at the same time. They hired a contractor to do that. So that's commendable.

The power contract people are commendable because they are really looking at biomass.

CHAIRMAN EDGAR: Mr. Urse, I'm sorry to break in, but can you give me an estimate of how much more time you need to cover your comments?

MR. URSE: Just three, three minutes or so.

CHAIRMAN EDGAR: Okay.

MR. URSE: Yeah. I wanted to finish with this biomass because Commissioner Deason had asked about it.

Essentially five different companies have approached the City of Tallahassee on, on biomass. The two that I'm most familiar with are Biomass Gas & Electric, Big Green Energy out

of Atlanta. And what they're proposing is kind of interesting. They're proposing a 75 megawatt biomass plant now on the FSU campus that they would fuel with wood waste, wood from the forest, and then feedstock, some feedstock and others shipped in. We had some doubts based upon what Sterling Planet did at the City whether they could actually meet that, so the City asked BG&E a bunch of questions. We'd gotten a small, I mean, a report by Virginia Wetherell, former Secretary of DEP, as you know, and she's a principal in that company and she gave us a report. But we had a lot of questions, as did the City because they attended the meeting, afterwards, so we prepared a list of questions. And I would invite an interested Commissioner or interested staff next Tuesday at 2:00, City Hall, they're bringing five of their people down from, from Atlanta to answer, to answer -- have written responses to all those questions that we had and indeed to explain and answer any additional questions. So you are welcome certainly to attend. And I would encourage, if a Commissioner is not able to, that someone from staff that's working in biomass take advantage of that. They've also proposed a second 75-megawatt biomass plant in the area a few years down the road.

The last thing that I kind of want to, want to finish with is the, the ask that we would have or I would have, and that is if, if there were enough questions raised here today that you have, that you can consider not making a decision on

the need determination today. That you consider getting those questions, formulating the questions, getting those questions asked and then pick a date not too far down the road and address them then. And then indeed if you are satisfied that they truly exhausted all the potential energy efficiency and clean energy and that that coal plant is still the best one, then I think from a justice point of view you're going to feel that all your questions are answered and that you can go forward. So that would be my ask. And in considering that, certainly the question would be, well, what harm would there be to Seminole Electric to postponing this about a month?

I understand that the DEP environmental assessments may not be until January. I don't know. That was -- so I don't know whether that's true or not. But indeed if that's the case, it seems like we would have plenty of time to, to address these matters. So that would be, that would be my request. And thank you for your patience.

CHAIRMAN EDGAR: Thank you, Mr. Urse. Any questions, Commissioners?

Mr. Guyton.

MR. GUYTON: I have no questions for Mr. Urse.

CHAIRMAN EDGAR: Thank you, Mr. Urse.

Ms. Brown, how many remaining do you have on the list before you?

MS. BROWN: Three.

CHAIRMAN EDGAR: Three. Okay. It is almost 11:15. I'd like to take a short break, about approximately ten minutes. Let's come back by 11:25 on the clock on the wall, and then we'll start up where we have left off with that list.

(Recess taken.)

CHAIRMAN EDGAR: We'll go back on the record. And, Ms. Brown, if you could call the next speaker.

MS. BROWN: Yes, Madam Chairman. The next speaker is Linda Jamison.

LINDA JAMISON

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

MS. JAMISON: Thank you, Madam Chair, Commissioners. My name is Linda Jamison. I'm a Talquin Electric customer. And I read in the staff's prehearing statement, Page 2, Issue 4, yesterday that no reasonable conservation measures that can -- there are no reasonable conservation measures that can be taken.

I'd like to make an observation. As a Talquin customer I get a little monthly publication called "The Current." And I just picked up three of them at random yesterday and kind of had a look at them, and in one of them is a nice little list of conservation measures that the household can employ. In the other two I looked at there was maybe one

mention of one particular conservation measure. And I feel that they've done a pretty good job, but I feel like they need to get more aggressive with their conservation measures that they encourage households to do. And I think that overall a conservation campaign can be stepped up. So I'd like to see that before anyone gives up on conservation measures. I think all over, in Tallahassee and everywhere, a lot of people are not aware of things they could do to save quite a bit more energy. I'd like to see them put in each issue of the Talquin newsletter, for instance, in bold, in bullets as a start.

My next topic that I'd like to talk about is social responsibility. And I've heard a lot of aspects of the coal plant Tallahassee is considering debated at length, but most of the debate centers on stack technologies and trying to make sure that the emissions are cleaner and cost projections as we've heard earlier. I don't hear much about upstream costs especially to the people working with and living in the areas where the extraction occurs.

I'd like to reiterate some things I saw in the Mountain Top coal removal presentation that three elderly citizens from West Virginia made in our town. That process desecrates entire areas. It has altered terrain to the point where streams that were once usually quite placid have become flashy enough to claim people's lives. That's been caused by alteration of the terrain.

Houses in that area have been grossly devalued. We saw one photo of a house that had been valued at $147,000. Its Tallahassee equivalent would likely be quite a bit more than that. That house had been devalued to $11,000 by the countryside having been ruined in many ways around it, and the owner of that house couldn't sell it and get anything out of it. Its estate was substantially devalued.

For our personal convenience in flipping a light switch or pushing our computer keys, people living in distant locales are losing their lives, they're losing the value of their estate and their children are attending a school in one place sited right below an earthen dam holding toxic mining sludge. That's available on my laptop computer up there if you'd like to see an aerial view of it. Because it involves the health, education and welfare of people living a thousand miles away, out of sight, out of mind, it's called an externality. Younger economists are kind of ditching that term. There aren't really any externalities. In an age of globalization, the concept of an externality doesn't have a place. What if we had to pay prices like that with our lives and the devaluation of our property to get our electricity? Somebody else is making that sacrifice for us without their own permission, it's just being forced upon them, and that's not socially responsible.

Fiscal externalities, that's a fiscal externality.

It's external to the power company's fiscal cycle. But it's not external; a lot of people are paying that price and it's not just. Please consider the social costs of extraction.

Some of the other presentations earlier have brought me to something I'd like to say that, that I had not planned on saying here. I work with the Department of Oceanography at FSU and I do environmental education. Some of the topics that were broached earlier are studied by the scientists in the oceanography department at FSU. We have one professor who specializes in methane research. He had a letter in the paper yesterday. Our local waste management company is, actually has a sensor that they've set up to collect data on escaping methane gas and to trap it and to channel it to a place where it can be burned and used to produce power. The company is pioneering its device for use all over this country. That was in yesterday's Democrat. The professor is Jeff Chanton. Jeff Chanton is also a specialist in methane gas hydrates. He makes voyages on research vessels in the ocean to study the methane gas hydrates that are trapped on the sea floor, and he undoubtedly would have information for you. Our chair, Dr. William Dewar, I think he would be interested in having people from your country -- from your, excuse me, from your company talk to him about ways that we can work with oceanography and some of the scientific findings they have there to help people be more forward-looking.

There's enormous wind potential off the coast of Florida. Florida is labeled a nonwind state because the statistics have been taken from land stations. If you're used to the coast of Florida, you know that there is a very vigorous wind exchange going on there. From day to night it will switch direction, but it's usually quite powerful.

We have a power company that is partnered, I think it's Southern Company, partnered with Georgia Tech. They are putting in the first experimental wind farm off Savannah and their plans were announced for that a year ago. About a month ago plans were announced for the second wind farm off the coast of Texas near Padre Island. Right now we have NOAA buoys that take wind data at the ocean surface, but we do not have that data extrapolated to the heights at which wind turbines could perform. That's a data gap. I've been given a way by one of the oceanography scientists to take data from the buoys at the surface and convert it to wind speeds at altitude. And I think everyone has something there that they need to be looking at as future potential.

The particular use of the turbines offshore has an added bonus. Once they put a turbine complex in, the shrimp trawls will not be able to get in there. And shrimp trawls completely destroy the sea floor and the habitat for our marine organisms that feed our fishery, and 150 times more habitat is destroyed on the ocean floor than rainforest on earth's surface

by these shrimp trawls. So I've talked to the fishery scientists. Putting in wind farms off the coast of the Gulf Coast would help preserve our sea floor and the organisms that use that as their place to live. So that's more information that can be talked about by oceanographers, meteorologists and, and people like yourselves.

So I have the contact information for our department chair. I would love to put you in touch with him. I'm going to be here for a few minutes, and my computer is up there with the aerial photo of what's going on in West Virginia. So I thank you for this opportunity.

CHAIRMAN EDGAR: Thank you. Ms. Jamison, just a moment. Ms. Jamison, if you could remain for just a moment.

MS. JAMISON: Sorry.

CHAIRMAN EDGAR: Commissioner Carter, I believe, has a question.

COMMISSIONER CARTER: Thank you, Madam Chairman. I was going to ask Mr. Garner if he would make sure he got her number and the number for and the name of the chair for the department. I'd like to do some follow-up.

CHAIRMAN EDGAR: Thank you.

Mr. Guyton.

CROSS EXAMINATION

BY MR. GUYTON:

Q Good day, Ms. Jamison. Ms. Jamison, just --

A I'm in a hurry to get away. Not really.

(Laughter.)

Q Just one question.

A Yeah.

Q Are you aware that none of the coal used for the Seminole Generating Station is mined through Mountain Top Mining?

A No, I'm not aware. I'm glad to hear that. But that's today. We don't know what tomorrow brings.

MR. GUYTON: Thank you.

CHAIRMAN EDGAR: All right. Thank you, Ms. Jamison.

Ms. Brown.

MS. BROWN: Brian Lupiani.

CHAIRMAN EDGAR: And, sir, if you could repeat your name and maybe spell it for us too. Thank you.

BRIAN LUPIANI

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

MR. LUPIANI: Sure. My name is Brian Lupiani. That's Brian with an I. L-U-P-I-A-N-I. And I'm a resident of Tallahassee.

Madam Chair and Commissioners, I appreciate you having us here today, and, and I also appreciate that you've, despite an objection from Mr. Guyton as to the scope of the

comments, that you have allowed us to, to speak. I say us because these are, these are my friends here.

I belong to a number of nefarious organizations, but I'm here just speaking for myself today. And I'll save my friend Charlie Guyton a few questions and say right up-front that I'm not an expert in anything that I'm about to talk about, nor do I have experience, working experience in any of these topics or pretty much anything worthwhile. So I'll try not to let my ignorance of certain matters, including the procedures before the PSC, mess up my comments too much. And I'll try not to ramble on too long. I know it's getting close to noon, and I appreciate everyone being here for the morning on this.

One of the things that was mentioned earlier was that the Commission has ruled, I believe it was three times, as a matter of law that externalities are not to be considered. Now one of the things I am ignorant of is your rules and procedures, but I'm guessing that, although you're obviously not the Supreme Court, like the Supreme Court you can revisit past decisions. And perhaps it's time to revisit that whole idea of whether or not so-called externalities should be included in cost analysis and that sort of thing.

To continue a Hollywood theme that my friend Dan mentioned earlier, it happens to be an inconvenient truth that some utilities, including, I believe, utilities in California

at least and probably in some other states, are now including in their cost projections for coal a $20-a-ton carbon tax or coal depletion allowance or whatever you want to call it. And, in fact, a measure to include some sort of carbon tax is even being debated in the United States Congress and has support among Republicans as well as Democrats. Now I realize that this is something that you can't, you can't say for sure that there will be this component added to the cost within the life of this plant and during the time that it's using coal. But it's something that should be -- it would be irresponsible to not consider. And it's my understanding, and I may be wrong, because I come to this like a few of the other folks that have spoken, I come to this through the perspective of being involved in the campaign against Tallahassee's coal plant and things that I've learned along those ways. But it's my understanding that Seminole's cost analysis and projections don't include that in the cost of the, in the cost of the fuel. So I think something should be done there. Like I said, the utilities in California are doing it and it's something that should responsibly be included when comparing the cost to other fuels.

And speaking of costs, again, this is -- I may be ignorant of exactly what's going on with this particular proposal, but I know in terms of the Tallahassee proposal the cost estimate for construction, which I realize is a minor

component of the ultimate lifetime cost of a plant, but the construction cost in Tallahassee hasn't been updated since when the proposal first came out last June when it became public. Now I see in some of the documents that I've looked at about this hearing that the cost, construction cost estimate for the Seminole plant is $1.4 billion. And I don't expect an answer right now, but I think one of the things that ought to be considered is is that -- when was that estimate made? Is that a pre-Katrina estimate? Because if it is, there's certainly going to be an impact on the construction costs and materials and labor when we have this entire rebuilding of the Gulf Coast going on.

Another thing that was brought up before was talk about the demand-side management capabilities. And I think I get the idea that Seminole being basically in the business of just producing and distributing, selling the energy and not having any final end customers, that it's not really in their best interest, not to mention it's really not part of their job, their scope, to have the end-users subject to demand-side management. But on the other hand, it seems like that's sort of a loophole too. That it's really a way that, that a power producer can just get beyond all that by saying, you know, I'm sorry, you know, that's not my table in this restaurant, that's somebody's else's area. And, frankly, I, I didn't really give this a whole lot of thought before now, as you can tell by my

stumbling, but, you know, it just seems like there's got to be a way to handle that; that the end-user utilities or the retailers need to be involved in it and do something to reduce demand.

Now something that was said earlier was that the demand-side management only -- is primarily concerned with peak times and is sort of to be considered like a peaking unit and it is not something that is constant. Now, again, this is something I may be ignorant of. When y'all said DSM or demand-side management, maybe you don't include things that I would think of that are maybe properly termed as conservation. But it seems to me when you do things like weatherize houses or maybe take a little bit off of the demand by some sort of, you know, solar water heater, something or another like that, that that is also demand-side management. Maybe not in some sort of strict legal sense, but that's something that applies to the base and is a constant 24 hours a day or at least eight hours a day in the case of a solar water heater effect on the demand. And those sort of things need to be explored and given more credence.

Almost done. I also wanted to say, well, first of all, I think it's probably obvious from what I've been saying, but I do pretty much agree with all the comments that have been said up to this point about the environmental and health aspects, and that's better handled by other folks. And so --

and I realize that, again, may be outside the scope. I'm hoping that the things that I've mentioned are within the scope of the need determination.

I'd also like to respond to one or two things that were said earlier. I'm not necessarily saying that biomass is the way to go or anything like that, but in some of the discussion about that there was made mention that there was probably about 500 megawatts currently in the state, and that even if that doubled, it wouldn't be enough to handle the supposed need currently identified for Seminole. But I don't think that's really a logical argument. I think biomass, even though maybe it's something that's been around for decades, is something that's still in commercial generation, it's in its infancy. And I think it might be more appropriate to say what was it ten or 20 years ago and what is it now and what is possible? And, again, this also gets into the whole thing of -- similar to the cost analysis of including a carbon tax. You can't sit here and say, well, we can assume that we'll be able to get X amount of power from biomass in the future. But on the other hand, you can't pooh-pooh that or any other alternative just because it hasn't caught on yet or it hasn't had support yet.

And I think one example of that would be -- and, again, my ignorance. I've always had a problem -- I've lived in Florida since I was four years old and I still can't

distinguish between Florida Power Corporation and Florida Power & Light. And I know one of them at least has changed its name to Florida Progress or Progress Energy, and I don't know what the other one is called. But I think one of the, one of the Florida Power companies is one of the biggest wind, wind-produced generators in the country. Now it's not in Florida, so it may not be very helpful to Seminole at this point. Apparently Florida Power, whichever one it is, has a lot of land or at least a lot of access to a lot of land in the midwest and in Texas. And they have -- I will find the information and send it to y'all, but I can't remember off the top of my head. But something that caught my eye especially as being concerned about the power plant that's proposed for Taylor County, Florida, there was a press release from, I think it was about a year ago, from Florida Power about Taylor County, Texas, where they were going to be putting up a -- if I recall correctly, it was something like a 250 megawatt wind-powered generating installation and it was going to be up in six months. It was supposed to be up in six months. And it had a number of little, I think it was 150 or 200 turbine units, each of which produced more than a megawatt of electricity or had the capacity to produce more than a megawatt. So we're not talking about little things on people's houses or something or the other like that.

And this is -- and my point in this is to say that

biomass and other possibilities like wind power may be the sort of thing where it's coming and it's even to the point that it's not on people's radar yet. But like I said, this is something where they're going to throw up something within six months or certainly less than a year -- the projection was that I think it was supposed to go online by the beginning of this year -- of a couple of hundred megawatts. And their wind production capacity has been growing at a phenomenal rate. A few years ago they had basically nothing, but it's really grown in the last few years. And, you know, again, you can't bank on this sort of technology, but you can -- on the other hand, do you really want to get tied into something for 30 years or more that's using technology of the 19th century and, you know, the ratepayers, the ratepayers and other citizens of Florida will, may wind up getting stuck with these white elephants and having to decommission them or something or the other like that or just subsidize them? And I think that's something that really needs to be considered.

We talk -- you know, we hear all the time about this inexhaustible supply of coal. But it is dirty and it's being recognized as dirty and there are costs associated with it. And if half of the coal plants that have been proposed around the country actually get through and built, it's not going to be cheap, and these other alternatives are going to seem a lot more attractive and feasible.

So having said that, I think I'm done. And, again, I appreciate the time that you've given me and everyone else.

CHAIRMAN EDGAR: Thank you, Mr. Lupiani. Questions?

Mr. Guyton.

MR. GUYTON: I have four or five questions for my friend Mr. Lupiani.

MR. LUPIANI: I don't have any answers for you. No, I'm kidding.

(Laughter.)

CROSS EXAMINATION

BY MR. GUYTON:

Q Brian, are you aware that the R. W. Beck study performed for Seminole assessed the risk of a carbon tax being imposed in the future?

A No, I'm not aware of that.

Q Okay. Are you aware that the study found that there was an 80 percent probability that coal would prove to be less costly than gas alternatives?

A I am not aware of that. But I would like to know when that -- has that -- how up-to-date is that study? And not to, not to ramble on, but I would just call your attention to a column and subsequent letters in the Tallahassee Democrat over the last couple of weeks from, originating with "In My View" by Brian Armstrong, and then a follow-up letter that pointed out that recent figures have shown a much closer cost between gas

and coal.

Q Okay. It's in the need filing. I'll show you when we're through.

A Okay.

Q You spoke of DSM not being offered by Seminole because it provides wholesale power and doesn't serve end-use retail customers. Are you aware that Seminole's members do offer conservation and DSM?

A I do not know specifics, but I'm not surprised that that's the case. I would certainly hope that would be the case.

Q Are you aware that those demand reductions associated with DSM and conservation were captured in Seminole determining its capacity need for 2012?

A Again, I'm not, not familiar with the specifics, but that, I would certainly hope that would be the case. And, in fact, actually I think I do know that. I've noticed in a summary document, for lack of a better word, that, that there were demand-side management included. But I would question whether or not they were, they go far enough.

Q You also mentioned biomass and wind energy coming. Are you aware that Seminole Electric Company did a capacity RFP, an all-source capacity RFP?

A Yes, I'm aware of that.

Q And are you aware that no biomass or wind producers

bid into that RFP?

A No, I wasn't aware of that.

MR. GUYTON: That's all I have. Thank you.

CHAIRMAN EDGAR: Okay. Thank you. Thank you, Mr. Lupiani.

Ms. Brown.

MS. BROWN: Leon Jacobs.

LEON JACOBS

was called as a witness and, having been duly sworn, testified as follows:

DIRECT STATEMENT

MR. JACOBS: Good morning, Madam Chairman and Commissioners. This is an interesting place, way to view this room. I haven't viewed it this way before, but it's --

CHAIRMAN EDGAR: Welcome back, Commissioner.

MR. JACOBS: Thank you. I'll try and be brief in my comments. I know you've been very patient during the day.

What I'd like to do is really narrow in on what I think are really important and pertinent issues for the Commission to consider in its deliberations going forward. And I've given you a brief handout; I'll try and walk through that very quickly.

I begin by kind of noting that we are on a path that really you've set, and I think it's a path that on its, on its, on the surface is not unreasonable. Projections are for

incredible demand growth in the state, pretty much at baseload. And in 2004 in your planning process you asked the industry to diversify because at that time I think our projection was that almost all the new plants were going to be natural gas-fired. And, of course, we were experiencing incredible turbulence in the natural gas markets, and you specifically asked the company to consider building more solid fuel plants. In the 2005 filings the companies did respond to that and came back and proposed, I think, seven new coal-fired plants, and you're in the process of entertaining those applications now.

If you look at what's happening around the country, I think in Texas there are 15 plants, coal plants that have been proposed around the country and particularly in the southeast. I think what we're going to see in the midterm and maybe even more so in the short-term is a prevalent shift from new natural gas plants to coal plants.

My, the essence of my comments today is to suggest to you that we may want to take some time to give serious thought to some of the issues that are raised by that policy and maybe even some, some of the unforeseen ramifications of it.

You have, you have done, I think, a very good job. And I, of course, have a great deal of respect for your staff, and I think your staff is probably amongst the tops in this region, if not the country, in a lot of these issues. So -- and I'm certainly not an engineer or an expert, so I'll save

Mr. Guyton that round of questioning. But in my, in my humble experience and in exposure I think there are some real important financial risks, I'm sorry, overall risks that, that I would suggest to you are important to consider at this point.

When you did your, your recommendation, I'm sorry, when you did your review in 2004 and sought to look at how to diversify, you asked, I think, Florida Power & Light to go away and do a report on the whole issue of resurrecting coal, and I think they came back to you with a report. I haven't seen that. I wanted to try and review it before today, but I saw a summary of it. It's my understanding that that report, and I stand to be corrected, please, if I misstate it, but it's my understanding that that report came back and said, yeah, it probably is going to be a moderate to low cost option, but there are considerable risks associated with, with building new coal plants, and it listed out some of those risks. I've summarized some of them here for you on my handout.

The stability of coal prices in global markets. You've heard some comments already that -- and I've seen, I've seen -- I briefly reviewed the projections that Seminole made. I looked also, I looked also at the scope of projections that were made in the 2005 Ten-Year Site Plan, and the scope of those projections were considerable. In the short-term they were considerable in that they proposed reduction, a moderation or reductions in cost of coal, but in the long-term they

proposed increases that were, some were nominal but others were less than nominal. I think there was one that was over 3 percent increase over the ten-year planning cycle in the price of coal. And you, of course, took a weighted average of those in determining how to review those plans. But I think that emphasizes that this idea of projecting what's going to happen out there to this fuel source over the planning cycle is not simple. This is rocket science, as former Commissioner Gunter used to say. And I used to chuckle at that, but over the years I've gained a very serious appreciation of that comment. This is not -- there is no crystal ball that you can look into and find a silver bullet on this. And I recognize that, that to sit here and say that, or even to do Monday morning quarterbacking when you rule on a decision is not reasonable. But I would suggest to you that there is a more -- there is a very balanced and, I think, constructive opportunity here to, to sit down and set a consistent process by which you will look at these decisions and hold them accountable and consistent over time, and I'll bring, I'll go back to that in a moment.

But stability of coal prices generally in the global markets. I think in a similar proposal they're going to be coming from Illinois and Kentucky.

One of my first assignments here, if I may digress for a minute, when I was hired as an attorney was I was thrown

into an investigation of, of coal delivery for one of our state's utilities. And I'll never forget, we went up to Kentucky, flew into Frankfort, Kentucky, and went over to the state Capitol and started digging into the corporate records of all these coal mines. I've never seen anything so elaborate and confusing in my life as to how all of these entities were woven together, and they were woven together with the transportation companies. And figuring out whether, whether or not the structures were appropriate and whether or not the costs were fair to the consumers was an eye-opening experience. The -- I'll come back to that in a moment.

But it's becoming evident that the low -- one of the issues in that docket was whether or not low sulfur coal was being delivered to Florida as was required. And it's becoming clear that low sulfur coal is going to become a high-priced commodity. At present, as I understand it in this docket, they're not purchasing low sulfur coal. But it becomes more and more clear that that's going to have to be an option the company is going to have to look at on the long-term, and I'll come back to why that is the case in a moment. That market is going to, that is going to impose more, more demand problems in that market in Florida, maybe even for all grades of coal, but certainly in that, in that class.

Stability of coal prices throughout the planning cycle. What you are clear on is that when you do coal plants,

you've extended your planning cycle, and so the projections that you're going to rely on in making that decision are really further out in advance, and that thus more subject to volatility in the markets as you, as you reach more and more of the time frame when you're going to be bringing that plant online. And so how then are your projections at this point accommodating for and dealing with that cycle that you've got to ride through before that plant comes online and actually the coal gets delivered to that plant? Because you're going to see it one way or another. Whatever happens in that cycle, you're going to see it through recovery clauses or whatever.

Transportation costs. You heard already the idea that there are already issues with regard to delivery of coal that are being imposed by, by the concerns in the rail, rail service. Those, those -- there is no indication that those problems are going to go away in the near term. In fact, if you read what press I see, there's probably even going to be more problems with the rail before less. Now, couple that with the idea that there's this significant shift to coal plants around the country and we're already having problems getting coal to the plants that we have now. I think you can begin to understand that there are going to be issues. And if those -- and if that's not understood and regulated correctly, that's going to have a direct impact on, impact on delivered price of coal to these plants. So if we're deciding that we're going to

put more coal plants on the ground and this price projection that we've done is many years out and we see these kind of issues that are going to have an impact on that, I think you're beginning to see why it's really a concern how, how you pin down on those projections of delivered price of coal.

You've seen mine safety issues that have been arising. There's regulatory risk to the coal company that is not even yet understood yet about what's going to happen now as a result of some of those issues. So I won't speak about that much. I'll just raise those in passing.

But, but here is something that is very real, my next one. There's growing scrutiny in financial markets and amongst investors of how companies who generate greenhouse gasses are doing their tea leaf reading. What I mean by that is it's becoming clear that somebody has to step back for a minute and figure out, okay, who, when, where is this, is this hat going to drop on? And somebody is beginning to ask the questions, okay, what are you going to do about it? What are your, what are your preparations, what are your risk mitigation measures for how you're dealing with this? Those discussions are being actively engaged in in the financial markets right now.

Yesterday, it was interesting, PBS, public radio rather had a segment on this that one of the major brokers with Morgan Stanley or one of them was talking about the fact that it is becoming mainstream now that institutional investors are

beginning to ask questions about risk exposure for climate change. And so those industries that are heavily engaging in producing greenhouse gases are going to be on the forefront of that discussion; i.e., stock prices will be directly impacted if companies do not undertake measures to deal with their risk in this area.

And then one of the other interesting issues for Florida is that we import almost all of our fuels. And so every increase in fuel sources that we, we engage in is a direct transfer of wealth outside of the state. And for coal, I think that's probably the most dramatic one because of all -- some of the things I mentioned earlier, but it has historically been that it has been the furthest distance away and all those other issues that are there. And then, of course, we all know that there are -- when you, when you do coal plants, there are more capital upfront costs that are going to be incurred. So what we're doing by, by choosing to now build more coal plants is we're saying to the consumers, you're going to absorb more upfront capital costs until we get this plant online. And then the break-even analysis for this is heavily driven by what's happening with the price of gas. Okay? So it may very well be that if we have a downturn in the gas market, that the break-even point for these coal plants is going to be shifted out further.

All those issues are important, I think, for you --

an important financial risk. And whether you address them here or not, they will be considered either in the financial markets or by the shareholders of these companies.

Regulatory risk. This really is, this is really, I think, is probably the behemoth that's sitting at the gates. Attached to my presentation is a, I think a four- or five-page listing of, of public policy measures in 2006 alone that were either drafted or enacted to deal with greenhouse gas emissions. Most of them were directed towards utilities. If you just glance down through this listing, and I know you can't look at it now, but what struck me when I looked at this was -- and let me digress for a moment. This was precipitated by the United States EPA coming out in, I think, a few months in 2005 with some requirements on, on air quality that were intended to kind of bridge this gap, to kind of move us further down the road, but yet not impose very high stake requirements on the companies that were generating greenhouse gases to moderate their emissions. Well, what has become obvious, I think, by this particular listing is that the states that most of them are critically impacted have chosen, have decided that that was not enough and they've chosen -- they decided they can't wait on a consistent federal policy. And so what you see are a whole array of, of approaches to addressing this issue. And I think what you also see is a statement of urgency from many of these states about where this issue stands in their relative

quality of life.

But what struck me when I looked at this list was what many of them were asking: Connecticut, a 90 percent reduction in mercury; Iowa, 83 percent reduction in mercury; Massachusetts, 95 percent by 2012; Minnesota, 70 percent, and so on and so on.

Now here's the issue. If any one of these laws are enacted and passed, it would go directly to the bottom line of every company in that state. You know why? Because they've got to go back and re -- I can't think of the word. They've got to go to older plants. They can't just do this by new plants coming onboard. They've got to deal with some plants that are already operating. And I don't know if you're familiar, but there's an incredible dance that's been going on about whether or not federal rules apply to plants and how much you can change before you invoke new air quality rules for existing plants. That dance is in force in all of these states where they're requiring, where they enact these kinds of requirements for emission reductions because there's no way they're going to just be, do it by affecting new plants that come online.

So there is incredible -- the bottom line of all of that is that I believe there is an incredible regulatory risk sitting out there now. And Florida may not enact measures such as this. As you noticed, Florida is not on this list. But

guess what just happened in Washington? It's called a wake-up call. And I would venture to guess that somehow, someway in the not too distant future they're going to figure, they're going to have to figure out how to deal with this issue. It would be untenable to let these many states go off with this scope of approaches to solving this problem. So whether Florida does it or not, I think the Florida utility is going to have to figure out how to address this issue because I think the federals, the feds are going to do something.

And I'll list some of these other reasons why also. The strong -- the science is becoming much clearer. More and more scientists are coming out being more consistent on what they're saying. We're seeing severe events that whether you believe it or not are being tied to climate change.

Now, setting the pure environmental arguments aside for the moment, when it comes to the point that, that oil rigs in the Gulf get shut down because of what are perceived as a severe event brought about by climate change that results in school districts in Florida don't know if they're going to get diesel to run their busses, those, that's going to get attention across the economy. And whether or not you deal with it in this, in this forum, somebody is going to say, wait a minute, I can't accept that risk. We've got to figure out what to do about this perceived cause of my risk. And at this point the perceived cause of the risk to that school district that

couldn't get diesel fuel because an oil plant was shut down was because of the hurricane which came from the climate change.

And so what I'm suggesting to you is that we're on the cusp of what I believe to be an incredible bit of public debate about how to deal with this issue. And I think what has to happen is somebody has to begin to say, okay, let's stop and think through this very rationally and very coherently to figure out how to get the reasonable answers that bridge this alternative.

What you, what you're seeing in your Ten-Year Site Plan are most of these coal plants are not going to be online until 2010, 2011 or something like that. And in the meantime, you're still going to do, you're still going to do natural gas. I would suggest to you that if this begins to take shape, you're going to see impacts on your Ten-Year Site Plan, because I suggest to you that companies are going to come in and begin to understand what that means and even deal with the short-term planning cycle as opposed to pushing some of these off to the longer term.

Competitive/reputational risk. The classic example here is Power & Light. Power & Light has done what most people in the country view as a very admirable job of addressing a fuel diversity mix. I mean, what they've done in wind and now even in biofuels is impressive. None of that -- let me step back. I do not know how much of that resource, those resources

are put in place in Florida. But let me suggest to you that Power & Light is now operating at what I believe to be important financial benefits, advantages because of the, of the management that has been done in this area as opposed to AEP and some others, and that's off the top of my head, I don't want to slander anybody, but those companies that proceed, they have major climate greenhouse gas emissions exposure and have not dealt with it -- if you look at what's happening with them in the bond ratings and so forth and so on. There are clear now and distinct economic value in addressing this issue on a positive and affirmative basis.

Not only that, there's now clear market presence advantages. Companies that now can come to you -- a classic example today is Toyota. Toyota has a partnership where they have a fuel cell plant with GM in California. Guess who came out with all the hybrids as soon as the gas prices went up? Guess who you can't go and find a hybrid car on the floor, on the floor right now? It's Toyota. Not only that, but as distributed generation kicks in, guess who has now the primary manufacturing capacity to bring as many fuel cells to the marketplace as anybody?

That's, that's not directly related to utilities, but I think it has, it has some significance because folks are now getting the point; the price of my electric bill equals something having to do with the cost of fuel. I don't know

what. Something is there. They're starting to get the connection. And I guarantee you -- and now you're seeing companies like BP doing commercials saying, hey, we're doing something about this. I wonder why they're doing that commercial. I think sooner or later the industries are going to have to come to the conclusion that they've got to figure out how to make this work in the minds of consumers, and that's happening now in some places around the country.

Those are essentially my comments. I would offer you some recommendations. You heard today the idea that, that there was an analysis, and Commissioner Deason touched on this and I thought it was a very important point, there was an analysis done in the OUC docket of what these costs are, and we're not certain, but it does not appear that that same analysis was done here. My point to you is that is an important thing to eliminate. There needs to be consistency in how companies are going to look at how they measured this risk and how they're measuring even -- I don't know -- you can't -- I don't know if you can dictate what everybody does because I think the plants are different, the scenarios are different, the companies are different. But how they -- you ought to have the ability to ask the question how they got to their solution of that problem. First of all, you've got to know, identify the problem. Second of all, you ought to be able to ask questions about how they got to solve that problem.

Seminole, I have to admit, this is not just because I like Mr. Guyton, but I have to admit that I'm somewhat impressed with some of the things they did. As I understand it, they're putting scrubbers on one unit and then putting scrubbers on even another unit as a retrofit. And it's wet, it's a wet scrubber, which is, my understanding, some of the highest and best technology that's out there. They've gone and done some things. There are some things that I don't see here that OUC seems to have done.

But my question for you is how -- and here's an important point. When you chose to say we want more solid -- you, the Commission -- you may not -- probably most of you weren't even here, but the Commission is where this responsibility lies. When you say that, okay, now, Power & Light, we see your report, we understand your concerns about doing coal plants, but we want you to build more coal plants, guess what? You're on notice of those risks. And when those plants get built and they come online and those risks present themselves, guess what you're going to also see? Environmental cost recovery clause proceedings, fuel cost proceedings. All the controversy that you may not have been aware, but I am very astutely aware of, that we just saw in our TECO docket, Docket Number 030226.

TECO was sued by the Environmental Protection Agency because of emission concerns with their Big Bend plant, entered

a consent decree, which there was a whole, whole, whole range of discussions about the fairness of that consent decree, what were the prices, what was paid, so forth and so on, and technology, the whole nine yards. But anyway, long story short, there were measures that were agreed to in that consent decree. But when that consent decree got signed, guess where they showed up? We've got to recover these costs. After everything was signed, it was all said and done, you now, we now had to go back in and backtrack through all that stuff and figure out whether or not what was reasonable was done. Forget about whether or not it was effective in addressing the concerns. That was an assumed conclusion. If it wasn't, we would have had all kind of problems because they were paying all this money to not solve their problem.

But my suggestion to you is that you have innumerable examples of the TECO scenario sitting before you now if you continue to build an innumerable number of new coal plants, or even if you don't. Because I think if the feds come back and do a sizable reduction that some of these states are offering, you may have to look, as TECO did, they had to go back and retrofit Big Bend.

So the offshot of all of this is I'm suggesting to you that there's an opportunity here for you to rethink and hone in on all these factors and come to -- and probably more so on process than individual details. Understand what process

you ought to engage in as you go down this road. If you're going to build ten, 12, 15 new coal plants in the next ten to 12 years, you ought to have a lot of thought going into what the ramifications are.

And as my next point, I think there ought to be a role to play for emission controls. I think it was proper for OUC to do a cost analysis. I think it is proper for others, as Seminole has done here, to do an analysis of what the potential cost on coal delivered price and other auxiliary price costs that are going to be imposed when you do this.

And then finally, I think you've got to begin to look at demand reduction as a more fundamental business case opportunity. Yes, it is done. I don't question that. But the goal for several of the companies is zero. For most of the munis it's zero. The assumption is that most of the options out there have been saturated. What I'm seeing around the country and what I'm seeing in Florida in contrast to the rest of the country is that there is, first of all, new life in the technology. And as DG comes online, there's even more new opportunities. So I think to restate the business case for demand reduction in light of all of these factors is an important consideration that I would offer you. And with, with that, I think that's about it.

CHAIRMAN EDGAR: Thank you, Commissioner Jacobs. Questions? No?

Mr. Guyton?

CROSS EXAMINATION

BY MR. GUYTON:

Q Commissioner Jacobs, it's good to have you back.

A Thank you. I'm glad to be here.

Q I have a few questions. You spoke of the risk of coal price increases. Are you aware that the R. W. Beck study performed on behalf of Seminole assessed the risk of coal price increases?

A I am aware. I saw -- I briefly looked at Mr. Reid's testimony, I think. I don't know if that was in there or not.

Q You spoke about a break-even point between coal and gas. Are you aware the Seminole analysis showed that the SGS Unit 3 was on a net present value basis some $500 million more cost-effective than an all-gas alternative?

A I'm aware of that.

Q All right. Are you aware that the break-even analysis for Seminole shows that it breaks even in the very first year; that from year one coal was more cost-effective than gas?

A I was not aware of that.

Q Okay. You spoke also of greenhouse gases and some of the risk associated with that. Are you aware that the NOX, SO2 and mercury admissions at Seminole Generating Station will actually be lower after the addition of Seminole Unit 3 than

current levels?

A Yes, I was aware of that.

Q Okay.

A Because of them putting on all the control technology.

Q Because of the retrofits to 1 and 2.

A Yes. Uh-huh.

Q And are you aware that because of the retrofits to 1 and 2, Seminole projects that it will have sufficient emission allowances that would cover any generation alternative, be it coal or gas?

A You mean in the future?

Q Yes.

A I hadn't seen a discussion, but that seems reasonable.

Q That seems reasonable?

You spoke of a scenario where all the rigs in the Gulf were shut down. Do you recall that?

A Yes.

Q Wouldn't Florida be in a better position of reliability if it were relying more on coal and less on gas with the prospect of all the gas rigs in the Gulf being shut down?

A To give you a short answer, I think it has a lot to do with the scenario at the time that you, that you're faced

with that issue. At this present time it does appear that natural gas is in a much more volatile -- that the markets for natural gas are in a much more volatile state than coal. And so at this time I think you'd have to agree with that.

MR. GUYTON: All right. That's all the questions I have. Thank you, Commissioner.

MR. JACOBS: You're welcome.

CHAIRMAN EDGAR: Thank you, Mr. Guyton.

Ms. Brown.

MS. BROWN: Madam Chairman, I'd like to ask the Commissioner if he would like his presentation marked and placed in the record.

MR. JACOBS: Yes. Yes.

MS. BROWN: All right. We will call this the June 7th, '06, Presentation before the Florida Public Service Commission. That's a short title. Thank you.

CHAIRMAN EDGAR: Thank you. Note the title from Ms. Brown and that this will be numbered as Number 39.

(Exhibit 39 marked for identification and admitted into the record.)

MS. BROWN: And, Madam Chairman, that concludes the public testimony as far as I know.

CHAIRMAN EDGAR: Okay. Commissioner Jacobs, thank you very much.

MR. JACOBS: Thank you.

CHAIRMAN EDGAR: Is there anyone here that has not yet had the opportunity to speak before the Commission that did not have the opportunity to sign up on the list that would like to at this time? Seeing none, then that concludes the public testimony portion of our proceedings this morning.

MS. BROWN: Madam Chairman, I have one typo to correct before we close the record. It has to do with the docket title on the comprehensive exhibit list. It's left over from the last one of these I did. It should be Docket Number 060220-EC, and I'll provide a corrected copy to the court reporter. And that's, that's all I have about the record.

CHAIRMAN EDGAR: Okay. We'll take notice of the typo correction from Ms. Brown.

MS. BROWN: All right. Thank you.

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: Just for, for the record, Madam Chairman, I'd like to say how much I appreciate you, even though the procedures were not such that the people that presented today were applicable, you allowed them, as you always do, public input. And I just want to say publicly for the record that you are always more than fair to our citizens, and I think that we learned a lot today and I appreciate that. I just wanted to say that. Thank you.

CHAIRMAN EDGAR: Thank you, Commissioner Carter.

Ms. Brown.

MS. BROWN: Madam Chairman, the Commission has a choice to make here now: Whether they want to move forward with a bench decision on the petition, whether or not to grant Seminole's need petition. We suggest that since the parties, the formal parties to the proceeding are proposing stipulated positions on all the issues, the Commission could go ahead. But it's certainly within its discretion to, to not make a decision at this time.

CHAIRMAN EDGAR: Thank you, Ms. Brown.

Commissioners, as our counsel has advised us, all of the issues that are before us today have been stipulated by the parties and there is the opportunity to make a bench decision at this time. However, I'd note that we have had significant comment and testimony presented to us today, and I think that my preference may be to give our staff the opportunity to review that and to come back to us with a written recommendation per the schedule that had been laid out prior. Is there comment or discussion?

Commissioner Carter.

COMMISSIONER CARTER: Yes. I'd just say, Madam Chair, I think that's an excellent idea because we, you know, as you always do, even in our public hearings around the state, you always give the public an opportunity to be heard. And I think that we got some valuable information today and I think that's a more reasonable approach to take.

CHAIRMAN EDGAR: Thank you.

Commissioner Arriaga.

COMMISSIONER ARRIAGA: Madam Chair, just a quick question to you. And how much time will this delay the process? When will this come back to us?

CHAIRMAN EDGAR: And I was just going to ask Ms. Brown if you could lay out the time frame and describe that to us, please.

MS. BROWN: Yes. The transcript of the hearing will be due the 9th of June. Posthearing filings would be due the 15th. The staff recommendation would then come the 6th of July, for an agenda decision to be made the 18th of July. And I would point out that those time periods fall within the procedural time periods required by our rules and 403.519.

CHAIRMAN EDGAR: Mr. Guyton, the time frame that Ms. Brown has laid out, do you have comments on that?

MR. GUYTON: Commissioner, Seminole will yield to whatever the Commission feels like it needs to do to decide this case. Obviously, it would like a bench decision. But if the Commission needs more time, then we'll take the opportunity to brief it and address it through that process.

CHAIRMAN EDGAR: And I thank you for that, Mr. Guyton. And, again, I recognize that there is the opportunity for Seminole as the Petitioner before us to, to file in response to the proceedings that we've had here this

morning.

Commissioner Arriaga, did you have any further question?

COMMISSIONER ARRIAGA: I'm just wondering, Madam Chairman, and please help me out with this, and I do understand that this Commission has the obligation to listen to the public, but I'm wondering if we're not violating anybody's rights over here, and by, by allowing testimony or testimony that was presented out of order, not in due time or due process, to delay dishing out justice, if that's the proper term. And I'm not trying to contradict your suggestion. I'm going to vote for your suggestion. I just wanted to speak out loud and say is this proper? Is this something that -- is it just to all parties? Shouldn't the intervenors today, shouldn't they have come on time and presented all their arguments on time so we could consider them during due process? That's the only, the only, the only issue I have, and I'm concerned with that. But as I said, I have no problem with delaying. Mr. Guyton said that he has no problem with delaying. But I wonder if in the future we should ask and request all intervenors to accommodate themselves to due process. Thank you, Madam Chair.

CHAIRMAN EDGAR: Thank you, Commissioner Arriaga. I hear you. I would perhaps suggest that this is not a delay in that it is a time frame that was laid out at the prehearing

conference and that the party, parties did agree to at that, at that time. I have shown some latitude in allowing comments today, and I would ask that our staff, you know, again review the record. And I think there may be some benefit in giving the opportunity for our staff and then for each of us to review the record and have a written recommendation come before us that, that may or may not, we'll see, address some of the comments that we have had today.

I would also note for the record that when this item does come back before us at Agenda Conference for a decision, that the record has been closed at that time and that there will not be the opportunity for further public testimony.

Ms. Brown, any further matters?

MS. BROWN: Nothing further that I'm aware of, Madam Chairman.

CHAIRMAN EDGAR: Okay. Commissioners, any other comments, questions, concerns?

MR. GUYTON: Commissioners, might I make just a brief comment?

CHAIRMAN EDGAR: Mr. Guyton.

MR. GUYTON: Seminole has asked me to thank and commend to the Commission the staff in this case. They have been diligent, they have pressed us on a few issues and we understand that responsibility, but they've been thoroughly professional in their, in their conduct in this case. And we

would be remiss if we didn't acknowledge Ms. Brown and Mr. Colson and numerous other people that we've had interaction with, and we appreciate the courtesy that we've been shown.

CHAIRMAN EDGAR: Mr. Guyton, thank you for those comments.

And with that, this hearing is concluded and we are adjourned.

(Hearing concluded at 12:35 p.m.)

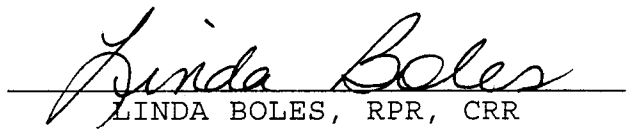
STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, 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' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 9TH DAY OF JUNE, 2006.



LINDA BOLES, RPR, CRR
FPSC Official Commission Reporter
(850) 413-6734

Comprehensive Exhibit List			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
Staff			
1		Comprehensive Exhibit List	Comprehensive Exhibit List
2		Composite Stip-2	SEC's responses to Staff's First Set of Interrogatories (Nos. 1-36)
			SEC's responses to Staff's First Request for Production of Documents (Nos. 1-8)
			Newspaper Notice and Affidavit of Publication by The Palatka Daily News
Testimony Exhibit List			
SEC			
3	Woodbury, Opalinski, Klover, Reid, Lawton, Novak, Mahaffey	SEC-1	Need Study and Appendices
4	Timothy S. Woodbury	TSW-1	Seminole's Member Distribution Cooperatives
5	Timothy S. Woodbury	TSW-2	Seminole's 2006 Capacity Resources
6	Timothy S. Woodbury	TSW-3	Seminole's Power Purchase Contracts with Renewable Resources
7	Timothy S. Woodbury	TSW-4	Seminole Power Purchase Contracts
8	Timothy S. Woodbury	TSW-5	Seminole Interconnections
9	Timothy S. Woodbury	TSW-6	Seminole Reliance Upon Natural Gas Generation

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060220-EC Exhibit No. 1
Company/ FPSC Staff
Witness: Comprehensive Exhibit List
Date: 6-07-06

Comprehensive Exhibit List			
Testimony Exhibit List			
SEC			
10	Mike Opalinski	MPO-1	Site Location Map – Putnam County
11	Mike Opalinski	MPO-2	Site Arrangement with SGS Unit 3
12	Mike Opalinski	MPO-3	SGS Unit 3 Project Capital Cost Components
13	Richard Klover	RAK-1	Summary of Richard Klover's Experience
14	Richard Klover	RAK-2	Summary of Burns & McDonnell Steam Electric Power Station Experience
15	Richard Klover	RAK-3	Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study, dated August 2004
16	Richard Klover	RAK-4	Seminole Generating Station 750 MW (Net) Solid Fuel Fired Unit Feasibility Study, Dated February 2005
17	Richard Klover	RAK-5	Seminole Generating Station Technology Assessment Study
18	Richard Klover	RAK-6	SGS Unit 3 Steam Cycle
19	Richard Klover	RAK-7	SGS Unit 3 Fact Sheet
20	Richard Klover	RAK-8	SGS Unit 3 Expected Construction Schedule

Comprehensive Exhibit List			
Testimony Exhibit List			
SEC			
21	Wm. Jack Reid	WJR-1	August 2003 Fuel Price Forecast
22	Wm. Jack Reid	WJR-2	April 2004 Fuel Price Forecast
23	Wm. Jack Reid	WJR-3	December 2004 Fuel Price Forecast
24	Wm. Jack Reid	WJR-4	August 2005 Fuel Price Forecast
25	Wm. Jack Reid	WJR-5	June 2005 Global Insights
26	Wm. Jack Reid	WJR-6	July 2005 Pace Global Energy Services Report
27	William (Bill) Lawton	WTL-1	Seminole's Member Distribution Cooperatives
28	William (Bill) Lawton	WTL-2	Seminole Electric History and Forecast Annual Energy (GWH), Winter Peak Demand (MW) and Summer Peak Demand (MW)
29	Trudy Novak	TSN-1	Seminole Electric Cooperative, Inc. History of Seminole's Formal Request for Proposals
30	Trudy Novak	TSN-2	Seminole Electric Cooperative, Inc. April 2004 Request for Proposals Direct Contact List
31	Trudy Novak	TSN-3	Seminole Electric Cooperative, Inc. April 2004 Request for Proposals Summary Responses

Comprehensive Exhibit List

Testimony Exhibit List

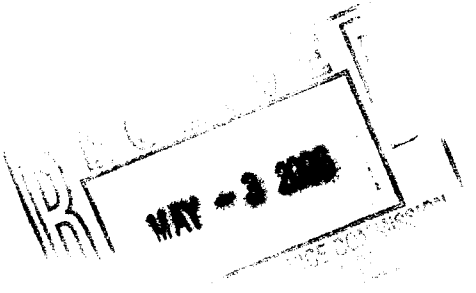
SEC			
32	Lane Mahaffey	LTM-1	Seminole's Capacity Need Without SGS Unit 3
33	Lane Mahaffey	LTM-2	Seminole Power Supply Resource Requirements
34	Lane Mahaffey	LTM-3	Summary of Bus Bar Costs
35	Lane Mahaffey	LTM-4	Present Worth Revenue Requirements Results
36	Lane Mahaffey	LTM-5	Cumulative and Annual PWRR Results
37	Public Testimony Rob Brinkman		testimony provided in North Carolina
38	Public Testimony of Susan Caplow		~~newspaper~~ NE journal of medicine + medical Resolutions
39	Public testimony Leon Jacobs		6/07/06 presentation before the Commissioners

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Seminole Generating Station Unit 3 electrical power plant in Putnam County, by Seminole Electric Cooperative, Inc.	)	**Docket No. 060220-EC**
	)	**Date: May 2, 2006**

SEMINOLE ELECTRIC COOPERATIVE INC.'S RESPONSE
TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-8)

Petitioner, Seminole Electric Cooperative, Inc. ("Seminole"), pursuant to Rule 28-106.106, Florida Administrative Code and Rule 1.350, Florida Rules of Civil Procedure, by and through its undersigned attorney, responds as follows to Staff's First Request for Production of Documents (Nos. 1-8).



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060220-EC Exhibit No. 2
Company/ FPSC Staff
Witness: Composite Stip-2
Date: 06-07-06

Q. **Regarding the economic assumptions in Appendix G of the application, please provide complete copies of all source documents, reports, etc. that support the selection of the assumed escalation rates, the 6.0 percent long term debt rate and the 6.0 percent AFUDC rate.**

A. Please see attached documents, at pages Bates numbered 00001-00008, which are responsive to the request. Included in the attached documents is a CD, numbered 00002, containing an Excel spreadsheet from Economy.com that reflects economic forecasts for the years 1970 to 2034. The data in this spreadsheet is printed and included in the attached documents at the pages numbered 00003-00008.

Description:	Interest Rates for 2005 SGS3 Base Case
Subschedule:	I1

Analyst:	J. Baker
File:	H:\Fin\SCM_subs\2006 cap impr loan\I1_interest_rat
Date:	12/01/05
Time:	08:57 AM

		Short-Term	Short-Term	Treasury Rates (4)					Long-Term Debt		PCRB	PCRB	CFC
YEAR	IPD (1)	Invstmt (2)	Debt (3)	3 month	5 Year	10 Year	20 Year	30 Year	RUS (5)	Non-RUS(6)	Wkly (7)	Semis (7)	Variable (8)
2004	2.10%	1.37%	2.12%	1.58%	3.43%	4.27%	4.67%	5.11%	6.00%	6.75%	1.26%	1.26%	2.33%
2005	2.60%	3.08%	3.83%	3.23%	4.39%	4.65%	5.05%	5.17%	6.00%	6.75%	2.58%	2.58%	3.98%
2006	2.60%	4.27%	5.02%	4.36%	5.45%	5.82%	6.22%	6.29%	6.00%	6.75%	3.49%	3.49%	5.11%
2007	2.40%	4.74%	5.49%	4.82%	5.50%	5.76%	6.16%	6.11%	6.00%	6.75%	3.86%	3.86%	5.57%
2008	2.00%	4.40%	5.15%	4.49%	5.25%	5.56%	5.96%	5.91%	6.00%	6.75%	3.59%	3.59%	5.24%
2009	2.00%	4.38%	5.13%	4.47%	5.40%	5.82%	6.22%	6.14%	6.00%	6.75%	3.58%	3.58%	5.22%
2010	2.00%	4.38%	5.13%	4.47%	5.42%	5.85%	6.25%	6.17%	6.00%	6.75%	3.58%	3.58%	5.22%
2011	2.00%	4.38%	5.13%	4.47%	5.32%	5.69%	6.09%	6.03%	6.00%	6.75%	3.58%	3.58%	5.22%
2012	1.90%	4.38%	5.13%	4.47%	5.35%	5.75%	6.15%	6.07%	6.00%	6.75%	3.58%	3.58%	5.22%
2013	1.90%	4.38%	5.13%	4.47%	5.36%	5.76%	6.16%	6.09%	6.00%	6.75%	3.58%	3.58%	5.22%
2014	1.90%	4.38%	5.13%	4.47%	5.36%	5.75%	6.15%	6.08%	6.00%	6.75%	3.58%	3.58%	5.22%
2015	1.90%	4.38%	5.13%	4.47%	5.37%	5.78%	6.18%	6.10%	6.00%	6.75%	3.58%	3.58%	5.22%
2016	1.80%	4.34%	5.09%	4.42%	5.38%	5.76%	6.16%	6.05%	6.00%	6.75%	3.54%	3.54%	5.17%
2017	1.80%	4.35%	5.10%	4.43%	5.34%	5.76%	6.16%	6.05%	6.00%	6.75%	3.54%	3.54%	5.18%
2018	1.80%	4.35%	5.10%	4.43%	5.34%	5.78%	6.18%	6.07%	6.00%	6.75%	3.54%	3.54%	5.18%
2019	1.80%	4.35%	5.10%	4.43%	5.36%	5.81%	6.21%	6.09%	6.00%	6.75%	3.54%	3.54%	5.18%
2020	1.80%	4.35%	5.10%	4.43%	5.37%	5.82%	6.22%	6.10%	6.00%	6.75%	3.54%	3.54%	5.18%
2021	1.80%	4.35%	5.10%	4.43%	5.38%	5.83%	6.23%	6.11%	6.00%	6.75%	3.54%	3.54%	5.18%
2022	1.80%	4.35%	5.10%	4.43%	5.39%	5.84%	6.24%	6.12%	6.00%	6.75%	3.54%	3.54%	5.18%
2023	1.80%	4.35%	5.10%	4.43%	5.39%	5.84%	6.24%	6.12%	6.00%	6.75%	3.54%	3.54%	5.18%
2024	1.80%	4.35%	5.10%	4.43%	5.38%	5.84%	6.24%	6.12%	6.00%	6.75%	3.54%	3.54%	5.18%
2025	1.80%	4.35%	5.10%	4.43%	5.38%	5.82%	6.22%	6.11%	6.00%	6.75%	3.54%	3.54%	5.18%
2026	1.80%	4.35%	5.10%	4.43%	5.38%	5.82%	6.22%	6.11%	6.00%	6.75%	3.54%	3.54%	5.18%
2027	1.80%	4.35%	5.10%	4.43%	5.37%	5.81%	6.21%	6.10%	6.00%	6.75%	3.54%	3.54%	5.18%
2028	1.80%	4.35%	5.10%	4.43%	5.37%	5.81%	6.21%	6.10%	6.00%	6.75%	3.54%	3.54%	5.18%
2029	1.80%	4.35%	5.10%	4.43%	5.36%	5.81%	6.21%	6.12%	6.00%	6.75%	3.54%	3.54%	5.18%
2030	1.70%	4.35%	5.10%	4.43%	5.35%	5.80%	6.20%	6.12%	6.00%	6.75%	3.54%	3.54%	5.18%

Discount Rate/AFUDC (average over projection period of 2004-2030) 6.00%

Note: The source for all Debt & Investment Rates and IPD Rates is Economy.com with a vintage of May 2005.

(1) The IPD rates are from Corporate Modeling Assumption IPDcomparison.xls.

(2) The Short-term Investment rate is the same as the 3-month Treasury rate.

(3) The Short-term Debt rate is the Short-term Investment rate plus 75 basis points.

(4) The 2004-2021 Treasury Rates as provided by B. Lawton via e-mail, with the exception of the 20-year rate. 2022-2030 are extensions of 2021. The 2004-2030 20-year rates are calculated as the 10-year rate plus 40 basis points (based on historical trend). Historical rates for 3-month (secondary market), 5-year, 10-year, 20-year, and 30-year are from Federal Reserve Statistical Releases (see FM-F2920).

(5) The RUS Long-term Debt rate is the RUS recommended rate for projections, which is present FFB rate plus 1/4 percent. However, since this rate changes every day, and after discussions with RUS, Seminole will use 6% for long-term debt.

(6) The Non-RUS Long-term Debt rate is the RUS Long-term Debt rate plus 75 basis points.

(7) The 2004-2030 PCRB Weekly and Semi (weighted average) rates are 80% of the 3-month Treasury rates. Historical rates are from FM-R39.

(8) The CFC Variable rate is equal to the Short-term Debt.

Assumptions regarding refinancing existing FFB Debt (G-8):

Each of the following is assumed to be refinanced at a fixed-to-final maturity interest rate:

06/30/2008 Refinancing: There are 11 full years remaining to final maturity in 2019. The rate will be an interpolation of the 2008 10-year and 20-year Treasury rates based on years to final maturity plus an 1/8, or

(5.96% - 5.56%)/10 years x 1 year = 0.04% + 5.56% + 0.125% = 5.73%

06/30/2009 Refinancing: There are 10 full years remaining to final maturity in 2019. The rate will be the 2009 10-year Treasury rate plus an 1/8, or

5.82% + 0.125% = 5.95%

06/30/2010 Refinancing: There are 9 full years remaining to final maturity in 2019. The rate will be an interpolation of the 2010 5-year and 10-year Treasury rates based on years to final maturity plus and 1/8, or

(5.85% - 5.42%)/5 years x 4 years = 0.34% + 5.42% + 0.13% = 5.89%

Developed by: J. Baker Date: 6/29/2004

Final Approval by: _____ Date: _____

Sources: FRB, BLS, BEA, Federal Reserve Board

Mnemonic:	Concept:	Description:	Geography:	Dec-1965	Dec-1966	Dec-1967	Dec-1968	Dec-1969
FRTB3M.US	FRTB3M	3-Month T-Bill, (%)	United States	3.95	4.86	4.31	5.34	6.67
FRTB6M.US	FRTB6M	Interest Rates: 6-Month Treasury Bills - Secondary Market, (% P.A.)	United States	4.05	5.06	4.62	5.47	6.86
FRGT5Y.US	FRGT5Y	Interest Rates: 5-Year Constant Maturity Securities, (% P.A.)	United States	4.25	5.10	5.11	5.70	6.93
FRGT10Y.US	FRGT10Y	Interest Rates: 10-Year Constant Maturity Securities, (% P.A.)	United States	4.28	4.92	5.07	5.65	6.67
FRGT30Y.US	FRGT30Y	Interest Rates: 30-Year Constant Maturity Securities, (% P.A.)	United States	na	na	na	na	na
FRTB12MEBY.US	FRTB12MEBY	12-month T-Bill EBY, (%)	United States	4.34	5.49	5.15	6.03	7.64
FCPIU.US	FCPIU	CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)	United States	31.53	32.47	33.38	34.79	36.68
FPDIGDP.US	FPDIGDP	NIPA: Implicit price deflator - GDP, (Index 2000=100)	United States	22.53	23.17	23.89	24.91	26.15
FRILIBOR6M.US	FRILIBOR6M	LIBOR Rates: 6-Month US Dollar Deposits, (%, NSA)	United States	5.01	6.25	5.69	6.49	9.71
FRILIBOR12M.US	FRILIBOR12M	LIBOR Rates: 1-Year US Dollar Deposits, (%, NSA)	United States	na	na	na	na	na
FRBB20Q.US	FRBB20Q	Bond Buyer Index: General Obligation 20-Years to Maturity, (%)	United States	3.26	3.81	3.94	4.45	5.72

Dec-1970	Dec-1971	Dec-1972	Dec-1973	Dec-1974	Dec-1975	Dec-1976	Dec-1977	Dec-1978	Dec-1979	Dec-1980	Dec-1981	Dec-1982	Dec-1983
6.39	4.33	4.07	7.03	7.83	5.78	4.97	5.27	7.19	10.07	11.43	14.02	10.61	8.61
6.51	4.51	4.48	7.20	7.94	6.09	5.25	5.53	7.58	10.06	11.36	13.80	11.07	8.73
7.38	5.99	5.98	6.87	7.80	7.77	7.18	6.99	8.32	9.52	11.48	14.24	13.01	10.80
7.35	6.16	6.21	6.84	7.56	7.99	7.61	7.42	8.41	9.44	11.46	13.91	13.00	11.10
na	na	na	na	na	na	na	7.74	8.49	9.29	11.30	13.44	12.76	11.18
7.39	5.14	5.23	7.86	8.85	7.23	6.24	6.48	9.04	11.78	13.49	16.92	13.78	10.48
38.84	40.48	41.81	44.43	49.32	53.82	56.93	60.62	65.24	72.58	82.38	90.93	96.53	99.58
27.53	28.91	30.16	31.85	34.73	37.99	40.19	42.74	45.74	49.54	54.04	59.12	62.73	65.19
8.91	7.11	6.00	9.40	10.84	7.75	6.12	6.37	9.20	12.15	14.03	16.72	13.60	9.93
na	na	na	na	na	na	na	6.87	9.30	11.70	13.44	15.88	13.69	10.18
6.33	5.47	5.26	5.19	6.17	7.05	6.64	5.68	6.02	6.52	8.59	11.33	11.66	9.51

Dec-1984	Dec-1985	Dec-1986	Dec-1987	Dec-1988	Dec-1989	Dec-1990	Dec-1991	Dec-1992	Dec-1993	Dec-1994	Dec-1995	Dec-1996	Dec-1997
9.52	7.48	5.98	5.77	6.67	8.11	7.49	5.37	3.43	3.00	4.25	5.49	5.01	5.06
9.76	7.65	6.03	6.03	6.91	8.03	7.45	5.44	3.55	3.12	4.63	5.57	5.08	5.18
12.24	10.13	7.31	7.93	8.47	8.50	8.37	7.37	6.19	5.15	6.68	6.39	6.18	6.22
12.44	10.62	7.68	8.38	8.85	8.50	8.55	7.86	7.01	5.87	7.08	6.58	6.44	6.35
12.39	10.79	7.80	8.58	8.96	8.45	8.61	8.14	7.67	6.60	7.37	6.88	6.70	6.61
12.05	9.13	6.90	7.23	8.24	9.26	8.51	6.22	4.06	3.58	5.62	6.32	5.83	5.96
103.93	107.60	109.69	113.62	118.28	123.94	130.66	136.17	140.31	144.47	148.23	152.38	156.86	160.52
67.65	69.71	71.25	73.19	75.68	78.55	81.59	84.44	86.38	88.38	90.25	92.10	93.85	95.41
11.29	8.64	6.85	7.30	8.13	9.27	8.35	6.08	3.90	3.41	5.07	6.10	5.59	5.86
11.82	9.11	6.95	7.61	8.41	9.31	8.45	6.29	4.20	3.64	5.59	6.25	5.78	6.08
10.10	9.10	7.32	7.64	7.68	7.23	7.27	6.92	6.44	5.60	6.18	5.95	5.76	5.52

Dec-1998	Dec-1999	Dec-2000	Dec-2001	Dec-2002	Dec-2003	Dec-2004	Dec-2005	Dec-2006	Dec-2007	Dec-2008	Dec-2009	Dec-2010	Dec-2011
4.78	4.64	5.82	3.39	1.60	1.01	1.37	3.08	4.27	4.74	4.40	4.38	4.38	4.38
4.83	4.75	5.90	3.33	1.68	1.05	1.58	3.23	4.36	4.82	4.49	4.47	4.47	4.47
5.15	5.54	6.15	4.55	3.81	2.97	3.43	4.39	5.45	5.50	5.25	5.40	5.42	5.32
5.26	5.64	6.03	5.02	4.61	4.01	4.27	4.65	5.82	5.76	5.56	5.82	5.85	5.69
5.57	5.87	5.94	5.49	5.42	5.05	5.11	5.17	6.29	6.11	5.91	6.14	6.17	6.03
5.33	5.34	6.50	3.63	2.06	1.27	1.80	3.69	4.98	5.52	5.11	5.07	5.06	5.06
163.01	166.58	172.19	177.07	179.84	183.96	188.89	193.85	198.71	204.07	208.98	213.87	218.89	223.92
96.47	97.86	100.00	102.40	104.09	105.99	108.23	111.00	113.87	116.58	118.91	121.30	123.71	126.16
5.56	5.53	6.65	3.72	1.89	1.23	1.79	3.60	4.80	5.26	4.93	4.93	4.93	4.93
5.57	5.71	6.86	3.85	2.21	1.36	2.11	3.94	5.19	5.71	5.32	5.28	5.27	5.27
5.09	5.43	5.71	5.15	5.04	4.75	4.68	4.72	5.75	5.69	5.45	5.59	5.61	5.50

Dec-2012	Dec-2013	Dec-2014	Dec-2015	Dec-2016	Dec-2017	Dec-2018	Dec-2019	Dec-2020	Dec-2021	Dec-2022	Dec-2023	Dec-2024	Dec-2025
4.38	4.38	4.38	4.38	4.34	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35
4.47	4.47	4.47	4.47	4.42	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43
5.35	5.36	5.36	5.37	5.38	5.34	5.34	5.36	5.37	5.38	5.39	5.39	5.38	5.38
5.75	5.76	5.75	5.78	5.76	5.76	5.78	5.81	5.82	5.83	5.84	5.84	5.84	5.82
6.07	6.09	6.08	6.10	6.05	6.05	6.07	6.09	6.10	6.11	6.12	6.12	6.12	6.11
5.06	5.06	5.06	5.06	5.06	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07
229.02	234.22	239.47	244.80	250.16	255.61	261.12	266.76	272.54	278.39	284.30	290.28	296.35	302.48
128.55	130.99	133.42	135.90	138.39	140.90	143.46	146.03	148.66	151.40	154.18	156.99	159.85	162.73
4.93	4.93	4.93	4.93	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91
5.27	5.27	5.27	5.27	5.27	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28
5.53	5.52	5.50	5.50	5.40	5.38	5.39	5.40	5.40	5.39	5.40	5.39	5.38	5.37

Dec-2026	Dec-2027	Dec-2028	Dec-2029	Dec-2030	Dec-2031	Dec-2032	Dec-2033	Dec-2034
4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35
4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43
5.38	5.37	5.37	5.36	5.35	5.34	5.33	5.30	5.27
5.82	5.81	5.81	5.81	5.80	5.80	5.78	5.77	5.75
6.11	6.10	6.10	6.12	6.12	6.12	6.10	6.09	6.07
5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07
308.79	315.16	321.66	328.30	335.03	341.88	348.86	356.03	363.38
165.67	168.61	171.59	174.63	177.67	180.75	183.88	187.09	190.39
4.91	4.91	4.91	4.91	4.91	4.91	4.94	4.94	4.94
5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28
5.37	5.37	5.36	5.35	5.34	5.33	5.32	5.31	5.30

Q. Please provide a complete copy of Seminole's most recent registration statement/documents for the issuance of securities.

A. Seminole has not issued securities requiring a registration statement under the Securities Act of 1933.

Q. Please provide complete copies of all credit/bond rating reports for Seminole done by Standard & Poor's, Moody's, or Fitch since January 1, 2004.

A. Please see attached documents, at the pages Bates numbered 00009-00031, which are responsive to the request.

STANDARD
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Corporate & Government
55 Water Street
New York, NY 10041-0003

November 23, 2005

Tim Rogers
Director of Treasury Services
Seminole Electric Cooperative
16313 North Dale Mabry Highway
PO Box 272000
Tampa, FL 33688-0994

Re: ***Seminole Electric Cooperative***
$300,000,000 Senior Notes, Series A, Due 2024, Series B Due 2033, Series C Due 2035

Dear Mr. Rogers:

Pursuant to your request for a Standard & Poor's rating on the above-referenced obligations, we have reviewed the information submitted to us and, subject to the enclosed *Terms and Conditions*, have assigned a preliminary ratings of "BBB+". Standard & Poor's views the outlook for these ratings as Stable.

The rating is not investment, financial, or other advice and you should not and cannot rely upon the rating as such. The rating is based on information supplied to us by you or by your agents but does not represent an audit. We undertake no duty of due diligence or independent verification of any information. The assignment of a rating does not create a fiduciary relationship between us and you or between us and other recipients of the rating. We have not consented to and will not consent to being named an "expert" under the applicable securities laws, including without limitation, Section 7 of the U.S. Securities Act of 1933. The rating is not a "market rating" nor is it a recommendation to buy, hold, or sell the obligations.

This letter constitutes Standard & Poor's permission to you to disseminate the above-assigned rating to interested third parties on a confidential basis but only in accordance with applicable law and only if a copy of this rating letter is provided in its entirety to such third parties. Since you have requested a confidential rating, the rating will not be published by Standard & Poor's unless you authorize its publication or it otherwise becomes public.

Standard & Poor's relies on the issuer and its counsel, accountants, and other experts for the accuracy and completeness of the information submitted in connection with the rating. This rating is based on financial information and documents we received prior to the issuance of this letter. Standard & Poor's assumes that the documents you have provided to us are final.

If any subsequent changes were made in the final documents, you must notify us of such changes by sending us the revised final documents with the changes clearly marked.

To maintain the rating, Standard & Poor's must receive all relevant financial information as soon as such information is available. Placing us on a distribution list for this information would facilitate the process. You must promptly notify us of all material changes in the financial information and the documents. Standard & Poor's may change, suspend, withdraw, or place on CreditWatch the rating as a result of changes in, or unavailability of, such information. Standard & Poor's reserves the right to request additional information, if necessary, to maintain the rating. Please send all information to Jodi Hecht at Standard & Poor's Corporate Ratings, 55 Water Street, New York, NY 10041.

Standard & Poor's is pleased to have the opportunity to be of service to you. For more information please visit our website at www.standardandpoors.com. If we can be of help in any other way, please contact us. Thank you for choosing Standard & Poor's and we look forward to working with you again.

Very truly yours,

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Terms and Conditions
Applicable To
U.S. Corporate Ratings

Scope of Rating. The Company understands and agrees that (i) an issuer rating reflects Standard & Poor's current opinion of the Company's overall financial capacity to pay its financial obligations as they come due, (ii) an issue rating reflects Standard & Poor's current opinion of the likelihood that the Company will make payments of principal and interest on a timely basis in accordance with the terms of the obligation, (iii) a rating is an opinion and is not a verifiable statement of fact, (iv) ratings are based on information supplied to Standard & Poor's by the Company or by its agents and upon other information obtained by Standard & Poor's from other sources it considers reliable, (v) Standard & Poor's does not perform an audit in connection with any rating and a rating does not represent an audit by Standard & Poor's, (vi) Standard & Poor's relies on the Company, its accountants, counsel, and other experts for the accuracy and completeness of the information submitted in connection with the rating and surveillance process, (vii) Standard & Poor's undertakes no duty of due diligence or independent verification of any information, (viii) Standard & Poor's does not and cannot guarantee the accuracy, completeness, or timeliness of the information relied on in connection with a rating or the results obtained from the use of such information, (ix) Standard & Poor's may raise, lower, suspend, place on CreditWatch, or withdraw a rating at any time, in Standard & Poor's sole discretion, and (x) a rating is not a "market" rating nor a recommendation to buy, hold, or sell any financial obligation.

Publication. Standard & Poor's reserves the right to publish, disseminate, or license others to publish or disseminate the rating and the rationale for the rating unless the Company specifically requests that the rating be assigned and maintained on a confidential basis. If a confidential rating subsequently becomes public through disclosure by the Company or a third party other than Standard & Poor's, Standard & Poor's reserves the right to publish it. As a matter of policy, Standard & Poor's publishes ratings for all public issues in the U.S. market and 144A issues with registration rights. Standard & Poor's may publish explanations of Standard & Poor's ratings criteria from time to time and nothing in this Agreement shall be construed as limiting Standard & Poor's ability to modify or refine Standard & Poor's criteria at any time as Standard & Poor's deems appropriate.

Information to be Provided by the Company. The Company shall meet with Standard & Poor's for an analytic review at any reasonable time Standard & Poor's requests. The Company also agrees to provide Standard & Poor's promptly with all information relevant to the rating and surveillance of the rating including information on material changes to information previously supplied to Standard & Poor's. The rating may be affected by Standard & Poor's opinion of the accuracy, completeness, timeliness, and reliability of information received from the Company or its agents. Standard & Poor's undertakes no duty of due diligence or independent verification of information provided by the Company or its agents. Standard & Poor's reserves the right to withdraw the rating if the Company or its agents fails to provide Standard & Poor's with accurate, complete, timely, or reliable information.

Confidential Information. For purposes of this Agreement, "Confidential Information" shall mean information received by Standard & Poor's from the Company which has been marked "Proprietary and Confidential" or in respect of which Standard & Poor's has received from the Company specific written notice of its proprietary and confidential nature. Notwithstanding the foregoing, information disclosed by the Company shall not be deemed to be Confidential Information, and Standard & Poor's shall have no obligation to treat such information as Confidential Information, if such information (i) was substantially known by Standard & Poor's at the time of such disclosure, (ii) was known to the public at the time of such disclosure, (iii) becomes known to the public (other than by Standard & Poor's act) subsequent to such disclosure, (iv) is disclosed lawfully to Standard & Poor's by a third party subsequent to such disclosure, (v) is developed independently by Standard & Poor's without reference to the Confidential Information, (vi) is approved in writing by the Company for public disclosure, or (vii) is required by law to be disclosed by the Company or Standard &

Poor's provided that notice of such required disclosure is given to the Company. Commencing on the date hereof, Standard & Poor's will use Confidential Information only in connection with the assignment and monitoring of ratings and will not directly disclose any Confidential Information to any third party. Standard & Poor's may also use Confidential Information for research and modeling purposes provided that the Confidential Information is not presented in a way that can be directly tied to the Company. The Company agrees that the Confidential Information may be used to raise, lower, suspend, withdraw, place on CreditWatch, and change the Outlook assigned to any rating if the Confidential Information is not directly disclosed.

Standard & Poor's Not an Advisor, Fiduciary, or Expert. The Company understands and agrees that Standard & Poor's is not acting as an investment, financial, or other advisor to the Company and that the Company should not and cannot rely upon the rating or any other information provided by Standard & Poor's as investment or financial advice. Nothing in this Agreement is intended to or should be construed as creating a fiduciary relationship between Standard & Poor's and the Company or between Standard & Poor's and recipients of the rating. The Company understands and agrees that Standard & Poor's has not consented to and will not consent to being named an "expert" under the applicable securities laws, including without limitation, Section 7 of the U S Securities Act of 1933.

Limitation on Damages. The Company agrees that Standard & Poor's, its officers, directors, shareholders, and employees shall not be liable to the Company or any other person for any actions, damages, claims, liabilities, costs, expenses, or losses in any way arising out of or relating to the rating or the related analytic services provided for in an aggregate amount in excess of the aggregate fees paid to Standard & Poor's for the rating, except for Standard & Poor's gross negligence or willful misconduct. In no event shall Standard & Poor's, its officers, directors, shareholders, or employees be liable for consequential, special, indirect, incidental, punitive or exemplary damages, costs, expenses, legal fees, or losses (including, without limitation, lost profits and opportunity costs). In furtherance and not in limitation of the foregoing, Standard & Poor's will not be liable in respect of any decisions made by the Company or any other person as a result of the issuance of the rating or the related analytic services provided by Standard & Poor's hereunder or based on anything that appears to be advice or recommendations. The provisions of this paragraph shall apply regardless of the form of action, damage, claim, liability, cost, expense, or loss, whether in contract, statute, tort (including, without limitation, negligence), or otherwise. The Company acknowledges and agrees that Standard & Poor's does not waive any protections, privileges, or defenses it may have under law, including but not limited to, the First Amendment of the Constitution of the United States of America.

Term. This Agreement shall terminate when the ratings are withdrawn. Notwithstanding the foregoing, the paragraphs above, "Confidential Information", "Standard & Poor's Not an Advisor, Fiduciary, or Expert", and "Limitation on Damages", shall survive the termination of this Agreement or any withdrawal of a rating.

Third Parties. Nothing in this Agreement, or the rating when issued, is intended or should be construed as creating any rights on behalf of any third parties, including, without limitation, any recipient of the rating. No person is intended as a third party beneficiary to this Agreement or to the rating when issued.

Binding Effect. This Agreement shall be binding on, and inure to the benefit of, the parties hereto and their successors and assigns.

Severability. In the event that any term or provision of this Agreement shall be held to be invalid, void, or unenforceable, then the remainder of this Agreement shall not be affected, impaired, or invalidated, and each such term and provision shall be valid and enforceable to the fullest extent permitted by law.

Complete Agreement. This Agreement constitutes the complete agreement between the parties with respect to its subject matter. This Agreement may not be modified except in a writing signed by authorized representatives of both parties.

Governing Law. This Agreement and the rating letter shall be governed by the internal laws of the State of New York. The parties agree that the state and federal courts of New York shall be the exclusive forums for any dispute arising out of this Agreement and the parties hereby consent to the personal jurisdiction of such courts.

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Ratings Services
55 Water Street
New York, NY 10041-0003

December 22, 2005

Tim Rogers
Director of Treasury Services
Seminole Electric Cooperative
16313 North Dale Mabry Highway
PO Box 272000
Tampa, FL 33688-0994

Re: ***Seminole Electric Cooperative***
$300,000,000 Senior Notes, Series A, Due 2024, Series B Due 2033, Series C Due 2035

Dear Rogers:

Pursuant to your request for a Standard & Poor's rating on the above-referenced obligations, we have reviewed the information submitted to us and, subject to the enclosed *Terms and Conditions*, have assigned a rating of "BBB+". Standard & Poor's views the outlook for this rating as Stable.

The rating is not investment, financial, or other advice and you should not and cannot rely upon the rating as such. The rating is based on information supplied to us by you or by your agents but does not represent an audit. We undertake no duty of due diligence or independent verification of any information. The assignment of a rating does not create a fiduciary relationship between us and you or between us and other recipients of the rating. We have not consented to and will not consent to being named an "expert" under the applicable securities laws, including without limitation, Section 7 of the U.S. Securities Act of 1933. The rating is not a "market rating" nor is it a recommendation to buy, hold, or sell the obligations.

This letter constitutes Standard & Poor's permission to you to disseminate the above-assigned rating to interested third parties on a confidential basis but only in accordance with applicable law and only if a copy of this rating letter is provided in its entirety to such third parties. Since you have requested a confidential rating, the rating will not be published by Standard & Poor's unless you authorize its publication or it otherwise becomes public.

Standard & Poor's relies on the issuer and its counsel, accountants, and other experts for the accuracy and completeness of the information submitted in connection with the rating. This rating is based on financial information and documents we received prior to the issuance of this letter. Standard & Poor's assumes that the documents you have provided to us are final.

If any subsequent changes were made in the final documents, you must notify us of such changes by sending us the revised final documents with the changes clearly marked.

To maintain the rating, Standard & Poor's must receive all relevant financial information as soon as such information is available. Placing us on a distribution list for this information would facilitate the process. You must promptly notify us of all material changes in the financial information and the documents. Standard & Poor's may change, suspend, withdraw, or place on CreditWatch the rating as a result of changes in, or unavailability of, such information. Standard & Poor's reserves the right to request additional information, if necessary, to maintain the rating. Please send all information to Jodi Hecht at Standard & Poor's Corporate Ratings, 55 Water Street, New York, NY 10041

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RESEARCH

Research Update: Seminole Electric's $300 Million Notes Rated 'BBB+'

Publication date: 11-Jan-2006
Primary Credit Analyst: Jodi E Hecht, New York (1) 212-438-2019; jodi_hecht@standardandpoors.com

Credit Rating: A-/Stable/--

Rationale

On Jan. 11, 2006, Standard & Poor's Ratings Services assigned its 'BBB+' rating to electric utility Seminole Electric Cooperative Inc.'s $300 million senior notes.

The outlook is stable. As of Sept. 30, 2005, the Tampa, Fla.-based cooperative had $730 million of debt outstanding.

The unsecured notes are notched down from Seminole's 'A-' corporate credit rating because a significant amount of the company's assets collateralize first priority debt, therefore placing the unsecured bondholders at a disadvantage. If Seminole opts to secure these notes on a parity lien with its existing first mortgage debt, pending the Rural Utility Service's (RUS) approval of the lien accommodation application, then the rating on the notes will be raised to 'A-', reflecting the improvement in bondholder security.

The ratings on Seminole reflect the following credit strengths:

- A strong capacity to meet financial obligations through take-or-pay all-requirements wholesale power agreements with the 10 member distribution cooperatives located throughout Florida.
- A primarily residential revenue stream, accounting for 70% of the distribution cooperatives' retail sales. Residential customers provide stable revenue and, due to their low load factors, are not attractive targets for alternative energy providers in a competitive environment.
- Solid historical growth in electric demand and energy sales averaging annual 2.3% and 5.3%, respectively, during 2000-2004. Seminole projects that future growth will remain strong at 4.2% per year over the next 10 years.
- Below average wholesale energy rates, despite recent increases due to rising fuel costs. In addition, the member weighted average retail residential rates are slightly above the state average.
- Financially strong member distribution cooperatives.

These strengths are tempered by the following:

- Concentration of power supply in two owned and leased coal-fired facilities comprising 60% of the members' energy needs,
- Material counterparty credit exposure to Calpine Corp. (D/--/--) and Reliant Energy Inc. (B+/Watch Neg/B-2), and
- Weak financials, with debt service coverage projected to range from 1.05x to 1.08x and below average levels of liquidity.

The rating also reflects the cooperative's weak financial projections despite implementation of its equity development plan. The plan only slightly improves projected debt service coverage that continues to be at the lower end of the rating expectations.

Seminole is a generation and

transmission cooperative serving 805,000 retail customers through its 10 distribution cooperatives that serve portions of 45 counties throughout Florida. Debt service and lease obligations are paid from revenues generated under all-requirements wholesale power contracts.

An ongoing credit concern continues to be dissonance among some of the cooperative's key members. While Seminole benefits from a very sophisticated management team, the ongoing member discord presents challenges that limit the cooperative's operational and financial flexibility. Seven of the 10 members (representing 56% of load) extended the contract until 2045, providing Seminole with some certainty to advance long-term power supply planning. Two remaining members (23% of load) are expected to sign extensions that provide all of the members the choice to find alternative energy suppliers for incremental energy needs after 2020 while still paying capacity charges under the existing take-or-pay contracts.

The last member, Lee County Electric Cooperative, a member representing 23% of the cooperative's load, is also considering the extension if it provides for member choice. While the loss of Lee County after 2020, would reduce some of Seminole's revenue and load diversity, the loss is not projected to increase costs for remaining members. Significant reliance on purchased power tempers the exposure to increased fixed costs because purchased power can be reduced should load be lost. Furthermore, the proposed new generation projects would still be needed to meet the remaining members' projected load growth.

Future power needs will continue to be met through a combination of new construction and purchased power. Some of the new construction projects increase Seminole's risk profile. The near-term 2006 load need will be met through new purchased-power contracts and construction of 310 MW combustion turbine units, which should not increase risk. However, the board-approved 750 MW pulverized coal plant does introduce more risk to the cooperative. Seminole will oversee the construction process and assume the risk of financial overruns and construction delays. The cooperative will make a final decision on the project in 2007 based on the ability to complete the permitting and obtain approvals needed for construction.

Seminole, which sets its own rates, budgets for narrow excess financial margins. It adopted a policy to set rates to provide 1.05x debt service coverage, slightly above the level required under the mortgage granted to RUS and National Rural Utilities Cooperative Finance Corp. The cash-basis debt service coverage was a slim 1.11x for the 12 months ended Sept. 30, 2005, which is low for the rating category. Debt service coverage improved slightly from 1.0x in the quarter ended June 30, 2005 as higher revenues from the three approved 2005 fuel surcharge increases were collected.

Liquidity

Concerns over thin margins exist because Seminole is forecasting low levels of liquidity through 2010, with days' cash ranging from about two weeks to just over one month. Days' cash improves to over 45 days when the $50 million of committed lines of credit are considered. The cooperative is planning on increasing the lines of credit to $150 million, which is expected to improve liquidity to over 70 days cash. In addition, Seminole's liquidity will improve when it begins drawing on the $136.4 million RUS loan approved to fund the 310 MW combustion turbine project, allowing the cooperative to reimburse itself for cash funded project costs.

Outlook

The stable outlook on Seminole reflects continued strong growth and slight increases in wholesale rates. Rating stability also depends on the utility maintaining adequate liquidity for construction and rising fuel costs, especially given the cooperative's lag in collecting revenues from automatic fuel adjustments. The rating could be lowered if member discord results in reduced revenue flexibility, weaker contracts, or diminished

load diversity. An outlook change to positive, which is less likely, will require additional financial improvement with no meaningful increase in business risk.

Ratings List

Seminole Electric Cooperative Inc.	
Corporate credit rating	A-/Stable/--
Rating Assigned	
$300 million senior notes	BBB+

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Standard and Poors Research:

Summary: Seminole Electric Coop

Publication date:	31-May-2005
Primary Credit Analyst(s):	Jodi E Hecht, New York (1) 212-438-2019; jodi_hecht@standardandpoors.com
Secondary Credit Analyst(s):	Judith Waite, New York (1) 212-438-7677; judith_waite@standardandpoors.com

Credit Rating: A/Negative/--

Rationale

The 'A' issuer credit rating for Seminole Electric Cooperative, Fla. reflects the following credit strengths:

- A strong capacity to meet financial obligations through "all-requirements" wholesale power agreements with the 10 member distribution cooperatives located throughout Florida;
- A primarily residential revenue stream, accounting for 70% of the distribution cooperatives' retail sales. Due to their low load factors, residential customers are not attractive targets for alternative energy providers in a competitive environment;
- Solid historical growth in electric demand and energy sales averaging an annual 2.3% and 5.3%, respectively, between 2000 and 2004. Seminole projects that future growth will remain strong at 4.2% per year over the next 10 years; and
- Low debt levels with low debt per kilowatt of installed generation of $398.

These strengths are tempered by:

- Concentration in two owned and leased coal-fired facilities that provide 60% of the members' energy needs,
- Management's ability to address the divergent needs of the members, and
- Narrow financial margins.

Seminole sells energy under all-requirements contracts to 10 distribution cooperatives that serve portions of 45 counties throughout peninsular Florida. Debt and contractual obligations are satisfied with revenues received through the sale of electricity to the distribution cooperatives under the wholesale power contract (WPC). Although the WPC expires in 2020, seven of the 10 members extended the contract until 2045, providing Seminole with some financial certainty to advance long-term power supply planning.

As of March 31, 2005, the Tampa, Fla.-based electric cooperative had about $705 million in total debt outstanding.

Electricity sales to members totaled about 15,601 gigawatt-hours in 2004, which placed Seminole among the nation's five-largest generation and transmission cooperatives.

Seminole owns 1,827 MW of efficient base and intermediate load, generating winter capacity that has historically exhibited reliable performance at moderate production costs. The cooperative supplements its installed generation with higher-cost power purchased to meet demand peaks and load shaping. About one-quarter of Seminole's energy needs are typically met with purchased power. The cost of self-generation and purchased power blended into a competitive average wholesale rate of 56.16 mills per kWh in 2004. This rate compares favorably with regional wholesale providers. Current rates are expected to increase over the near-to-intermediate term as gas prices remain elevated and power supply resources are added to the portfolio.

Future power needs will continue to be met through a combination of installed generation and purchased-power contracts. The addition of new purchased-power contracts and completion of construction of its 310 MW of combustion turbine units in late 2006 will satisfy the projected 2006 load. In addition, SEC is in the initial licensing and engineering phase of a new 750 MW coal fired plant to be sited at one of its existing sites. The $1.2 billion project, which is expected on line by 2012, is needed to meet the projected needs of its members, even if the remaining three members do not extend its WPC beyond 2020.

Currently, no member has advised Seminole of its desire to leave the system, possibly because of the uncertainty in the national wholesale markets and Seminole management's focus on addressing members' needs. However, an ongoing credit concern continues to be member discord among some of the cooperative's key members. Recently, two members, Clay Electric and Lee County Electric Seminole, filed a civil suit against Seminole. The suit involves Seminole's wholesale rate structure, as approved by its board. While Seminole benefits from a very sophisticated management team, the ongoing member discord presents challenges that could limit the cooperative's rate-setting flexibility, affecting its financial margins going forward. Moreover, a member's departure could impair the cooperative's revenue stream or drive costs up for remaining members. Yet, significant reliance on purchased power helps temper this exposure because market power purchases can be reduced if load is lost.

Seminole, which sets its own rates, budgets for narrow excess financial margins. The mortgage granted by Seminole to the U.S. Rural Utilities Service and National Rural Utilities Cooperative Finance Corp. merely requires that Seminole set rates to produce margins that provide a debt-service coverage ratio of at least 1.0x and a times interest earned coverage ratio of 1.05x. The cooperative continues to meet these covenant requirements. However, cash-basis debt service coverage was only marginally above 1.13x in 2004, which is low for the rating category. Concerns over thin margins exist because Seminole is forecasting low levels of liquidity through 2010, with a cash supply ranging from about two weeks to just over one month. That improves to more than 30 days when the $50 million of committed lines of credit are considered. The period with higher levels of liquidity is forecast during the construction of its combustion turbine project.

Outlook

The negative outlook reflects expectations that Seminole's issuer credit rating could be lowered if financial margins remain at break-even levels and if member discord results in reduced rate-setting flexibility or weaker contracts.

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Research:

Research Update: Seminole Electric Coop Issuer Credit Rati To 'A-'; Outlook Stable

Publication date: 29-Jul-2005

Primary Credit Analyst(s): Jodi E Hecht, New York (1) 212-438-2019;mailto:jodi_hecht@standardandpoo

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• Outlook
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• Glossary of Terms

Credit Rating: A-/Stable/--

RatingsDirect Alert Manager Tutorial

Rationale

On July 29, 2005, Standard & Poor's Ratings Services lowe credit rating on the Florida electric utility, Seminole E Cooperative, to 'A-' from 'A'. The outlook is stable.

As of March 31, 2005, the Tampa, Fla.-based electric about $705 million in total debt outstanding.

The rating action reflects the cooperative's weak fi projections despite implementation of its equity developm plan only slightly improves projected debt service covera to be at the lower end of the rating expectations.

The 'A-' rating reflects the following credit streng

- A strong capacity to meet financial obligations thro all-requirements wholesale power agreements with the distribution cooperatives located throughout Florida
- A primarily residential revenue stream, accounting f distribution cooperatives' retail sales. Residential provide stable revenue and, due to their low load fa attractive targets for alternative energy providers environment.
- Solid historical growth in electric demand and energ an annual 2.3% and 5.3%, respectively, during 2000-2 projects that future growth will remain strong at 4. the next 10 years.
- Below average wholesale energy rates, despite recent rising fuel costs. In addition, the member weighted residential rates are slightly above the state avera
- Financially strong member distribution cooperatives.

These strengths are tempered by the following:

- Concentration of power supply in two owned and lease facilities comprising 60% of the members' energy nee
- Material counterparty credit exposure to Calpine Cor (B-/Negative/--) and Reliant Energy Inc. (B+/Stable/
- Weak financials, with debt service coverage projecte 1.05x to 1.08x and below average levels of liquidity

Seminole is a generation and transmission cooperativ retail customers through its 10 distribution cooperatives portions of 45 counties throughout Florida. Debt service obligations are paid from revenues generated under all-re wholesale power contracts.

An ongoing credit concern continues to be dissonance the cooperative's key members. While Seminole benefits fr sophisticated management team, the ongoing member discord challenges that limit the cooperative's operational and f flexibility. Seven of the 10 members (representing 56% of the contract until 2045, providing Seminole with some cer long-term power supply planning. Two remaining members (2 expected to sign extensions that provide all of the membe find alternative energy suppliers for incremental energy while still paying capacity charges under the existing ta contracts. The last member, Lee County Electric Cooperati representing 23% of the cooperative's load, is also consi extension if it provides for member choice. While the los after 2020, would reduce some of the Seminole's revenue a diversity, it is not projected to increase costs for rema Significant reliance on purchased power tempers the expos

fixed costs because purchased power can be reduced should Furthermore, the proposed new generation projects would s meet the remaining members' projected load growth.

Future power needs will continue to be met through a new construction and purchased power. Some of the new con projects increase Seminole's risk profile. The near-term will be met through new purchased power contracts and con MW combustion turbine units, which should not increase ri board-approved 750 MW pulverized coal plant does introduc the cooperative. Seminole will oversee the construction p the risk of financial overruns and/or construction delays will make a final decision on the project in 2007 based o complete the permitting and obtain approvals needed for c

Seminole, which sets its own rates, budgets for narr financial margins. It adopted a policy to set rates to pr service coverage, slightly above the level required under granted to the U.S. Rural Utilities Service and National Cooperative Finance Corp. The cash-basis debt service cov marginally above 1.09x as of March 31, 2005, which is low category.

Liquidity

Concerns over thin margins exist because Seminole is fc levels of liquidity through 2010, with days' cash rangi two weeks to just over one month. Days' cash improves t when the $50 million of committed lines of credit are c cooperative is planning on increasing the lines of cred million, which is expected to improve liquidity to abou

Outlook

The stable outlook on Seminole reflects continued strong increases in wholesale rates. Rating stability also depen maintaining adequate liquidity for construction and risin especially given the cooperative's lag in collecting reve automatic fuel adjustments. The rating could be lowered i results in reduced revenue flexibility, weaker contracts load diversity. An outlook change to positive, which is l require additional financial improvement with no meaningf business risk.

Ratings List

Rating Lowered

	To	From
Seminole Electric Cooperative		
Issuer credit rating	A-/Stable/--	A/Negative

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Research:

Seminole Elec Coop

Publication date: 11-Aug-2005
Primary Credit Analyst(s): Jodi E Hecht, New York (1) 212-438-2019; jodi_hecht@standardandpoors.com

Corporate Credit Rating

A-/Stable/--

Corporate Credit Rating History

June 30, 2000	A
July 29, 2005	A-

Rationale

The issuer credit rating on the Florida electric utility, Seminole Electric Cooperative, reflects the following credit strengths:

- A strong capacity to meet financial obligations through take-or-pay all-requirements wholesale power agreements with the 10 member distribution cooperatives located throughout Florida.
- A primarily residential revenue stream, accounting for 70% of the distribution cooperatives' retail sales. Residential customers provide stable revenue and, due to their low load factors, are not attractive targets for alternative energy providers in a competitive environment.
- Solid historical growth in electric demand and energy sales averaging annual 2.3% and 5.3%, respectively, during 2000-2004. Seminole projects that future growth will remain strong at 4.2 % per year over the next 10 years.
- Below average wholesale energy rates, despite recent increases due to rising fuel costs. In addition, the member weighted average retail residential rates are slightly above the state average.
- Financially strong member distribution cooperatives.

These strengths are tempered by the following:

- Concentration of power supply in two owned and leased coal-fired facilities comprising 60% of the members' energy needs,
- Material counterparty credit exposure to Calpine Corp. (B-/Negative/--) and Reliant Energy Inc. (B+/Stable/B-2), and
- Weak financials, with debt service coverage projected to range from 1.05x to 1.08x and below average levels of liquidity.

The rating also reflects the cooperative's weak financial projections despite implementation of its equity development plan. The plan only slightly improves projected debt service coverage that continues to be at the lower end of the rating expectations.

Seminole is a generation and transmission cooperative serving 805,000 retail customers through its 10 distribution cooperatives that serve portions of 45 counties throughout Florida. Debt service and lease obligations are paid from revenues generated under all-requirements wholesale power contracts.

An ongoing credit concern continues to be dissonance among some of the cooperative's key members. While Seminole benefits from a very sophisticated management team, the ongoing member discord presents challenges that limit the cooperative's operational and financial flexibility. Seven of the 10

members (representing 56% of load) extended the contract until 2045, providing Seminole with some certainty to advance long-term power supply planning. Two remaining members (23% of load) are expected to sign extensions that provide all of the members the choice to find alternative energy suppliers for incremental energy needs after 2020 while still paying capacity charges under the existing take-or-pay contracts. The last member, Lee County Electric Cooperative, a member representing 23% of the cooperative's load, is also considering the extension if it provides for member choice. While the loss of Lee County, after 2020, would reduce some of the Seminole's revenue and load diversity, it is not projected to increase costs for remaining members. Significant reliance on purchased power tempers the exposure to increased fixed costs because purchased power can be reduced should load be lost. Furthermore, the proposed new generation projects would still be needed to meet the remaining members' projected load growth.

Future power needs will continue to be met through a combination of new construction and purchased power. Some of the new construction projects increase Seminole's risk profile. The near-term 2006 load need will be met through new purchased power contracts and construction of 310 MW combustion turbine units, which should not increase risk but the board-approved 750 MW pulverized coal plant does introduce more risk to the cooperative. Seminole will oversee the construction process and assume the risk of financial overruns and/or construction delays. The cooperative will make a final decision on the project in 2007 based on the ability to complete the permitting and obtain approvals needed for construction.

Seminole, which sets its own rates, budgets for narrow excess financial margins. It adopted a policy to set rates to provide 1.05x debt service coverage, slightly above the level required under the mortgage granted to the U.S. Rural Utilities Service (RUS) and National Rural Utilities Cooperative Finance Corp. The cash-basis debt service coverage was only marginally above 1.09x as of March 31, 2005, which is low for the rating category.

Liquidity

Concerns over thin margins exist because Seminole is forecasting low levels of liquidity through 2010, with days' cash ranging from about two weeks to just over one month. Days' cash improves to over 30 days when the $50 million of committed lines of credit are considered. The cooperative is planning on increasing the lines of credit to $100 million, which is expected to improve liquidity to about 60 days cash.

Outlook

The stable outlook on Seminole reflects continued strong growth and slight increases in wholesale rates. Rating stability also depends on the utility maintaining adequate liquidity for construction and rising fuel costs, especially given the cooperative's lag in collecting revenues from automatic fuel adjustments. The rating could be lowered if member discord results in reduced revenue flexibility, weaker contracts, or diminished load diversity. An outlook change to positive, which is less likely, will require additional financial improvement with no meaningful increase in business risk.

Business Profile

Markets

Seminole's members provide retail electric service to customers in the north central and southwest portion of the state, serving two of the fastest growing regions in the state. Over the past five years, the customer growth rates have exceeded those of the investor-owned and municipal utilities in the state. The areas, while primarily residential, are economically diverse, serving some of the more densely populated areas outside of Tampa and Fort Myers and rural farm areas in the central portion of the state. The distribution cooperatives serve about 805,000 end users. Many of the customer's characteristics lend stability to Seminole and also make them less attractive to alternative energy suppliers if the area were open to competition. Residential energy usage is lower than other utilities in the region. Only a small portion of the energy sales are to small commercial (22%) and large commercial (8%) customers. The area has low customer density, decreasing the economies of scale. The average number of customers per line mile is less than 15 compared with investor-owned utilities' average of less than 60 and municipals' average of more than 60. Future growth is expected to be strong, averaging 3% over the next five years, in line with historic average, driven both by

intrastate and interstate residential growth.

The three largest distribution cooperatives, Withlacoochee River Electric Cooperative, Lee County Electric Cooperative, and Clay Electric Cooperative, together account for about two-thirds of Seminole's revenues in nearly equal shares followed by Sumter Electric Cooperative, contributing an additional 15% of revenues. The composition of the distribution cooperatives' retail customers creates few incentives for alternative energy providers to pursue Seminole's members' customers in a competitive environment. A relatively small industrial presence is reflected in the low load factors of the member systems. Even those cooperatives with the greatest industrial presence have load factors below 50%. The two distribution cooperatives with the highest concentration of industrial customers, Glades and Tri-County Electric Cooperatives, have industrial loads that represent a moderate 19% and 17%, respectively, of each cooperative's annual revenues. The limited presence of industrial customers and the low load factors bode well for the stability of the revenue stream and for credit quality, barring the departure of distribution cooperatives from the Seminole system.

Operations

Seminole owns or leases 1,827 MW (winter rating) of efficient base and intermediate load, generating capacity that has historically exhibited reliable performance at moderate production costs. The cooperative supplements its installed generation with higher cost power purchased to meet demand peaks and load shaping. About a quarter of Seminole's energy needs are typically met with purchased power. However, in terms of energy supplied, the majority of its supply is from its owned or leased units, which are baseload units. Its 1,300 MW coal-fired units supply about 60% of its energy. The historic availability of these units has been above industry averages, but it recently experienced an extended unplanned outage in the fourth quarter 2004 due to problems with its intermediate turbine blades.

The Payne Creek Generating Station, a 500 MW gas-fired combined cycle unit, began initial operations in January 2002. The units continue to have operational problems related to the combustion turbine and steam turbine blades, similar to other Siemens Westinghouse units. Additional capital spending to address these problems has been a minimal $7 million as concessions from Siemens and insurance proceeds have covered the balance of the costs. Although the availability of these units has been less than 60%, well below budget, the capacity factor has been in line with expectations at 37% in 2005.

The board favors the diversity of fuel source, provider, and flexibility to adjust to members needs provided by a combination of owned and leased generation and purchased power. The cost of the purchased power is significantly higher than the cooperative's own generation. Seminole purchases a mix of full and partial requirement system power and unit contingent block power to meet a portion of its intermediate and peaking needs. The 45% system load factor indicates low typical usage, combined with sharp spikes in power usage over limited periods of time. This portfolio approach provides flexibility if a member were to leave the system. However, some contracts require three to seven years' notice before existing power purchase requirements can be reduced. In addition to the operational flexibility from the power purchase agreements, the company faces counterparty credit exposure as it has unit contingent contracts with Calpine and Reliant Energy.

Seminole's Palatka units are located in northeastern Florida, while their ultimate customers are dispersed throughout peninsular Florida, making Seminole a transmission dependent utility. It has transmission service agreements with several Florida utilities. Historical transmission expense was reasonable at approximately 3 mills per kWh, or 5% of revenue requirements, a trend that is projected to continue.

Operational and financial risk has increased because of two construction projects. The first project, construction of 10 31 MW Pratt & Whitney combustion turbines, is less complicated and costly. The cost is a projected $136.5 million (about $440 per kW, above average cost). It will be built on an existing site through a modular assembly process, which is expected to take 10 months to construct. Standard & Poor's will monitor construction process for availability and cost.

The project with more risk is construction of a 750 MW pulverized coal-fired unit that will use clean coal technology employing a super critical boiler. The project is expected to take four years and cost

$1.2 billion. While the board has approved the project, environmental studies and permitting still need to be completed before final approval on the project is given. If the project proceeds, construction is expected to begin by 2008. Seminole will oversee construction, taking on any financial risk if the project exceeds budget or gets delayed. At the same time, Seminole plans on installing SCRs and adding other improvements to the existing 2 units to address more stringent emission requirements at an estimated cost of $260 million or about $200 per kW. Seminole's concentration in coal-fired facilities will continue but not increase significantly to 67% projected in 2014 after completion of the proposed Unit 3 from 62% in 2005.

Management

Seminole is governed by its board of trustees, composed of the member coops. Despite these strengths, dissension within Seminole's ranks erodes some of the benefits associated with a strong management team and the self-governance that is common to generation cooperatives. Seminole's board of trustees is composed of representatives of each of Seminole's member distribution cooperatives. Each cooperative has an equal say in setting Seminole's policy, irrespective of a distribution cooperative's load or the amount of revenues produced. The extent to which smaller members can influence board policy is an issue at this cooperative as it is at some others. Due to divergent load profiles and growth patterns, Seminole's members' interests are not always in accord.

Competitive position

Seminole's wholesale rates consist of two components: a demand charge that is designed to recover fixed costs associated with owned and contracted capacity and an energy charge that principally recovers variable costs, but that also recovers a portion of Seminole's fixed costs. Although all members purchase electricity under the same tariff, there is variation in the actual wholesale rates paid by members due to varying usage patterns. On a systemwide basis, Seminole's average cost of power to members was 56.11 mills per kWh in 2004. Rates have been steadily increasing because of the rise in natural gas prices. Seminole's 2005 average wholesale rate was budgeted at 56.9 mills per kWh.

Two base fuel rate increases have been subsequently implemented, raising the projected average rate for the year to 60.9 mills per kWh. This rate remains competitive with other wholesale providers within the Southeast. Seminole's cost of producing electricity to meet base load demand was a favorable 38.79 mills/kWh in 2004. Yet, Seminole's average rates were 50.57 mills per kWh, due to the higher cost of procuring electricity to meet peak demand. The average cost of purchased power was 76 mills per kWh in 2004.

While the favorable wholesale rates benefit all of the member systems, the three largest member systems, Withlacoochee River Electric Cooperative, Lee County Electric Cooperative, and Clay Electric Cooperative, are able to offer very competitive retail rates for its retail, commercial, and industrial customers. However, the smaller members of the Seminole system are not as competitive, as retail rates for the residential customers of Glades Electric Cooperative, Tri-County Electric Cooperative and Peace River Electric Coop, are 104% to 109% of Florida's average residential rates for all electric utilities. The rate disparities attributable to these systems do not present credit concerns because these systems serve customers in sparsely populated areas. Customer density per line mile for these utilities is extremely low at 5-10 meter connections per line mile and usage is below the levels for residential customers of Florida's investor-owned and municipal utilities. It is unlikely that competitors would be able to bypass or reduce these costs, mitigating credit concerns.

Regulation

Seminole sets its own wholesale rates. The Florida Public Service Commission lacks jurisdiction over the level of rates set by Seminole, which was reaffirmed last year when the commission determined and later the Supreme Court concurred, that the commission lacks jurisdiction over cooperative wholesale energy providers.

Financial Profile

Seminole budgets for narrow financial margins. It operates under a traditional RUS mortgage that establishes financial benchmarks that Seminole must meet as an RUS borrower. The mortgage requires that rates be set to provide debt service and times interest earned (TIER) coverage of not less than 1.0x and 1.05x, respectively. However, in July 2004, the board approved an equity development

plan which increased the financial target for annual debt service coverage only modestly to 1.05x. Seminole does not budget for margins in excess of these requirements.

Seminole sets rates annually in connection with the budget process, which essentially is a break-even analysis. Revenues to be collected from members are set at a level that, together with interest income, will meet all obligations and provide the coverage required under the mortgage. Depreciation expense has exceeded the annual amortization of principal on debt obligations producing debt service coverage in excess of 1.0x. However, the gap between actual and required debt service coverage will disappear over the next several years because annual principal amortization is approaching and will exceed annual depreciation expense. In 2005, rates were set to achieve 1.05x DSC and the TIER ratio is projected to rise significantly above the required 1.05x. This type of budgeting yielded funds from operations of $53 million in 2004, a limited 6% of operating revenues.

While budgeting for break-even operations is not uncommon with the practices of other not-for-profit generation cooperatives, concerns regarding limited excess margins are usually offset by strong liquidity. Seminole's liquidity, in terms of unrestricted available cash was low at the end of 2004 at less than one week, but increases to about one month when considering the $75 million of available lines of credit. Future liquidity will improve as the board is expected to increase its committed lines of credit to $100 million in September 2005. In addition, two base fuel rate increases were approved in 2005, which will be effective in July and September to address the timeliness of the underrecovered fuel costs.

Future capital expenditures are a manageable $314 million through 2010 and are largely for generation projects (98%). Seminole received an RUS loan to fund construction of the $136.5 million combustion turbine project and is considering several options for interim financing. Debt to equity was a low 7% in 2004, reflecting Seminole's reliance on debt for capital projects. However, the total debt per kW of installed capacity is a low $419, offset by a moderate ratio of debt per retail customer at about $950 per customer.

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Publication date: 01-Oct-2004
Reprinted from RatingsDirect

Summary: Seminole Elec Coop

Credit Analyst: Jodi E Hecht, New York (1) 212-438-2019

Rationale

The 'A' issuer credit rating (ICR) on Seminole Electric Cooperative, Fla. reflects the following credit strengths:

- The cooperative has a strong capacity to meet financial obligations through "all-requirements" wholesale power agreements with the 10-member distribution cooperatives located throughout Florida.
- The cooperative primarily has a primarily residential revenue stream, accounting for 77% of the distribution cooperatives' revenues. Due to their low load factors, residential customers are not expected to be attractive targets for alternative energy providers in a competitive environment.
- The cooperative has had solid historical growth in electric demand and energy sales averaging an annual 8.5% and 5.0%, respectively, between 1998-2002. Seminole projects that future growth will remain strong at 3.8% per year over the next 10 years.
- The cooperative has low debt levels with low debt per kilowatt of installed generation of $411.

These strengths are tempered by:

- Concentration in two owned and leased coal-fired facilities comprising 60% of the members' energy needs,
- Management's ability to address the divergent needs of the members, and
- Narrow financial margins.

Seminole sells energy under all-requirements contracts to 10 distribution cooperatives that serve portions of 45 counties throughout the Florida peninsular. Debt and contractual obligations are satisfied with revenues received through the sale of electricity to member distribution cooperatives. As of June 30, 2004, the cooperative had approximately $734.3 million in total debt outstanding. Electricity sales to members totaled approximately 15,588 gigawatt-hours for the 12 months ended June 30, 2004, which placed Seminole among the nation's five-largest generation and transmission cooperatives.

Seminole owns 1,814 MW of efficient base and intermediate load, generating winter capacity that has performed reliably at moderate production costs. The cooperative supplements its installed generation with higher cost power purchased to meet demand peaks and loan shaping. About a quarter of Seminole's energy needs are typically met with purchased power. The cost of self-generation and purchased power blended into a competitive average wholesale rate of 52.72 mills per kilowatt-hour for the 12 months ended June 30, 2004. The slightly higher rate reflects the higher gas costs used to supply the Payne Creek Generating Station, which went into commercial operation in the beginning of 2002. The wholesale rate compares favorably to the rates

charged by regional wholesale providers. Current rates are expected to increase over the near-to-intermediate term as gas prices remain elevated and power supply resources are added to the portfolio. The capacity addition displaces costlier power purchases.

Future power needs will continue to be met through a combination of installed generation and purchased power contracts. The cooperative expects to finish construction of 310 MW of combustion turbine units in late 2006. Additionally, a portion of the increased need forecast in December 2006 will be met with a recently approved, competitively priced power purchase agreement.

Currently, no member has told Seminole it wants to leave the system, possibly because of the uncertainty in the national wholesale markets and Seminole management's focus on addressing members' needs. However, an ongoing credit concern continues to be member discord among some of the cooperative's key members. Seven of the 10 members, representing 57% of the load, recently extended the wholesale power contract by 25 years through 2045. Additionally, Seminole was served a civil suit by two of its members, Clay Electric and Lee County Electric. The suit concerns Seminole's wholesale rate structure, as approved by its board. While Seminole benefits from a very sophisticated management team, the ongoing member discord presents challenges that could limit the cooperative's rate-setting flexibility, affecting its financial margins going forward. Moreover, a member's departure could impair the cooperative's revenue stream or drive up costs for remaining members. Yet, significant reliance on purchased power helps temper this exposure because market power purchases can be reduced should load be lost.

Seminole, which sets its own rates, budgets for narrow excess financial margins. The mortgage granted by Seminole to the United States Rural Utilities Service and National Rural Utilities Cooperative Finance Corp. merely requires that Seminole set rates to produce margins that provide a debt service coverage ratio of at least 1.0x and a times interest earned coverage (TIER) ratio of 1.05x. The cooperative met these covenant requirements in 2002 and 2003. However, cash-basis debt service coverage was only marginally above 1.1x for the 12 months ended June 30, 2004, which is low for the rating category. Concerns over thin margins are heightened because Seminole is forecasting very low levels of liquidity through 2010, with days' cash ranging from less than one day to slightly more than one month. Days' cash improves slightly to 30-75 days when the $75 million lines of credit are considered. However, only $50 million are committed lines of credit. Higher levels of liquidity are forecast during the construction of its combustion turbine project. To address these concerns, the board approved the Equity Plan in May 2004, which requires the cooperative to maintain both TIER and debt service coverage at 1.05x. This plan should improve liquidity and debt service coverage.

Outlook

The negative outlook reflects expectations that Seminole's ICR could be lowered if financial margins remain at break-even levels and if member discord results in reduced rate-setting flexibility or weaker contracts.

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Q. Please provide all work papers supporting the fuel price forecast.

A. Please see attached documents, at the pages Bates numbered 00032-00042, 00046-00101, 00106-00164, 00169-00234, 00236, and 00239-00277, which are responsive to the request. Copies of confidential documents responsive to the request, at the pages Bates numbered 00043-00045, 00102-00105, 00165-00168, 00235, and 00237-00238 will be produced for Staff's review during regular business hours, 8:00 a.m. to 5:00 p.m. at the Tallahassee office of Seminole's counsel, Squire, Sanders & Dempsey LLP, 215 S. Monroe St., Suite 601, Tallahassee, Florida 32301, upon reasonable notice to Seminole's counsel and upon the signing of a Confidentiality Representation by Staff members conducting the review

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FUEL PRICE FORECASTS
TIMELINE

- **June 2005** – Global Insight Long term fuel price forecast
  - Implemented August, 2005
  - 2005 Load Forecast
  - Seminole's final economic analyses underlying SGS 3 need application economics (7 members as of 8/1/2020):
    - 750 MW coal-fired resource 1/2012 (05BASEA1)
    - 500 MW gas-fired combined cycle resource 1/2012 (05SBCCA1)

- **October 2004** – Global Insight Long term fuel price forecast
  - Implemented December, 2004
  - 2003 Load Forecast
  - Coal vs. gas economic analyses which were used as a basis for the R. W. Beck risk analysis (7 members as of 8/1/2020):
    - 600 MW self-build coal-fired resource and 150 MW share of joint coal resource 1/2012 (BASE05A1)
    - 500 MW gas-fired combined cycle resource 1/2012 (BASE5GS1)
    - 750 MW coal-fired resource 1/2012 (BS05A141) – 6/2005 study with 12/2004 assumptions
    - 600 MW Invenergy coal-fired resource purchase and 150 MW share of joint coal resource (BS05A142) – 6/2005 study with 12/2004 assumptions

- **December 2003** – Global Insight Long term fuel price forecast
  - Implemented April, 2004
  - 2003 Load Forecast
  - Busbar analyses of RFP bids, FMPA offer and self-build coal and gas alternatives

- **March 2003** – Global Insight Long term fuel price forecast
  - Implemented August, 2003
  - 2001 Load Forecast
  - August 2003 coal studies (10 members):
    - Base (NOCOALBS)– all future capacity needs are filled with gas-fired resources
    - 150 MW of coal capacity 1/1/2010 (SECI150)
    - 300 MW of coal capacity 1/1/2010 (SECI300)
    - 450 MW of coal capacity 1/1/2010 (SECI300)
    - 600 MW of coal capacity 1/1/2010 (SECI300)

AUGUST 2005 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the June 2005 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	12.70	9.25	9.11	2.16	1.77
2006	12.91	9.36	9.23	2.39	1.55
2007	12.19	8.85	8.73	2.10	1.58
2008	11.64	7.98	7.87	2.10	1.64
2009	11.21	7.11	7.02	2.37	1.92
2010	10.86	6.25	6.16	2.44	2.00
2011	9.28	6.41	6.32	2.49	2.07
2012	9.44	6.56	6.47	2.53	2.12
2013	9.48	6.94	6.84	2.57	2.17
2014	9.49	7.13	7.04	2.60	2.22
2015	9.50	7.26	7.16	2.64	2.28
2016	9.61	7.41	7.31	2.67	2.35
2017	9.74	7.89	7.78	2.74	2.45
2018	9.88	7.41	7.30	2.78	2.52
2019	10.02	7.75	7.64	2.82	2.58
2020	10.16	8.05	7.93	2.85	2.65
2021	10.68	8.16	8.04	2.89	2.70
2022	11.07	8.38	8.26	2.97	2.78
2023	11.56	8.59	8.47	3.01	2.82
2024	11.98	8.81	8.68	3.05	2.86
2025	12.41	9.03	8.90	3.09	2.90
2026	12.80	9.23	9.10	3.13	2.93
2027	13.20	9.44	9.30	3.22	3.02
2028	13.57	9.65	9.51	3.26	3.05
2029	13.95	9.87	9.73	3.30	3.09
2030	14.37	10.06	9.91	3.35	3.12
AAGR (4)					
2005-2030	0.5%	0.3%	0.3%	1.8%	2.3%
2010-2030	1.4%	2.4%	2.4%	1.6%	2.3%

Notes:
(1) FGT means Florida Gas Transportation
(2) GS means Gulfstream Natural Gas System
(3) Delivered prices represent:
Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.
Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.
Coal: 1) Commodity price of coal from Illinois basin plus
2) rail transportation, freight rate, plus cost of rail cars.
Petcoke: Similar to coal.
(4) AAGR means Average Annual Growth Rate

DECEMBER 2004 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the October 2004 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	9.95	8.96	8.87	2.61	1.89
2006	8.69	8.27	8.20	2.41	1.61
2007	7.43	7.11	7.04	2.10	1.32
2008	7.28	6.87	6.80	1.78	1.04
2009	7.30	6.62	6.56	2.03	1.24
2010	7.29	6.38	6.32	2.09	1.31
2011	7.23	6.13	6.07	2.15	1.37
2012	7.17	6.27	6.21	2.19	1.40
2013	7.24	6.44	6.38	2.23	1.44
2014	7.48	6.57	6.51	2.30	1.52
2015	7.75	6.76	6.70	2.34	1.56
2016	8.02	6.92	6.86	2.38	1.62
2017	8.29	7.12	7.05	2.42	1.67
2018	8.56	7.17	7.10	2.46	1.72
2019	8.83	7.39	7.32	2.54	1.81
2020	9.10	7.61	7.54	2.58	1.87
2021	9.37	7.81	7.73	2.63	1.91
2022	9.65	8.01	7.93	2.67	1.94
2023	9.92	8.21	8.13	2.72	1.97
2024	10.20	8.42	8.34	2.81	2.04
2025	10.48	8.63	8.55	2.86	2.07
2026	10.76	8.85	8.76	2.90	2.10
2027	11.04	9.07	8.99	2.95	2.12
2028	11.33	9.30	9.21	3.00	2.15
2029	11.61	9.54	9.45	3.06	2.18
2030	11.90	9.78	9.69	3.11	2.22
AAGR (4)					
2005-2030	0.7%	0.4%	0.4%	0.7%	0.6%
2010-2030	2.5%	2.2%	2.2%	2.0%	2.7%

Notes:
(1) FGT means Florida Gas Transportation
(2) GS means Gulfstream Natural Gas System
(3) Delivered prices represent:
Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.
Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.
Coal: 1) Commodity price of coal from Illinois basin plus
2) rail transportation, freight rate, plus cost of rail cars.
Petcoke: Similar to coal.
(4) AAGR means Average Annual Growth Rate

APRIL 2004 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the December 2003 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	6.68	6.30	6.24	1.79	1.06
2006	6.22	5.88	5.83	1.80	1.10
2007	6.06	5.57	5.52	1.84	1.13
2008	5.90	5.47	5.42	1.89	1.16
2009	5.85	5.38	5.33	2.13	1.36
2010	6.25	5.38	5.33	2.20	1.40
2011	6.47	5.60	5.55	2.27	1.43
2012	6.70	5.78	5.73	2.31	1.46
2013	7.05	5.99	5.93	2.35	1.48
2014	7.36	6.16	6.10	2.43	1.54
2015	7.68	6.39	6.33	2.48	1.59
2016	8.01	6.56	6.50	2.53	1.61
2017	8.31	6.77	6.71	2.57	1.62
2018	8.62	7.00	6.93	2.63	1.64
2019	8.97	7.24	7.17	2.72	1.70
2020	9.33	7.49	7.42	2.78	1.72
2021	9.69	7.74	7.66	2.83	1.75
2022	10.07	8.01	7.93	2.89	1.77
2023	10.48	8.27	8.20	2.95	1.79
2024	10.93	8.56	8.48	3.05	1.86
2025	11.34	8.86	8.78	3.12	1.88
2026	11.79	9.16	9.07	3.18	1.91
2027	12.27	9.48	9.39	3.25	1.93
2028	12.76	9.82	9.73	3.31	1.96
2029	13.31	10.16	10.06	3.38	1.99
2030	13.82	10.52	10.42	3.45	2.01
AAGR (4)					
2005-2030	3.0%	2.1%	2.1%	2.7%	2.6%
2010-2030	4.0%	3.4%	3.4%	2.3%	1.8%

Notes:

(1) FGT means Florida Gas Transportation

(2) GS means Gulfstream Natural Gas System

(3) Delivered prices represent:

Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.

Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.

Coal: 1) Commodity price of coal from Illinois basin plus
2) rail transportation, freight rate, plus cost of rail cars.

Petcoke: Similar to coal.

(4) AAGR means Average Annual Growth Rate

AUGUST 2003 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the March 2003 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (2)

Year	Distillate Oil	GS (1) Natural Gas	Pittsburg Seam 13,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	5.02	5.01	1.79	0.97
2006	5.31	4.84	1.78	0.99
2007	5.51	4.96	1.78	1.00
2008	5.66	5.11	1.80	1.02
2009	5.80	5.21	1.86	1.03
2010	5.97	5.36	1.89	1.05
2011	6.15	5.63	1.91	1.07
2012	6.38	5.83	1.92	1.09
2013	6.73	6.00	1.93	1.11
2014	7.04	6.13	1.94	1.13
2015	7.38	6.33	1.96	1.15
2016	7.72	6.50	1.98	1.18
2017	8.03	6.66	2.00	1.20
2018	8.34	6.86	2.02	1.23
2019	8.70	7.04	2.04	1.26
2020	9.04	7.24	2.06	1.28
2021	9.38	7.49	2.08	1.31
2022	9.75	7.73	2.11	1.34
2023	10.14	7.99	2.13	1.37
2024	10.57	8.24	2.15	1.41
2025	10.97	8.50	2.18	1.44
AAGR (4)				
2005-2025	4.0%	2.7%	1.0%	2.0%
2010-2025	4.1%	3.1%	0.9%	2.1%

Notes:
(1) Natural gas delivered into Florida market area.
(2) Delivered prices represent:
Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports
Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.
Coal: 1) Commodity price of coal from Pittsburg seam plus
2) rail transportation, freight rate, plus cost of rail cars.
Petcoke: Similar to coal.
(3) AAGR means Average Annual Growth Rate

AUGUST 2005 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the June 2005 Global Insight Long Term Fuel Price Forecast
COMMODITY PRICES

Year	Distillate Oil	Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	3.04	2.31	0.83	
1999	3.68	2.45	0.78	
2000	6.36	4.10	0.73	0.53
2001	5.43	4.39	1.25	0.50
2002	4.99	3.27	0.97	0.34
2003	6.29	5.38	0.92	0.50
2004	8.25	6.02	1.33	0.43
2005	12.27	8.02	1.31	0.57
2006	12.48	8.13	1.24	0.33
2007	11.75	7.64	1.22	0.33
2008	11.20	6.80	1.20	0.37
2009	10.77	5.96	1.19	0.42
2010	10.43	5.13	1.20	0.47
2011	8.84	5.28	1.25	0.52
2012	9.01	5.43	1.29	0.56
2013	9.05	5.79	1.31	0.59
2014	9.06	5.98	1.34	0.62
2015	9.06	6.11	1.36	0.66
2016	9.18	6.25	1.39	0.71
2017	9.31	6.71	1.42	0.75
2018	9.45	6.25	1.45	0.80
2019	9.59	6.57	1.48	0.84
2020	9.73	6.86	1.51	0.89
2021	10.25	6.97	1.54	0.91
2022	10.64	7.18	1.57	0.93
2023	11.13	7.39	1.60	0.95
2024	11.55	7.60	1.63	0.96
2025	11.98	7.81	1.66	0.98
2026	12.37	8.01	1.70	0.99
2027	12.77	8.21	1.73	1.00
2028	13.14	8.41	1.76	1.00
2029	13.52	8.62	1.80	1.01
2030	13.94	8.80	1.84	1.02

Natural Gas NYMX futures as of 6/21/2005 then merged with Global forecast, 2010-2030 Global forecast.
Distillate oil NYMX futures as of 6/21/2005 then merged with Global forecast, 2011-2030 Global forecast.
Coal and Petcoke, 2005-2030 Global forecast.

DECEMBER 2004 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the October 2004 Global Insight Long Term Fuel Price Forecast
COMMODITY PRICES

Year	Distillate Oil	Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	3.04	2.11	0.83	
1999	3.68	2.27	0.78	
2000	6.36	3.88	0.73	0.53
2001	5.43	4.26	1.25	0.50
2002	4.99	3.22	0.97	0.34
2003	6.29	5.38	0.92	0.50
2004	8.25	6.14	1.33	0.43
2005	9.51	7.78	1.88	1.23
2006	8.25	7.12	1.64	0.93
2007	6.99	5.99	1.32	0.64
2008	6.85	5.75	1.00	0.34
2009	6.87	5.52	1.05	0.38
2010	6.86	5.28	1.10	0.43
2011	6.80	5.04	1.14	0.48
2012	6.74	5.17	1.18	0.51
2013	6.81	5.34	1.20	0.54
2014	7.05	5.47	1.22	0.57
2015	7.32	5.65	1.25	0.60
2016	7.59	5.81	1.27	0.65
2017	7.86	6.00	1.30	0.69
2018	8.13	6.04	1.33	0.73
2019	8.39	6.27	1.36	0.77
2020	8.66	6.48	1.38	0.82
2021	8.94	6.67	1.41	0.84
2022	9.22	6.86	1.44	0.86
2023	9.49	7.06	1.47	0.88
2024	9.77	7.26	1.51	0.89
2025	10.04	7.46	1.54	0.90
2026	10.33	7.68	1.57	0.92
2027	10.61	7.90	1.61	0.94
2028	10.89	8.12	1.64	0.95
2029	11.18	8.35	1.68	0.97
2030	11.46	8.58	1.72	0.98

Natural Gas NYMX futures as of 10/29/2004 then merged with Global forecast, 2011-2030 Global forecast.
Distillate Oil for 2005-2010 adjusted for current market prices, 2011-2030 Global forecast.
Coal adjusted to EIA in 2005 then merged with Global; 2008-2030 Global forecast.
Petcoke adjusted 2005 based on 2004 actual then merged with Global; 2008-2030 Global forecast.

APRIL 2004 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the December 2003 Global Insight Long Term Fuel Price Forecast
COMMODITY PRICES

Year	Distillate Oil	Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	3.04	2.31	0.83	
1999	3.68	2.45	0.78	
2000	6.36	4.10	0.73	0.53
2001	5.43	4.39	1.25	0.50
2002	4.99	3.27	0.97	0.34
2003	6.29	5.38	0.92	0.50
2004	8.25	6.02	1.33	0.43
2005	6.25	5.20	1.03	0.30
2006	5.79	4.80	1.03	0.33
2007	5.63	4.50	1.06	0.34
2008	5.47	4.40	1.10	0.37
2009	5.42	4.31	1.15	0.40
2010	5.82	4.31	1.21	0.42
2011	6.04	4.53	1.26	0.45
2012	6.27	4.70	1.29	0.47
2013	6.62	4.90	1.32	0.48
2014	6.93	5.07	1.35	0.49
2015	7.25	5.29	1.39	0.53
2016	7.57	5.46	1.42	0.54
2017	7.87	5.66	1.46	0.54
2018	8.19	5.88	1.49	0.55
2019	8.54	6.12	1.53	0.56
2020	8.90	6.36	1.58	0.57
2021	9.26	6.60	1.62	0.58
2022	9.64	6.86	1.66	0.59
2023	10.05	7.12	1.71	0.60
2024	10.50	7.40	1.75	0.61
2025	10.90	7.69	1.80	0.62
2026	11.36	7.98	1.85	0.64
2027	11.83	8.29	1.90	0.65
2028	12.33	8.62	1.95	0.66
2029	12.88	8.95	2.00	0.67
2030	13.38	9.30	2.06	0.68

Coal price represents a blending of EIA and Global Insight's forecast.
All other fuels are the Global forecast entire forecast period.

AUGUST 2003 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the March 2003 Global Insight Long Term Fuel Price Forecast
COMMODITY PRICES

Year	Distillate Oil	Natural Gas	Pittsburg Seam 13,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	3.04	2.31	0.83	
1999	3.68	2.45	0.78	
2000	6.36	4.10	0.73	0.53
2001	5.43	4.39	1.25	0.50
2002	4.99	3.27	0.97	0.34
2003	6.29	5.38	0.92	0.50
2004	8.25	6.02	1.33	0.43
2005	5.02	3.95	1.09	0.34
2006	5.31	3.79	1.07	0.34
2007	5.51	3.91	1.06	0.35
2008	5.66	4.06	1.08	0.36
2009	5.79	4.15	1.12	0.37
2010	5.96	4.30	1.15	0.37
2011	6.15	4.56	1.16	0.38
2012	6.38	4.76	1.16	0.39
2013	6.73	4.92	1.17	0.40
2014	7.04	5.05	1.17	0.41
2015	7.38	5.24	1.18	0.42
2016	7.71	5.40	1.19	0.43
2017	8.03	5.56	1.20	0.44
2018	8.34	5.76	1.21	0.45
2019	8.69	5.93	1.22	0.47
2020	9.04	6.12	1.23	0.48
2021	9.38	6.36	1.25	0.49
2022	9.75	6.60	1.26	0.50
2023	10.14	6.85	1.28	0.52
2024	10.57	7.09	1.29	0.53
2025	10.97	7.35	1.31	0.55

Coal price represents a blending of EIA and Global Insight's forecast.
All other fuels are the Global forecast entire forecast period.

NOTES:

(1) 2005 & 2010 - 2030 is forecast as provided by Global Insight in June 2005, Henry Hub price.
(1a) 2005, 2006, & 2007 is futures forecast as provided by WSJ on June 21, 2005, NYMX.
(1b) 2008 & 2009 merges the futures forecast with the Global Insight forecast.
(1c) 2031-2034 increases gas price into pipe based on the ave. annual rate of increase for the prior 5 year period(2025-2030).

(2) The charges for up to 57,000 Dth/day are based on 25,000 Dth/day of FGT firm capacity with 3.5% compressor fuel and $.04/Dth usage charge, and 32,000 Dth/day of Gulfstream firm capacity with 2.0% compressor fuel and $.02/Dth usage charge.

(3) The charges for daily bundled volumetric transportaion assume Gulfstream volumetric daily market interruptable capacity will set market prices on both Gulfstream and FGT. Compressor fuel is assumed to be 2.0% and daily market transportation is a weighted average of estimated $0.78/Dth in the summer and in the shoulder months.

(4) Provides for the facility to be located on either the FGT or the Gulfstream pipelines with firm. capacity to be reserved on either Gulfstream or FGT.

(5) Assumes transportation is provide by a firm contract for 44,000 Dth/day. Assumes the facility will be located on the Gulfstream pipeline with 2.0% compressor fuel and $0.02 usage charge. Use $0.70/Dth for the reservation cost of firm transportation.

(6) The FGT compressor fuel charge for HPS is 3.5%. Variable transportation is the current PGS shoulder month price of $0.48/Dth applied to all 12 months recognition that the majority of energy is consumed during the shoulder months.

(7) The Payne Creek fixed annual reservation charge is calaculated as follows:

2005
FGT 25,000 x 365 x $0.6517 = $5,946,762
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $12,604,362

2006
FGT 25,000 x 365 x $0.6804 = $6,208,650
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $12,866,250

2007 - 2009
FGT 25,000 x 365 x $0.6829 = $6,231,462
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $12,889,062

2010 and beyond
FGT 25,000 x 365 x $0.8357 = $7,625,763
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $14,283,363

2005 BASE CASE GAS PRICE FORECAST; June, 2005

		PAYNE CREEK (7)																	
		Up to 57 K Dth/day		Over 57 K Dth/day		New Units (CC) firm pricing negotiated amount/day					Reliant Constellation New Peaking Units		Calpine Osprey Up to 44 K Dth/day		Calpine Osprey Over 44 K Dth/day		Hardee Power Station	
	Gas Price into Pipe $/Dth	Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	FGT Trans Use & Fuel $/Dth	FGT Delvd Price $/Dth	GS Trans Use & Fuel $/Dth	GS Delvd Price $/Dth	Generic CC's: w/o Firm Transp. Included $/Dth	FGT Vary Trans Use & Fuel $/Dth	FGT Delvd Price $/Dth	Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth
	(1)	(2)		(3)		(4)			(3)				(5)				(6)	
	FGT Compressor Fuel %:				3.5%	GS Compressor Fuel %:			2.0%						PGS Compressor Fuel %:			3.5%	
	FGT Usage Fees $/Dth:				$0.04	GS Usage Fees $/Dth:			$0.02						PGS Usage Fees $/Dth:			$0.041	
	FGT Mkt Swing Trans:				$0.78	GS Mkt Swing Trans:			$0.78						PGS Mkt Swing Trans:			$0.48	
	Transportation Basis - HHub:				$0.15														
Year																			
2005	$8.02	$0.41	$8.43	$1.22	$9.24	$1.23	$9.25	$1.09	$9.11	$8.41	$1.23	$9.25	$0.33	$8.35	$1.09	$9.11	$0.96	$8.98
2006	$8.13	$0.41	$8.54	$1.22	$9.35	$1.23	$9.36	$1.10	$9.23	$8.52	$1.23	$9.36	$0.34	$8.47	$1.10	$9.23	$0.97	$9.10
2007	$7.64	$0.40	$8.04	$1.21	$8.85	$1.21	$8.85	$1.09	$8.73	$8.02	$1.21	$8.85	$0.33	$7.97	$1.09	$8.73	$0.95	$8.59
2008	$6.80	$0.38	$7.18	$1.18	$7.98	$1.18	$7.98	$1.07	$7.87	$7.16	$1.18	$7.98	$0.31	$7.11	$1.07	$7.87	$0.92	$7.72
2009	$5.96	$0.35	$6.32	$1.15	$7.11	$1.15	$7.11	$1.05	$7.02	$6.29	$1.15	$7.11	$0.29	$6.26	$1.05	$7.02	$0.89	$6.85
2010	$5.13	$0.33	$5.46	$1.12	$6.24	$1.12	$6.25	$1.03	$6.16	$5.43	$1.12	$6.25	$0.27	$5.40	$1.03	$6.16	$0.86	$5.98
2011	$5.28	$0.33	$5.62	$1.12	$6.40	$1.13	$6.41	$1.04	$6.32	$5.59	$1.13	$6.41	$0.28	$5.56	$1.04	$6.32	$0.86	$6.15
2012	$5.43	$0.34	$5.77	$1.13	$6.56	$1.13	$6.56	$1.04	$6.47	$5.74	$1.13	$6.56	$0.28	$5.71	$1.04	$6.47	$0.87	$6.30
2013	$5.79	$0.35	$6.14	$1.14	$6.93	$1.14	$6.94	$1.05	$6.84	$6.11	$1.14	$6.94	$0.29	$6.08	$1.05	$6.84	$0.88	$6.67
2014	$5.98	$0.35	$6.34	$1.15	$7.13	$1.15	$7.13	$1.05	$7.04	$6.31	$1.15	$7.13	$0.29	$6.28	$1.05	$7.04	$0.89	$6.87
2015	$6.11	$0.36	$6.46	$1.15	$7.26	$1.16	$7.26	$1.05	$7.16	$6.44	$1.16	$7.26	$0.29	$6.40	$1.05	$7.16	$0.89	$7.00
2016	$6.25	$0.36	$6.61	$1.16	$7.41	$1.16	$7.41	$1.06	$7.31	$6.59	$1.16	$7.41	$0.30	$6.55	$1.06	$7.31	$0.90	$7.15
2017	$6.71	$0.37	$7.09	$1.17	$7.89	$1.18	$7.89	$1.07	$7.78	$7.06	$1.18	$7.89	$0.31	$7.02	$1.07	$7.78	$0.91	$7.63
2018	$6.25	$0.36	$6.61	$1.16	$7.40	$1.16	$7.41	$1.06	$7.30	$6.58	$1.16	$7.41	$0.30	$6.54	$1.06	$7.30	$0.90	$7.14
2019	$6.57	$0.37	$6.94	$1.17	$7.74	$1.17	$7.75	$1.06	$7.64	$6.92	$1.17	$7.75	$0.30	$6.88	$1.06	$7.64	$0.91	$7.48
2020	$6.86	$0.38	$7.24	$1.18	$8.04	$1.18	$8.05	$1.07	$7.93	$7.22	$1.18	$8.05	$0.31	$7.17	$1.07	$7.93	$0.92	$7.78
2021	$6.97	$0.38	$7.35	$1.18	$8.15	$1.19	$8.16	$1.07	$8.04	$7.33	$1.19	$8.16	$0.31	$7.28	$1.07	$8.04	$0.92	$7.90
2022	$7.18	$0.39	$7.57	$1.19	$8.37	$1.20	$8.38	$1.08	$8.26	$7.55	$1.20	$8.38	$0.32	$7.50	$1.08	$8.26	$0.93	$8.11
2023	$7.39	$0.39	$7.78	$1.20	$8.58	$1.20	$8.59	$1.08	$8.47	$7.76	$1.20	$8.59	$0.32	$7.71	$1.08	$8.47	$0.94	$8.33
2024	$7.60	$0.40	$7.99	$1.21	$8.80	$1.21	$8.81	$1.09	$8.68	$7.97	$1.21	$8.81	$0.33	$7.92	$1.09	$8.68	$0.95	$8.54
2025	$7.81	$0.40	$8.21	$1.21	$9.02	$1.22	$9.03	$1.09	$8.90	$8.20	$1.22	$9.03	$0.33	$8.14	$1.09	$8.90	$0.95	$8.77
2026	$8.01	$0.41	$8.42	$1.22	$9.23	$1.23	$9.23	$1.09	$9.10	$8.40	$1.23	$9.23	$0.33	$8.34	$1.09	$9.10	$0.96	$8.97
2027	$8.21	$0.41	$8.62	$1.23	$9.43	$1.23	$9.44	$1.10	$9.30	$8.60	$1.23	$9.44	$0.34	$8.54	$1.10	$9.30	$0.97	$9.17
2028	$8.41	$0.42	$8.83	$1.24	$9.65	$1.24	$9.65	$1.10	$9.51	$8.81	$1.24	$9.65	$0.34	$8.75	$1.10	$9.51	$0.98	$9.39
2029	$8.62	$0.43	$9.05	$1.24	$9.86	$1.25	$9.87	$1.11	$9.73	$9.03	$1.25	$9.87	$0.35	$8.97	$1.11	$9.73	$0.98	$9.60
2030	$8.80	$0.43	$9.23	$1.25	$10.05	$1.25	$10.06	$1.11	$9.91	$9.22	$1.25	$10.06	$0.35	$9.15	$1.11	$9.91	$0.99	$9.79
2031	$9.01	$0.44	$9.45	$1.26	$10.27	$1.26	$10.28	$1.11	$10.13	$9.43	$1.26	$10.28	$0.35	$9.37	$1.11	$10.13	$1.00	$10.01
2032	$9.23	$0.44	$9.67	$1.26	$10.49	$1.27	$10.50	$1.12	$10.35	$9.66	$1.27	$10.50	$0.36	$9.59	$1.12	$10.35	$1.01	$10.24
2033	$9.45	$0.45	$9.90	$1.27	$10.72	$1.28	$10.73	$1.12	$10.57	$9.88	$1.28	$10.73	$0.36	$9.81	$1.12	$10.57	$1.01	$10.47
2034	$9.68	$0.45	$10.13	$1.28	$10.96	$1.29	$10.96	$1.13	$10.81	$10.12	$1.29	$10.96	$0.37	$10.05	$1.13	$10.81	$1.02	$10.70

2005 Base Case Distillate Oil Price Forecast

	Distillate # 2			
	Commodity Price		Delivered	
	@ Tampa, FL		Inland @ $0.06/Gal	
Year	Cents/Gallon	$ / MMBtu	Cents/Gallon	$ / MMBtu
2005	170.21	12.27	176.21	12.70
2006	173.68	12.43	179.05	12.91
2007	163.00	11.75	169.00	12.19
2008	155.39	11.20	161.39	11.64
2009	149.41	10.77	155.41	11.21
2010	144.65	10.43	150.65	10.86
2011	122.67	8.84	128.67	9.28
2012	124.96	9.01	130.96	9.44
2013	125.47	9.05	131.47	9.48
2014	125.62	9.06	131.62	9.49
2015	125.72	9.06	131.72	9.50
2016	127.3	9.18	133.30	9.61
2017	129.14	9.31	135.14	9.74
2018	131.06	9.45	137.06	9.88
2019	132.94	9.59	138.94	10.02
2020	134.9	9.73	140.90	10.16
2021	142.12	10.25	148.12	10.68
2022	147.5	10.64	153.50	11.07
2023	154.31	11.13	160.31	11.56
2024	160.15	11.55	166.15	11.98
2025	166.18	11.98	172.18	12.41
2026	171.53	12.37	177.53	12.80
2027	177.06	12.77	183.06	13.20
2028	182.22	13.14	188.22	13.57
2029	187.54	13.52	193.54	13.95
2030	193.31	13.94	199.31	14.37
2031	199.30	14.37	205.30	14.80
2032	205.48	14.82	211.48	15.25
2033	211.85	15.28	217.85	15.71
2034	218.42	15.75	224.42	16.18

Note - Delivery charge of $0.06 per gallon added to commodity cost.
2005 & 2006 represents the average annual futures price of #2 heating oil from the 06/21/05 WSJ.
2007 -2010 represents a smoothed transition from 2006 to 2011; consistent with nat gas
For all Oil; 2031 -2034 increase based on ave annual increase for the period 2025 to 2030.

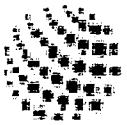
2005 Base Case Residual Oil Price Forecast

B	A	B	C	D	E	F	G	H	I
41	**Residual Fuel Oil Prices - Gulf Coast Cargoes - Commodity Price**								
42			Dollars per Barrel				Dollars Per MMBtu		
43			Sulfur Content				Sulfur Content		
44	Year	0.7%	1.0%	3.0%		0.7%	1.0%	3.0%	
45	2005	36.99	42.19	31.44		5.88	6.71	5.00	
46	2006	36.11	41.56	29.73		5.74	6.61	4.73	
47	2007	34.90	39.17	28.61		5.55	6.23	4.55	
48	2008	34.59	39.86	28.32		5.50	6.34	4.50	
49	2009	38.24	36.88	31.00		6.08	5.87	4.93	
50	2010	37.40	36.07	29.94		5.95	5.74	4.76	
51	2011	38.36	37.00	30.41		6.10	5.89	4.84	
52	2012	38.82	37.44	30.50		6.17	5.96	4.85	
53	2013	38.69	37.31	30.15		6.15	5.93	4.80	
54	2014	38.49	37.12	29.72		6.12	5.90	4.73	
55	2015	38.26	36.90	29.28		6.09	5.87	4.66	
56	2016	38.48	37.11	29.18		6.12	5.90	4.64	
57	2017	38.78	37.39	29.13		6.17	5.95	4.63	
58	2018	39.09	37.70	29.10		6.22	6.00	4.63	
59	2019	39.39	37.99	29.04		6.27	6.04	4.62	
60	2020	39.71	38.29	29.00		6.32	6.09	4.61	
61	2021	41.56	40.07	30.05		6.61	6.37	4.78	
62	2022	42.85	41.32	30.68		6.82	6.57	4.88	
63	2023	44.53	42.94	31.57		7.08	6.83	5.02	
64	2024	45.91	44.28	32.23		7.30	7.04	5.13	
65	2025	47.33	45.64	32.88		7.53	7.26	5.23	
66	2026	48.87	47.13	33.95		7.77	7.50	5.40	
67	2027	50.45	48.66	35.05		8.02	7.74	5.57	
68	2028	51.94	50.09	36.08		8.26	7.97	5.74	
69	2029	53.47	51.56	37.15		8.50	8.20	5.91	
70	2030	55.12	53.16	38.30		8.77	8.46	6.09	
71	2031	56.83	54.81	39.49		9.04	8.72	6.28	
72	2032	58.59	56.51	40.71		9.32	8.99	6.48	
73	2033	60.41	58.26	41.97		9.61	9.27	6.68	
74	2034	62.28	60.06	43.27		9.91	9.55	6.88	
75		Adjusted 1% residual to spread pf Global Insight nat gas to resid							

Residual Fuel Oil Prices - Gulf Coast Cargoes - Delivered Price

	Dollars per Barrel			Dollars Per MMBtu			
	Sulfur Content			Sulfur Content			Transp
Year	0.7%	1.0%	3.0%	0.7%	1.0%	3.0%	Adder
2005	40.51	45.71	34.96	6.44	7.27	5.56	0.56
2006	39.63	45.08	33.25	6.30	7.17	5.29	
2007	38.42	42.69	32.13	6.11	6.79	5.11	
2008	38.11	43.38	31.84	6.06	6.90	5.06	
2009	41.76	40.40	34.52	6.64	6.43	5.49	
2010	40.92	39.59	33.46	6.51	6.30	5.32	
2011	41.88	40.52	33.93	6.66	6.45	5.40	
2012	42.34	40.96	34.02	6.73	6.52	5.41	
2013	42.21	40.83	33.67	6.71	6.49	5.36	
2014	42.01	40.64	33.24	6.68	6.46	5.29	
2015	41.78	40.42	32.80	6.65	6.43	5.22	
2016	42.00	40.63	32.70	6.68	6.46	5.20	
2017	42.30	40.91	32.65	6.73	6.51	5.19	
2018	42.61	41.22	32.62	6.78	6.56	5.19	
2019	42.91	41.51	32.56	6.83	6.60	5.18	
2020	43.23	41.81	32.52	6.88	6.65	5.17	
2021	45.08	43.59	33.57	7.17	6.93	5.34	
2022	46.37	44.84	34.20	7.38	7.13	5.44	
2023	48.05	46.46	35.09	7.64	7.39	5.58	
2024	49.43	47.80	35.75	7.86	7.60	5.69	
2025	50.85	49.16	36.40	8.09	7.82	5.79	
2026	52.39	50.65	37.47	8.33	8.06	5.96	
2027	53.97	52.18	38.57	8.58	8.30	6.13	
2028	55.46	53.61	39.60	8.82	8.53	6.30	
2029	56.99	55.08	40.67	9.06	8.76	6.47	
2030	58.64	56.68	41.82	9.33	9.02	6.65	
2031	60.35	58.33	43.01	9.60	9.28	6.84	
2032	62.11	60.03	44.23	9.88	9.55	7.04	
2033	63.93	61.78	45.49	10.17	9.83	7.24	
2034	65.80	63.58	46.79	10.47	10.11	7.44	

Note - Delivery charge of $3.52 per Barrel added to commodity cost.



GLOBAL INSIGHT

Energy Price Forecast

Prepared for
Seminole Electric

June 2005

GLOBAL INSIGHT, INC.
24 HARTWELL AVE., LEXINGTON, MA 02421

Contributors

Mary Novak
Managing Director, Energy Services & Oil
(781) 860-6057
Fax: (781) 860-6332

Jim Osten
Principal, Natural Gas
(781) 860-6730
Fax: (781) 860-6332

Margaret Rhodes
Manager, Energy Forecasting & Power
(781) 860-6650
Fax: (781) 860-6332

John Dean
Consulting Economist, Coal and Nuclear
(301) 815-5470
Fax: (301) 815-5470

Hongyan Lin
Economist, Oil
(781) 860-6459
Fax: (781) 860-6332

Yanqun Shi
Economist, Natural Gas
(781) 860-6454
Fax: (781) 860-6332

Junya Tanizaki
Economist, Power
(781) 860-6704
(781) 860-6807

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PETROLEUM OUTLOOK

Short-term Outlook

Overview

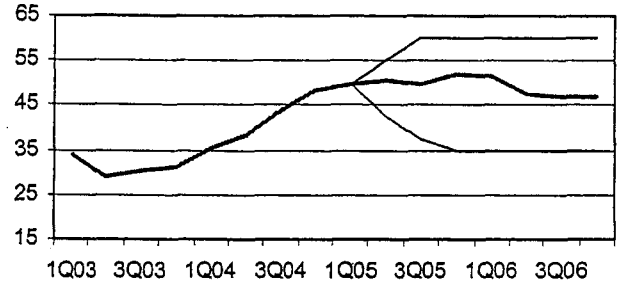
The past month has done little to ameliorate the "anomalies, paradoxes, mysteries, and uncertainties" we commented on a month ago. Crude price have fallen further, scarcely surprising as stocks have risen higher, but despite crude stocks in the United States now at levels last seen in mid 1999, when the price of WTI was around $20/barrel, prices still remain close to $50/barrel. Accepting that the historic relationship between crude prices and stock levels in days cover is currently in abeyance, nevertheless one must ask how much longer can stocks go on building without some major downward adjustment in prices? Latest data from the IEA includes a further upward adjustment to first quarter OECD stock levels so that end March cover is now estimated at some 53 days. If OPEC carries on producing at close to current levels, as it is indicating it will, then total OECD stocks could potentially remain around 53 days all year. If that is so then there is no reason to expect serious problems in the fourth quarter, and one of the key underpinnings of high prices would be removed. For the present, however, the market is likely to remain skeptical of such a potentially rosy outcome and the latest fall in prompt prices has merely served to steepen the contango; clearly concern remains about the fourth quarter.

OPEC's stance cannot be taken for granted. Although Ministers take every opportunity to emphasize their role in promoting market stability and price moderation, the facts are not so clear. Several points should be noted: (1) first quarter production was at least 0.5 million b/d below that in the fourth quarter, (2) April output barely exceeded the new 27.5 million b/d target for the OPEC 10, (3) discussion on the second 0.5 million b/d tranche of extra production agreed at the March 16 meeting was quickly shelved when prices softened in April, despite prices remaining at levels that OPEC spokesmen constantly affirm are "too high", (4) Saudi prices for Western markets for June are set at unattractive levels, possibly not unreasonably as it is in the East that crude stocks are low, but scarcely a factor promoting lower prices. OPEC will have a few weeks to digest the implications of the latest IEA data, and June's data will be published nearly a week before the next Ministerial meeting, on 15 June. We would not be surprised to hear talk of output cuts.

Although global stocks appear to be rising strongly, it is more often US data that moves the market. US refineries have been slow to return from maintenance, but are expected to ramp up output steeply in coming weeks which will pull down crude stocks. Gasoline stocks will decline anyway. Although both of these developments are normal for the time of year, reports of lower stocks could put an end to further falls in the crude price. Moreover, the next bout of speculative pressure could be an upward push.

Our expectation is that prices will not fall much further, will hover around current levels for a month or two and will then begin to rise again. OPEC actions could be the factor that will precipitate the turnaround, but may not be. We expect that concerns about the fourth quarter will remain, and will focus on the increase in call between the third and fourth quarter without looking too closely at the role that stocks might play in alleviating this increase. An outside possibility exists, however, that slowing economic growth and further rises in stocks could see prices plunge sharply.

WTI Price Outlook Scenarios
(Quarterly, dollars per barrel)



Market Review

Average prices in April were lower than in March as the market seesawed downwards. WTI peaked at nearly $57.50/barrel on April 1, fell to around $50/barrel and subsequently spiked to nearly $55/barrel in the middle weeks, and ended the month some $7/barrel below where it started, having briefly dropped below $49/barrel on April 29. In early May prices encountered an important psychological support level at $50/barrel, and tended to rebound quickly whenever they edged below this level. WTI broke through the barrier in mid May and is currently trading n the $47-48/barrel range for prompt crude. The market in the Atlantic basin is still characterized by a steep contango, with August WTI trading at over $2/barrel above June, and December at nearly $4/barrel above June. Although this reflects prompt weakness and expectations of later strength, paradoxically it also helped to underpin the $50/barrel support level as any fall was quickly offset by short covering, which can be profitable in this market structure.

Marker Crude Prices
(Dollars per barrel)

	March	April	May 1-18
WTI	54.28	51.89	49.98
BFO	53.03	52.85	48.78
OPEC Reference Basket	49.49	47.68	46.85

BFO prices have moved broadly with WTI but the differential between the two markers has become very narrow. WTI prices are depressed by very high crude stocks in the Midwest, as refineries have been slow to return fully from maintenance. Meanwhile, BFO prices have been supported by an open arbitrage to Asia

Pacific for Atlantic Basin sweet crudes. Movements of West African crudes to Asia Pacific in May are expected to be at the highest level since last October, when refiners were building stocks for the winter.

A number of factors underlie the downward trend in prices. Rising US crude stocks, seen as a proxy for global stocks, have reached levels not seen since July 1999. Gasoline stocks are also looking healthy, although the market is still nervous about the summer. The prospects for total crude supply look good following upward revisions to OECD stocks data and as OPEC output continues to rise and is seen as rising further, albeit there remains an imbalance in terms of crude quality, with the market looking for light/sweets and only heavier/sours on offer at the margin. Saudi Aramco reports that is has offered its term customers more crude but has had no takers of the quality on offer. There seems to be no shortage of prompt supplies. The belief is developing that demand growth rates are slowing; concern about the impact of high oil prices on economic activity is growing, while the data suggest slowing growth in the United States, and possibly China, the two primary motors of oil demand growth. Speculative support has also faded as strengthening of the U.S. dollar has contributed to the hedge funds moving investments away from commodities and into currency. The net long position of the non-commercial players on NYMEX has fallen very sharply, from a new peak at the beginning of April at over 88 thousand lots, most recent data shows holdings down to less than one hundred lots.

For some weeks, there was a widespread feeling among market analysts and commentators that prices "ought" to have fallen further. Most believed that the $50/barrel support level would eventually be breached and then prices would fall to the mid $40s/barrel, before rising again later in the summer and, in the view of some, reaching new records next winter. Now that the $50 support level has been breached, the market needs to catch its breath and decide where it goes next. The contango structure is still being maintained, however, by strong expectations of tightness later in the year, whether in crude markets as the U.S. and Asia-Pacific compete for available supplies, or in product markets as demand stretches the capabilities of refining systems, especially in the United States, and has actually deepened since mid month.

Demand and Supply Fundamentals

Economics

Doubts about the world economy's short-term outlook have once again increased, mainly because of renewed inflation worries, high global energy prices, and signs of weakness in some G-7 economies. Furthermore, the global economy's growth engine—the US economy—appears to have downshifted this year more than had been anticipated by most forecasters, including Global Insight. This less robust economic outlook is reflected in recent financial market volatility and lower yields on long-term government bonds. While the downside risks have increased, one should not exaggerate them. Despite its slowdown, the US economy still has a considerable amount of steam, most of Asia outside of Japan is going very strong, and other emerging markets are growing at paces well above their trend. In a simi-

lar vain inflation concerns appear to be excessive, since the global economy's persistent gap between potential and actual output should continue to constrain inflationary pressures around the globe, as well as dissuade central banks from tightening their monetary policies too aggressively. Furthermore, periodic currency appreciation in countries that float their exchange rates against the US dollar has further reduced inflationary pressures in many countries, including most major economies in Europe and Asia, giving the monetary authorities a strong reason to delay raising their policy rates. To be sure, the dollar's depreciation does act as a headwind for economies with floating currencies against the greenback, such as the Eurozone members. In a world where the US economy remains the main engine of global growth, however, a depreciating US dollar will be the only remedy for avoiding global stagnation. Given the huge US current account deficit, there can only be two ways of escaping from this predicament. Either the other major industrialized countries adopt policies that put their economies on a much more robust growth path, or there will be a dollar crash and US recession, which would in all likelihood trigger a global recession and unleash deflationary pressures around the globe.

Forecast Highlights: Global Insight's latest bottom-up forecast of the global economy, which was completed 15 May, projects world economic growth to slow from 4.1% in 2004 to 3.1% in 2005. The estimated number for 2004 represents a substantial improvement from the world economy's lackluster performance during the preceding three years; however, it no longer has any significant cushion to allow for potential policy errors or external shocks, since the projected, 3.1% annual pace is equal the global economy's long-term trend growth rate. On a year-on-year basis, we estimate the world economy's quarterly growth decelerated to 3.5% in the fourth quarter of 2004, after having peaked at 4.4% in the second quarter of last year. We estimate global growth further decelerated in the first quarter of this year, to about 3% year-on-year (y/y), but moderating global oil prices and strong international trade growth should sustain the pace close this trend rate for the remainder of 2005. With recent data releases indicating that the US economy is holding up better in the second quarter than had been anticipated, we expect adjustments to our forecasts will elevate our June global GDP growth projections by at least one or two tenths of a point, which puts the world economy in a less-vulnerable position in case there are adverse shocks or policy errors.

Real GDP Growth, World and Major Seven Economies
(Year-on-Year percent change)

	2004	2005				2006
	Q4	Q1	Q2	Q3	Q4	Q1
US	3.9	3.6	3.5	3.4	3.2	3.0
Canada	3.0	2.9	2.5	2.4	2.6	2.7
France	2.3	2.0	1.8	2.3	1.9	2.0
Germany	0.4	0.5	0.5	0.9	1.6	1.3
Italy	0.8	-0.2	-0.3	-0.4	0.5	1.3
UK	2.9	2.8	2.4	2.4	2.2	2.2
Japan	1.0	0.3	0.7	1.1	1.5	1.3
World	3.5	3.1	3.0	3.2	3.2	3.1

Demand

Latest estimates of demand continue to show divergent views of the prospects for this year. Whereas the IEA has made another marginal reduction to its growth estimate, albeit leaving it at 1.8 million barrels per day (b/d) in round numbers, and most other analysts are also tending to hold or even reduce their growth estimates, this month the U.S. Department of Energy (DOE) has *increased* its estimate of growth to 2.3 million b/d. The increase results from a 0.1 million b/d downward adjustment to 2004 actuals, but the effect is to leave the DOE much more optimistic than others.

Provisional demand data for the first quarter shows European demand much weaker than expected, primarily due to very low deliveries of gasoil and diesel in Germany. This may be partly because the timing of Easter meant the reduced number of working days occurred in the first quarter this year, but also reflects the ongoing reluctance of German consumers to restock with heating oil at current prices, and may be indicative of economic weakness. Elsewhere North American demand also shows signs of a slowing in gasoline sales, thought to be a response to high prices at the pump, and in diesel, as truck tonnage movements are reported down. Fuel oil use has been high, however, in response to high natural gas prices, and jet continues to grow strongly. In Asia, Japanese nuclear power station output remains below expectations which results in increased use of low sulfur fuel oil (LSFO) and crude for direct burning, and in South Korea demand has recently been looking up, with higher consumption in both the industrial and transport sectors.

For China, there are the usual conflicting reports. Some reports focus on signs of a slowing in apparent demand, but this is heavily influenced by stocks movements, which are believed to have been abnormal over the past year. If this effect is excluded, it may be that a more steady growth pattern can be seen in which slowdown is scarcely evident. A further complication is the impact of Government price control measures that shield consumers from the full effect of international prices and so diminish the incentive to economize. At the same time, however, the inability to recover their costs discourages traders from importing products, so supply falls short of potential demand. If domestic oil prices were raised and electricity prices de-controlled, that would end one constraint on consumption, but it might also lead to price-induced conservation. What the net result of these two effects would be remains a matter of substantial uncertainty.

Non-OPEC Production

There is general agreement that non-OPEC production will increase this year but views differ concerning the scale and timing of the increase. There is also general agreement that, whatever the increase, it will not match the rise in demand so an increased call on OPEC is inevitable. The uncertainties over timing are significant in that most of the increases are scheduled for the second half of the year. If they come through on time, that will ease the pressure on OPEC and the reduction of its spare capacity cushion in the winter quarters. If the more pessimistic estimates

prove correct – especially if combined with robust demand growth – then the winter quarters could be very tight indeed.

Globally production from around 60 new projects is due this year but the location of the largest scheduled increments - Russia, Brazil, and Angola, with increases also due in the U.S. Gulf of Mexico - explains and underlines the uncertainty over timing. In Russia conflicting projections create uncertainty, while in the deep offshore waters of Brazil and Angola the scope for last minute technical problems remains substantial. In the Gulf of Mexico there remains scope for further technical problems and delays, and for summer disruptions from hurricanes; full recovery from hurricane Ivan is still some months away. The BTC pipeline carrying Azeri crude from the Caspian to the Mediterranean is due to start filling and testing in July, with first exports due in the fourth quarter, resulting in further large increments to supply next year, but any problems that come to light during testing could delay first exports into next year. Estimates of total annual growth are between 0.5 million b/d and 1.0 million b/d, but in the light of the record of recent years we are inclined to discount the higher end estimates and continue to include a non-specific downward adjustment averaging some 0.2 million b/d over the balance of the year.

OPEC Production

OPEC output rose by a further 0.5 million b/d in April to approaching 29.5 million b/d (IEA assessment), with the largest increase again in Saudi Arabia but with other countries recording smaller rises, though Iraq remains stuck on some 1.8 million b/d. Although OPEC ministers continue to make much of their efforts to supply what the market needs and to contribute to market stability and a lessening of prices, these protestations need to be tempered by the facts, as emphasized in the Forecast Highlights section; OPEC rhetoric and action continue to be slightly out of sync. In fairness, it should be added that further output increases are expected in May, but any decision on further formal additions now seems scheduled to await discussion at the June 15 meeting.

The IEA's assessment of OPEC capacity is unchanged this month, save for a decision to settle on a figure for Saudi capacity of 10.5 million b/d in place of the 10.0-10.5 range shown for some months, and leaves effective spare capacity at some 1.3 million b/d, almost all in Saudi Arabia. The assessment of OPEC capacity will be raised steadily as the year progresses as a succession of new projects come on stream. By the end of the year, sustainable capacity should be conservatively at least 0.5 million b/d higher than at the beginning. This excludes any increases in Saudi Arabia, where the build up in Qatif and Abu Safah should take the total increment to 1 million b/d or more, while additions from countries where current reliable information is lacking may add more still.

OPEC Compliance in April 2005
(Million barrels per day)

	Target as of Mar.16	Production (1) Apr 2004	Production vs. Target	Estimated Sustainable Capacity (2) (IEA Mar 05)	Spare Capacity
Algeria	0.878	1.35	0.47	1.35	0.00
Indonesia	1.425	0.95	-0.48	1.00	0.05
Iran	4.037	3.90	-0.14	4.00	0.10
Kuwait (3)	2.207	2.45	0.24	2.50	0.05
Libya	1.473	1.64	0.17	1.65	0.02
Nigeria	2.265	2.45	0.19	2.45	0.00
Qatar	0.713	0.78	0.07	0.80	0.02
Saudi Arabia (3)	8.937	9.45	0.51	10.50	1.05
UAE	2.400	2.45	0.05	2.55	0.10
Venezuela	3.165	2.16	-1.01	2.20	0.05
OPEC 10	**27.500**	**27.57**	**0.08**	**29.00**	**1.43**
Iraq (4)		1.83		1.95	0.12
Total OPEC		**29.40**		**30.95**	**1.55**
Excl. Venezuela/Nigeria/Indonesia/Iraq					1.33

1. Secondary source estimates of OPEC production regulary differ. The above reflects the IEA estimate except for Iraq.

2. Capacity figures are levels achievable within 30 days and sustainable for 90 days.

3. Figures for Saudi Arabia and Kuwait each include 50% of the Neutral Zone.

Note: Saudi Arabia capacity figure represents mid point of IEA's estimate of 10.0-10.5. Saudi Arabia itself claims its capacity is now 11 million b/d.

4. Iraq estimate represents the average of the past twelve months. Post war production has not yet exceeded 2.5 million b/d. Iraq capacity figure represents gross capacity, before any reinjection.

Market Balance

Total OECD Commercial Inventories

Following last month's large upward adjustment to the estimated end January stock position, another large adjustment has been made this month, this time to the end February position. End February stocks are now assessed as 21 million barrels higher than was thought a month ago. The first look at the end March position for total OECD suggests a small stock draw during March, as refinery maintenance allowed crude stocks to rise while product stocks were drawn down, more than offsetting the build in crude. This leaves end March stocks 119 million barrels above those of March 2004. The first quarter as a whole now shows a contra-seasonal build of 0.2 million b/d for total OECD and forward cover at the end of the first quarter is assessed by the IEA at 53 days, two days above year-ago levels. This is the first time since 1996 that total OECD stocks have built in the first quarter; by comparison, the past five years have seen an average first quarter stock draw of some 0.4 million b/d.

Turning to the global position, the top-down balance still suggests demand exceeded supply in the first quarter, suggesting a stock draw of around 0.5 million b/d was necessary. A stock draw of around 0.7 million b/d in non-OECD areas is thus indicated. Increasing evidence is accumulating that Chinese stocks were drawn down heavily in the first quarter, so a large non-OECD stock draw is certainly credible although the size of the implied draw is quite large. Any reductions in demand estimates for the first quarter in non-OECD areas would reduce the scale of the implied stocks draw.

The table below shows the overview position in each region and illustrates the unbalanced nature of stocks holdings. It also shows the danger of making generalizations about stocks levels. Total OECD stocks are high while those in Asia-Pacific remain low as stocks in OECD Asia Pacific represent only some 17% of total OECD stocks. Moreover, within a region stocks for an individual product can be worryingly lower or higher than for all products taken together.

Crude and Product Stock Levels by OECD Regions at end March
Relative to Average of Previous Five Years

	N. America	Europe	Asia-Pacific	Total OECD
Crude	High	High	Low	High
Products	High	High	Low	High
Total	High	High	Low	High

Atlantic Basin Inventories

US

Crude stocks have continued to rise, notably in PADD 2 and at Cushing, thereby contributing to softening of the WTI price, as well as price more generally. Total stocks at end April reached 327 million barrels according to weekly data, up by 10 million barrels since end March and some 17 million barrels above the average of the previous five years. Imports were again above 10 million b/d, as they have been for eight of the past twelve months, but were scarcely changed from March's level, and the other element of supply, domestic production, fell slightly. The major reason for the further rise in stocks was the slow return of refineries from maintenance: crude throughput in April averaged 15.3 million b/d, below the average of the previous five years, and only 0.13 million b/d above March's level. Runs this year, however, have been atypical, with January to March all well above any previous year's levels, but with April barely above March, whereas the average March-to-April increase of the previous five years was 0.7 million b/d. Runs are still expected to be ramped up sharply once maintenance is finally completed to well over 16 million b/d and utilization later in the summer could again match last year's figures of around 97%. This will inevitably pull crude stocks down and imports will need to average consistently above 10.5 million b/d over the summer months in order to keep end-summer stocks in line with the average of the previous five years.

Gasoline stocks rose by 2 million barrels in April, to end the month at 214 million barrels, 8 million barrels above the average of the previous five years. A rise like this is around the norm for the time of year. Although the average gasoline yield over April was a new record high for the month, it was eclipsed by the increase in distillate yields as refiners apparently took advantage of the high absolute level of gasoline stocks to maximize distillate yields and thereby benefit from distillate and diesel prices above those of gasoline, as well as contributing to replenishing low distillate stocks.

Despite this unseasonal preference for making distillate over gasoline, distillate stocks still fell by 2 million barrels over the month to 102 million barrels, slightly below the average of the previous five years of 105 million barrels, but above the past two years. A modest stock draw in April is normal, with the stock build in preparation for winter normally beginning in May. Achieving an adequate stock build over the summer still should not prove a problem as gasoline yields are not expected to need to be exceptionally high, allowing distillate yields to move towards the top end of the range.

Europe

According to provisional Euroilstock data, crude stocks in Europe fell slightly during April, but remain very high, close to record levels for the time of year. The narrow differential between BFO and WTI has kept the transatlantic arbitrage closed and penned North Sea crudes into Europe. The arbitrage is expected to open in coming months and North Sea output will reduce with normal summer maintenance, so stocks are expected to drift downwards over the summer but with rising output in Nigeria and Libya, and later in the year from Azerbaijan, Europe should remain well supplied with crude.

Gasoline stocks have been falling since January, following the normal seasonal pattern, after the abnormal rise in January. With continuously declining demand, stocks would be expected to be at the bottom of their historic range, but in fact current gasoline stocks are above the level of three of the past four years as, despite modest yields, total levels of throughput have been high, producing high gasoline output. Stocks of gasoline in independent storage in the Rotterdam area were at the highest early May level of the past ten years.

Gasoil stocks are also high. European refinery production and Russian exports have both been at record high levels for the time of year while demand has been weak as German heating oil consumers continue to avoid buying at high prices. Stocks in independent storage in the Rotterdam area, however, are relatively low.

Prospects for the Global Balance

The upward revisions to the end January and end February stocks positions over the past two months have put a rather different gloss on the global outlook. Stocks in terms of days cover looked low at 50-51 days, but the end March level of 53 days (will next month's data show another upward adjustment, this time to March?) provides a much more secure basis for the remainder of the year. More-

over a recent statement from the OPEC President that OPEC will continue to increase its output to 30.5 million b/d should reassure the market that OPEC is not currently thinking of a cut to output when ministers meet on June 15.

Assuming that OPEC output continues around current levels through the summer in order to allow stocks to build, and that demand and non-OPEC supply turn out broadly as currently projected, then global stocks could remain between 53 and 54 days for the remainder of the year, a level that just a few months ago seemed inconceivable, but now possible because of upward revisions to stocks and a change in OPEC attitude. The exact end year position obviously depends on the particular combination of supply and demand projections, hence a projection based on the IEA's figures plus flat OPEC output implies around 54 days by the end of the year, while the U.S. DOE, which has higher projections for demand growth and lower projections for non-OPEC supply, estimates cover equivalent to 51 days. Our projection, assuming demand might still prove a little stronger than current estimates and that new non-OPEC supply might suffer some deferments, indicates end year cover of around 53 days.

This is all rather different to the way things looked only a short while ago. On these figures the summer stock build should certainly prove sufficient to allow a draw in the winter quarters. Even a fourth quarter stock build is not impossible, indeed balance suggests that unless OPEC cuts back then a small build looks likely. Increases in output from new capacity to be commissioned in Nigeria and Iran over the summer months now look secure, and neither country will be inclined to make compensating cuts elsewhere. The outlook for the fourth quarter could still vary between tight and relatively easy depending on OPEC capacity increments over coming months.

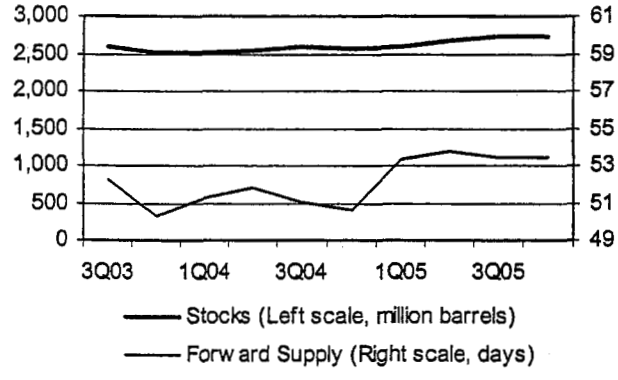
Stock cover of this magnitude would traditionally have been associated with much lower prices, but that link between stocks and prices remains broken, at least as an indicator of absolute price levels. On the other hand, the rising level of stocks in the Atlantic basin is undoubtedly one factor responsible not only for the steep contango in Atlantic basin prices, but also for the decline in the absolute level of prices. How OPEC will view this turn of events remains to be seen.

Turning away from global stocks levels and looking at the regional and quality imbalance, however, yields a different perspective. U.S. refinery runs have been kept low by an extended maintenance season, but could rise by as much as 1 million b/d over coming weeks, which would reduce crude stocks by nearly 30 million barrels over a month unless supply increases to offset the fall. Domestic production should rise in the third quarter but imports will need to rise too. Much depends on the quality of crude that U.S. refiners will seek. Many are understood to have invested heavily over the past year so as to be able to handle higher volumes of heavy/sour crudes, on which margins are potentially more attractive, and if that enables them to absorb high volumes of Middle East crude without needing to compete unduly with Asia/Pacific refiners for light/sweets then obtaining the necessary levels of imports should not be a problem. Crude stocks would still fall seasonally, but the fall should not cause alarm. Given the unpredictability of mar-

ket reactions to stocks reports over recent months, however, a rational response is far from assured. Similarly falling gasoline stocks over May to August, although a normal seasonal pattern, could easily spook a market looking for excuses to mark up prices.

Asia/Pacific also remains a wild card. Cold weather in the first quarter has depleted stocks of middle distillate heating fuels in Japan and Korea, and Chinese stocks both of crude and products are believed to have been run down sharply. Refineries in the region are mostly running close to capacity and if China needs to import to replenish depleted inventories and if recent firm demand in Japan and Korea continues, then the call for both crude and products imports from outside the region could prove substantial.

OECD Commercial Stocks and Forward Supply



Crude Price Forecast

Base Case

Now that the $50/barrel support level for WTI has been breached there would appear to be scope for some further downside movement in price in response to stock levels which are looking increasingly healthy, even bloated, in the Atlantic basin. How long such softness might last, however, is a major uncertainty. The global balance now looks easier, and the prospects for the fourth quarter could be seen as less worrying, but the substantial rise in the "call on OPEC crude plus stocks" between the third and fourth quarters could still worry a market focused more on OPEC's output versus capacity and less on the potential contribution of changes in stocks; a rise of say 1.5 million b/d in the call does not mean OPEC needs to increase output by that amount, as the third quarter will see a stock build and the fourth a draw, so much of the increase in call will be met by stock movements. This is not the popular perception, however, as the steep contango WTI between June and December suggests not just prompt oversupply but continued concern about the winter.

The behavior of non-commercial players on NYMEX could prove important. They have currently reduced their net long holding to virtually nil and if prices fall further might begin buying again, supporting a price rise, though they may wait a while longer to see how things develop. OPEC actions are also uncertain. Now that the balance is looking easier and prices have fallen below $50/barel the more hawkish members may want to press again for output cuts to prevent further falls in response to higher stocks. The Kuwaiti minister and OPEC President reportedly recently suggested, however, that $40/barrel would be an acceptable level for the OPEC basket, some $5/barrel below its current level. If that thinking proves dominant, then no cuts would be expected.

We still expect prices to remain below $50/barrel for a while, reflecting the ready availability of prompt crude and oversupply in the Atlantic basin, but $50/barrel proved a much more resilient support level than we had anticipated, and the hedge funds unexpectedly fast liquidation of their holdings now makes them more likely to support a rise than a fall in prices. Even if OPEC do not make actual cuts, the tone of their pronouncements may change. Accordingly we now think that prices may even recover sooner than previously projected, on the back of falling stocks of crude and gasoline in the United States, and continued concerns about the winter, even despite the easier outlook for the balance.

Short Term Marker Crude Price Forecast
(Dollars per barrel)

	Apr	May	Jun	July	Aug	Sep	Oct
WTI	52.85	50.00	48.50	49.00	49.50	50.00	51.00
BFO	51.89	48.75	47.25	47.50	48.00	48.25	49.00

Alternative Cases

High-Price Scenario: A higher price scenario could result from:

- Further terrorist attacks/political tension in the Middle East;
- Geo-political concerns;
- Renewed Chinese imports;
- Major losses in Nigeria, Iraq, or elsewhere;
- OPEC implementing cuts in fear of prices falling too rapidly;
- Disappointments with increments to OPEC capacity;
- Further disruptions and delays in new non-OPEC production;
- Further upward pressure from financial traders.

The greatest concern remains terrorist action, which could result in price spiking to very high levels. Absent such a development, prices above $60/barrel for WTI now look less likely but remain possible. Any major loss of output anywhere

would cause a spike, as the spare capacity cushion will remain thin all year. It is uncertain what scale of loss would drive governments to take emergency action to curb consumption and release strategic stocks, however if they did so we would be in a wholly different world and prices would depend on these reactions and their timing. Cuts by OPEC or a succession of geo-political alarms could push price sharply up.

Low-Price Scenario: A lower price scenario could result from:

- Recession or at least further economic slowdown, and resultant substantially weaker demand, especially from the United States and China;
- Further upward revisions to stocks data;
- Further easing of concerns about loss of supply due to higher stocks and slowing demand growth;
- OPEC are slow to cut as stocks rise due to internal dissent;
- Non-OPEC supply proves more robust than expected;
- Financial traders build net short positions.

In this situation, prices would moderate steadily but would remain above $35/barrel due to the perception of tightness next winter. It will still take some time for a sizeable cushion of spare capacity to be restored.

Oil Product Prices

Gasoline

Weekly data for April show demand growth of 0.9%. Monthly data for the first quarter now shows growth of 1.2%, less than indicated by previous weekly data. Monthly gasoline demand data is very volatile, hence, year-on-year comparisons can be misleading as the growth in any individual month is influenced by developments in the same month a year earlier. Hence, although U.S. gasoline consumption remains on a growing trend, the rate of growth is still highly variable. By removing seasonality and reducing month-to-month volatility by taking a twelve month moving average, it is clear that the rate of growth has been slowing since the middle of last year, when it had reached 2%; it is now down to below 0.9%. Data from the Department of Transportation show a decline in "Highway miles traveled" since around the same time. Moreover, the DOE's "Product Supplied" data does not, strictly speaking, report actual demand, i.e. purchases at the pump, but deliveries from primary storage into the distribution system which take place some weeks in advance of purchases at the pump and are based on assumptions about consumer demand. If motorists reduce consumption, there will be a lag before this shows up in DOE statistics. Nevertheless, a recent reported survey showed 58% of U.S. motorists saying they would drive less if prices stay high. All these signals seem to suggest that demand is slowing, possibly due to price, but whether this will seriously reduce demand for the summer driving season remains to be seen. The DOE's forecast is unchanged this month at 1.8% growth for the summer quarters.

Stocks at end April were high in absolute terms and closely in line with the average of the previous five years in terms of days cover. As mentioned in the stocks section, refiners achieved a new record high yield of gasoline for April, at 57.1%, and this despite also setting a new record high yield for distillate. Distillate stocks are towards the low end of the range for the time of year but there is plenty of time to raise them before winter, so there is no reason to think that gasoline yields cannot be very high this summer if necessary. Imports of finished gasoline and components, which amount to around 10% of total gasoline supply, have also been high recently, with imports of finished gasoline very high and the 4 week average for total imports including components has been over 1 million b/d for the past three weeks. The issues of unscheduled refinery outages and grade proliferation remain sources of concern, however, despite a supply outlook that looks healthy.

Gasoline prices relative to crude were volatile over April and reports of problems at refineries, mostly on gasoline units, resulted in upward spikes, but latterly high imports and rising stocks have led to a softening. Spreads are currently very close to where we projected for the month. Supplies of high octane components remain tight but this does not seem to be seriously affecting prices of regular grades. The arbitrage from Europe has only been open intermittently as European prices, although falling, have remained stubbornly high, and further adjustments are still expected. We expect U.S. prices relative to crude to continue to soften through the summer as it becomes apparent that supply is adequate, and for European prices to fall further to maintain a (mostly) open arbitrage. The forecast spreads are unchanged.

Distillate

Latest data brings yet another marking down of distillate deliveries. Although March still shows a year on year increase of 4.5% following cold weather early in the month, data for January and February now point to declines in both months. Overall deliveries over the first quarter now exactly match those of last year. Within the total, highway diesel continues to grow, although growth in January and February was well below the trend rate, while deliveries of heating oil were very low, as the weather in the North East in January and February was much milder than in the previous two winters. Weekly data for April shows total distillate deliveries 2.2% up on a year ago.

Stocks are towards the lower end of the historic range but we do not anticipate a problem in replenishing them in time for next winter. Although by this stage of the year distillate yields in the refineries would normally be well down on their early winter peak and moving toward their mid summer low, this year yields have risen steadily since January with April a full percentage point above any previous April, at just over 26%, a level not normally reached till October or later. It appears that, in distinction to the market, refiners felt sufficiently relaxed about the gasoline position to be able to maximize distillate yields to take advantage of distillate and diesel prices above those of gasoline in April. With diesel prices still well above gasoline, and expected to remain so for a couple of months more at

least, we expect refiners to continue to favor distillate, though recent data suggests that to do so does not necessarily imply low gasoline yields. Imports in April were lower than in the first quarter but were in line with April imports over recent years; indeed during April the Gulf Coast was exporting diesel to Europe where prices were very high, a reversal of the more usual direction of trade.

As mentioned last month, to see such high prices this late in the year is unprecedented. April spreads for all three middle distillate grades were not only extremely high for April but in each case set a new record high for any month of the year, at least for the past ten years. It is not possible to explain these prices in terms of developments in the U.S. market alone, such prices must rather be seen in the context of very high prices in Europe also, which in turn partly reflect high prices East of Suez. The whole complex of high prices seems to be inter-related, with extra Indian demand the only clearly identifiable unusual feature, since elsewhere in the East demand has been relatively muted in the face of high prices. Spreads of all three grades in New York Harbor have now come off several dollars from the peak levels reached in late April, but are still extremely high for the time of year. In Europe, spreads are narrowing and in the East we expect some moderation as Persian Gulf refineries return from maintenance. Nevertheless, Far East maintenance only peaks in May and June so some additional demand may still be expected there and India continues to draw in low sulfur diesel. China remains a major uncertainty. Its stocks are believed low and there are reports of diesel shortages in the retail sector, but Government price control measures make importing product uneconomic as local prices are below international prices.

In the absence of any real clarity as to exactly why global middle distillate prices should be at such unusually high premia, we feel the best course is to profile spreads back down to lower levels but to keep them at the upper end of historic ranges.

Residual Fuel

High natural gas prices have continued to contribute to increased resid use by utilities. Deliveries over the first four months of the year were higher than for the same period in the previous three years. Refiners, meanwhile, continue to squeeze resid yields down, leaving an increased proportion of total deliveries to be met from imports; 51% of deliveries were supplied by imports in the January to April period. In addition, increased Mexican utility demand has resulted in increased exports.

Regarding prices, the past month has seen a change from the trend we commented on a month ago. Whereas resid prices had been following crude closely, with discounts little changed since last October, over the past month, as crude price have fallen, low sulfur resid prices have declined more slowly, and high sulfur grades have actually risen in absolute terms. Discounts relative to crude have thus narrowed by some $7-8.barrel. The strength of higher sulfur grades has been caused by the coincidence of higher Mexican demand and reduced exports from Venezuela due to refinery maintenance, and partly by strength of import demand in Asia where refinery maintenance has reduced local supply. With the end of main-

tenance around the world, the expected summer peak of Russian exports, and with more increases in Middle East crude supply, the supply of high sulfur resid is expected to ease and discounts to widen again. Similarly for the lower sulfur grades the relatively higher price may draw in more exports and push prices down again relative to crude. We are not, therefore, assuming that recent price strength heralds the beginning of an imminent major narrowing of resid spreads, but as crude prices begin to harden again we expect discounts to widen again.

Long-term Outlook

Making the link between the immediate and the longer term is always a challenge in projections that extend some years into the future. Changes in the here-and-now do not necessarily mean that the outlook for say five or ten years hence has changed. However, crude oil prices have stayed at or near $50/barrel since October 2004. Faced by a short term change of this magnitude the requirement to consider the implications for not just the short/medium term is unavoidable. It has become our view, however, that developments over recent months have implications for the longer term.

Changes since January include the following:

- Prices have remained much higher;
- Nevertheless, demand expectations have been stronger;
- Supply expectations have been weaker; with yet more non-OPEC disappointments; and increased uncertainty over OPEC capacity increments;
- The call on OPEC crude has increased;
- OPEC aspirations have changed.

It is the final point that we believe is crucial. Up till early April high there did not seem to be any substantial evidence that prices were having any effect on demand. All the indications were that demand growth estimates for 2005 might again be understated and that OPEC would again be called on to produce at close to capacity. Over the course of April some doubts have begun to creep in regarding the apparent insensitivity of demand to price, but nevertheless the high call on OPEC crude this year seems unlikely to change even if there are no more increases in demand growth estimates. OPEC members have observed the inexorable rise in prices since early 2002, but especially since early 2004, an era when price have consistently exceeded $30/barrel, and have seen demand rising strongly, apparently oblivious to price. If the market could bear $50/barrel, why should OPEC settle for less?

With the formal abandonment of the $22-28/barrel price band, OPEC has set itself free to decide on a new target price. Whilst no formal decision has yet been made, aspirations have risen with rising prices. OPEC now seems to aspire to a price for its Reference Basket (ORB) of $40-50/barrel. Until the middle of 2004 the value of the ORB was $0.50-$1.50/barrel below Brent. Since mid 2004, however, as prices have risen sharply and as OPEC output increases have put more heavy crude onto the market, the value relative to Brent has fallen to a discount of

$3-5/barrel. An aspiration of $40-50/barrel for the ORB therefore implies a range of say $44-54/barrel for Brent and somewhat higher for WTI

With aspirations having ratcheted up, the issue then becomes: if OPEC members now aspire to prices in this range, what is there to stop their achieving them?

Supply Prospects

Non-OPEC output is not expected to be able to respond much in the next few years as oil companies are already fully committed to a number of long lead time projects and do not have the capacity in terms of manpower to start additional projects. Oil companies anyway remain cautious and will not assume that high prices are necessarily here to stay, but will stick with lower "screening values" for assessing the profitability of projects.

As for OPEC, with production close to capacity the old problem of cheating on quotas has, for the present, ceased to be an issue. Even if those members with increments to capacity scheduled to come on stream over the next year or so choose to produce from those increments, regardless of any agreements on production restraint, that might still have little impact on prices, as many of the increments are of light sweet crudes that can be easily placed in the market without depressing prices. Relatively few increments to capacity are definitely expected in the Middle East, and even if those that are expected produce at maximum, Saudi Arabia could easily cut back its own output by sufficient to keep prices from falling, and would probably involve other Arab Middle East producers in the policy.

It has been observed that OPEC has been powerless over recent months to stop prices from rising. That is largely true, but it remains far from powerless to stop them from falling. Even just the threat from Saudi Arabia to cut back on output would probably be sufficient to end a fall in price in current circumstances. So how far would the Saudis be prepared to allow prices to fall before stepping in and cutting output?

In recent high level discussions with the U.S. Government prominent Saudis have opined that prices around $55/barrel are "too high". Such references are probably to WTI rather than the ORB. That would suggest that currently it is recognised that the upper end of the potential $40-50/barrel band for the ORB is regarded as too high, too liable to induce economic slowdown at this stage of the economic cycle, and too liable to induce measures that might undermine the long term demand for oil. On the other hand it is unlikely that $40/barrel as a floor has been conceded. We therefore believe that for the next two to three years OPEC will seek to defend a floor for the ORB around $40/barrel, say $45/barrel for WTI.

Over the next few years every member of OPEC will see increments to capacity from developments already under way. The list of projects is long and includes light, medium, and heavy crudes. Longer term, however, OPEC members will have to decide how much to invest in adding more new capacity. They all recognise that most projections of the longer term future indicate an increased call on OPEC crudes, as the rate of growth of non-OPEC output falls short of that of de-

mand. On the other hand no-one wants to spend money on adding to capacity that will then sit idle as part of the spare capacity cushion that the present world oil market seems to require. In addition growing budgetary requirements from areas other than oil, notably welfare expenditure as many countries are facing high levels of youth unemployment, create increasing competition for revenues from oil. One policy option therefore would be to delay investments, just sufficient to keep the market tight and prices high. That would increase the probability of being able to utilise new capacity and not keep it idle, while also maximising the price, and making money available for other projects. The difficulty, however, is that such a policy, whilst nominally possible, would require OPEC members to show a degree of co-ordination that has historically not been seen. While competition for revenue may delay investments to a certain degree, therefore, nevertheless individual states are still likely to make their own independent decisions, each member believing that in its own uniqueness and in its ability to sell all its production without depressing the price; the problem of having to maintain idle capacity will be someone else's. Indeed, there may be some truth in this: many members face circumstances that mean that there is always a strong demand for their particular production, provided it is competitively priced relative to other crudes, and therefore that their production can be maximised with little impact on general price levels. For example:

Libya, Algeria, Nigeria	All produce light sweet crudes that are in strong demand for their quality in both Europe and North America, and increasingly even in Asia Pacific as regional production of such qualities is static while demand is rising.
Venezuela	Is close to the US, meaning freight costs are low and output can respond more quickly to demand. Supply is regarded as secure despite political differences. Many US refineries have been built specifically to use cheap extra-heavy Venezuelan crudes.
Indonesia	Produces sweet crudes and enjoys proximity to fast-growing Asian markets. Indonesia is anyway now a net importer of oil.
UAE	Most of its grades are lighter than other Middle East crudes and some are particularly highly prized in Japan for their quality.

This means that it is predominantly the Middle East producers of heavier, more general purpose crudes, Saudi Arabia, Kuwait, Iran, Iraq, and Qatar, who could face greater difficulties with marketing their output, and on whom the burden of maintaining spare capacity would primarily fall. Neither Iran nor Qatar have good track records on quota compliance, but equally neither is expected to be able to add very much to its capacity. When Iraq manages to restore and build up its output it is likely to be granted special status in relation to quotas. Thus the burden may come to rest mostly on Saudi Arabia, possibly aided by Kuwait, a situation not that different from today.

Against this background, in the longer term the spare capacity cushion could increase in size again, easing market concerns, while individual OPEC members choose to utilize the capacity on which scarce revenue resources have been spent.

All the more would this be so if, as a response to price, demand does not grow as strongly as previously projected.

Demand Prospects

At price levels around or below $50/barrel we do not believe that the resultant retail prices to consumers in OECD countries, or even in China or other richer non-OECD countries, will be high enough to provoke widespread "don't consume" decisions. Such prices may be high enough to encourage consumers to consider investing in more energy efficient appliances when those appliances are next due for replacement, but are probably not high enough to bring forward that date. The progressive introduction of more efficient appliances, notably cars, will eventually impact on demand, but it will take some years before that impact becomes sizeable. Nevertheless there are early indications that behaviour is moving in that direction, for example a downsizing by US motorists from large SUVs to medium and small SUVs. Even small SUVs may be rather fuel inefficient, but less so than their larger counterparts. With around 50% of new car sales in the US in terms of SUVs the impact of this over time could be significant. In Brazil sales of dual fuel vehicles able to run on cheap locally-produced ethanol, as well as on gasoline, have increased dramatically. In the longer term, therefore, even in OECD countries the cumulative effect of individual decisions to use energy more efficiently, aided by continuing technological progress in improving efficiency, and possibly abetted by a variety of regulatory, fiscal, or policy measures, may result in slower demand growth.

Outside OECD, however, even short term reactions to high prices may be different. Here prices may prove high enough to provoke "don't consume" decisions among poorer consumers. More importantly, however, in many such countries retail prices of fuels to households are subject to price control and are kept well below international market levels by systems of subsidies. There are signs that the burden of maintaining these subsidies at current prices is becoming intolerable for some governments. Hence there have been reports of increases in retail prices recently in a number of Asian countries, China, Malaysia, Thailand, Indonesia, Vietnam. If this trend spreads, which we expect to occur, it will have an impact on demand. Subsidies, once removed, are unlikely to be reinstated, so an increasing proportion of consumers will progressively be exposed to the true international cost of the fuels they use.

Implications for Price

Beyond the next few years, therefore, we still expect OPEC to seek to defend a price in the $40-50/barrel band, but with the progress of time this may become more difficult.

- Demand may be trimmed both by income-elasticity and price-elasticity effects, aided by technology improvements and the turn-over of the capital stock, and policy measures;
- Non-OPEC capacity will continue to rise and while we do not expect significant supply responses to price in the early years, nevertheless high

prices will provide an incentive to get projects on stream as quickly as possible;

- Later, additional non-OPEC supply may result as settled high prices are progressively factored into project evaluations;
- OPEC's own output capacity will rise, and there will be increasing pressures to use that capacity rather than keep it idle;
- The spare capacity cushion may rise, easing market concerns.

Against this background we have decided to raise our projection of prices beyond just the short term. We have projected the price of WTI to fall to around $45/barrel by 2008 and then staying fairly constant in nominal terms for some years. This implies a falling real terms price, reflecting the difficulties we believe OPEC will face in maintaining high prices; they will be forced to accept broadly flat nominal prices but will be unable to maintain their real-terms value.

NATURAL GAS OUTLOOK

Short-term

Natural gas supply trends remain negative in the United States, but slightly positive for Canada. The most recent supply-and-demand indicators show a neutral position of the market in March and April after it tightened this winter.

Canadian receipts into Alliance and Nova slightly exceeded year-ago levels while Canadian demand is down; thus exports to the United States are up. Also, Mexico is reported as having reduced its imports of natural gas from the United States. Natural gas demand appears weak, while fuel oil demand rises despite high oil prices. Although this usually signals some inter-fuel substitution away from gas, there cannot be much remaining capacity to switch. Almost all the indicators are now showing supply difficulties.

US natural gas demand fell about 6% in January and February according to EIA monthly reports. Canadian demand was also down, as high prices and weather trends contributed to weaker consumption. Most of the decrease was in the core sectors, with industrial demand down about 5%, and power generation demand actually neutral. These trends could be reflective of 2005 as a whole. Industrial natural gas consumption has been lagging output since 2003, and with manufacturing growth slowing in 2005, natural gas consumption could decrease. The power-generation sector is expected to increase demand for natural gas 6% in 2005. Significant new power generation is coming on line in Florida, and along with stringent environmental regulations, high oil and coal prices, and limited hydroelectric availability, natural gas has room to grow even with $7 prices. Overall natural gas demand will decrease by 1.6% in 2005, reflecting near $7-prices.

US natural gas prices fell to less than $7 in mid-April, and then battled back and forth, finally entering May headed lower. The June bid week price is expected to also hold at $6.62. The daily shifts in natural gas prices have apparently been following the movements of the crude oil market. Summer prices are expected to remain at $6.50–$7, as high oil prices, negative trends in U.S. supply, and the start of storage injections all contribute to a tightening market and sustained, high expectations.

The outlook for North American natural gas supply remains negative, as the huge decline in offshore production in 2004 and the recent drop in onshore Texas production would have to be reversed for it to be otherwise. Net imports of natural gas will increase in 2005, but this will only offset part of the U.S. production drop. During 2004, offshore gas production declined more than 1 billion cubic feet per day (bcf/d). In January and February 2005, Texas onshore production also fell more than 1 bcf/d. It is increasingly likely that U.S. production will decline more rapidly in 2005 than in 2004. Other information—such as expansive reserves additions in the United States, high levels of drilling, recovery from hurricane damage, and high natural gas prices—suggest some possible offsets to the recent

negative trends in production later in 2005 or in 2006. A small gain in LNG imports is expected for 2005, to a more than 2-bcf/d level.

The supply and demand balance occurs at a lower volume level in 2005 and at a higher price than in 2004. LNG imports are expected to change this deteriorating balance, but a surge in LNG imports is still several years away.

Supply

If the decline in Texas onshore production is correct, U.S. natural gas supply will decrease 2–4% in 2005. This follows a drop of 1.3% in 2004, mostly in the second half of 2005, and primarily from the offshore markets. The trends in other U.S. regions are more down than up, although the Rocky Mountains region continues to expand.

Still, there are positive trends for some areas of the US production outlook for 2005:

- Reserve additions continue to exceed production. Part of the reserve additions reflects higher prices rather than additions to discoveries or producing wells.
- The Cheyenne Plains pipeline will add 540 million cubic feet/day (mmcf/d) of takeaway capacity for the Rocky Mountains. Production is increasing in Colorado and Wyoming. Rocky Mountain production is growing around 0.3–0.5 bcf/d per year.
- Drilling activity will remain strong at 2,000 gas wells/month and a 160 increase in the rig count as of May 2005.
- Recovery from Hurricane Ivan will restore most of the 150 bcf of offshore production lost during 2004.
- Deepwater gas production continued to increase in 2004, with 14 new projects coming online. Several large offshore projects are expected to come online this year, including Thunder Horse. Shallow-water declines overwhelm the deep-water increases, however. The Minerals and Management Service (MMS) expects total offshore production to increase after 2007.

The MMS has released a forecast showing that the production from the Gulf of Mexico will increase substantially after 2007. This will be a welcome change, as Gulf production fell 500 bcf in 2004, and may continue to fall in 2005. Trends in onshore production are generally ambiguous in 2005, while trends in total production are negative. Most other onshore basins will experience neutral to net decreases in supply; thus, it is becoming more difficult to find evidence that production will reverse these negative trends in 2005.

Although net imports will increase in 2005, most of this is expected to come from Mexico and Canada rather than from LNG. For 2006, LNG will provide most or all of the gain from net trade. Although LNG imports will increase in 2005, most of the growth will come at the end of 2005 and continue into 2006.

Demand

Demand destruction is likely to occur in 2005, as a decrease in overall availability coupled with growing demand in the power sector squeeze consumption in energy-intensive industry. Thus, several sectors will be squeezed, such as fertilizers, chemicals, paper and other energy-intensive industry. Consumption levels are expected to decline despite both economic and weather trends favorable to growth. Early indicators for 2005 show a decrease in consumption of natural gas.

Power generation is growing about 1% so far into 2005. The growth rate is expected to increase this summer with hot weather. Also, low hydro levels will support an increase in natural gas use. Cooling degree-days will increase at the national level, but this will not have as great an impact on gas generation. In 2004, the Northeast and some other northern states had a very mild summer, while the South experienced fairly normal temperatures. Since most of the nation's gas generation occurs in Texas, Louisiana, Florida, and California, and since these states had nearly normal weather in 2004, the increase in gas demand in 2005 will be lower than extrapolating from national degree days.

Natural gas demand in the power sector is expected to increase in 2005, as a result of growing demand and constraints from other power sources. From 2003 to 2010, the power sector will account for nearly 80% of US natural gas demand growth. Utilization of baseload coal and nuclear plants has been trending up. During periods of slow growth, increased utilization of coal plants has meant weaker gas demand, as seen in 2004. The difference for 2005 is that demand growth of 1.2% will be higher than the increases in coal and nuclear generation, implying greater gas usage.

Price

U.S. natural gas prices fell to less than $7 in mid-April, and then battled back and forth, finally entering May headed lower before turning back up in June. The daily shifts in natural gas prices have apparently been following the movements of the crude oil market. Although other fundamentals for natural gas have slowly been shifting to a more neutral position, oil prices remain near $50/barrel and supply difficulties support high prices.

- The weather adjusted changes in storage suggest a neutral supply-and-demand balance for recent months.
- Working gas in storage remains 200 bcf better than year-ago levels.
- Although production trends are negative, the rig count has risen 160 during the past year.
- Demand growth is negative for the first part of 2005, although forecasts of gas use for power generation show significant growth for 2005.
- Although natural gas demand is down, fuel oil consumption is up, suggesting some additional switching capacity has come to the market.
- Natural gas net imports are up so far in 2005, with LNG, Canada, and reduced exports to Mexico all contributing.

- Natural gas production is reportedly up in Mexico and Canada so far in 2005, although the increase is minor, and could be reversed.
- Weather effects are supportive of high prices, as water flows in the Pacific Northwest are expected to be about 70% of normal, while summer temperatures could be warmer.
- In the longer term, energy policy is evolving towards clean coal and new nuclear as well as opening up areas for drilling.

The most recent data on U.S. natural gas production is showing a sharp decline in January and February in Texas that contributes to a 2% decrease for the country as a whole. Although high frequency data is often revised, the simultaneous decrease in consumption, the increase in net imports, and the relative neutrality of the storage indicator support rather than contradict a downward trend in U.S. production. Since the United States still supplies 85% of its own natural gas consumptions, this remains quite serious. The implication is that high natural gas prices will be with us for a longer time than would be the case if production were increasing. Summer prices are expected to remain at $6.50–$7, as high oil prices, negative trends in U.S. supply, and the start of storage injections all contribute to a tightening market and sustained, high expectations.

Long-term Outlook

LNG's Importance Will Increase. Although demand growth has been restrained by high prices recently, a steady pace of growth is expected over the long term. Annual increases are expected to average about 1 bcfd between 2005 and 2030. With prospects for traditional gas supply sources bearish, natural gas prices will evolve to reflect the interaction between new domestic and imported sources of natural gas. Supply costs for potential incremental supplies are all higher than supply costs during the previous decade. LNG will be the predominant source of incremental supplies, owing to more limited growth prospects for other domestic and import sources.

The contribution from new supply sources in size, timing, and cost will be a major determinant of long-term natural gas prices. Although LNG imports are already increasing, the first big test of the impact of LNG on prices will come later this decade when several LNG terminals come on-line. Prices could fluctuate temporarily, depending on how trends in domestic production and Canadian imports evolve between now and then. Continued weakness in North American supplies would provide a supply gap large enough for the higher LNG supplies to fill, while improvements in those other supplies could cause supply capacity surpluses during this period that would drive down prices temporarily. We are currently anticipating that this buildup in LNG supplies will supplement North American supplies sufficiently to enable prices to drop down to a more sustainable level. Fluctuations are not depicted in our projections because they cannot be timed with precision.

Prospects for North American supplies are somewhat uncertain in the near term, but generally weak in the long term. The Minerals and Management Service has

recently projected that production from the Gulf of Mexico, which has been declining, will increase after 2007. Onshore U.S. production in general is ambiguous, with Rocky Mountain increases offsetting declines in most other areas.

The Gap Between Demand and Traditional Supplies Will Grow. With the Canadian gas industry facing struggles similar to those confronting U.S. producers, imports from Canada have little scope to rise, and are most likely to decline in the long term. Canadian natural gas reserve additions have lagged production for several years, implying lower gas production in the future. Canada is planning to undertake the Mackenzie Delta pipeline project, with construction starting in 2006. However, this project is relatively expensive, at $7 billion, and the established reserves are still lagging the desired level to support the pipeline. Rising costs and lagging reserves may delay this project.

Alaskan North Slope gas will begin to flow to the lower-48 states during the second half of the forecast period, eventually rising to 3 trillion cubic feet (tcf) per year. The required increase in LNG imports will be more than twice this amount.

LNG currently makes up a very small portion of U.S. supplies, just 2% in 2003 and 3% in 2004. That share will grow substantially, potentially exceeding one-fourth of total supplies by 2030. There will be a market for 5-9 additional LNG terminals by 2010 and 15–20 new LNG terminals by 2030. Imports projected for the medium term reflect analysis of known projects, as discussed in detail in a separate section below.

Long-Term Prices Will Average $4.00-4.50. While expanding LNG imports will fill most of the growing gap between domestic demand and domestic supply, it is unclear if LNG will actually displace U.S. production. The difference is important for pricing. When demand and supply increase at about the same rate, the impact on prices would be less. If LNG displaces lower-48 production, the resulting price competition would drive prices down. Global Insight expects that the process will be a combination of the two; LNG will meet all growth other than that met by Arctic pipelines. Also, LNG will cost a little less to produce that the marginal U.S. supply. LNG will thus displace a small part of U.S. lower-48 production, thereby lowering prices. The supply cost of incremental supplies of U.S. lower-48 gas is expected to be between $4 and $5 per mmBtu in 2003 dollars. Future LNG supply costs are about $3.00 to $3.75 at a 10% rate of return. At a normal 16% return and with a higher level for sovereign take, LNG will price closer to $4.50. Thus the interaction between the two supply sources is expected to produce prices in the middle of this range of supply costs, at around $4.00–4.50.

Technically speaking, there will be no "supply gap" per se, but rather, a market niche for LNG *at a given price*. This is because demand and supply eventually balance at a given price level. A much higher price than projected here would both destroy more demand and attract more domestic supplies, requiring fewer LNG supplies. With ample LNG supplies available at lower prices, though, competition would eventually drive prices back toward the levels projected here. Given our expectation of the prices of competing fuels and competing sources of natural gas, the projection of long-term wellhead prices in the $4.00–4.50 range

reflects our estimation of the point at which a stable long-term supply/demand balance could best be achieved.

Prices are expected to decline toward this range as LNG supplies build up later this decade. Prices will then gradually shift to a slow growth within this range, as supply costs gradually rise. Although below current prices, this expected long-term price level is nevertheless about $2.00 above 1990s levels. Not only were there more incremental supplies available at lower costs then, but there was an overhang of spare producing capacity.

How LNG Will Help Set the Price Level. The interaction between domestic gas and LNG in setting the price level is complex. LNG costs are a bit lower than current U.S. supply costs, and LNG is the principal marginal supply on an annual average basis. Domestic production will continue to account for the majority of gas supply, such that it will remain the swing supply source—at least at times—in many U.S. regions. Thus, the costs of both supplies will contribute to the general natural gas price level, with LNG costs setting a floor price while domestic supply conditions determine the peak and seasonality of prices. Prices will hold close to the supply cost at which domestic supply can be sustained but above the supply costs for new LNG facilities. Thus LNG will be able to pick up market share by providing for demand growth and also a small amount of displacement.

The five to eight year gestation period for LNG projects and the relatively high cost of some projects will make it difficult for LNG to substantially displace U.S. conventional production. There are many reasons why the costs of conventional domestic supplies should remain a key driver of U.S. natural gas prices. While LNG and Arctic gas supplies are expected to meet most of the increase in U.S. demand, conventional production from the lower-48 is still expected to provide the majority of required supplies. U.S. conventional production can adjust quickly downwards (though only slowly upwards) to changes in market balances, thanks to the rapid decline rate for existing U.S. conventional production, which in 2001 averaged 27%. Because about one-fourth of U.S. production has to be replaced each year, a slowdown in exploration would quickly eliminate any oversupply. Also, because production now operates at high rates throughout the year while U.S. demand is strongly seasonal with a high variability depending on weather, prices will be influenced by the value placed upon firm supply during the peak winter heating season. Storage supplements production and imports during the winter peak, but storage capacity is not unlimited. Thus, U.S. natural gas prices in peak periods rise until prices constrain demand to available supply, which at times in recent winters has been far above domestic supply costs. Estimates of LNG supply costs are a measure of the lower price in the market rather than the average natural gas price. That LNG will be on the margin does not mean that seasonal price variations will disappear. Rather, most LNG producers will be able to obtain some rent in the U.S. market from the occasional seasonal peaks.

LNG Projects

Because of the rising importance of LNG in natural gas pricing, this section provides detail on LNG projects. LNG infrastructure in the United States is already

expanding, and increases in LNG imports are expected to accelerate in the next few years as multiple new projects come into operation. Increases over the latter part of this decade will be equivalent to one new LNG terminal per year.

Increases in LNG Imports Expected This Decade

Year	LNG Imports (TBTU)	LNG Imports (Bcf/day)	LNG Imports Change from Prior Year (Bcf/day)
2003	506	1.38	0.6
2004	649	1.78	0.4
2005	740	2.0	0.2
2006	1247	3.3	1.3
2007	1744	4.7	1.3
2008	2072	5.9	1.2
2009	2579	7.1	1.2
2010	3018	8.3	1.2

LNG receiving and regasification terminals in this country are being proposed in conjunction with development of LNG supply projects in producing countries. Considering the LNG terminals in conjunction with the supply projects is useful in determining whether and when the projects might proceed. Some LNG industry participants are choosing to specialize. Marathon has decided to develop the LNG project in Equatorial Guinea and sell the LNG to BG Group. Other companies, such as Cheniere, Main Pass Energy, and Excelerate Energy, are developing LNG import terminals for the United States. These are specialized companies. While most world trade in LNG is supplied by integrated companies such as Royal Dutch Shell, this is not the case for the United States at present. By 2010, the major oil companies could reassert their dominance, since they have a large stake in many of the projects that are likely to be developed.

The United States imported 506 bcf of LNG in 2003 and will likely import 3 tcf by 2010 if most of the approved projects and several of the proposed projects go ahead. In order to support our market balance forecast that relies upon LNG, Global Insight surveyed the potential supply to ensure that the timing of supplies to satisfy needed increases is feasible.

Construction is under way on several projects. The projects that are judged most likely to go forward are those that (1) have sufficient reserves of natural gas to support world-scale LNG plants, (2) have the active support of a coalition of international oil companies and support of the host country, (3) have plans and progress on developing an LNG terminal, and (4) have a likely market. Projects now under construction will increase U.S. LNG imports to about 40 billion cubic meters (bcm) by 2007. Likely projects should add about 60 bcm to imports by 2010. These projects are not definite, and there is room for more projects or replacement projects. Also, there will be a significant short-term trading in LNG that could provide 10 to 20 bcm to the United States by 2010 from other projects.

LNG Terminals

The United States has expedited the LNG terminal approval process so that decisions will be made within a definitive time frame. Several LNG terminals have already received licenses from FERC. Offshore terminals are regulated by the U.S. Coast Guard, while FERC permits are required for the pipeline facilities. International projects require only pipeline permits from FERC to serve the U.S. market. LNG terminals in Canada that use existing export pipelines to the United States would not be subject to any U.S. permitting requirements.

There are four existing LNG terminals in the United States, and all have applied for expansions. Approvals have either been received or are in process for all four existing terminals: Lake Charles, Elba Island, Cove Point, and Distrigas. In addition, several proposed LNG terminals have received approvals:

- Sempra: Hackberry LNG in Louisiana has its FERC license but construction was deferred until later in 2005.
- Cheniere: Freeport Texas LNG terminal is licensed and under construction; Sabine Louisiana LNG terminal has FERC approval.
- Excelerate Energy: Energy Bridge platform, 100 miles offshore Texas, will receive its first cargo in mid-March 2005.

Many other terminals are at various stages of the permitting process. Over 40 terminals have been proposed, and 5–9 new LNG terminals will be constructed in the United States by 2010. In addition, LNG terminals are being developed in the Bahamas, Baja California, and eastern Canada to serve the U.S. market.

LNG Supply Projects

There are six LNG plants under construction that will supply the U.S. gas market. More than 15 additional LNG plants that are either planned or proposed could be operational by 2010. In total, these projects have the potential of adding up to 5.7 tcf to U.S. gas supplies within seven years, more than twice the amount that will be required within this time frame. Their level of commitment to the U.S. market at this point varies from project to project.

World LNG Projects with Potential to Supply the U.S. Market This Decade

Country and LNG Project	2005-2006 Under Construction (Bcf/Year)	2006/2007 Planned (Bcf/Year)	2008+ Planned or Proposed (Bcf/Year)	Planned or contracted U.S. LNG Terminal
Algeria-Arzew			194	U.S., Europe
Angola-Soya			390	CVT, U.S.
Egypt-Idku II	175			Europe, BG Lake Charles, Elba Island
Egypt-Idku III			175	BG, U.S., Europe
Equatorial Guinea- Boiko Island		165		BG, Lake Charles
Nigeria-Trains IV&V	399			Shell,Total Europe, U.S.
Nigeria-Train VI		200		Shell, Total U.S.
Nigeria-Brass River			487	CP, CVT
Nigeria-West Niger Delta			240	U.S.
Nigeria-Floating LNG			250	Shell
Norway-Snohvit	199			Europe, Statoil, Cove Point
Norway-Snohvit II			200	Statoil, Cove Point
OMAN-Qalhat	160			BP, Shell Cove Point
PERU-Camisea		194		Hunt Oil
Qatar-Qatargas III			380	Conoco Phillips Freeport
Qatar-RasLaffan V&VI			730	Exxon Mobil Sabine
Russia-Sakhalin II	233	233		Shell Baja, Mexico
Trinidad-Train IV	253			Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Trinidad-Debottlenecking trains I,II and III		100		Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Trinidad-Trains V&VI			500	Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Venezuela			228	Shell U.S., Mexico
Total	**1741**	**892**	**3190**	

Short-term Outlook

- We're in the shoulder months, but coal prices are still firming
- The first signs of coal-on-coal competition are beginning to emerge
- Production is rising but must grow more to meet rising demand
- Imports are booming as foreign coal prices look more attractive

Market Outlook

We are still officially in the shoulder months, when markets are traditionally soft, but we are seeing a slight firming in most markets and strong upward price movement in the Western coals. Even though Appalachian (both North and Central) coal prices are currently high, low inventories throughout much of the East have kept coal purchases moving at a steady pace. For Western coal regions, improvements in rail shipments are allowing demand to expand throughout the Midwest and East in response to $800+ SO2 prices and those high Appalachian prices.

Indeed, we are seeing significant price shifts in both the Powder River Basin and Western Bituminous coals. We have been expecting the PRB move for some time, and the price of the 8800 Btu coal from that region, which began the year below $6/ton, has now moved into the $8 range. Earlier in the year, we were less confident that the Western Bituminous coal price would rise as quickly, but events have transpired that have led us to revise our outlook for this year by adding a few dollars per ton to the outlook, as opposed to dropping the price several dollars over the year. Specifically, the Western Bituminous coals have benefited from the second surge in SO2 prices that created greater urgency among Eastern/Midwestern buyers, the belief that buying out of the West should be diversified due to transportation issues, and the continued uncertainty on the environmental front due to significant doubts as to the viability of the mercury regulations.

For Eastern and Midwestern coal buyers, the question of buying coal from the West means greater concern about transportation rates and service than mine-mouth prices. Not that the latter is insignificant; as mentioned last month, the precipitous rise in PRB prices in early 2001 sent many prospective coal buyers who were looking at that region into a hasty retreat. Yet there is no doubt that the rail rate is the major component of the delivered coal price as Western coal tries to penetrate further east. Several recent developments are being watched carefully by Eastern/Midwestern coal buyers in that regard, specifically the suits against the BNSF and UP pricing practices out of the PRB (filed separately by the WCTL

and the U.S. Department of Justice) and a major approval by the Surface Transportation Board for the DM&E to be a third option out of the PRB.

In this *Coal Monthly* issue, we have expanded our price coverage out through the end of December 2008. With natural gas prices so high and very little excess coal capacity in evidence, most observers agree that we are there is nothing to constrain coal prices in the current market. Yet, as shown in our forecast, we do foresee a moderation in prices coming down the road. This will not arrive overnight, but already we are beginning to see the first signs of coal-on-coal competition beginning to emerge. Specifically, foreign import prices have been falling dramatically and the volume moving into the United States is already rising sharply. We are forecasting imports of 31.3 million tons for this year (up from 27.3 million last year), but this figure is less than half what could ultimately be imported if there is no downward price response from Central Appalachia. Likewise, we are just now starting to see PRB coal moving further east, posing the question of how much market share Appalachian producers are willing to cede before adjusting their price as well. The coal-on-coal situation only intensifies as scrubbers are added, allowing buyers to leverage off a number of competing regions as well as alternatives such as petroleum coke.

Coal Production

Higher electricity generation, coupled with greater tonnage needed due to more use of lower Btu western PRB coal, leads us to forecast a roughly 22 million ton increase in production for 2005, nearly 2% above last year's output. We show lower exports and higher imports for both 2005 and 2006, but these are offset by anticipated growth in stockpile levels as many power companies seek to get out from underneath the hand-to-mouth lifestyle they have been forced to deal with due to extremely low inventory numbers.

We anticipate that electricity demand will drive coal demand even higher in 2006, aided in part by a few new units (Gilbert, Hardin) and greater transmission access by coal-fired generators to areas such as PJM.

Output in the **East** dropped significantly in the first quarter, but we are expecting a gradual recovery to slightly higher levels over the next several quarters. Growing imports continue to cut into the (largely Central) Appalachian market share, but Powder River Basin coal is also beginning to show signs of impacting Northern Appalachian markets in light of high SO2 prices coupled with generally high Appalachian coal prices. By 2006, however, we anticipate stronger growth in the Appalachian market as come coals are forced to become more price-competitive and demand for coal-fired electricity generation continues to rise.

Production from the **Interior** region began with a very strong push in the first quarter of this year, but now appears to have settled to a more sustainable level for the short term. While many observers (such as the Department of Energy) are looking for a relatively substantial decline in output from this region, we are projecting a modest increase. This more optimistic outlook is based less on any in-

trinsic superiority of Interior coals, and more on the inability of other regions to increase their production any more than we are currently forecasting.

Production in the **West** has been increasing at the rate of about 20 million tons annually, a development pushed by high SO2 prices, high Eastern coal prices, and a grudgingly slow improvement in transportation out of the region. We anticipate a strong near-term market for coals out of both the PRB and Western Bituminous regions for the same reasons.

The Stock Situation

"Exceeding low inventories" has been the catchphrase in describing the coal stockpile situation over the last six months, but the situation is not necessarily as clear-cut as that term implies. A first glance at the first-quarter 2005 consumption and production estimates suggests that very little was actually added to inventory levels, but we question that assumption in light of the lower burn (relative to the first quarter of 2004), even after adjusting for more Western coal in the mix (due to lower heating values). In any event, we are anticipating inventories rising to just short of 165 million tons by the end of June, a level that actually exceeds last year's level. With a normal summer drawdown, however, we are looking at about 155 million tons by the end of the year. Nevertheless, unless several regions ante up with increased production, this will be a stretch and we may end 2005 with an inventory level no larger than the 147 million tons registered at the end of 2004.

Coal Stocks (million tons)

Jan 2005	Jan 2004	Percent Difference	EOY 2004	EOY 2005	Percent Change
146.1	152.0	-3.9%	147.3	154.9	5.2%

Exports & Imports

Coal exports slowed considerably in the first quarter of 2005 after a very fast start in January, but are still running about 5% ahead of the 2004 pace. Met coal shipments continue to lead the way and we expect demand for this component of steel-making to remain strong throughout the year. On the steam coal side, there is still very little interest in Atlantic markets. Indeed, global markets have not really responded with higher prices to a series of supply disruptions in South Africa (major rail delays), a roof fall at a major Australian mine, and adverse weather disrupting Indonesian operations. Canadian imports are down so far this year and U.S. coal exporters continue to watch the Ontario deliberations carefully, but the likelihood that all coal plants could be closed even within several years of the 2007 target date set by the new provincial government appears remote at this time.

The major price decline that has occurred in Colombian and most other Atlantic coals has not been met by reciprocal reductions in Central Appalachian coals, so interest by U.S. power companies is mounting. Preliminary data for March, released on May 11, suggests that imports topped 3 million tons in a single month for the first time. This greater interest in imports is beginning to manifest itself in

the form of inland plants, as in the case of the Gainesville (Florida) Deerhaven station, which is starting to solicit foreign bids for the first time. U.S. railroads are reportedly being more cooperative in considering these kinds of shipments, although the railroads will still likely evaluate them on a case-by-case basis.

U.S. Exports and Imports (Million Tons)

	YTD 2005*	YTD 2004*	Percent Change	Forecast 2005	Forecast 2006
U.S. Exports-Total	10.1	9.7	4.6%	43.8	38.8
U.S. Imports	7.7	5.3	43.9%	31.3	34.1

**YTD is through March 2005*

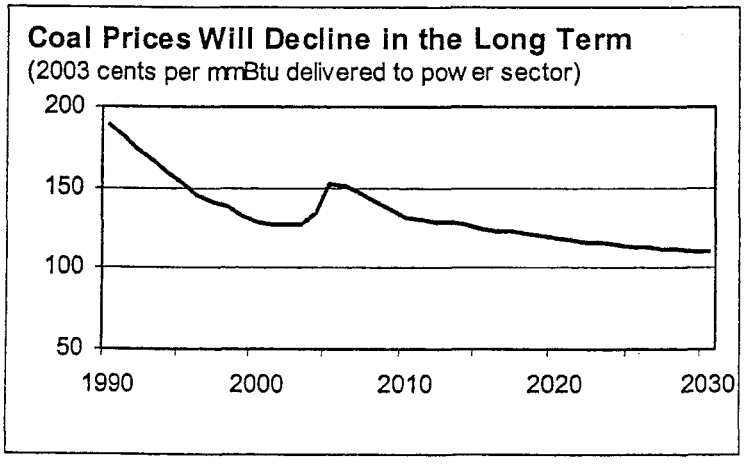
Long-Term Outlook

The issue of long-term coal pricing is one lacking widespread consensus, perhaps a problem common to more fuels than just coal. In this article, we will critically examine our contention that most coal prices will eventually decline in real terms, with a start date perhaps sooner than most expect. We review the major issues that lead us to the conclusion that the kind of pricing we have seen recently in many mining regions of the country is not sustainable.

A number of well-versed coal consultants believe that high coal prices are a permanent fixture of the energy landscape. They point to:

- the absence of any meaningful competition from natural gas in the electricity dispatch order due to high fuel prices,
- the rise in production costs in coal mining, and
- the consolidation of the coal industry that has led to unprecedented market power for a very small number of suppliers.

In this article, we will address these issues and explain why we believe they will ultimately work in the direction of lower prices.

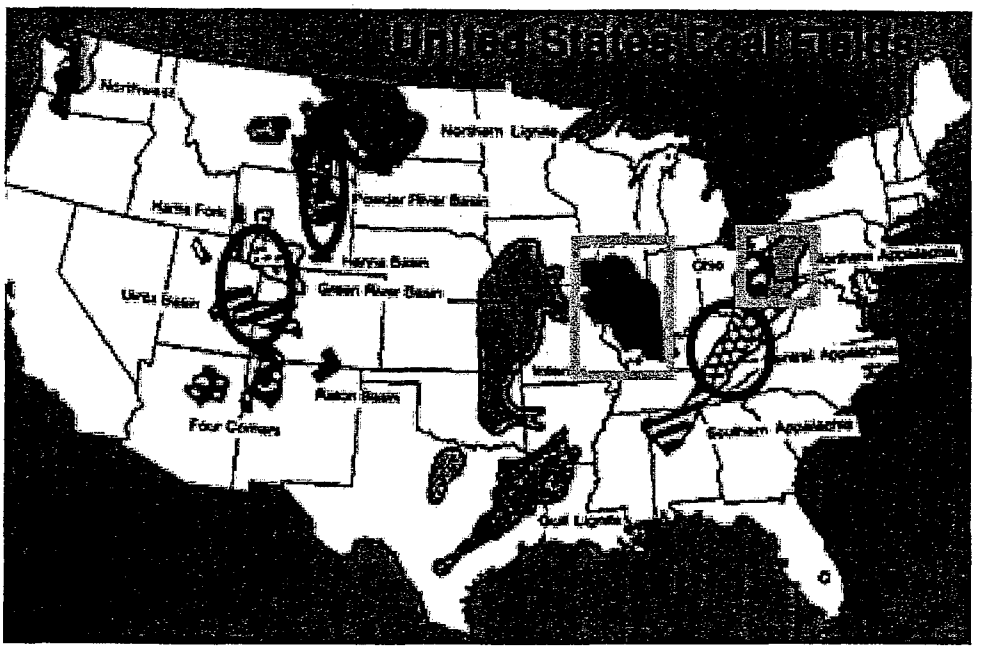


What do we mean by high or low prices? In discussing coal prices in general, this may be little more than a semantic problem. Our perspective is that prices will and must be considerably higher than they have been historically (pre-2000), but that current pricing levels are too high to be sustained. Yet we continually encounter the assumption that prices will not move too far from the current markers, so we do believe there exists a strong professional difference on this point.

The high energy price environment. There have been major price increases in virtually every fuel source since 2000, including coal, oil, natural gas, and uranium. There is a feeling among many observers that high prices in other energy sectors breed high prices in all of them, and to a limited extent, we concur. Certainly the very high price of natural gas lifts the ceiling on how high coal prices can be (although, as we will explain further, they do not necessarily mean that coal prices will rise significantly). Yet we also believe that each of those four fuels have individual industry structures, resource availabilities, and production differences that, under the right circumstances, would allow one or more to break from the pack. With regard to coal, we believe that is the case. Its abundance in the United States allows for potentially strong competition (which currently does not exist) so long as the return on new coal investment appears promising, which we think it will.

What about a lack of competition from other fuels? Indeed, natural gas prices at $6.00–7.00 per million Btu (mmBtu) will do nothing to strike fear into the hearts of coal producers. Yet we anticipate gas prices to subside to levels at which we believe coal suppliers will have to exercise some pricing restraint if they still wish to capture a significant share of the new generation market, factoring in the cost of high capital investment in boiler equipment and environmental compliance. Moreover, if coal prices really do remain as high as current levels, how much more attractive does that make nuclear power, which is already gaining significant momentum on the bases of both improved plant performances and, perhaps more importantly, concern over global climate change? Yet, as described in the next paragraph, it is really the prospect of coal-on-coal competition—not competition with natural gas—that leads us in the direction of lower prices.

Coal-on-coal competition. Our theory of coal-on-coal competition as a principal source of lower coal pricing rests heavily on the additional leverage power companies can attain by accessing coal from beyond their current procurement areas. In the near term, this may mean bringing Powder River Basin or western bituminous coal into the Midwest and East, a trend now well under way. Over the next few years, however, a much broader form of inter-regional coal competition should emerge as power plants add pollution control equipment, particularly scrubbers for SO2 control. Plants that currently rely on low-sulfur coal are highly restricted to three coal regions—the Powder River Basin (PRB), the western bituminous regions (Uinta and Green River Basins), and Central Appalachia. Installing scrubbers gives plants in the Midwest and East a good shot at using coal from two regions of low mining cost and high reserves, the Illinois Basin and Northern Appalachia. The low-sulfur areas are highlighted on the map in ovals and the high-sulfur areas are depicted with rectangles.



Critics of this theory often counter that the extreme consolidation in the coal industry simply means that everyone's prices will remain high and that competition will not actually develop. That certainly is a possibility. Yet as we look at major battlegrounds as to where we think this competition might develop (the Carolinas, for example), we find it hard to accept that coal companies will "stick to their guns" on high pricing when they are reaping such strong profits and face losing a massive market opportunity. With regard to the Carolinas, we foresee strong competition involving both two high-sulfur regions (Northern Appalachia and Illinois Basin). In looking at Central Appalachia producers, the current "incumbents" in the Carolina market, we also find it difficult to believe that they will be willing to give up their current status without a fight, especially considering that the Carolinas are their own backyard in market terms.

Finally, we expect foreign (import) coal prices to be much more attractive as prices fall in the face of lower ocean freight rates and declining demand as the Kyoto greenhouse-gas treaty begins to take a toll on European coal demand. To that end, with regard to our recent example, it is noteworthy that Progress Energy (Carolina) is currently testing foreign coals at stations other than their Sutton plant, which has taken South American coal for the past few years. Finally, we are aware of a large number of companies exploring in earnest the possibility of burning petroleum coke (petcoke). As production of that byproduct of the refining process continues to ramp up, power companies are finding it an attractive source of lower-than-coal cost fuel. Its (generally) much higher sulfur content becomes largely a non-issue when units are equipped with scrubbers. While certain qualities of petcoke (e.g., volatile matter) may prohibit 100% burning in existing coal-based units, a substantial percentage of the fuel can in fact be burned in most instances.

The theme of this argument is that following the 2005–06 period, power companies are likely to have a much wider array of coal opportunities at their disposal. While we do not expect this development to lead to "low" coal prices, we do anticipate that the prices we project in our long-term forecasts accurately portray achievable pricing levels we will see in a more competitive environment.

Production costs. The final component of the argument that coal prices will not fall is based on the premise that production costs have risen and will not be coming down. We counter with three items in this regard.

First, a good deal of the rise in production cost increase has been based on the rise in diesel fuel and steel markets (affecting a wide array of items, such as mining machinery parts). These material costs, like energy, have also experienced major price spikes. While certain contributors to production costs, such as trucking in Central Appalachia, will not be retreating from their recent rises, the majority of the material costs that increased substantially in the past few years are going to decline in the years ahead, although they will not reach their pre-2000 levels.

Second, in looking at "production costs," many analysts include the various fees and taxes to which coal is subjected. Yet some of these, such as royalties and severance taxes, are based on a percentage of the selling price. If the selling price were to decline, so would these so-called "production costs," with virtually no impact on the profit picture for the coal company.

Finally, and most importantly, production costs are heavily affected by productivity changes, and we expect this picture to improve for most of the coal industry. There has always been a strong correlation between capital investment and productivity levels in the coal industry, and as coal prices began to wane in the late 1990s, we saw capital investment decline markedly as well. The failure of new capital investment to return until just recently has had a major, negative impact on productivity levels in virtually all regions. There may be some regions where reserve degradation argues against any productivity improvement (notably Central Appalachia), but we expect most regions to respond as investment recovers. We are not looking for the historical productivity gains that were registered in much of the 1980s and 1990s, because many of those gains were achieved by simply closing less-efficient mines. We do expect, however, that the targeted, selective investment that is now becoming the trademark of the coal industry will produce worthwhile returns in both financial and productivity terms that will result in a lowering of production costs for coal mines.

Conclusion: In conclusion, we do not expect a return to the low pre-2000 coal price levels; however, we do see a substantial set of factors that will lead coal pricing away from the very high levels we have experienced over the last year or so. These reasons include potential competition from other fuel sources (natural gas and nuclear), lower production costs in the future, and—most importantly—competition from within the coal industry itself.

U.S. ECONOMIC OUTLOOK[1]

Highlights

- Real GDP growth will average 3.0% per year in 2004–30.
- The outlook for inflation remains moderate. Consumer price index (CPI) inflation will average 2.6% per year over the forecast period. Core inflation will average 2.7%.
- High investment and a slower growing labor force should result in higher productivity growth. Nonfarm business productivity growth averages 2.4% over the forecast period, compared with the 2.2% average experienced since 1953.
- The current account deficit is negative through 2025. Afterward, the current account surpluses grow.
- Real oil prices will creep up over the forecast period. The real price of imported oil is $26.3 per barrel in 2003 to $30.4 per barrel in 2030.
- The labor market improves over the forecast period, with the unemployment rate eventually settling at 4.95%.
- The federal budget deficit remains in deficit throughout the forecast period.

Long-Term Forecast

Real GDP. The trend projection assumes that the U.S. economy experiences no major mishaps between now and 2030. The projection is identical with our February 2005 baseline forecast through 2015, and represents Global Insight's best estimate of the economy's path over that period. Beyond 2015, the projection should be interpreted as the mean of all possible "near-full-employment" paths the economy could follow. The smooth-growth characteristics of the trend projection make it most useful for tasks largely impervious to short-term cyclical fluctuations, such as planning capacity additions and evaluating new markets. This projection is also the best base from which to evaluate the effects of various assumptions about key exogenous elements, such as fiscal policy or energy prices, on the overall economic outlook.

Annual real GDP growth averages 3.0% in 2004–30, about the same rate as the average of the past 25 years. The economy's underlying growth will slow after 2011, as baby boomers begin to retire, slowing labor force growth. Potential output growth should hold up fairly well in the future, with greater business fixed investment and R&D spending offsetting the slowdown in labor force growth. Eventually, though, the effects of weaker labor force growth become dominant and, in a sense, self-perpetuating. As output growth drops off, business fixed in-

[1] Global Insight's Long-term US Economic Outlook, February 2005.

vestment rises more slowly, limiting capital stock growth and thus future output gains.

Employment. Slower long-run increases in the labor force indicate more moderate long-run employment growth in the future. Total civilian employment will rise at an average annual rate of 1.0% from 2004 to 2030. Total establishment employment will rise from 131.5 million in 2004 to 172.0 million in 2030, an increase of 31%. Manufacturing's share of total employment will continue to decline over the forecast period, falling to 7.3% in 2030, from 10.9% in 2004. The broad service sector will generate an increasing share of employment growth in the forecast period, although the federal government's share of employment will decline during the forecast period.

Inflation. Over the long run, inflation is a monetary phenomenon. Its future course will be determined by policies implemented by Alan Greenspan and his successors. Since we do not know who his successors will be, we assumed the Fed will try to stabilize the inflation rate in the second half of the forecast.

The CPI is expected to average 2.6% annual increases in 2004–30, somewhat less than the 4.4% average in 1977–2003. The broader-based GDP deflator will rise 2.3% per year.

Consumption. Expenditures, in the long term, are primarily determined by the growth of real permanent income, demographic influences, and changes in relative prices. The share of personal consumption expenditures in GDP will stabilize at just under 70% of GDP. Real consumption expenditure growth will average 2.7% per year over the forecast. In per capita terms, growth will advance about 1.9% per year, down 0.3 percentage point from the 1978–2004 rate. The share of consumption devoted to services will rise, mainly because of rising health expenditures, while that for goods will fall over the forecast period.

The long-term outlook for auto and light truck sales calls for a slowdown in the rate of increase relative to past performances. Vehicle sales growth will average close to 1.0% over the next 25 years. Light-vehicle sales are forecasted to reach 21.4 million units by 2030. Although the number of vehicles per person has increased significantly in the past 20 years, the United States is approaching a saturation point in the rate of vehicle ownership. Future growth in vehicle sales will be primarily driven by growth in population and demand for replacement vehicles. Automobile sales should be relatively strong throughout the projection period, averaging 7.9 million units per year.

Energy conservation efforts will continue. This stems partly from a stock/flow phenomenon: despite the trend toward minivans and sport/utility vehicles, for example, the average new vehicle is still more fuel-efficient than the existing stock. Gasoline usage per vehicle should fall for several more years, even if relative energy prices remain flat. Similar considerations apply to business capital and housing stocks. The ongoing employment shift from manufacturing to services also implies lower energy usage per unit of output.

Real personal disposable income, which climbed 3.2% in 1970–2003, will rise 3.1% annually over the next 25 years. This does not take into account the rising volume of withdrawals from existing retirement plans.

Housing. Household growth clearly depends on population growth, but real incomes, employment, the age distribution of the population, and societal values also influence it. Net additions to the housing stock are closely linked to household growth, which is the primary driver of housing starts. Many analysts tend to overlook another key factor for housing starts: the geographic location of the demand for net additions.

The 25–34-age cohort is key for the demand for new housing. This is the age group where individuals typically purchase their first home. The demand for new housing was boosted by the large gains in this age group in the late 1960s and 1970s, as the baby-boom generation entered the housing market. Unfortunately for the housing sector, the baby-boom generation began to pass through this age bracket in the mid-1980s, limiting the demand for additions to the housing stock. The number of households in this cohort will begin a modest increase after 2005. The overall headship rate will gradually increase toward older segments due to the shift in the age composition.

The demographic demand for housing will be about the same over the next 25 years as over the past 25 years. Thus, housing starts are projected to average 1.6 million units annually in 2003–29, about the same as during 1972–2004. Meanwhile, the housing stock will climb from 111.4 million units in 2004 to 142.5 million units in 2030.

Business Fixed Investment. Good profitability and solid demand growth should keep investment healthy over the next 25 years. The share of GDP devoted to business fixed investment will hover around 10.0–12.5% of GDP through most of the forecast period. The effective capital stock (in 2000 dollar terms) is projected to increase 3.7% annually, below the average growth rate recorded for 1970–2003. Inventory investment will remain a small percentage of GDP. Although inventories have played significant roles during past business cycles, inventory investment represents an average in the stable growth scenario and is thus artificially smooth. Capital inflow will contribute to net domestic investment throughout the forecast period, although the federal debt clearly hurt it in the later years of the forecast. The government saving projection assumes that state and local governments continue to run modest operating surpluses.

The composition of investment will continue to change in the forecast period; both structures' share of investment and equipment's share rises over the forecast period.

International Trade. A decline in the dollar relative to industrialized-country-currencies, combined with modest unit labor cost growth, will stimulate U.S. exports abroad and result in an eventual improvement in the U.S. current account balance. Global Insight projects that real exports will expand at an average annual rate of 7.3% over the entire forecast period. Real imports, meanwhile, will grow at an average annual rate of 5.2%.

FORECAST TABLES

Seminole Electric
Coal Prices (FOB CSX)
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb	Venezuelan Low Sulfur 12200 Btu/Lb
1998	21.85	19.90	25.77	22.74		26.01	28.45
1999	21.42	18.81	24.30	20.84		23.47	27.32
2000	21.26	17.51	24.70	22.25	14.75	25.12	28.44
2001	31.96	29.93	46.71	36.31	14.03	32.08	38.75
2002	25.45	23.34	28.96	27.75	9.45	25.36	31.51
2003	24.10	22.09	34.00	28.93	14.07	30.60	32.61
2004	**34.22**	**31.83**	**58.15**	**48.33**	**12.17**	**53.96**	**45.76**
2005	40.16	31.52	63.31	51.77	16.01	46.38	51.13
2006	37.48	29.66	58.13	41.47	9.33	36.84	42.42
2007	35.48	29.33	49.12	33.11	9.33	36.13	41.53
2008	36.03	28.74	46.67	32.73	10.46	36.55	40.76
2009	36.36	28.53	46.21	33.11	11.66	36.41	40.59
2010	36.70	28.85	46.26	34.24	13.30	34.58	38.56
2011	37.18	30.02	47.21	34.92	14.69	34.29	38.23
2012	37.93	30.87	48.50	35.53	15.56	34.29	38.23
2013	38.77	31.52	49.74	35.88	16.43	34.51	38.49
2014	39.62	32.12	50.73	36.20	17.39	34.94	38.96
2015	40.49	32.74	51.46	36.52	18.45	35.43	39.51
2016	41.40	33.37	52.59	36.85	19.93	36.28	40.45
2017	42.35	34.03	53.96	37.17	21.10	37.19	41.47
2018	43.33	34.72	55.36	37.51	22.27	38.18	42.57
2019	44.35	35.42	56.78	37.86	23.43	39.21	43.72
2020	45.38	36.12	58.21	38.20	24.89	40.28	44.91
2021	46.44	36.84	59.69	38.52	25.59	41.06	45.78
2022	47.53	37.58	61.21	38.83	26.11	41.90	46.72
2023	48.64	38.33	62.77	39.15	26.58	42.78	47.71
2024	49.79	39.10	64.37	39.50	26.98	43.72	48.75
2025	50.95	39.88	66.01	39.85	27.39	44.68	49.82
2026	52.15	40.68	67.33	40.19	27.62	45.21	50.41
2027	53.38	41.50	68.68	40.53	27.86	45.76	51.03
2028	54.63	42.34	70.07	40.89	28.10	46.35	51.68
2029	55.92	43.19	71.48	41.25	28.35	46.95	52.35
2030	57.25	44.06	72.93	41.61	28.60	47.57	53.04

Price Deflator (2004=1.0)
0.891
0.904
0.924
0.946
0.961
0.979
1.000
1.018
1.035
1.055
1.077
1.099
1.124
1.151
1.179
1.207
1.236
1.265
1.295
1.327
1.360
1.394
1.428
1.464
1.500
1.537
1.575
1.614
1.654
1.695
1.737
1.781
1.825

Seminole Electric
Coal Prices (FOB CSX)
($2004 Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb	Venezuelan Low Sulfur 12200 Btu/Lb
1998	24.52	22.34	28.92	25.52		29.19	31.93
1999	23.70	20.81	26.89	23.05		25.96	30.23
2000	23.02	18.96	26.75	24.09	15.97	27.20	30.80
2001	33.79	31.64	49.39	38.40	14.84	33.93	40.97
2002	26.48	24.28	30.13	28.87	9.83	26.38	32.77
2003	24.62	22.56	34.73	29.55	14.37	31.26	33.31
2004	**34.22**	**31.83**	**58.15**	**48.33**	**12.17**	**53.96**	**45.76**
2005	39.46	30.97	62.19	50.86	15.73	45.56	50.23
2006	36.19	28.65	56.14	40.05	9.01	35.58	40.97
2007	33.63	27.80	46.56	31.39	8.85	34.24	39.37
2008	33.45	26.68	43.34	30.39	9.71	33.94	37.85
2009	33.07	25.95	42.04	30.12	10.61	33.12	36.93
2010	32.66	25.67	41.17	30.47	11.84	30.78	34.32
2011	32.31	26.09	41.03	30.35	12.77	29.80	33.23
2012	32.18	26.19	41.14	30.14	13.20	29.08	32.43
2013	32.12	26.11	41.20	29.72	13.61	28.59	31.88
2014	32.07	25.99	41.06	29.30	14.08	28.28	31.53
2015	32.01	25.89	40.68	28.87	14.59	28.01	31.24
2016	31.96	25.76	40.60	28.45	15.39	28.01	31.23
2017	31.92	25.65	40.66	28.01	15.90	28.03	31.25
2018	31.86	25.53	40.71	27.58	16.37	28.07	31.30
2019	31.82	25.41	40.74	27.16	16.81	28.13	31.37
2020	31.78	25.29	40.76	26.75	17.42	28.20	31.45
2021	31.73	25.18	40.79	26.32	17.49	28.05	31.28
2022	31.69	25.06	40.81	25.89	17.41	27.94	31.15
2023	31.65	24.94	40.84	25.48	17.30	27.84	31.04
2024	31.61	24.83	40.87	25.08	17.13	27.76	30.95
2025	31.57	24.71	40.90	24.69	16.97	27.68	30.87
2026	31.53	24.60	40.71	24.30	16.70	27.33	30.48
2027	31.49	24.48	40.52	23.91	16.43	27.00	30.10
2028	31.45	24.37	40.33	23.53	16.18	26.68	29.75
2029	31.41	24.25	40.14	23.16	15.92	26.36	29.40
2030	31.36	24.14	39.95	22.80	15.67	26.06	29.06

Florida
Delivered Coal Prices
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB from Farmersburg, Indiana	Illinois Basin High Sulfur 12,000 Btu/Lb from Providence, Kentucky	Central Appalachia 12,400 Btu/Lb from Pike County, Kentucky	Pittsburg Seam 13100 Btu/Lb from Waynesburg, Pennsylvania	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb from Puerto Bolivar	Venezuelan Low Sulfur 12200 Btu/Lb from Lake Maricaibo
2000	38.17	36.72	40.97	45.05			
2001	49.18	49.49	63.29	59.54			
2002	42.65	42.41	45.51	50.94			
2003	41.90	41.56	51.13	52.92	25.69	38.72	44.23
2004	**52.63**	**51.46**	**75.86**	**73.15**	**30.54**	**66.81**	**64.14**
2005	59.06	51.33	81.49	77.25	35.19	59.79	70.31
2006	56.34	49.68	76.27	66.90	20.84	44.89	53.93
2007	54.52	49.52	67.44	58.79	16.03	40.81	48.23
2008	55.28	49.17	65.20	58.70	16.58	40.83	46.88
2009	55.92	49.25	65.03	59.48	18.22	40.99	47.15
2010	56.54	49.85	65.35	60.99	20.18	39.39	45.44
2011	57.36	51.32	66.62	62.13	21.94	39.35	45.48
2012	58.45	52.49	68.24	63.19	23.09	39.55	45.77
2013	59.63	53.48	69.81	64.01	24.23	39.97	46.29
2014	60.84	54.42	71.14	64.81	25.46	40.58	47.03
2015	62.07	55.37	72.22	65.62	26.80	41.27	47.86
2016	63.36	56.34	73.72	66.45	28.51	42.28	49.04
2017	64.69	57.37	75.46	67.30	29.80	43.27	50.17
2018	66.07	58.48	77.24	68.17	31.14	44.38	51.44
2019	67.50	59.61	79.05	69.07	32.50	45.54	52.78
2020	68.95	60.76	80.89	69.98	34.15	46.76	54.18
2021	70.46	61.94	82.80	70.90	35.37	47.89	55.56
2022	71.99	63.13	84.75	71.81	36.45	49.12	57.05
2023	73.56	64.36	86.74	72.75	37.36	50.32	58.49
2024	75.17	65.62	88.80	73.73	38.19	51.55	59.96
2025	76.81	66.90	90.89	74.72	39.04	52.82	61.47
2026	78.50	68.21	92.68	75.71	39.71	53.66	62.50
2027	80.22	69.55	94.51	76.72	40.32	54.47	63.49
2028	81.98	70.92	96.37	77.75	40.75	55.19	64.33
2029	83.78	72.32	98.28	78.80	41.28	55.99	65.28
2030	85.63	73.75	100.23	79.87	41.82	56.81	66.26

NOTE: All transportation rates are assumed to be from the CSX origin points listed above except for the petroleum coke and South American shipments made by ocean vessel.

Florida
Delivered Coal Prices
($2004 Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB from Farmersburg Indiana	Illinois Basin High Sulfur 12,000 Btu/Lb from Providence, Kentucky	Central Appalachia 12,400 Btu/Lb from Pike County Kentucky	Pittsburg Seam 13100 Btu/Lb from Waynesburg, Pennsylvania	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb from Puerto Bolivar	Venezuelan Low Sulfur 12200 Btu/Lb from Lake Maricaibo
2000	41.33	39.76	44.36	48.78			
2001	52.01	52.33	66.92	62.96			
2002	44.37	44.11	47.34	52.98			
2003	42.80	42.45	52.22	54.06	26.24	39.55	45.18
2004	**52.63**	**51.46**	**75.86**	**73.15**	**30.54**	**66.81**	**64.14**
2005	58.02	50.43	80.05	75.89	34.57	58.73	69.07
2006	54.41	47.98	73.66	64.61	20.13	43.35	52.08
2007	51.68	46.94	63.93	55.73	15.20	38.68	45.72
2008	51.33	45.66	60.54	54.50	15.39	37.91	43.53
2009	50.87	44.80	59.16	54.11	16.58	37.29	42.89
2010	50.32	44.37	58.16	54.28	17.96	35.06	40.44
2011	49.85	44.60	57.91	54.00	19.07	34.21	39.53
2012	49.58	44.52	57.89	53.60	19.59	33.55	38.82
2013	49.40	44.30	57.83	53.02	20.07	33.11	38.35
2014	49.24	44.04	57.58	52.45	20.61	32.84	38.06
2015	49.07	43.78	57.10	51.88	21.19	32.63	37.84
2016	48.91	43.50	56.91	51.30	22.01	32.64	37.86
2017	48.75	43.24	56.86	50.72	22.45	32.61	37.81
2018	48.58	43.00	56.80	50.13	22.89	32.63	37.82
2019	48.42	42.77	56.72	49.55	23.31	32.67	37.87
2020	48.28	42.54	56.64	49.00	23.91	32.74	37.93
2021	48.14	42.32	56.58	48.44	24.17	32.73	37.96
2022	48.01	42.10	56.51	47.89	24.30	32.76	38.04
2023	47.87	41.88	56.44	47.34	24.31	32.74	38.06
2024	47.73	41.66	56.38	46.81	24.25	32.73	38.07
2025	47.59	41.45	56.31	46.29	24.19	32.73	38.08
2026	47.46	41.24	56.03	45.77	24.01	32.44	37.78
2027	47.32	41.03	55.75	45.26	23.78	32.13	37.45
2028	47.18	40.82	55.47	44.75	23.45	31.76	37.02
2029	47.05	40.61	55.19	44.25	23.18	31.44	36.66
2030	46.91	40.40	54.91	43.76	22.91	31.12	36.30

NOTE: All transportation rates are assumed to be from the CSX origin points listed above except for the petroleum coke and South American shipments made by ocean vessel.

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Dollars per Million Btu)

Year	Henry Hub	(Current) FGT Bidweek	FGT Cash	Deflator (2004=1.0)	Henry Hub	(2004$) FGT Bidweek	FGT Cash
1998	2.11	2.09	2.00	0.891	2.31	2.29	2.19
1999	2.27	2.26	2.21	0.904	2.45	2.44	2.39
2000	3.88	3.89	4.22	0.924	4.10	4.11	4.46
2001	4.26	4.26	3.81	0.946	4.39	4.40	3.93
2002	3.22	3.24	3.33	0.961	3.27	3.29	3.38
2003	5.38	5.39	5.49	0.979	5.38	5.39	5.49
2004	6.13	6.15	6.10	1.000	6.02	6.04	5.99
2005	6.79	6.75	6.89	1.018	6.56	6.52	6.65
2006	6.81	6.81	6.78	1.035	6.48	6.48	6.45
2007	6.57	6.57	6.47	1.055	6.13	6.14	6.04
2008	5.69	5.69	5.61	1.077	5.21	5.21	5.13
2009	4.89	4.89	4.85	1.099	4.38	4.38	4.34
2010	5.13	5.13	5.09	1.124	4.49	4.49	4.46
2011	5.28	5.29	5.26	1.151	4.52	4.52	4.49
2012	5.43	5.43	5.41	1.179	4.53	4.53	4.52
2013	5.79	5.79	5.77	1.207	4.72	4.73	4.71
2014	5.98	5.99	5.96	1.236	4.76	4.77	4.75
2015	6.11	6.11	6.09	1.265	4.74	4.75	4.73
2016	6.25	6.25	6.26	1.295	4.74	4.74	4.75
2017	6.71	6.72	6.69	1.327	4.97	4.97	4.95
2018	6.25	6.25	6.25	1.360	4.50	4.51	4.50
2019	6.57	6.58	6.59	1.394	4.62	4.62	4.63
2020	6.86	6.87	6.87	1.428	4.70	4.71	4.71
2021	6.97	6.97	6.98	1.464	4.65	4.66	4.66
2022	7.18	7.18	7.19	1.500	4.67	4.67	4.68
2023	7.39	7.39	7.39	1.537	4.68	4.69	4.69
2024	7.60	7.60	7.60	1.575	4.69	4.70	4.70
2025	7.81	7.81	7.82	1.614	4.70	4.70	4.71
2026	8.01	8.01	8.02	1.654	4.70	4.70	4.70
2027	8.21	8.21	8.21	1.695	4.69	4.69	4.69
2028	8.41	8.41	8.42	1.737	4.68	4.68	4.68
2029	8.62	8.62	8.63	1.781	4.67	4.67	4.67
2030	8.80	8.80	8.81	1.825	4.65	4.65	4.65

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	NOMINAL			*CONSTANT 2004 DOLLARS*		
	0.7%	1.0%	3.0%	0.7%	1.0%	3.0%
1995	15.18	14.69	13.77			
1996	18.04	17.47	15.58			
1997	16.59	16.15	14.41			
1998	12.85	12.14	9.69			
1999	15.99	15.33	14.28			
2000	27.54	26.05	20.65	29.82	28.21	22.36
2001	22.90	21.68	17.12	24.21	22.93	18.10
2002	23.41	22.32	20.50	24.35	23.21	21.32
2003	29.04	28.02	23.93	29.67	28.62	24.44
2004	29.52	28.46	24.73	29.52	28.46	24.73
2005	36.99	35.76	31.44	36.34	35.13	30.88
2006	36.11	34.82	29.73	34.87	33.63	28.71
2007	34.90	33.66	28.61	33.08	31.90	27.12
2008	34.59	33.36	28.32	32.12	30.97	26.30
2009	38.24	36.88	31.00	34.79	33.55	28.20
2010	37.40	36.07	29.94	33.28	32.10	26.64
2011	38.36	37.00	30.41	33.34	32.15	26.43
2012	38.82	37.44	30.50	32.93	31.76	25.87
2013	38.69	37.31	30.15	32.05	30.91	24.97
2014	38.49	37.12	29.72	31.15	30.04	24.06
2015	38.26	36.90	29.28	30.25	29.17	23.15
2016	38.48	37.11	29.18	29.71	28.65	22.53
2017	38.78	37.39	29.13	29.22	28.18	21.96
2018	39.09	37.70	29.10	28.74	27.72	21.40
2019	39.39	37.99	29.04	28.26	27.25	20.84
2020	39.71	38.29	29.00	27.80	26.81	20.30
2021	41.56	40.07	30.05	28.39	27.38	20.54
2022	42.85	41.32	30.68	28.57	27.55	20.46
2023	44.53	42.94	31.57	28.97	27.94	20.54
2024	45.91	44.28	32.23	29.15	28.11	20.46
2025	47.33	45.64	32.88	29.32	28.28	20.37
2026	48.87	47.13	33.95	29.54	28.49	20.53
2027	50.45	48.66	35.05	29.76	28.70	20.68
2028	51.94	50.09	36.08	29.89	28.83	20.77
2029	53.47	51.56	37.15	30.02	28.95	20.86
2030	55.12	53.16	38.30	30.20	29.12	20.98

DSTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	NOMINAL		CONSTANT 2004 DOLLARS	
	Posted Price at Tampa, FL	Spot Price at Gulf Coast	Posted Price at Tampa, FL	Spot Price at Gulf Coast
1995	50.68	47.48		
1996	63.75	58.98		
1997	58.57	54.10		
1998	42.17	38.19		
1999	50.99	47.07		
2000	88.17	80.85	95.47	87.55
2001	75.28	68.91	79.61	72.87
2002	69.15	65.64	71.93	68.28
2003	87.20	80.59	89.08	82.32
2004	114.38	108.16	114.38	108.16
2005	137.70	133.38	135.28	131.03
2006	126.06	121.65	121.74	117.49
2007	122.21	117.91	115.85	111.76
2008	119.66	115.41	111.11	107.16
2009	121.29	116.94	110.34	106.38
2010	118.00	113.72	105.01	101.21
2011	122.67	118.18	106.62	102.72
2012	124.96	120.34	105.99	102.08
2013	125.47	120.80	103.94	100.06
2014	125.62	120.89	101.67	97.85
2015	125.72	120.96	99.40	95.63
2016	127.30	122.43	98.28	94.52
2017	129.14	124.15	97.32	93.56
2018	131.06	125.96	96.37	92.62
2019	132.94	127.72	95.38	91.63
2020	134.90	129.56	94.46	90.72
2021	142.12	136.44	97.11	93.23
2022	147.50	141.56	98.36	94.40
2023	154.31	148.04	100.41	96.33
2024	160.15	153.59	101.68	97.52
2025	166.18	159.32	102.96	98.71
2026	171.53	164.49	103.70	99.44
2027	177.06	169.83	104.44	100.18
2028	182.22	174.82	104.88	100.62
2029	187.54	179.97	105.32	101.07
2030	193.31	185.55	105.90	101.65

2004 BASE CASE GAS PRICE FORECAST; October 29, 2004

		PAYNE CREEK (7)				Reliant - Constellation - New Units							Calpine Osprey				Hardee Power Station	
		Up to 57 K Dth/day		Over 57 K Dth/day		New Units (CC) firm pricing negotiated amount/day							Up to 44 K Dth/day		Over 44 K Dth/day			
	Gas Price into Pipe $/Dth	Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	FGT Trans Use & Fuel $/Dth	FGT Delvd Price $/Dth	GS Trans Use & Fuel $/Dth	GS Delvd Price $/Dth	Generic CC's: w/o Firm Transp. Included $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth
	(1)	(2)		(3)		(4)			(3)				(5)				(6)	
	FGT Compressor Fuel %:				3.0%	GS Compressor Fuel %:			2.0%						PGS Compressor Fuel %:			3.0%
	FGT Usage Fees $/Dth:				$0.04	GS Usage Fees $/Dth:			$0.02						PGS Usage Fees $/Dth:			$0.041
	FGT Mkt Swing Trans:				$0.78	GS Mkt Swing Trans:			$0.78						PGS Mkt Swing Trans:			$0.48
	Transportation Basis - HHub:				$0.15													
Year																		
2004	$6.14	$0.34	$6.48	$1.12	$7.26	$1.12	$7.26	$1.06	$7.20	$6.47	$1.12	$7.26	$0.30	$6.44	$1.06	$7.20	$0.86	$7.00
2005	$7.78	$0.38	$8.16	$1.17	$8.95	$1.18	$8.96	$1.09	$8.87	$8.16	$1.18	$8.96	$0.33	$8.11	$1.09	$8.87	$0.91	$8.69
2006	$7.12	$0.37	$7.49	$1.15	$8.27	$1.15	$8.27	$1.08	$8.20	$7.48	$1.15	$8.27	$0.32	$7.44	$1.08	$8.20	$0.89	$8.01
2007	$6.99	$0.34	$6.33	$1.12	$7.11	$1.12	$7.11	$1.05	$7.04	$6.32	$1.12	$7.11	$0.29	$6.28	$1.05	$7.04	$0.86	$6.85
2008	$6.75	$0.33	$6.09	$1.11	$6.86	$1.11	$6.87	$1.05	$6.80	$6.08	$1.11	$6.87	$0.29	$6.04	$1.05	$6.80	$0.85	$6.60
2009	$6.52	$0.33	$5.84	$1.10	$6.62	$1.11	$6.62	$1.04	$6.56	$5.83	$1.11	$6.62	$0.28	$5.80	$1.04	$6.56	$0.84	$6.36
2010	$6.28	$0.32	$5.60	$1.09	$6.37	$1.10	$6.38	$1.04	$6.32	$5.59	$1.10	$6.38	$0.28	$5.56	$1.04	$6.32	$0.83	$6.11
2011	$6.04	$0.32	$5.36	$1.09	$6.13	$1.09	$6.13	$1.03	$6.07	$5.34	$1.09	$6.13	$0.27	$5.31	$1.03	$6.07	$0.83	$5.87
2012	$6.17	$0.32	$5.49	$1.09	$6.26	$1.09	$6.27	$1.04	$6.21	$5.48	$1.09	$6.27	$0.28	$5.45	$1.04	$6.21	$0.83	$6.00
2013	$6.34	$0.32	$5.67	$1.10	$6.44	$1.10	$6.44	$1.04	$6.38	$5.65	$1.10	$6.44	$0.28	$5.62	$1.04	$6.38	$0.84	$6.18
2014	$6.47	$0.33	$5.79	$1.10	$6.57	$1.10	$6.57	$1.04	$6.51	$5.78	$1.10	$6.57	$0.28	$5.75	$1.04	$6.51	$0.84	$6.31
2015	$6.65	$0.33	$5.98	$1.10	$6.76	$1.11	$6.76	$1.05	$6.70	$5.97	$1.11	$6.76	$0.29	$5.94	$1.05	$6.70	$0.85	$6.50
2016	$6.81	$0.34	$6.15	$1.11	$6.92	$1.11	$6.92	$1.05	$6.86	$6.13	$1.11	$6.92	$0.29	$6.10	$1.05	$6.86	$0.85	$6.66
2017	$6.00	$0.34	$6.34	$1.12	$7.12	$1.12	$7.12	$1.05	$7.05	$6.33	$1.12	$7.12	$0.29	$6.29	$1.05	$7.05	$0.86	$6.86
2018	$6.04	$0.34	$6.39	$1.12	$7.16	$1.12	$7.17	$1.05	$7.10	$6.38	$1.12	$7.17	$0.29	$6.34	$1.05	$7.10	$0.86	$6.90
2019	$6.27	$0.35	$6.61	$1.12	$7.39	$1.13	$7.39	$1.06	$7.32	$6.60	$1.13	$7.39	$0.30	$6.56	$1.06	$7.32	$0.86	$7.13
2020	$6.48	$0.35	$6.83	$1.13	$7.61	$1.14	$7.61	$1.06	$7.54	$6.82	$1.14	$7.61	$0.30	$6.78	$1.06	$7.54	$0.87	$7.35
2021	$6.67	$0.36	$7.02	$1.14	$7.80	$1.14	$7.81	$1.07	$7.73	$7.02	$1.14	$7.81	$0.31	$6.97	$1.07	$7.73	$0.88	$7.54
2022	$6.86	$0.36	$7.22	$1.14	$8.00	$1.15	$8.01	$1.07	$7.93	$7.22	$1.15	$8.01	$0.31	$7.17	$1.07	$7.93	$0.88	$7.74
2023	$7.06	$0.37	$7.42	$1.15	$8.20	$1.15	$8.21	$1.07	$8.13	$7.42	$1.15	$8.21	$0.31	$7.37	$1.07	$8.13	$0.89	$7.95
2024	$7.26	$0.37	$7.63	$1.15	$8.41	$1.16	$8.42	$1.08	$8.34	$7.62	$1.16	$8.42	$0.32	$7.58	$1.08	$8.34	$0.90	$8.15
2025	$7.46	$0.38	$7.84	$1.16	$8.63	$1.17	$8.63	$1.08	$8.55	$7.84	$1.17	$8.63	$0.32	$7.79	$1.08	$8.55	$0.90	$8.37
2026	$7.68	$0.38	$8.06	$1.17	$8.84	$1.17	$8.85	$1.09	$8.76	$8.06	$1.17	$8.85	$0.33	$8.00	$1.09	$8.76	$0.91	$8.58
2027	$7.90	$0.39	$8.28	$1.17	$9.07	$1.18	$9.07	$1.09	$8.99	$8.28	$1.18	$9.07	$0.33	$8.23	$1.09	$8.99	$0.92	$8.81
2028	$8.12	$0.39	$8.51	$1.18	$9.30	$1.19	$9.30	$1.10	$9.21	$8.51	$1.19	$9.30	$0.34	$8.45	$1.10	$9.21	$0.92	$9.04
2029	$8.35	$0.40	$8.75	$1.19	$9.54	$1.19	$9.54	$1.10	$9.45	$8.75	$1.19	$9.54	$0.34	$8.69	$1.10	$9.45	$0.93	$9.28
2030	$8.58	$0.40	$8.99	$1.20	$9.78	$1.20	$9.78	$1.11	$9.69	$8.99	$1.20	$9.78	$0.35	$8.93	$1.11	$9.69	$0.94	$9.52

NOTES:

(1) 2004 & 2011 - 2030 is forecast as provided by Global Insight in October 2004, Henry Hub price.
(1a) 2005 - 2007 is futures forecast as provided by WSJ on October 29, 2004, Henry Hub price.
(1b) 2008 - 2010 merges the futures forecast with the Global Insight forecast.

(2) The charges for up to 57,000 Dth/day are based on 25,000 Dth/day of FGT firm capacity with 3.0% compressor fuel and $.04/Dth usage charge, and 32,000 Dth/day of Gulfstream firm capacity with 2.0% compressor fuel and $.02/Dth usage charge.

(3) The charges for daily bundled volumetric transportaion assume Gulfstream volumetric daily market interruptable capacity will set market prices on both Gulfstream and FGT. Compressor fuel is assumed to be 2.0% and daily market transportation is a weighted average of estimated $0.78/Dth in the summer and in the shoulder months.

(4) Provides for the facility to be located on either the FGT or the Gulfstream pipelines with firm. capacity to be reserved on either Gulfstream or FGT.

(5) Assumes transportation is provide by a firm contract for 44,000 Dth/day. Assumes the facility will be located on the Gulfstream pipeline with 2.0% compressor fuel and $0.02 usage charge. Use $0.70/Dth for the reservation cost of firm transportation.

(6) The FGT compressor fuel charge for HPS is 3.0%. Variable transportation is the current PGS shoulder month price of $0.48/Dth applied to all 12 months recognition that the majority of energy is consumed during the shoulder months.

(7) The Payne Creek fixed annual reservation charge is calaculated as follows:

2004

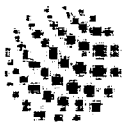
FGT 25,000 x 366 x $0.7852 = $6,937,703
GST 32,000 x 366 x $0.570 = $6,675,840
Total = $13,613,543

2005 - 2009

FGT 25,000 x 365 x $0.7959 = $7,262,659
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $13,920,259

2010 and beyond

FGT 25,000 x 365 x $0.8357 = $7,625,763
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $14,283,363



GLOBAL INSIGHT

Energy Price Forecast

Prepared for
Seminole Electric

October 2004

GLOBAL INSIGHT, INC.
24 HARTWELL AVE., LEXINGTON, MA 02421

Contributors

Mary Novak
Managing Director, Energy Services & Oil
(781) 860-6057
Fax: (781) 860-6332

Jim Osten
Principal, Natural Gas
(781) 860-6730
Fax: (781) 860-6332

Margaret Rhodes
Manager, Energy Forecasting & Power
(781) 860-6650
Fax: (781) 860-6332

John Dean
Consulting Economist, Coal and Nuclear
(301) 815-5470
Fax: (301) 815-5470

Hongyan Lin
Economist, Oil
(781) 860-6459
Fax: (781) 860-6332

Yanqun Shi
Economist, Natural Gas
(781) 860-6454
Fax: (781) 860-6332

Junya Tanizaki
Economist, Power
(781) 860-6704
(781) 860-6807

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PETROLEUM OUTLOOK

Short-term Outlook

Overview

Things have changed over the past month. It is still too early to say definitively what the implications of the recent developments will be for even the short-term outlook (let alone the longer term). Nonetheless, 2004 may come to be seen as an historic year in both the development of the oil market and oil prices, along with 1973, 1979-80, 1986, and 1998-99.

The current set of high prices contains two features that are different from any previous period of high prices. Firstly, all previous periods were driven by supply disruptions; in contrast, the primary cause of WTI hitting $55/barrel in October 2004 is the strength of demand. True, the immediate short-term cause was the Ivan-related losses in the Gulf of Mexico, but in a less tight market the impact would almost certainly have been much less. It was only against a backdrop of virtually zero spare capacity that WTI and Brent prices rose by $10/barrel in less than a month. That leads to the second difference. Heavier/sourer Dubai has only added around $2/barrel over the same time. Rising production of relatively heavy/sour crudes from the Middle East has made it clear that the global refining system is now, for all practical purposes, operating at its maximum capacity for handling either heavy or sour crudes, and cracking and desulfurizing plant are fully loaded. If refiners want to increase throughput, and the ability to do so at all is limited, they need to obtain 1) light crudes that do not produce large volumes of heavy fuel oil that they have no more ability to upgrade, and 2) sweet crudes that do not produce output with sulfur content they have no ability to sweeten.

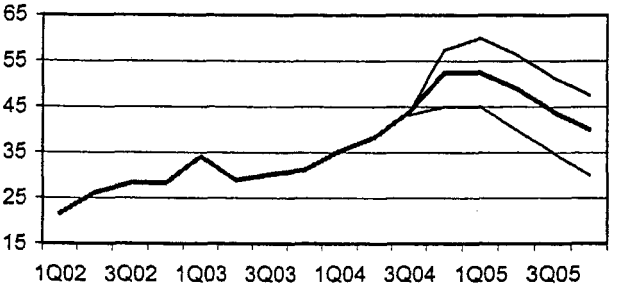
For some time, it has been evident that the global oil-refining system has been approaching a "crunch point" with regard to capacity: a doubling of the discount of Dubai to Brent over the past month. High-sulfur fuel oil prices in Europe at less than 45% of the price of crude. Naphtha, jet, and gas oil recording all-time high spreads. All indicate that that point has now been reached.

The world's refineries can no longer supply what the market requires. In the short term the solution may come from some depression of demand by high prices, either as economic activity slows, efficiency measures or fuel switching increase, or individual consumers baulk at the prices asked. In the longer term the only answer can come from building more refineries and more desulfurizing capacity.

In the short term all this implies continuing very high prices for the light sweet markers—we are projecting around $52.50/barrel for WTI through the winter—and the development of a two-tier market, with heavy/sour grades trading at very large discounts to the light sweet markers. It also means continuing high prices for the light products and very large discounts for fuel oil. In 2005, some easing of the

supply tightness, with additional non-OPEC output and increasing OPEC capacity, and therefore restoration of the spare capacity cushion, should see crude and product prices falling and the heavy/sour discount narrowing. But unless there are substantial additions to refinery capacity over the coming years, as yet by no means certain, repetitions of recent events will be all-too possible.

WTI Price Outlook Scenarios
(Quarterly, dollars per barrel)



Market Review

The month of September had two distinct halves. For the first two weeks, the WTI price hovered between $42.50 and $45/barrel. Then, on September 17, as the scale of the impact of hurricane Ivan became clear, WTI jumped $1.60/barrel, initiating a run-up in prices that continued through the second week of October and took WTI to around $55/barrel and Brent to around $51.50. The after-effects of Ivan and fears of disruptions in Nigeria, Norway, and Brazil were the main factors propelling prices upwards. At the same time as the light/sweet markers were rising so rapidly, difficulties in disposing of heavy/sours sharply increased, as signs emerged of a bottleneck in both cracking and desulphurization capacity, and producers of heavy grades had to offer ever-larger discounts to gain sales.

Marker Crude Prices
(Dollars per barrel)

	August	September	October 1-20
WTI	44.70	45.87	52.85
Brent	42.71	43.3	49.22
OPEC reference basket	40.42	40.22	44.96

The mood of slight relaxation that had prevailed in early September was rapidly dispelled by one of the worst hurricanes on record, and certainly the most disruptive for oil industry operations in many years. Although industry observers knew Ivan was going to be disruptive, an initial EIA assessment predicted only a short-lasting impact. As reports emerged of the scale of disruption, however, and as recovery proved slower than expected, prices moved rapidly upwards. Concern focused not only on the loss of crude production, but also the loss of product output arising from the precautionary shutdown and then delayed restart of refineries. Although some losses will prove only temporary, e.g., delayed arrivals of imports, others are permanent, e.g., lost crude production, still running at nearly 0.5 million

b/d, and losses of product output as refineries are unlikely to be able to compensate. Crude stocks fell sharply, to around 270 million barrels, and distillate stocks fell in a month when rises are the norm and concerns were already building about the adequacy of heating oil supplies for the winter. U.S. refiners seeking to replace lost supplies turned to the international market—only to find that European and Far Eastern refiners had gotten there first. European buyers were purchasing further ahead than normal as a pre-emptive measure, expecting increased demand from the United States, while Far Eastern refiners were seeking to satisfy their own booming demand and low stocks of middle distillates. As a result, U.S. buyers have had to pay whatever price was asked to gain supplies, adding to the upward price pressure.

And other factors added to the upward momentum. On September 20, Yukos suspended rail exports to China. Then in late September a group of Nigerian insurgents in the Niger Delta oil-producing area threatened "all-out war" and warned oil companies to remove staff. Initial fears of a major loss of production soon receded, but despite a truce agreed on by the government and the rebels, uncertainty remained—only to be aggravated by the added threat of a stoppage to production from oil workers engaging in a union-inspired strike against recent reductions in subsidies to domestic fuel prices. A further limited strike by Norwegian oil workers is cutting production by up to 50,000 barrels/day (b/d) amid fears of further escalation, while Brazilian production is also threatened by a labor dispute.

Demand and Supply Fundamentals

Economics

With the world economy's post-Iraq-war recovery having already passed its peak, Global Insight has lowered its forecast of global economic growth slightly for 2004, to 4.1%—which remains the best performance since 1988. There is sufficient spare oil capacity worldwide for the expansion to continue for several more years. Nevertheless, there are risks and vulnerabilities, particularly since the world output gap has not yet been closed. With the economies of the United States and China now accounting for disproportionately large shares of global growth, if either of them slows down, the world economy could be left high and dry. While recent news from the Eurozone and Japan has not been too bad, their growth has been driven primarily by external demand, and major doubts persist about whether their economies can generate domestically driven growth.

Another potential risk to global expansion comes from rising oil prices. Higher oil prices add to inflation and also act as a drain on households' purchasing power in oil-consuming nations. An oil price sustained in the range $40-60 per barrel would dampen the global expansion, but not derail it. An oil shock of the dimensions similar to those in the late 1970s and early 1980s would require prices to reach $80-90 per barrel in the future.

During the past few months, data from many of the key regions of the world suggest that economic growth slowed down in the second quarter and early months of the third quarter. The slowdown was most pronounced in the United States and

Japan, but was also evident in quite a few other industrialized economies. While Global Insight believes that global growth peaked earlier this year, we do not expect the recent "soft patch" to augur the start of a much deeper downturn. The single biggest reason for the recent deceleration has been high oil prices, which have reduced the global economy's annual growth by about 0.5 percentage point. Contributing to this slowdown has been the lack of independent growth outside of the United States and, arguably, China.

At the same time, there are many reasons to believe that the current global recovery is sustainable. The U.S. locomotive—which so many economies are counting on for export-led growth—will probably not run out of steam soon. While U.S. consumer spending is set to slow, capital spending (thanks to record profits) and exports (thanks to a weaker dollar) will keep the recovery moving along at a steady pace. Since inflation remains quite tame, high oil prices have not translated into a sustained acceleration in core inflation. Unless oil prices continue to rise, the upward pressure on inflation will likely ease, allowing central banks to raise interest rates at a fairly leisurely pace. Indeed, Global Insight expects the global economy's pace to remain well above its trend through at least 2005.

Real GDP Growth, World and Major Seven Economies
(Year-on-Year percent change)

	2004			2005		
	Q2	Q3	Q4	Q1	Q2	Q3
US	4.6	3.7	3.7	3.4	3.6	3.4
Canada	3.0	3.6	3.9	3.8	3.5	3.4
France	3.0	2.6	2.6	2.3	2.1	2.3
Germany	1.5	1.6	1.7	1.7	1.8	2.0
Italy	1.2	1.1	1.4	1.4	1.6	1.9
UK	3.7	3.5	3.2	3.1	2.9	2.7
Japan	4.3	4.3	3.0	2.0	2.2	2.2
World	4.4	3.9	3.5	3.2	3.3	3.4

Demand

Latest data show exceptionally strong growth in the third quarter, resulting in an increase in the estimate of global demand for the quarter of 0.6 million b/d. The growth is evenly spread between OECD and non-OECD regions and is concentrated in the middle distillates with jet/heating kerosene and road diesel posting very strong gains. Both reflect vibrant economic activity, but also an element of kerosene stock building in Japan, where stocks are still well below year-earlier levels, and the ongoing effect of dieselization in Europe. Heating oil deliveries were also sharply up in the third quarter, as German consumers finally returned to the market, but large percentage increases there are misleading owing to extremely low deliveries in the corresponding periods of the past two years. Available data also suggest stronger demand in the FSU and non-OECD Asia outside China.

Most of the third-quarter increases have not been carried through to the fourth quarter, however, as the third quarter last year was relatively weak while the fourth was relatively strong, and there are preliminary indications that demand is beginning to be affected by high prices. Higher use of both crude oil for direct burning and fuel oil in Japan now appears inevitable, however, with further delays in the restoration of nuclear power stations.

As economic growth estimates for next year begin to be trimmed, in light of this year's high oil prices, so oil demand forecasts are also being trimmed. This reflects not only the lower economic growth projections but also provisional indications that current prices have stimulated energy efficiency and fuel switching measures.

Total growth in 2004 over 2003 is now estimated at 2.7 million b/d, and that of 2005 over 2004 at 1.5 million b/d. Since estimates of this year are still having to be adjusted upwards as data for both OECD and non-OECD regions suggest continuing strong growth, we are retaining our upward non-specific adjustment to demand.

Non-OPEC Production

Non-OPEC production was hard hit in the third quarter by the disruptive effects of hurricane Ivan on production in the Gulf of Mexico (GOM). Such was the damage to facilities that it will take until the first quarter of 2005 before output is fully restored. Lost production in September amounted to a little under 0.5 million b/d, equivalent to around one quarter of GOM production. Unfortunately, losses due to Ivan came on top of a series of scheduled and unscheduled stoppages to Alaskan production that brought total U.S. output to the lowest monthly level since 1950. Moreover, output over the first eight months of 2004 was already an average of 0.2 million b/d down on 2003.

North Sea output, on the other hand, should rise by some 0.25 million b/d between the third and fourth quarters, with the end of summer maintenance, providing a welcome addition to light/sweet crude supply. Strike action by drilling staff in Norway has resulted in small losses of output since July and continues to the present. Total losses of less than 50 thousand b/d are not expected to rise much higher, but such action poses another downside threat to North Sea output, already prone to more downside than upside surprises.

The growth rate of Russian output is slowing, as expected, but so far there seem to be no significant losses attributable to the problems of Yukos. Total FSU output is expected to grow by some 0.8 million b/d this year, with almost all of the gain from Russia, and by 0.6 million b/d next year, when one-third of the growth will come from Kazakhstan and Azerbaijan.

Total non-OPEC output for this year will now be lower than previously expected, as a result of the Ivan-related losses, and is now projected to grow by 1.1 million b/d. The projection for 2005 remains broadly unchanged, with growth of 1.3 million b/d. Although the North Sea will continue to decline, as well as the FSU,

large increases in output are expected in Africa (chiefly Angola) and in Latin America (chiefly Brazil but also Ecuador).

OPEC Production

Total OPEC output rose again in September, reaching 29.9 million b/d on the IEA's estimate. This represented an increase of some 0.7 million b/d from August, and was mainly due to a recovery of 0.5 million b/d in Iraqi output. Other increases were small and estimated to have occurred in Kuwait, Saudi Arabia, and Nigeria, while in Iran, the U.A.E., and Venezuela there were apparently small declines. (The inadequacy of data on OPEC output makes it difficult to be certain of small changes, however.)

In Iraq total gross output rose to 2.5 million barrels, the highest monthly level since the overthrow of the old regime, and was attributable to higher exports from both the north and the south of the country, although re-injection of some 0.2 million b/d of crude is still necessary. Attacks on pipelines continued, but these were less disruptive during September and allowed southern exports to rise sharply. Exports from Ceyhan remain at very low levels, however, relative to potential pipeline capacity.

Total OPEC spare capacity on a sustainable basis is estimated by the IEA at around 0.4 million b/d in September; but with Saudi Arabia producing 9.5 million b/d, its currently estimated sustainable maximum, it is debatable whether the small volumes of spare shown elsewhere are actually achievable. For instance, 0.1 million b/d of spare in the U.A.E. is especially doubtful, given the high level of demand for the Emirate's relatively light crudes. In the case of Saudi Arabia, confusion continues regarding the timing of the extra output from Qatif and Abu Safah and whether their contribution will merely replace closed wells elsewhere or represent a net addition. Most recent indications suggest the latter, whereas earlier information had pointed to the former. Whatever the actuality, undoubtedly Saudi Arabia and several other Gulf states do have the capacity to increase output on a *surge* basis for a limited period of time, if required, although increasingly the sharply rising differentials between light/sweet and heavy/sour crudes suggest that the market is sated with heavier sour crudes and that extra output from the Gulf would not be a useful increment. Algeria, and perhaps Libya and Nigeria, are set to increase output of lighter low sulfur grades before the end of the year. These will be eagerly consumed by a market thirsty for such grades, and will further exacerbate the problem of adjusting quotas for Algeria and Nigeria, in particular, if and when OPEC ministers choose to address this issue.

OPEC Compliance in September 2004
(Million barrels per day)

	Quota as of Aug 1	Production (1) Sep 2004	Production vs. Quota	Estimated Sustainable Capacity (2) (IEA Sept 04)	Spare Capacity	Quota as of Nov 1
Algeria	0.830	1.25	0.42	1.25	0.00	0.862
Indonesia	1.350	0.97	-0.38	1.00	0.03	1.399
Iran	3.820	3.90	0.08	4.00	0.10	3.964
Kuwait (3)	2.090	2.45	0.36	2.50	0.05	2.167
Libya	1.390	1.59	0.20	1.59	0.00	1.446
Nigeria	2.140	2.45	0.31	2.50	0.05	2.224
Qatar	0.670	0.80	0.13	0.80	0.00	0.700
Saudi Arabia (3)	8.450	9.55	1.10	9.50	0.00	8.775
U.A.E.	2.270	2.42	0.15	2.55	0.13	2.356
Venezuela	2.990	2.21	-0.78	2.25	0.04	3.107
OPEC 10	**26.000**	**27.58**	**1.59**	**27.94**	**0.40**	**27.000**
Iraq (4)		2.33		2.80	0.47	
Total OPEC		**29.91**		**30.74**	**0.87**	
Excl. Venez./Nigeria/Indon./Iraq					0.28	

1. Secondary source estimates of OPEC production regularly differ. The above reflects the IEA estimate.

2. Capacity figures are levels achievable within 30 days and sustainable for 90 days.

3. Figures for Saudi Arabia and Kuwait each include 50% of the Neutral Zone. (Note: Saudi Arabia claims it can produce 10.5 million b/d immediately and sustainably within 90 days.)

4. Iraq estimate represents pre-war capacity. Post war production has not yet exceeded 2.5 million b/d

Market Balance

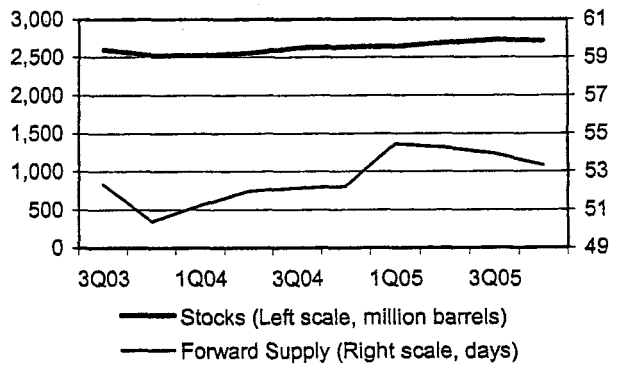
Total OECD Commercial Inventories

In last month's report we said the implied stock build in the third quarter was larger than appeared probable, given the bottom-up data available at that time, but that, assuming a retroactive upward adjustment to demand, it looked just credible. Latest data provide retroactive adjustments, not just to demand but also supply, and bring the two representations of the balance into harmony.

Global demand for the third quarter has been increased by a massive 0.6 million b/d, while supply has been cut by 0.3 million b/d, mostly but not exclusively as a result of hurricane-related losses in the United States. The top-down figures now suggest a much more reasonable global stock-build of around 1.5 million b/d, compared to the 2.3 million b/d implied a month ago. Bottom-up figures are only available to end-August for the whole of OECD, but to end-September for the United States. Assuming historical patterns for the other OECD regions, Europe and Asia-Pacific, a build of around 1.1 million b/d is indicated, leaving some 0.4 million b/d for increasing volumes of oil at sea and for builds in non-OECD areas, a level close to that in the first half of the year.

Total figures for the whole of OECD do not tell the full story, however. Crude stocks are around the middle of the historical range, but even that hides the fact that they are relatively high in Europe and low in North America. Moreover, the one figure that is becoming most critical—the split between light/sweet and heavy/sour crudes—is not available. Product stocks show a more worrying picture. Total product stocks at end-July were significantly below the average of the past five years; but more worrying still, at the beginning of winter, and at a time when middle distillate demand is growing strongly and refineries are running at or near capacity, is the fact that total middle distillate stocks were at a record low for the time of year in terms of days cover.

OECD Commercial Stocks and Forward Supply



Atlantic Basin Inventories

U.S.

The impact of hurricane Ivan on stocks was considerable. Crude stocks were depleted by reduced production and delayed tanker arrivals. On the other hand, reduction to refinery throughputs offset some of the stock impact, and total throughout was due to fall anyway with seasonal maintenance in September. Product stocks were reduced by lower refinery output. It is not possible to put a precise figure on the stock reductions, but clearly the impact has been substantial, and will remain so for months to come, as crude output remains affected and refineries struggle to make up lost output.

Crude stocks of 286 million barrels at the end of August were already some 11 million barrels below the average of the previous five years for the time of year. In the immediate wake of Ivan, stocks fell to 269 million barrels, but recovered to 274 million by the end of September and have since risen further. A figure of 274 million barrels is not the lowest recorded at end-September; 2002 was marginally lower; but it is still some 16 million barrels below the average of the previous five years for the time of year. Imports were only severely affected for one week, thus helping to moderate the impact, but production is some 0.3 million b/d below where it was before the hurricane.

Gasoline stocks, which had recovered to relatively comfortable levels by end-August, fell sharply in September and ended the month at 199 million barrels, the same as last year, but some 4 million barrels below the average. Stocks normally build during September and the full impact is seen in the lowest end-September days cover figure for at least the past ten years, despite weakening demand growth.

Distillate stocks also fell during September, a month when growth would normally be expected, to 123 million barrels, the lowest end-September figure since 2000. Like gasoline, distillate stocks were at a record low for the time of year in days cover.

Despite global concerns about surplus fuel oil, U.S. stocks have actually fallen steadily over recent months, partly as demand has recently been quite strong, and they currently represent no problem, although this could soon change.

Europe

Euroilstock provisional data show total European crude stocks rising during September, to end the month at the highest end-September level for at least the past ten years. Latest data show refinery runs in August were less than 0.1 million b/d short of the highest August in the past decade; but September runs were probably reduced for maintenance in line with normal practice. Nevertheless, profitable refining margins, especially for complex refiners, may have modified the normal seasonal pattern. Nevertheless, with OPEC output still rising and substantial volumes of crude from the Middle East still on the water, even higher-than-normal runs in September and October will not necessarily make a large dent in crude stocks.

Total product stocks are at the other extreme, however, at virtually the lowest end-September level for the past ten years. This overview is slightly misleading in isolation, however, as it is influenced by historically low stocks of both gasoline and fuel oil, demand for both of which are declining. Stocks of kerosene and gas oil/diesel, however, are in the middle of the historical range, following very high production and imports from other regions in response to exceptionally high prices.

Prospects for the Global Balance

All the indications are that OPEC will continue to produce at current levels through the end of the year. Unless prices show any sign of significant softening, which seems unlikely, ministers will not meet again until December 10, at which point they will decide on output for January and beyond. Total output could rise by December, with some 90,000 b/d of new capacity due to be commissioned in Algeria at the Gassi al Agreb and ROD fields, and the restoration of operations through the 0.2 million b/d GC15 gathering center in Kuwait. In addition small increments to capacity are possible in several other countries. In Saudi Arabia the rate of build up of production from Qatif and Abu Safah remains shrouded in uncertainty, amid conflicting reports of timing; but it is possible that full output has

still to be reached. There have also been reports that older wells due to be retired with the commissioning of Qatif and Abu Safah will now be kept active, and that Saudi Arabia is actively drilling to increase capacity. At the same time, the prospects for Nigerian output remain uncertain as strikes by oil industry unions intensify.

All this assumes, however, that OPEC members can continue to sell their crude. Global demand is predominantly for lighter and sweeter crudes, as global cracking and desulfurizing capacity now seems to be working virtually at capacity, and the discounts necessary to move the heavier grades are steadily increasing and have reached hitherto unprecedented levels, with North American and Far Eastern sweet markers WTI and Tapis both trading at over $15/barrel above Far East sour marker Dubai. The widening differential reflects both strong demand for the lighter/sweeter grades and a lack of demand for the heavier/sourer ones. Both gravity and sulfur content are important. Any additional output of light sweets from Algeria, and possibly Libya and Nigeria, as well as heavier sweets from Angola, will be welcomed, but are unlikely to reduce by much the upward price pressure on light grades or the downward pressure on heavier grades.

Assuming small increases in OPEC output, the total OECD stocks days cover figure would end the fourth quarter at around 52 days, not much different to the third quarter, although total stocks will continue to build. Thereafter, however, it would seem likely that the days cover figure would rise sharply, unless there is some cut in production: the call on OPEC crude plus stocks over the first half of next year averages some 27.3 million b/d, compared with current output of close to 30 million b/d. While stocks would normally rise in the second quarter, they would not rise sufficiently to absorb volumes of this magnitude. Nevertheless, although many OPEC members are facing difficulty in selling their crudes and are having to increase discounts to do so, it is far from clear that they would agree a cut to production at their December meeting, for fear this would send the wrong signal and drive prices even higher.

However, market forces may do the job for them—if global capacity to process heavy crudes and to desulfurize the output of sour ones is truly reaching a limit, as current price differentials suggest. There lies a further source of uncertainty, however. Data on refinery capacity and throughput even in OECD countries is poor. And for non-OECD countries it is worse. Hence although price differentials indeed point to limits being reached, no one can be quite sure exactly where those limits are. Low stocks of middle distillates in all regions and apparently little spare refinery capacity for producing or desulfurizing more will certainly add pressure to demand for the lighter/sweeter grades. Forecasts of a cold winter in the United States, the emergence of German demand for heating oil as consumers decide not to wait any longer before replenishing tanks, and fears of low Russian exports are all adding more pressure.

The markets for light/sweet and heavy/sour crudes are becoming disconnected to a degree never before encountered. Although at an aggregated level the numbers suggest further rises in stocks next year, such broad top-down calculations appear

increasingly abstracted from market reality. Stocks of light/sweet crudes will not rise; they will be used as fast as they are produced. Stocks of light products will not rise to the point that they become a drag on the market; there is only just sufficient refinery capacity to meet demand. Stocks of heavy crudes are not likely to rise, at least not with commercial operators; they are already a drag on the market and fuel oil spreads are becoming ever wider with no obvious outlets. Truly, these are uncharted waters.

Crude Price Forecast

Base Case

Prices and spreads have increased substantially over the past month; and as long as the demand for light/sweet crudes exceeds supply, the ability to handle heavy/sour crudes is at a limit, and the demand for (especially) low-sulfur middle distillates exceeds the refining system's capability to produce them, there is no physical limit to stop prices of the (light/sweet) markers WTI and Brent from rising further. However, the market appears to have found a temporary ceiling with WTI at around $55, with movement from that level tending to be downwards rather than upwards. Any renewed fears of disruption could send prices higher, but steady recovery of output from the Gulf of Mexico could offset that, and if there are no further actual serious losses prices, prices might not move much higher, at least on a sustained basis. On the other hand, the tight supply of light/sweet crudes will serve to keep support under the two sweet markers, WTI and BFO/Brent; so little change from current levels is expected through the winter in terms of average monthly prices, although normal short term volatility will see prices fluctuating in a band that could range from $45/barrel to $60/barrel.

Next year the losses from hurricane Ivan will gradually be restored, and extra output from non-OPEC producers will come to the market, while OPEC capacity will increase, allowing some spare capacity to be restored within OPEC—the absence of which has been one of the key "fear factors" supporting prices recently. Moreover, some of the new OPEC capacity will be light/sweet crude from Algeria, and possibly also from Nigeria and Libya, which will probably be produced regardless of quotas, displacing heavy Persian Gulf crudes.

To reflect this easing of tightness we show a moderation of the price through next year. In recognition that most of the recent run-up in prices was due to losses in the Gulf of Mexico, which will be restored by the second quarter of 2005, we see no reason at this stage to change the profile beyond 2005.

Short Term Marker Crude Price Forecast
(Dollars per barrel)

	Sep	Oct	Nov	Dec	Jan	Feb	Mar
WTI	45.87	52.50	52.50	52.50	52.50	52.50	52.50
Brent	43.30	49.00	49.25	49.25	49.25	49.25	49.25

Alternative Cases

High-Price Scenario: A higher price scenario could result from:

- Further terrorist attacks/political tension in the Middle East.
- Further disruptions or losses of supply in non-OPEC areas.
- Yet more backdated increases to demand leading to higher forecasts.
- OPEC implementing large cuts in fear of prices falling too rapidly.
- Further delays in new non-OPEC production.
- A cold winter causing spikes in distillate prices impacting crude.
- Further upwards pressure from financial traders.

The greatest concern remains terrorist action. Absent such a development, even in a high case we assume that WTI would likely remain below $60/barrel; but if Saudi exports were cut, short-term spikes could drive prices very high, in which case governments would almost certainly take emergency actions to curb consumption and release strategic stocks. It would be an entirely different world, and prices would depend on strategic reactions and their timing.

Low-Price Scenario: A lower price scenario could result from:

- Greater price reaction to high prices as global economic activity is dented by the burden of high prices, and slows more quickly than expected. Chinese demand moderates.
- Stocks rising rapidly around the world.
- Easing of concerns about loss of supply due to higher stocks and slowing demand growth.
- OPEC, over-confident in the strength of demand, is slow to cut as stocks rise.
- Russian gasoil exports recover and the winter is mild.
- Financial traders do not rebuild their large net long positions.

In this scenario, perceptions would probably still only change slowly, due to geopolitical uncertainties and risks, and it will still take some time for a sizeable cushion of spare capacity to be restored. Such a scenario would be one in which prices were driven primarily by fundamentals, with an absence of any "terror" of "fear" premiums.

Oil Product Prices

Gasoline

After three months in which gasoline demand growth was less than 1%, September posted growth of marginally over 1%. Growth for the year to end-September was 1.64%, continuing the trend of declining growth rates, down from around 3%

at the beginning of the year. Further increases in crude prices are inevitably feeding through into prices at the pump and may be having a depressing effect on demand, although it is still too early to see clearly whether this is happening. On the other hand, with national average gasoline prices at the pump again having exceeded $2/gallon and with winter approaching and less occasion for leisure motoring, it would not be surprising to see further slowing of demand growth, and the EIA again marking down its estimate of demand growth, with total 2004 growth now estimated at 1.6% and next year at 1.5%, as high prices are expected to continue through next year, albeit not at the current levels.

Stocks were seriously depleted in September by the reductions in refinery throughput resulting from hurricane Ivan, and ended September marginally below 200 million barrels, falling during a month when stocks would normally rise. Normal seasonal refinery maintenance in October, on top of any extra work required to repair Ivan-related damage, will reduce refinery throughputs further and end-October stocks are likely to be even lower than end-September.

Runs should recover sharply in November and are likely to stay high through December, as refiners seek to rebuild distillate stocks before the worst of the cold weather arrives in the first quarter. Maximization of distillate yields is normal for this time of year, but distillate yields have been high throughout this year already, so the scope for further increases would appear to be limited. Contrary to popular perceptions, the maximization of distillate yields does not imply minimization of gasoline yields. Generally speaking, gasoline yields also tend to rise in the latter part of the year, and this year is not expected to be an exception. Indeed, the average yield of 57.1% in September exceeds by more than 1% the highest for the month recorded over at least the past ten years, and yields over recent weeks are the highest ever recorded. That said, clearly the emphasis would still be expected to move towards distillate for the fourth quarter, especially as distillate prices have moved above those of gasoline over the past month. All of which may leave gasoline stocks looking low coming into next year's driving season, unless the winter proves very mild and refiners can switch to gasoline maximization earlier.

Gasoline spreads strengthened in mid-September in response to hurricane Ivan-related losses, but have since been weakening and in mid-October have fallen to the lowest levels this year, possibly as a response to the high production despite low stocks. Nevertheless we do not expect this depression of gasoline spreads to last. As refinery output moves more towards distillate, and if European prices remain relatively high, U.S. gasoline stocks could be further depleted quickly, which will necessitate a recovery of price to re-open the arbitrage from Europe. Moreover, the expected scramble for light/sweet crudes this winter could leave the U.S. poorly positioned relative to Europe or the Far East, requiring even higher levels of gasoline imports. Accordingly, we expect gasoline prices to rise again from their current low levels. Last year fears about the ability of foreign suppliers to meet new U.S. specifications, plus futures market speculative activity, drove spring prices rather high. We do not expect the same fears about foreign supplies over this winter; but total imports will certainly need to rise. Hence, spreads are expected to be wide again, but slightly lower than this year.

Distillate

Total distillate demand recorded only a small percentage growth in September, after a very strong September 2003; but year-to-end-September growth remains high, at 2.8%. Many residential heating oil consumers are believed to have eschewed their usual fixed price contracts with distributors this year, hoping for a price fall, but will now find themselves having to buy for winter at prevailing prices. This means that in addition to low primary stocks, tertiary stocks are also low, although secondary stocks should be high. Much depends on the weather. Weather Service forecasts are for a colder winter than last year, so distillate demand should remain firm. Likewise, diesel demand is growing strongly as the U.S. economy continues its robust growth, albeit now slowing from earlier heady rates. Jet consumption fell back sharply in September, but this is expected to be only a temporary setback, and strong growth is projected as aviation use shows all the signs of a belated recovery after 9/11.

Jet and diesel stocks are healthy, but heating oil stocks are very low after Ivan. Moreover, high European prices were attracting cargoes from the Gulf Coast during early September, but recent rises in U.S. prices have curtailed such movements. As noted above, distillate production has been very high for months, so although refiners are expected to maximize distillate production over the fourth quarter, there is relatively little scope for further rises. Worse, distillate stocks are low globally while demand is strong, and Russian exports, the marginal supplier to the United States last winter, are very uncertain after a summer when export volumes proved volatile. Low European and Far East stocks may also mean those regions pre-empt the larger part of whatever Russian exports are forthcoming.

Reflecting this current tightness and expected further tightness, spreads for all three grades of middle distillate rose sharply during September in the wake of losses arising from Ivan-related disruptions, although, after peaking at the beginning of October, they have since softened a little. Nevertheless, distillate, diesel, and jet all remain at record levels for the time of year. New York Harbor prices have been supported by a closed arbitrage from the Gulf Coast as a result of higher Gulf Coast prices due to Ivan losses and arbitrage opportunities to Europe. Firm demand and fears about future supply are expected to keep spreads high, probably rising further even from current inflated levels as winter begins. The NYMEX futures curve for heating fuel shows almost flat prices through January, but very steep backwardation thereafter, reflecting the strength of prompt demand for stock building. As the position tightens further, however, the curve could become steeper still or, less likely, could flatten as forward months' prices rise. The differential of diesel over distillate has recently risen to very high levels; and with a tight jet kerosene position and changing diesel specifications in Europe, this situation is expected to persist through the winter.

Residual Fuel

From June to September resid prices scarcely responded to upward movements in crude prices, apparently constrained within ceilings. The sharp increase in crude prices since mid-September, however, has seen resid prices move upwards in ab-

solute terms, although, with the exception of the 0.3% sulfur grade, the move has not fully matched crude and the discounts have thus widened.

A rise in natural gas prices since mid-September has made very low sulfur fuel oil grades more attractive to any utility users who have the scope to switch, and in early October consumption has been up 40% over a year ago.

U.S. refiners are still managing to avoid a major rise in resid yields or stocks, but how much longer this can continue is a moot point; yields rose in August and September, but remain low relative to history. With still-rising heavy crude supply, however, and especially with the reported high schedule of cracker shutdowns over coming months, fuel oil yields seem likely to increase with few obvious prospects for disposal. The two very low sulfur grades may find a partial market if gas prices remain high, but the 1% and higher grades will prove troublesome. Spreads are expected to remain very wide well into next year and only begin to reduce as crude prices fall. Falling crude prices and narrowing spreads will mean little absolute change in fuel oil prices.

Long-term Outlook

The Historical Context

Between the oil price collapses of 1986 and 1998/99 annual average dated Brent crude prices averaged $18.50/barrel (bbl) and ranged between $15/bbl and $24/bbl bbl in money of the day ($25/bbl, $23/bbl and $33/bbl respectively in $2003).

Prices collapsed to below $10/bbl in early 1999 as OPEC mistimed an increase in output to coincide with the beginning of the Asian economic crisis. The shock of such low prices stimulated a new degree of unity and resolve within OPEC. The $22-28/bbl price band for the OPEC Reference Basket (ORB - the average of a basket of seven crudes) was introduced in March 2000 and has been supported by pre-emptive management of the total OPEC quota so as to keep prices within the band. The ORB remained mostly within the band till late 2003. In December 2003 it moved above the band and has remained so since.

OPEC's task was made easier by several years of below-average increases in non-OPEC output and disruptions to supply in Iraq, Venezuela and Nigeria.

The Price Increase since late 2003

Prices have been much higher than previously expected due to stronger demand and weaker supply, especially delays in new non-OPEC output.

The price rise since late 2003 has been due to stronger than expected synchronous global economic growth, and explosive oil demand growth in China due to a rapid growth in private car ownership and the use of oil for power generation independent of an over-stretched and unreliable power grid.

Other factor adding to the pressure on prices have included further supply problems in Iraq, Venezuela, and Nigeria; speculation in the oil futures market; antici-

pated tight supply of gasoline in the U.S. market; geo-political worries focused on the possibility of terrorist action hitting Middle East oil supplies.

The Price Outlook

Prices are now thought likely to stay high for longer than previously thought, with WTI remaining above $40/bbl till the early summer of 2005 and thereafter declining only slowly. This assumes no further major and prolonged losses.

All the potential risks on crude oil supply are on the downside: possible further losses in Iraq, Venezuela and Nigeria; possible losses in Russia as a result of the Yukos affair; possible terrorist action disrupting supplies from other Middle East suppliers; further disappointments and deferments to new non-OPEC production.

Non-OPEC producers are all at maximum output and there is virtually no spare capacity in OPEC, other than around a million barrels/day (b/d) in Saudi Arabia, with this small margin itself doubted by some commentators.

Most of the potential risks on demand are on the upside: yet stronger growth in China, further upward adjustments to both historic data and to projections of global demand. Moreover peak winter demand is still to come

High prices seem to have had little impact on oil demand so far, due to the concentration of oil use in the transport and petrochemical sectors where demand is relatively price-inelastic.

Forward projections of the supply/demand balance point toward rising stocks in 2005 that should moderate price levels but such projections have recently been beset by serious data problems and may not be a reliable indicator.

In the Base Case, prices are assumed to moderate slowly from an annual average for WTI of some $40/bbl ($2003) in 2004 to a low of around $28/bbl by 2014, and thereafter to show only a very slow rise in real terms to $30/bbl by 2025, and to remain around that level to 2030.

Demand is projected to grow more strongly than in last year's Global Petroleum Outlook, but growth assumptions for China and India remain moderate compared to feasible futures. China is not projected to follow the historic growth path of other "Asian tiger" economies during this period, partly due to the scale of the infrastructural development that would be required and partly as higher prices are expected to provide an incentive to encourage increasingly efficient use of energy.

The strength of prices and the slow decline to 2010 is due to slow growth both in non-OPEC supplies and in the development of spare capacity in OPEC.

Growth in supply over the next five years comes mainly from high cost, remote, and politically less stable areas in Russia, the Caspian, and West Africa. Development issues include concern about the legal framework in Russia and developing new export infrastructure, technical problems and the complexities of laying pipelines that cross multiple international boundaries for the Caspian, and technology issues in deep water off West Africa as well as pressures on oil companies from shareholders and regulators in connection with issues of ethics. Long lead

times mean that most of the new supply expected by 2010 can already be projected, albeit substantial uncertainties remain. Any new finds today would scarcely be in production by 2010.

The prospects for production from other, longer established, regions are mostly flat at best, or downward in the case of the North Sea and North America, while depletion on existing fields is increasingly an issue, even within Saudi Arabia, so substantial volumes of new production are required simply to stand still.

OPEC countries' revenue needs are rising due to rapidly rising populations and increasing competition for oil revenues. It is assumed that capacity will expand steadily but that higher prices are now required to balance budgets.

Beyond 2010 it is assumed that high prices will have produced a supply reaction in terms of higher output from higher costs regions and of extended field life in areas where costs are more moderate but on a rising trend. All indications are that global reserves accessible at moderate costs still exist in sufficient volumes to meet demand.

All recent indications are that finding and development costs have risen rapidly over recent years, after stability at low levels in the 1990s. It is assumed that this will stimulate efforts to reduce costs in the upstream oil industry (as was achieved following the 1986 price collapse), which will assist supply growth.

Nevertheless substantial additions will be required every year from OPEC countries. The scale of extra supply needed post 2010 is massive – requiring the equivalent of the addition of a Libya every year. The reserves exist and OPEC countries will be willing to add capacity but competing demands for oil revenues will mean that prices will need to be relatively high. It is assumed that geopolitical developments do not change the need of OPEC countries, especially in the Middle East, for revenue derived from oil, and that productive capacity is not damaged by any such developments.

Price projections are a trend. It is likely that there will be periods, possibly of several years at a time, when prices are either above or below the trend. A price outcome higher than the projected trend could result from stronger demand growth (perhaps notably in China) and/or weaker supply (more disappointments in non-OPEC and loss of productive capacity in OPEC due to political upsets – as has occurred in Libya, Iran and Venezuela). A price outcome lower than the projected trend could arise from recession, enforcement of higher efficiency standards and/or better than expected supply prospects.

NATURAL GAS OUTLOOK

Overview

Natural gas supplies are constrained, which has driven gas prices up to a level sufficient to bring demand into balance with available supplies. U.S. and Canadian production has no significant spare capacity and is struggling to increase despite a strong rebound in drilling activity. Supplies are expected to improve gradually as higher drilling levels eventually lead to modest production increases, and as new LNG facilities come on-line later this decade.

Consumption of natural gas was restrained by the recent manufacturing sector slump and by high prices that caused the industrial and electric power sector to either shift to other fuels or, in the case of gas-intensive industry, to shift production overseas. Demand drivers are suggesting strong demand pressure in 2004, indicating the potential for further price-induced demand destruction in line with available supplies. Going forward, the potential growth in power sector demand is especially strong over the next ten years—price permitting—because of a large influx of new gas-fired generating capacity.

Henry Hub gas prices are expected to remain in the 6 per million Btu range through 2006, as supply constraints ease only gradually, and then to ease down to the $4.25-4.50 range (in 2003 dollars), where they will more closely resemble domestic and imported supply costs. The costs of finding and developing domestic gas supplies have risen sharply from levels of a decade ago, when prices were further restrained by a production capacity surplus that masked the gradual deterioration in exploration and development economics. Thus, real prices are likely to remain about $2.00 above levels sustained through most of the 1990s, even after short-term supply imbalances have been eased.

Supply

Near Term: Natural gas supply is constrained, which has driven gas prices up to a level sufficient to force gas demand to adjust to available supplies. The constraints are expected to loosen only slowly over the next few years.

U.S. natural gas production has changed very slowly over the past decade, with small increases until 2002, when output declined slightly. U.S. production may have increased slightly in 2003, as an upsurge in drilling for new supplies offset natural decline at existing properties. Drilling activity is headed for a new high in rigs running and gas wells drilled. Even so, the rapid decline rate of existing production that has become apparent in the past few years implies that high drilling rates are likely to have, at best, only a muted, and slow, impact on overall production levels. Early-2004 data show production has been increasing in the Rocky Mountains and Texas, but weaker output elsewhere is likely to offset these gains for 2004.

Evidence inferred from several recent asset sales by major oil companies indicates that the cost of finding and developing natural gas supplies in this country has risen to the $3.00-4.50 range, and even higher in some cases. This is at least $1.00-$2.00 above supply costs of several years ago. The implication of supply costs rising above $4 in the United States is that U.S. production would grow slowly at best, unless gas prices remain high. At this cost, domestic supply development does not compare favorably with overseas opportunities or LNG importation.

Canadian imports have long been a significant factor in U.S. natural gas price trends. Over the 1990s, steady increases in Canadian imports contributed to a U.S. supply surplus that suppressed gas prices in this country. More recently, however, Canadian production has resembled the sluggish trends in this country. Declining Canadian production caused U.S. imports from that country to fall in 2003, by over 1 bcfd, offsetting increases in LNG imports. Canadian production is showing some signs of increasing slightly in 2004, in response to a high level of drilling activity now under way. Much to all of this increase, however, is likely to be absorbed by domestic Canadian demand. Moreover, Canadian production could just as easily end up declining this year. Although drilling levels have been high, the targets have been shallow, low-production wells.

Liquefied natural gas (LNG) imports are constrained in the near term by a lack of new facilities. In mid-2003, the opening of Cove Point and Elba Island receiving facilities in this country, and the start of train 3 in Trinidad's LNG exporting industry, added to supply. For 2004, a full year's availability of these import terminals and Trinidad's expanded LNG supply will add a modest 0.1 tcf (0.3 bcfd) to the annual U.S. supply total. There may be additional spot cargoes available from other sources such as Malaysia, Nigeria, and Algeria that could give a small boost to imports. Increases in LNG imports will be only gradual until 2007-08, when several new LNG projects are scheduled to come into service.

Long Term: Lower-48 production is expected to be essentially flat over the next decade, with only small year-to-year fluctuations, and then to decline gradually in the following decade. This expectation is based on the continuing poor responsiveness of domestic supplies to heightened drilling activity, combined with basin-by-basin analysis of the natural gas resource base and supply costs. Increases in the Rocky Mountains and frontier regions are likely to offset small production declines in traditional areas. Shallow water offshore production in the Gulf of Mexico is expected to continue to decline.

The total resource base does not necessarily translate into supply, because of various restrictions on access. In the current outlook, access to Rocky Mountain resources is assumed to increase over time. Moratoria on development of various offshore regions already extend to 2012 under current federal executive orders, and these are not assumed to be rescinded in our base projection. Alaskan gas is assumed to begin flowing to the lower-48 states in the next decade, but the cost and magnitude of the pipeline project put those flows somewhat at risk.

North America has always been nearly self-sufficient in natural gas, with LNG making up only 2% of the market for 2003. With the Canadian gas industry facing struggles similar to those confronting U.S. producers, imports from Canada are likely to decline. Expanding LNG imports will fill most of the growing gap between domestic demand and domestic supply, thereby gradually increasing share in the U.S. market. The increase in required LNG will be substantially larger than the expected flow of Alaskan North Slope gas. Lower-48 natural gas will decrease from about 85% of required U.S. supply currently to around 50% by 2030.

Demand

Near Term: Natural gas demand averaged about 2% annual growth between 1990 and 2000, but has fluctuated since then. In 2003, natural gas demand declined by about 1 trillion cubic feet (tcf), or nearly 5%. Output sluggishness in the manufacturing sector contributed to this decline, but a key cause was the high natural gas price level. Consumers in the power-generating and industrial sectors either shifted to alternative fuel supplies or, in the gas-intensive industries, shifted focus to overseas production.

The drivers of natural gas demand are indicating greater strength for this year than 2003. Real growth in both GDP and industrial output is expected to exceed 4% in 2004, with the energy-intensive industries expected to share in this strengthening.

Natural gas demand will be continue to be constrained by supply this year, however. With few new sources of natural gas expected for 2004, demand growth will be limited by supply availability, which gets translated into higher prices. Given the strong expectations for the non-price drivers of demand, prices at $5–6 will be required to destroy enough demand to balance the market at about one-half percentage point growth for the year.

The power sector has very sizable potential for growth in the near term, in light of an enormous increase in natural gas-fired generating capacity in 2001-04. With high gas prices last year, however, gas use in this sector declined. Electricity generation was focused on other fuels to the extent possible, with higher utilization of coal plants and some switching from gas to fuel oil at dual-fired generating stations offsetting some of the demand increase from new gas-based plants. In fact, last year's high gas prices, combined with sluggish electricity demand growth, caused much of the new gas-fired generating capacity to be significantly underutilized. The gas-to-oil shifting that took place last year is probably close to the maximum displacement of natural gas by oil, at least without further investment and regulatory relief. Many power plants are limited by the number of days that they are allowed to burn oil, and tighter nitrogen oxide limits in eastern regions should further restrain the scope of gas-oil switching. Thus—depending on the pace of refurbishment at coal-fired facilities to increase sustainable utilization—power sector demand pressure on gas prices is likely to be stronger this year, implying continuation of a fairly high price level to force out demand and balance the market.

Industrial natural gas demand fell in 2003. Output of energy intensive industry significantly lagged the rebound in GDP, and high gas prices drove dual-fueled facilities to switch to oil, to the extent possible, and led to closures of gas-intensive fertilizer plants. In light of the sizable demand adjustments that already took place in 2003, further reductions this year—especially in light of economic recovery in this sector—would require fairly high gas prices. Residential and commercial demand does not respond dramatically to short-term price changes, owing to very limited fuel-switching capability.

Long term: Natural gas demand has a high market share in the residential, commercial, and industrial sectors and a growing share in the power generation sector. Natural gas currently represents (by energy value) approximately 23% of total energy consumption in the United States (compared with approximately 40% for petroleum and 23% for coal). The major areas of natural gas demand are for residential (23% of gas consumption), commercial (14%), power generation (22%), and industrial (33%). The rest of the gas is consumed in own-uses, including pipelines and lease and plant uses.

Natural gas has high shares of the energy used in the residential and commercial sectors. In those sectors gas has won the competition with oil in most regions and competes with electricity. The share of gas is a little lower in the industrial sector, where coal and fuel oil are more widely used, and is much lower—at 10-15%--in the power sector. In the power sector, the chief competition for gas in the near term is with oil and coal, and in the long term, primarily with coal. Nuclear and hydropower also have sizable shares of those sectors, but they have virtually no growth prospects, which will help increase the gas share in this sector. Most inter-fuel competition and substitution takes place in the power sector and, to a lesser degree, in the industrial sector. Environmental regulation will lower the potential for substitution away from gas in the future.

Key drivers of gas demand in the core sectors are relatively slow growing, compared with expected growth for the economy as a whole. Residential and commercial demand is linked closely to below-1% population growth, which is key in driving increases in households and commercial floor space. Industrial gas demand is more versatile than oil or coal in that sector, but its use is still disproportionately concentrated in traditional, heavy industries that are energy-intensive. Output growth in these industries is expected to lag overall economic growth—considerably, in some cases. Long-term gas consumption growth is expected to average about one percent per year in the residential and commercial sectors but little better than one-half percent per year in the industrial sector. Power sector demand growth will reflect electricity demand trends offset in part by power plant efficiency improvements, resulting in a more rapid impetus than in the other end-use sectors. In addition, power sector demand will reflect the huge buildup in gas-fired capacity now under way, as plants now under construction come on-line and the recent start-ups gradually increase utilization to more typical rates. These new plants—and those now under construction—were planned back before gas prices rose to today's levels. Between now and 2030, power sector gas demand will average nearly 3% per year, with growth stronger initially and slower in the later

years as more coal plants enter the mix. Total gas demand is projected to average about 1% annual growth, reaching 29 tcf by 2030.

Price

Near Term: Natural gas prices have reached a new plane. Although they will gradually recede from current highs, they should stay well above prices averaged through most of the 1990s. During the previous decade, the key feature of the gas market was the slow draining of a sizable supply capacity surplus. Natural gas prices hovered around $2.00 per million Btu (mmbtu) for most of that period. (The spot price at the Henry Hub is a key indicator for the industry and typically runs slightly above the U.S. average wellhead price.) Henry Hub prices shifted up to the $3-4 range at the start of the new decade, and in 2003-04 have ratcheted up again, to the $6 range.

While demand rose over the 1990s, the inventory of available low-cost reserves and resources shrank. There is a multitude of evidence suggesting that the cost of finding and developing new domestic gas supplies in this country has risen by around $1.00-2.00. Decline rates for existing wells accelerated, and the number of new wells needed to replace a given supply of gas increased. Competition with Canadian gas—which had exacerbated the surplus of the 1990s—largely disappeared, as the U.S. market increasingly relied on Canadian imports to supplement rising demand. More recently, Canadian supplies have run into the same problems facing the U.S. gas industry, as discussed. LNG imports started to expand to fill the growing gap between demand and North American supplies, but the capacity of LNG terminals in this country is currently quite small; expansion is under way, and much more is planned, but this construction takes time.

Although higher supply costs have been key in driving up gas prices this decade, Henry Hub prices have surpassed even those costs in 2003-04, rising to the $5-6 range. A variety of external circumstances have been partially responsible, including high competing oil prices, which were at least partially induced by geopolitical events, and an unusually deep storage drawdown (winter of 2002-03) that was partially weather-induced. Further explanation can be found within gas market fundamentals: with short-term natural gas demand flexibility fairly limited, prices have had to rise significantly above supply costs in order to quickly destroy enough potential demand to balance the market.

In 2004, there are signs of some loosening on the supply side, including small increases in LNG and normal storage levels at the end of winter. Demand pressure could be stronger this year, however, based on current indicators and expectations for the economy. This greater potential demand, combined with the fact that the most convenient demand adjustments have already taken place, suggest that prices will need to stay in the $6 range to balance the market.

Moreover, competing fuel prices have risen even further, bringing natural gas prices with them. Crude oil prices (West Texas Intermediate) have spiked above $40 recently, up from $30 last fall, while coal prices—especially for eastern compliance coal—have also shot up, with Central Appalachian compliance coal now exceeding $50 per ton up, from $25 last year. Crude oil prices will continue to be

pressured over the next several months by strong world oil demand, tight gasoline supplies globally, and concerns about Middle East supply security. Oil prices should gradually moderate later this year and next year as demand growth slows and tight supply eases.

Coal prices are being pressured by low inventories in the United States, as demand is outpacing production. Some power generators have had to limit use of coal because of diminished stockpiles. With few alternatives, some generators have turned to natural gas. Environmental considerations have also favored natural gas use. With the start of the May 1 to September 30, control program for NOx emissions in 19 eastern states (SIP Call), there has been increased demand for natural gas to meet emissions limits.

Natural gas supplies will gradually improve in response to higher price-induced drilling levels and incremental LNG increases, but supplies should remain constrained for the next year or two. In particular, by 2007-08, new LNG projects should ease supply constraints. Supply/demand pressures are also expected to ease in oil and coal markets over the next few years, enabling prices for those fuels to relax. Real natural gas prices are projected to ease back to around $4.25 by 2007-10, more closely reflecting supply costs.

Long Term: Real Henry Hub prices are expected to rise from around $4.25 later this decade to around $4.50 after 2020 (2003 dollars per mmbtu). The direction will be slowly upward over the period, as domestic supply costs gradually rise. Prices will hold somewhat between domestic supply costs and the costs of new LNG facilities. LNG costs are a bit lower than current U.S. supply costs, and LNG is the principal marginal supply on an annual average basis. Domestic production will continue to account for the majority of gas supply, such that it will remain the swing supply source—at least at times—in many U.S. regions. Thus, the costs of both supplies will contribute to the general natural gas price level, with LNG costs setting a floor price while domestic supply conditions determine the peak and seasonality of prices. Annual average prices will thus remain at their new plane, around $2.00 above prices of the 1990s.

Costs associated with new LNG projects have declined in recent years. Estimates of LNG supply costs generally range from $2.40 to $3.70 per mmBtu delivered to the United States—including liquefaction, shipping, and regasification—for projects now under construction or being considered. The variation in supply cost estimates reflects the degree of commitment of the host country to LNG development, the distance from the end market, and whether the LNG potential is large enough to take advantage of economies of scale.

Estimates of the supply cost for greenfield LNG sources available to the U.S. market range from $2.40 for gas from Trinidad to $3.70 for gas from Egypt assuming shipment in a 138,000 cubic meter tanker. Qatar, as the most likely large-scale supplier of LNG to the United States, has a supply cost of about $3.00-3.20. It is also noteworthy that LNG has an advantage over gas from Alaska, where the supply cost for a pipeline project to the Lower-48 states is expected to be $3.80.

There are many reasons why the costs of conventional domestic supplies should remain a key driver of U.S. natural gas prices. While LNG and Arctic gas supplies are expected to meet most of the increase in U.S. demand, conventional production from the lower-48 is still expected to supply the majority of required supplies. U.S. conventional production can adjust quickly downwards (though slowly upwards) to changes in market balances. The rapid decline rate for existing U.S. conventional production—which in 2001 averaged 27%—means that a slowdown in production can happen quickly. Because about one-fourth of U.S. production has to be replaced each year, a slowdown in exploration would quickly eliminate any over-supply. Also, because U.S. demand is strongly seasonal with a high variability depending on weather, while production now operates at high rates throughout the year, prices will be influenced by the value placed upon firm supply during the peak winter heating season. Storage supplements production and imports during the winter peak, but storage capacity is not unlimited. Thus U.S. natural gas prices in peak periods rise until prices constrain demand to available supply, which at times in recent winters has been far above domestic supply costs.

As discussed, LNG supply costs are estimated to be in the $2.40 to $3.70 range for delivery to the Gulf Coast. These supply costs are a measure of the minimum long-term price at the exit of an LNG terminal required to justify development of the entire value chain. As such, they represent a normal return when operating at close to 100% capacity and the *long-run* marginal cost. For this reason, estimates of LNG supply costs are a measure of the lower price in the market rather than the average natural gas price. That LNG will be on the margin does not mean that seasonal price variations will disappear. Rather, most LNG producers will be able to obtain some rent in the U.S. market from the occasional seasonal peaks.

Risks

In the near term, a plausible high-side scenario would combine hot summer weather, abnormally cold winters, and crude oil prices staying high. This would hold Henry Hub prices in the $6.50-7.00 range—with the potential for higher peaks at times, given the constraints on supply. On the low side, near-term prices could fall to $3.50 with some combination of abnormally mild summer and winter weather, crude oil prices in the $20s, and unexpectedly strong response of gas production to current high drilling levels. In such a case, prices could drop at times below this level.

Over the longer period, as supply constraints gradually disappear, the potential for sharp peaks, such as seen at times in recent winters, will be reduced. Much depends on how supplies evolve, however. Prices could hold at current levels, rather than relax as projected, if the responsiveness of gas supplies to heightened drilling levels fails to improve, or if oil and gas companies shift more sharply to lower-cost areas with higher potential overseas. Prices could also be higher than projected if new LNG facilities are not approved and built in a timely fashion, or if the Alaskan pipeline—a costly project whose sponsors have yet to commit—is further deferred.

Less likely, but also possible, prices could drop as low as $2.00-2.50 from a combination of lower oil prices and improvements in North American natural gas productivity.

Natural gas prices have shown periods of marked cyclicality over the years, reflecting ebbs and flows in exploration and development activity as producers wait until price signals are very strong, and then overreact to them. Thus, another risk to the natural gas price projection is that in some years prices will be higher and in some years they will be lower.

COAL OUTLOOK

Short-term Outlook

Highlights

- Coal markets tightened again in September in all regions but the PRB.
- Multiple forces lie behind our noticeable decline in prices by late 2006.
- The growing interest in IGCC is prompted by both efficiency and environmental benefits.
- Coal production should grow about 1% in 2005, restrained by both imports and exports.

Market Outlook

The abundance of coal conferences that occur throughout the year offer a good opportunity to hear divergent views on where coal markets are headed—and September 2004 was no exception. The head of a major producer (Consol) warned power companies to sign long-term contracts at today's elevated prices to ensure adequate supplies in the future, while the head of a major power company (AEP) characterized today's spot prices as "unsustainable." Who's right?

At present, there seems no end to future price increases. In September, prices have moved up again in every region except the Powder River Basin. Transportation problems—ranging from structural problems on the UP in the West, to the effects of hurricanes in Florida, to high water on the Ohio—are restricting inter-regional coal competition. Natural gas prices dipped during September, but appear destined to remain above the $5 mark for the short term, offering little baseload competition to coal generation. Meanwhile, regulatory and court decisions (and some indecision) continue to leave the future viability of Central Appalachian coal in question. And leasing rates in the PRB are pushing mining costs in that region to new levels.

A "first glance" assessment of 2005 does not appear to offer any prospects for change—but there are underlying changes already at work that could start to make a difference. While suppliers in some regions indicate they are already sold out for the year, transportation bottlenecks are being removed that will facilitate the shipment of coals into new areas, particularly from the West. Moreover, the opening of new mining capacity is beginning to occur at a slow but discernable pace in most regions.

Our forecast indicates a downward shift in prices by late 2006. That shift is noticeable, yet still leaves coal prices significantly above historical levels, and provides producers with sufficient return to satisfy both shareholders and needed mining investment. We look for transportation improvements that will force Central Appalachian compliance prices below the $50 mark, to fend off los-

ing substantial core markets to PRB coal. In addition, Central Appalachian prices for mid-sulfur coals must fall substantially further if they are to compete as scrubbing coals against higher sulfur, lower cost Pittsburgh Seam and Illinois Basin coals. International coals should also offer renewed competition, buoyed by what we expect to be markedly lower ocean freight rates and growing price pressures as the compliance deadlines with Kyoto (or Kyoto-style regulations in Europe) start to loom.

Some coal observers believe that Central Appalachia will simply attempt to maintain enormously high prices, seeking profit maximization, while its market share heads toward zero. That may be a strategy for some producers—but recent activity suggests otherwise. Arch has decided to move ahead with opening Mountaineer II in 2006; assessments are being made whether to reopen the 4-5 million ton-per-year Marrowbone operation; Quest is opening a modest compliance mine in Eastern Kentucky; and Massey's purchase of Cannelton and Starfire from Horizon portend renewed activity there. Whether these and similar activities represent efforts to take temporary advantage of today's high prices or are investments in a region with a still-viable if somewhat reduced future, only time will tell. Yet the magnitude of many of these investments does suggest to us that producers are looking for more than merely quick returns from a boom market.

Looking ahead, a huge amount of attention has been devoted to the growing interest in IGCC technology for coal. Recently, AEP has announces it will build a 1000MW unit this decade; a FirstEnergy-Consol combined effort appears to be leaning in that direction; Cinergy has long expressed interest; and groups such as ERORA and the Michigan Public Power Agency are actively pursuing the possibility. These actions all bolster the case for IGCC, even as the Bush Administration falters with FutureGen funding. The focus on IGCC for coal is good for the industry as a whole, since it promises to provide both generating efficiencies and environmental advantages needed for coal to compete in the future.

Coal Production

Production for 2004 is headed for a near-3.5% increase over 2003, when output was artificially suppressed by a 27-million-ton drawdown in inventories. This year, we expect the drivers behind the higher production to include not only less of a draw on stockpiles (by about 20 million tons), but also stronger coal-fired electricity demand (10 million tons) and higher exports (8 million tons). In 2005, we anticipate only about a 1% increase in production (about 11 million tons), with electricity demand and a small stockpile increase working to offset an expected large decline in exports coupled with a small increase in imports.

Revised DOE data now shows that the **East**'s production through the first half of this year is much stronger this year than earlier reported. The export boom has helped fuel what we expect to be a near-4% rise in production this year; but the export/import trend we see for 2005, mentioned above, effectively freezes the East's output at this year's level.

The **Interior** region's production will likely fall somewhat in the second half of 2004 in the face of the idling of both Zeigler #11 and Kindill mining operations in

the immediate aftermath of the Horizon sale. Some of that should return in 2005; but demand for this generally high sulfur region is expected to stall as it experiences the transition between tightening SO2 emission standards and the lag before most power companies finally decide to install scrubbers.

Production in the **West** apparently took a jump in the third quarter, and we expect continued gains in the last few months of 2004. Although many analysts believe Western production will stall, we anticipate even greater output from this region, as rail bottlenecks are resolved next year and more power plants in the East and Midwest convert to these coals in the face of outrageously-priced Eastern coal.

Coal Production
(Millions of tons)

	Q1	Q2	Q3	Q4	Total	% Change
Total Production						
2002	282.6	266.7	270.9	274.1	1,094.3	-2.96%
2003	264.2	268.5	268.6	270.5	1,071.8	-2.06%
2004	274.6	273.9	278.8	281.2	1,108.5	3.43%
2005	279.9	276.6	281.7	281.5	1,119.7	1.00%
Appalachian Production						
2002	108.1	98.5	95.2	95.2	397.0	-8.28%
2003	95.4	96.7	92.4	92.3	376.8	-5.09%
2004	98.3	97.6	97.8	97.6	391.3	3.86%
2005	97.6	96.8	98.0	97.6	390.0	-0.34%
Interior Production						
2002	36.9	37.3	36.7	35.9	146.9	-0.11%
2003	36.1	37.0	36.1	37.1	146.3	-0.40%
2004	36.2	36.1	35.6	35.9	143.8	-1.71%
2005	36.0	35.7	36.1	36.1	144.0	0.15%
Western Production						
2002	137.6	130.8	138.9	143.1	550.4	0.47%
2003	132.7	134.8	140.1	141.1	548.7	-0.32%
2004	140.0	140.2	145.5	147.7	573.4	4.51%
2005	146.3	144.1	147.5	147.8	585.7	2.14%

Coal Region Definitions: ***Appalachia*** - Northern Appalachia (Pennsylvania, northern West Virginia, Maryland), Ohio, Central Appalachia (southern West Virginia, eastern Kentucky, northern Tennessee, Virginia), Southern Appalachia (Alabama and southern Tennessee). ***Interior*** - Illinois Basin (Illinois, Indiana, western Kentucky), Central Interior (Iowa, Kansas, Missouri, Oklahoma), Lignite (Texas, Arkansas, Louisiana). ***West*** - Powder River Basin (northern Wyoming, southern Montana), Northern Lignite (Montana and North Dakota), Green River Basin (northwestern Colorado, southwestern Wyoming), Hanna Basin (south-central Wyoming), Uinta Basin (Utah, western Colorado), Raton Basin (northeastern New Mexico, southern Colorado), Four Corners (northeastern Arizona, northwestern New Mexico, southeastern Colorado), Northwest (Washington and Alaska).

The Stock Situation

The very large differentiation in mid-year inventories between this year and 2003 appears alarming, at first glance; but is primarily due to exceedingly high stock-

piles that existed last year as opposed to unduly low inventories this year. We are estimating a third-quarter 2004 drawdown of about 14 million tons, to be followed by a 10-million-ton stockpile buildup in the fourth quarter. Both of these adjustments are quite modest by historical standards. The relatively low drawdown we have calculated for the third quarter is largely the result of a cooler-than-normal summer, while the fourth-quarter estimate reflects the balance buyers are attempting to maintain between the need to prepare for winter demand and the very high price of coal, which serves as a disincentive to purchase.

Coal Stocks
(Million tons)

June 2004	June 2003	Change	EOY 2003	Forecast EOY 2004	Change
161.7	193.0	-16.2%	165.3	157.9	-4.5%

Exports and Imports

U.S. exports eased slightly in July, but still maintain a healthy margin over year-to-date totals from 2003. Metallurgical markets remain extremely strong, but there are signs of a slowdown in U.S. steam shipments outside the country. This slowdown may be occurring for several reasons—not the least of which is strong demand and high pricing in the U.S. itself, where most producers would rather be selling anyway. At the same time, the recent decision in China to allow more steam exports, coupled with indications of higher Indonesian output, may simply be creating too much competition for U.S. thermal exports. All attention will be focused on whether global steam coal buying for the fourth quarter, initially assumed to be high, but off to a slower-than-expected start, will pick up momentum. One potential bright note for U.S. coal exports is the recent Taiwan-KFx Memorandum of Understanding that could theoretically pave the way for some 8 million metric tonnes of Alaskan coal moving to Asia, if the expectations materialize.

On the met side, U.S. shipments continue to move at a strong pace. The key question down the road is whether or not this demand for U.S. coking coal will maintain itself, and even grow, or it will eventually subside in the face of strong competition from other global suppliers. Proponents of sustained exports point to seemingly insatiable demand from China and India. On the other hand, we are more inclined to emphasize the enormous reaction from major Canadian and Australian producers gearing up to meet this demand, particularly BHP-Billiton, which has indicated that it is prepared to match its future production to this rising demand. As such, we expect U.S. coal exports to decline to the low 40-million-ton mark in 2005, with declines in both steam and met shipments from the United States.

U.S. Exports and Imports
(Million tons)

YTD 7/04	YTD 7/03	Change	2003	Forecast 2004

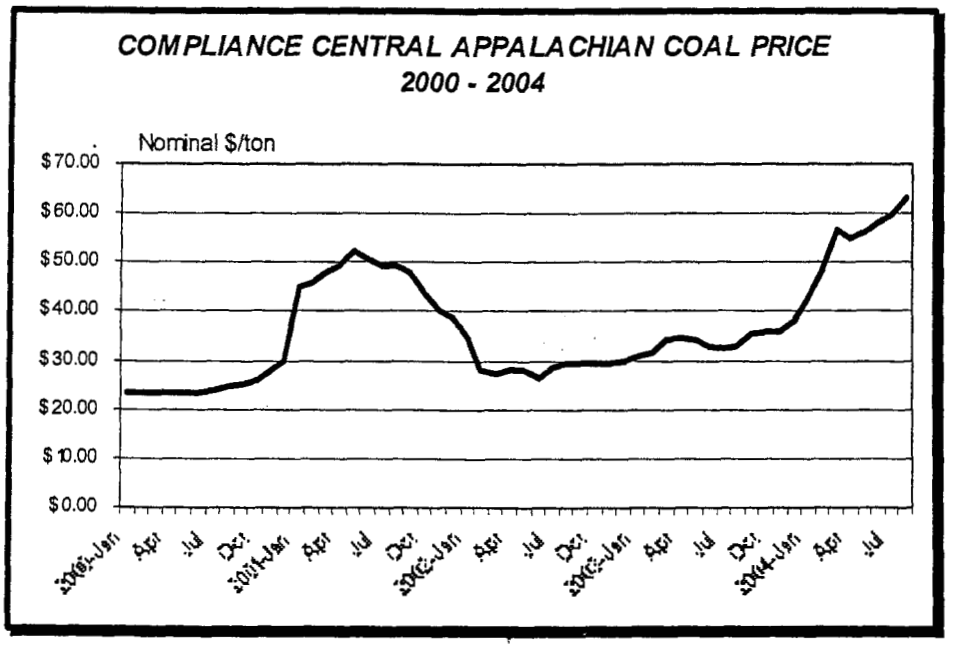
U.S. Exports - Total	28.9	24.2	19.3%	43.0	51.2
U.S. Imports	14.7	14.0	5.3%	25.0	26.1

Source: U.S. Department of Energy and National Mining Association

Imports remain an important counterbalance to Central Appalachia in Eastern and Gulf markets, in spite of sustained high FOBT prices and the promise of firming fourth-quarter freight rates. The recently discussed delivery of imported coal into the Bowen plant has revived the prospect that railroads will indeed cooperate in certain circumstances in allowing foreign coal to penetrate inland beyond just water-based powerplants.

Medium and Long-term

Since late in the year 2000, we have experienced two major surges in coal prices that, when compared with previous history, have been unique from the standpoint of both magnitude and duration. Coal price increases in earlier years were more often than not induced by events, such as a UMWA strike, that might last only one to three months and then quickly subside. As shown in the graph below depicting monthly changes in the compliance Central Appalachian coal price over the past four years, the two upward price shifts that have occurred in the last four years have been protracted. In fact, the elevated prices that dominate the market at present show little, if any, signs of abating soon.



At present, we view five major factors as being the major contributors to today's high prices. Each of these is discussed below.

1. Coal companies comprehend their new market power. The two price spikes we have seen since 2000 have witnessed an exhibition of market power by coal companies that in previous years simply was not feasible. The price rise in 2001 was the consequence of the convergence of a multitude of forces that many

analysts have described as the "perfect storm." Briefly, the period in mid-2000 was characterized by extremely high stockpiles and hence a greatly depressed spot market, the result of two warmer-than-usual winters that greatly reduced coal demand as power companies attempted to work down inventories. There was, simultaneously, a growing perception that coal's best days were past, and that natural gas would supply the vast majority of new electricity generation, leaving coal's market share to erode as coal plants gradually retired. This led to the rapid but little-noticed decline in mining capacity, particularly in Central Appalachia, as numerous mining firms viewed the prolonged soft spot market in the context of little future opportunity, and declared bankruptcy or simply left the market. Understanding this, some of the remaining coal companies began to slowly raise their prices after the summer in response to bids solicited by power companies as they prepared to replenish inventories after the normal summer drawdown and stockpile for the winter. Many power companies rejected these bids, based on the seemingly historically accurate perception that the perpetual oversupply in the coal industry would force a better price response. Within a few months, stockpiles had reached dangerously low levels and an early, very cold start to the winter caught buyers by surprise. With mining capacity now significantly reduced, even a concerted effort to ramp up production in Central Appalachia fell short, and price increases swept to other Eastern regions by the end of the year. As 2001 began, Western coal prices--which had remained generally flat, as Midwestern and Eastern prices had increased--surged several fold, rendering the coal price rise a nationwide phenomena. As shown in the graph above, it took more than a year for prices to withdraw from their very high peaks, although they settled in at a level noticeably higher than where they had been initially.

The price increase that began later in 2003 was notable from the standpoint that there was neither a significant event nor anything resembling the perfect storm of circumstances that had occurred in 2000 to spark the rise in prices. Indeed, this price rise that continues at full throttle today has been engineered by a combination of market power and market opportunity described in the remaining three points in this section of the article. The theme to be emphasized here is what has emerged is a relatively small number of very powerful coal companies who face very little competition, either within their own industry or from other "competing" fuel sources.

2. Consolidation of financially powerful coal companies. A major contributor to today's high coal prices has been the two-fold impact of the erosion of excess coal mining capacity. The first facet of this has been that the number of coal companies accounting for the bulk of US coal production has been greatly reduced at the national level and is even more concentrated within the different regional mining areas. Whereas the 8 top producing coal companies in the US have historically accounted for about 30% of the nation's coal production, they now garner more than 60% of the output. On a regional basis, with the recently approved acquisition of Triton by Arch, three companies now control more than 80% of the Wyoming Powder River Basin production. Similarly, Peabody's recent acquisition of the Twentymile mine in Colorado and properties in the Illinois Basin further solidify that company's ownership in those two regions. Finally, a single company

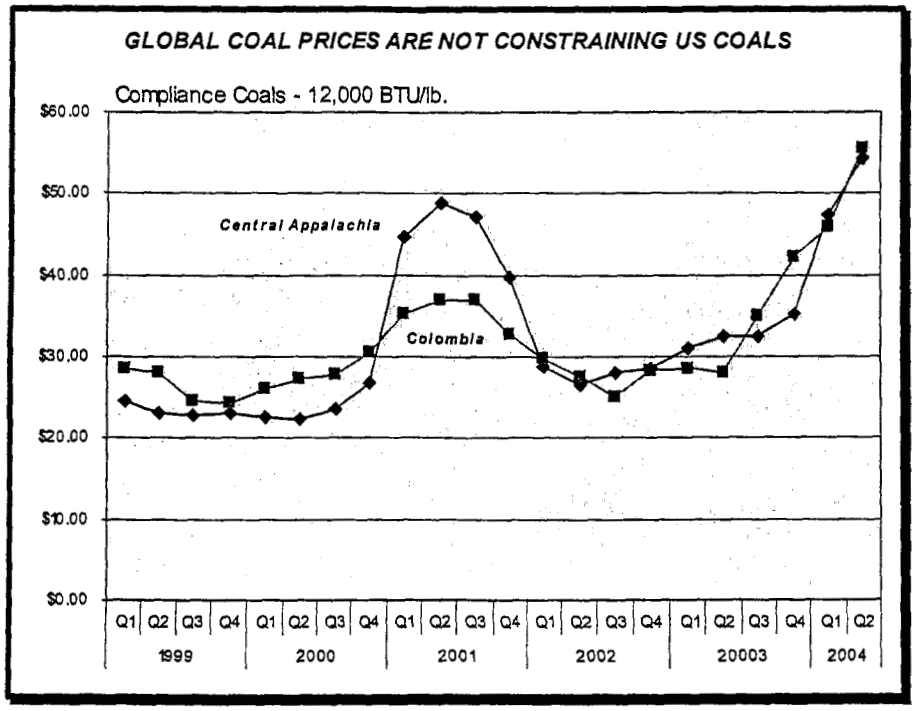
(CONSOL) now accounts for about 65% of production in the very promising Northern Appalachian region. The obvious inference here is that the evolution towards fewer coal companies elevate the market power of those firms, leading many buyers to worry over reduced competition.

A second facet of this consolidation is the bifurcation of coal companies into a relatively few powerful companies at the top and a wide array of financially weak companies beneath them. Among companies who have in recent years fallen into this latter category are Horizon, James River, Lodestar, AEP (Quaker), Anker, Pen Coal, and Cook & Sons. The significance of this division of companies reaches beyond consolidation; rather, it is the fact that this extreme concentration of financially healthy companies removes what has always allowed coal prices to remain generally low. By this, we mean that even when consolidation continued to grow throughout the 1990's, the vast majority of companies were in a position to open new capacity when market opportunities emerged and, much of the time, simply as a normal means of doing business. This practice resulted in a generally constant flow of new coal production into the marketplace when demand required, more often than not tending toward surplus, resulting in highly competitive pricing. Given today's situation, only a very few companies are able to introduce significant new quantities into the market and they are, by and large, reluctant to do so until the viability of both adequate pricing and long-term demand seems assured. As a result, price volatility and spikes of extended duration are inevitable.

3. Production cost increases. A great many reports have blamed much of this most recent coal price increase on higher production costs. Indeed, coal mining firms across the board have been faced, along with the rest of the economy, with higher steel prices (affecting, for example, mining machinery costs) and escalating oil prices (affecting diesel prices which account for a large percentage of surface mining costs and a smaller proportion of the cost of underground operations). Furthermore, Central Appalachian mines have been struggling with rising regulatory expenditures primarily associated with increased enforcement by state officials. It is our assessment that these expansions in cost factors have had some impact on the price rise we have seen, but they have been far outweighed by the market forces discussed in this section. A review of some of the claims of production cost increases neglect to inform the reader that several categories of "cost increases" (e.g., royalties, some severance taxes, some regulatory fees) rise only as the selling price of coal rises (and thus, will fall as the selling price of coal falls).

4. The absence of international coal competition. Coal imports have never accounted for a significant volume of US coal needs, representing less than 2.5% of domestic consumption. Yet their importance has largely derived from serving as leverage to the Central Appalachian market, where both of the nationwide price increases that have occurred since the year 2000 have originated. As seen in the graph below, the price of Colombian coal (the foreign coal most widely imported by US buyers) rose in advance of the Central Appalachian price surge of 2000 and even though it did not reach the heights attained by the US coal, was sufficiently high not to hold it back. In this current round of price surges, the Central Appalachian coal was the first out of the gates, but even its elevated price levels have

been matched and often surpassed by the Colombian competition. The factors contributing to this situation are numerous, but have been largely driven by high ocean freight rates that have substantially raised the marginal price of Pacific coal into the Atlantic markets, the strong Asian demand for coal, and the loss of competitive Chinese steam coal exports as that country focuses on satisfying its own domestic needs first.



Beyond this situation in global steam coal markets, however, the international coking coal market has also helped raise the price of US coals. Demand for metallurgical-grade coal has skyrocketed global, led by massive increases needed by China and India to accommodate their dramatic infrastructure growth. On top of this, international demand for met coal has been rekindled in the face of an improving global economic picture. Just as in the case of steam coal, however, China—a major exporter of both met coal and coke— has severely cut back on its shipments of both. In addition, the loss of a major US met coal mine (Pinnacle) in West Virginia in late 2003 continuing until late spring of this year only served to further tighten supply. Some of this coking coal shortfall has been met by Central Appalachian mines that normally serve the steam power market, as they willingly switch to the more lucrative met coal market. That turn of events is naturally generating further upward price pressure in the US steam coal market.

5. Limited competition from other sources of electricity generation. The final issue contributing to today's high coal prices has been the virtual absence of any meaningful competition from other energy sources in the electric generating sector. Natural gas prices have been well above $5/mmBTU (Henry Hub) for most of the past two years. Nuclear power generation peaked in 2002 in the face of

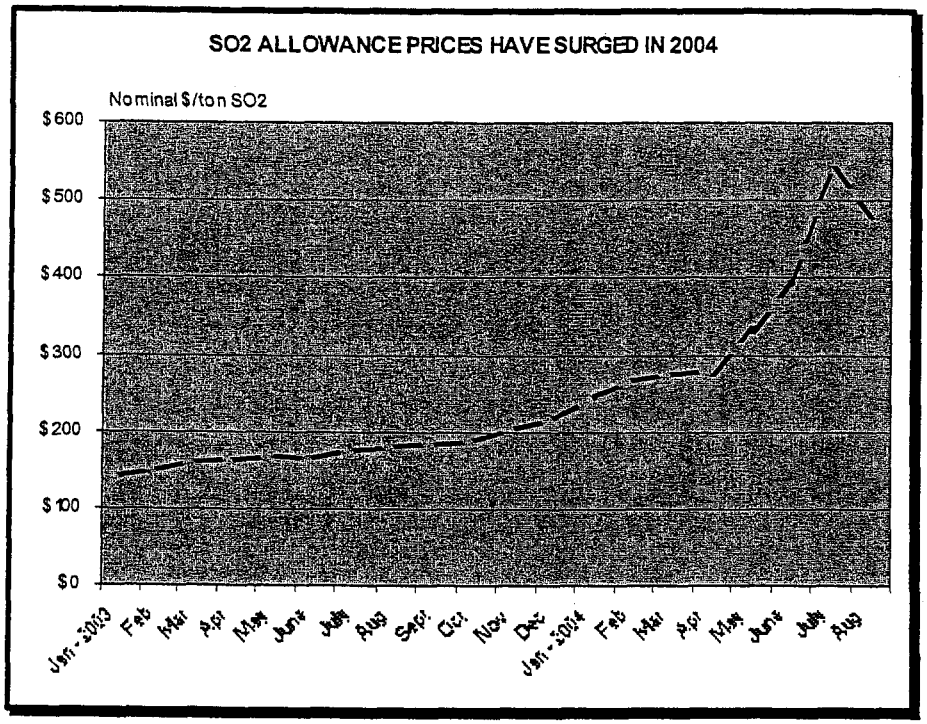
uprates and operational improvements, but has fallen off the past two years. Hydro is still attempting to recover since a disastrous 2001. All of these developments have left coal generation to climb, with normally intermediate load units being pushed to new levels. This increase in generation has only provided additional justification for the currently elevated price levels attained by coal from virtually every mining region.

Industry Changes in the Mid-Term

While there is no "silver bullet" or upcoming event that we foresee that will dramatically alter coal's strong position over the next few years, there are a series of developments underway that will significantly change the framework in which coal will compete. In this section, we briefly discuss four of those changes.

The high prices of low sulfur coals and SO2 allowances are expected to convince some power companies to accelerate their plans for installing pollution control equipment, allowing them to increase their use of mid-to-high sulfur coals. About one-third of coal-fired generating capacity in the electric generating sector is equipped with scrubbers (also known as FGD, or flue gas desulfurization equipment) for SO2 control. That leaves the remaining two-thirds to rely primarily on low sulfur coals to meet the more stringent SO2 requirements stemming from the year 2000 initiation of Phase II of the Clean Air Act Amendments. Most power companies have attempted to delay installing costly scrubbers (in which they could burn a wider variety of other [higher sulfur] coals), but now the price of and risk in using low sulfur coal has risen significantly, This situation is leading some power companies to explore the possibility of moving up the date when they plan to install scrubbers as a means of injecting strong price competition from the high sulfur coal regions. For the most part, low sulfur coals have been provided by mines in Central Appalachia, foreign countries (primarily Colombia, with lesser amounts from a wide number of countries including Venezuela and Indonesia), and in the West (from the Powder River Basin and western bituminous regions). As noted previously, a variety of factors have led to extremely high prices from the first two of these sources. Moreover, with regard to Central Appalachia, there is growing concern over the future viability of that region: there are problems of reserve degradation in this extensively mined region and production costs are rising rapidly in the face of more stringent regulations affecting both mining operations (e.g., the valley fill issue and acid mine drainage) and transportation (more rigidly enforced trucking limits in eastern Kentucky and southern West Virginia). In the case of the western bituminous regions (the Uinta and Green River Basins), prices have also risen dramatically as they can often serve as an almost immediate replacement for the Central Appalachian coals. The transportation costs from these western areas is formidable, however, and there is a general consensus that these coals do not constitute a viable long-term option for Midwestern and Eastern consumers. As for the Powder River Basin, we anticipate that region to make significant inroads, but buyer concerns over both logistics and rail rates will place upward limits on that expansion. In that same regard, the price of SO2 allowances that can be used in conjunction with non-complying coals has

risen substantially as seen in the graph below, so this technique has lost much of its attractiveness as a longer-term option for many power companies.



State and regional government entities are further promoting scrubbing by moving toward more stringent environmental standards than proposed by the Bush Administration. To the extent that these standards require scrubbing, they serve to enhance the prospects of further coal-on-coal competition from the use of higher sulfur coals. Geographically, governments well beyond the Northeastern states with which many observers associate tougher environmental policies are pushing the standards. The list of states that are currently implementing or planning more rigid standards include such major coal users as North Carolina, Wisconsin, and Illinois. In the West, the multi-state organization formed to deal with regional haze in national parks has already provided the impetus for scrubbers to be installed in Colorado and plans for more in other western states are well underway. These state and regional programs have targeted virtually every environmental air problem area, including NOx and CO2, but the need to install FGD has been largely driven by programs designed to reduce SO2, mercury, and PM2.5.

New investment is reaching the coal industry, opening up prospects of a broader universe of companies able to expand mining capacity. As noted earlier in this article, the number of companies that are sufficiently financially viable to open new coal mining capacity is extremely limited. The recent emergence of investors into the mining industry, such as Blackstone, First Reserve, and Wilbur Ross, has set the stage to provide more coal companies with the financial stability and assets needed to be among the major players capable of opening coal mining capacity when demand warrants. While this represents a significant first step in

strengthening the coal industry and opening up the potential for increased competition, two caveats must be kept in mind. First, as investors, these companies have no interest in flooding the market with coal and thereby undermining (no pun intended) their investment. Just as is the case with the few financially viable coal firms today, they are likely to initiate an expansion of production only when convinced it will serve a sustained demand and only when the returns are financially attractive. The second caveat is that the transition for the companies they have purchased will not occur overnight. Their first priority must clearly be to stabilize and cull through the current operations to maximize their value and only then turn to considerations of raising production to any significant degree.

Competition to coal in the electricity generating sector will slowly strengthen. Over the next few years, we expect coal to encounter a modest level of increased competition from many of the other sources of generation that will limit coal's growth. A wave of new, highly efficient natural gas combined cycles are scheduled to come on-line over the next few years that, in spite of our outlook for continued high natural gas pricing, they will cut into coal's growth. Moreover, both hydro and nuclear power are expected to continue their rebounds, further tightening competition in the baseload sector. We anticipate, however, that these developments will simply slow, rather than stall, coal's growth.

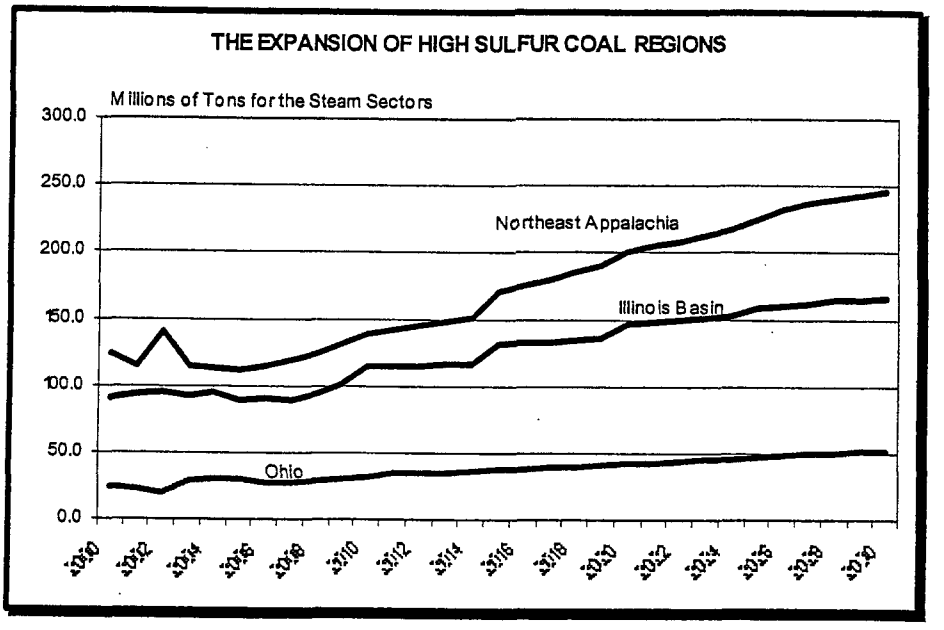
The Long-Term: A Stronger, More Competitively Priced Coal Industry

Over the long-term our theme is that coal will be more widely utilized and, in a world with an abundance of potential options, more competitively priced. Coal companies, however, are already moving to position themselves to lower production costs and thereby maintain attractive profit margins.

Below, we identify three major trends we anticipate for the long-term. The first two are developments that will place a ceiling on how high coal prices might go, while the last point suggests how coal companies will realistically maintain a strong financial footing.

Environmental standards will continue to tighten, squeezing the "economic rent" the price of coal can attain. There is a propensity of many coal observers today to envision the environmental standards contained in the Bush Administration CAIR package as the most stringent these requirements will become. Indeed, CAIR suggests cutting allowable SO2 and NOx emissions substantially in a 29-state area of the East by 2010 and the Administration is leaning towards a nationwide cap-and-trade mercury program for 2018. Yet our assumptions for the future also incorporate a widespread, on-going effort by states and regional entities that will collectively lead to a much stricter, earlier implemented set of standards affecting a large number of states. As noted previously, a second term for the current President will not alter that trend, and will probably intensify it. The upshot of both CAIR and the state/regional programs is that power companies will be required to spend considerable amounts of additional capital as well as deal with the higher O&M costs associated with the operation of this pollution control equipment. The current testing of new, integrated pollution reduction systems such as E

Beam technology and the ECO system is promising much lower costs than installing individual pieces of equipment to reduce separate pollutants, but the cost will nonetheless be significant. The consequences of this development for coal prices are two-fold. First, the cost of this equipment will significantly close the gap in busbar costs between coal-fired generation and its major competitor, natural gas. That fact will reduce the amount that coal and transportation companies can charge to get their product to the plant and still be competitive. The second implication is that this growing use of pollution control equipment will greatly expand the universe of coals that can be used (since almost all SO2/NOx/mercury emissions will be captured regardless of coal type), greatly enhancing access by power companies to the most competitively priced coals. As shown in the graph below, we anticipate that this increased opportunity for higher sulfur coals to compete for coal generation will result in greatly enhanced production from those regions.

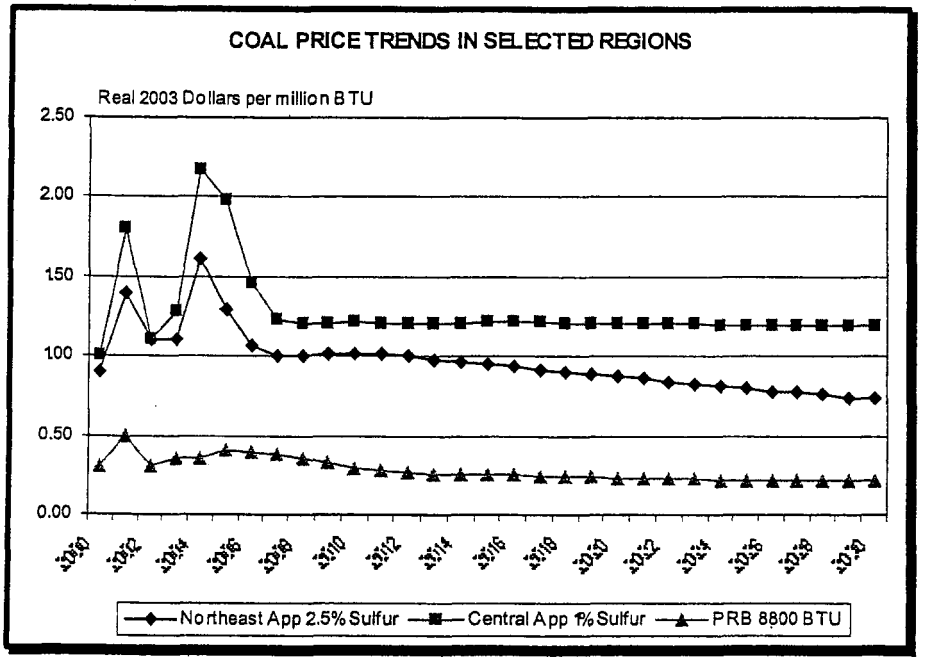


As a footnote, it should be appreciated that the use of this equipment will also open up the potential for the use of a variety of "opportunity fuels," such as waste coal or petroleum coke. In the latter case, anticipated refinery coker expansions in the US will tip annual output of petcoke to above 100 million tons in the not-too-distant future, providing a supply as large as most domestic coal regions. This additional option will serve as yet another limiter on how high coal prices can go.

Coal prices will be constrained by the need to not open the "window of opportunity" too wide for new coal entrants and other energy sources. Our forecast is based on the premise that the future needs of electricity generation will largely be sorted out in the competition between coal and natural gas. Both of these fuels have experienced high prices over the last several years and if the perception that these elevated price levels will be sustained over the long-term gains a foothold, power companies may seek to seriously explore other options. Already proponents are respectively lining up, both financially and politically, behind such alternatives as new nuclear power plants and a significant expansion in renew-

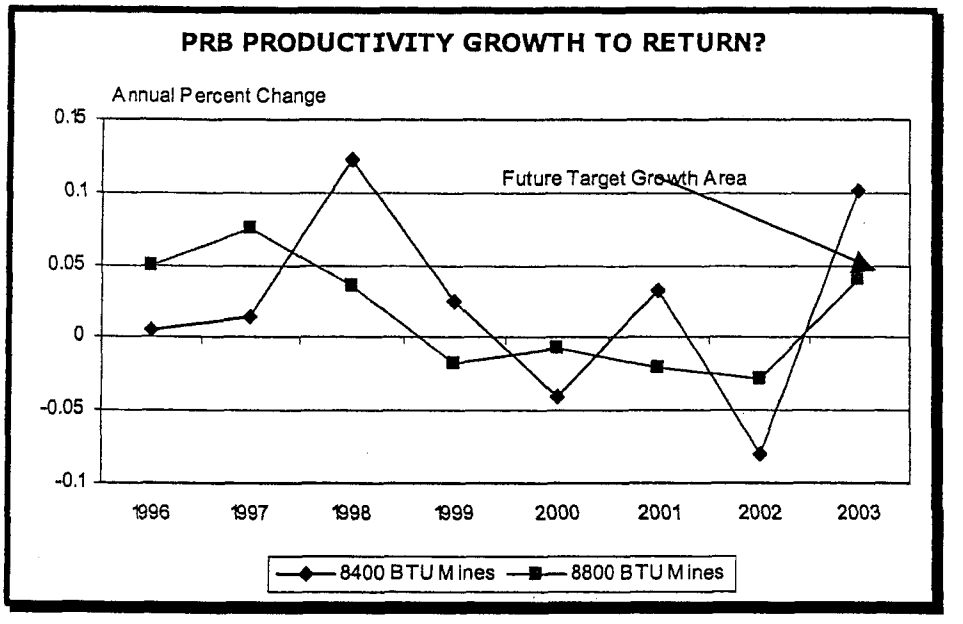
ables. As a corollary to this thought, it is also our belief that this same perception of sustained, overly high coal prices will similarly open the floodgates to a wave of investors and new mining entrants in the coal industry itself, willing to accept incrementally lower (but still high) rates of return on this high demand product.

Price trends for selected coals are shown in the graph below. There exists a noticeable difference among regions with regard to their respective ability of lower prices. In most regions, technological progress aided by favorable geology will facilitate the evolution towards lower prices, whereas in heavily mined areas, notably Central Appalachia, the potential for price improvement is severely limited by reserve degradation.



Coal producers will position themselves to maintain profit margins by cutting production costs through productivity-enhancing investments. While we have paid an extended amount of attention in this article as to why the prevailing level of coal prices must decline, we must stress an important market change that will enable coal suppliers to ultimately offer coal at more competitive prices but still maintain strong profits. As opposed to historical patterns where spot prices would surge and then quickly fall back as new production flooded the market, the sustained rise in spot coal prices has enabled producers to negotiate contracts at a much higher level than ever before achieved. These higher contract prices will provide coal companies will considerable confidence in their future revenue streams, allowing them to make sound decisions with regard to their strategies in positioning themselves for the future. While a good deal of this money will initially be allocated towards debt reduction (as well as to shareholders for the growing number of public companies), more of it will find its way into the investment in productivity-enhancing equipment that will lower the cost of production. As shown in the graph below reflecting productivity trends for the two major types of coal in the Wyoming Powder River Basin, efficiency gains trailed off in the late

1990's and early this decade, reflecting the decline in such investment as coal prices plummeted. The improvement in PRB productivity in 2003 is, in our view, a preview of what will happen in most regions over time, leading to the emergence of the lower production costs / lower prices / sustained profit margin relationship we have described.



U.S. ECONOMIC OUTLOOK[1]

Highlights

- Real GDP growth will average 3.0% per year in 2003–29.
- The outlook for inflation remains moderate. Consumer price index (CPI) inflation will average 2.9% per year over the forecast period. Core inflation will average 3.1%.
- High investment and a slower growing labor force should result in higher productivity growth. Nonfarm business productivity growth averages 2.2% over the forecast period, compared with the 1.9% average experienced since 1977.
- The current account deficit is negative through 2024. Afterward, the current account surpluses grow.
- Real oil prices will creep up over the forecast period. The real price of imported oil is $26.4 per barrel in 2003 to $26.8 per barrel in 2029.
- The labor market improves over the forecast period, with the unemployment rate eventually settling at 4.2%.
- The federal budget deficit shrinks through 2019 and then grows thereafter.

Economists focus on the short run. Will the Federal Reserve raise interest rates? Is the stock market overvalued? Will we have a recession next year? This focus is understandable. We care more about what will happen tomorrow than what will happen three years from today. The focus, though, is misplaced. When historians look back on the 20th century, the most striking economic fact that will distinguish it from previous centuries will not be the 21 recessions, but rather the steady, inexorable rise in per capita income.

The driving force behind rising per capita income is one that economists still do not quite understand: productivity growth. While they agree that new technologies eventually make workers more productive, many questions remain under debate. What determines the pace of technological progress? How long does it take for new technologies to catch on? As a growth accelerant, how does an innovation such as the Internet compare with the invention of the transistor, the airplane, or the electric bulb? Not knowing these answers makes productivity—and the course of the economy—extremely tricky to forecast.

A further complication made this forecast even trickier. Productivity, before the current slowdown, was surging, possibly because of what Alan Greenspan called "a revolution in information technologies." Although productivity growth eased

[1] Global Insight's Long-term US Economic Outlook, Summer 2004, published May 2004.

as the economy slowed in 2001, recent data indicate that it is surging again. Indeed, productivity growth in 2002 and 2003 was the highest and fourth highest in 50 years! Will the productivity boom continue much longer? While there are several promising new technologies in the pipeline, we think things will settle, with productivity growth rising faster than it did in during the 1970s and 1980s, but slower than in the second half of the 1990s.

Long-Term Forecast Assumptions

In the trend scenario, after the first five years of the forecast, we assume an environment free of exogenous shocks. Economic output will converge towards its potential level, with all resources fully utilized. As a result, the growth rates of output, real incomes, real expenditures, and the general standard of living of the population are determined by the growth rate of potential GDP. The long-range outlook is dominated by supply factors, such as population growth and demographics, labor force participation rates, average weekly hours worked, national saving and capital stock accumulation, productivity growth, fiscal and monetary policies, foreign developments, and internationally determined prices.

Population and Demographics

Global Insight's population projections are based on the Census Bureau's middle series assumptions for fertility, life expectancy, and net immigration. These projections have the U.S. population expanding at an annual rate of 0.8% in 2003–29, when the population reaches 359 million. Growth in the older-age cohorts will be stronger as the baby boomers age. The 65-years-and-over population share rises from 12.3% in 2003 to 19.4% in 2029.

The population projections incorporate the 2000 Census estimates, and are based on interim projections the Census posted on the international section of its Web site in 2003. In March 2004, the Census posted "official" end-of-decade interim projections. The population projections used in February's 25-year forecast closely match the Census' latest end-of-decade projections.

Productivity and Aggregate Supply

It is the economy's ability to increase supply in the long run that determines its potential growth path. Growth in aggregate supply depends on the increase in the labor force, the growth of the capital stock, and improvements in productivity.

Global Insight believes that productivity growth will average 2.2% per year in 2004–29. This is lower than the stellar 2.9% average annual growth achieved during the 1960s, although higher than the 1.8% annual growth rate for 1975–2002. The pickup in productivity growth, particularly over the next decade, is largely due to robust growth in equipment spending and new technologies.

The real capital stock will grow 4.6% annually, compared with 4.4% in 1977–2003. The declining price of capital goods relative to other inputs accounts for the robust capital stock growth rates.

Government Policy

The federal budget deficit will exceed $500 billion in 2004, as the 2003 tax act reduces receipts and the war on terrorism boosts spending. In 2005–11, the budget deficit shrinks, but never disappears, as taxes rise in the second half of the decade. An easy way for Congress to achieve this is to let the tax cuts sunset as scheduled; however, this seems unlikely regardless of who may be in the White House or in control of Congress. One way or another, the well-off will be forced to pay more, perhaps by applying the Social Security tax to all incomes, as well as by raising marginal rates.

With the economy growing faster than the pace of government spending, the government sector's share of GDP will decline over the forecast period. The state and local government maintains the dominant share of total government purchases, growing from 63% in 2003 to 73% in 2029. At the federal level, the military accounts for 66% of federal purchases in 2003, and slowly drops to 64% in2029.

Monetary Policy and Financial Markets

The Federal Reserve decides on the "steady-state" rate of inflation. Monetary policy can cause inflation to accelerate by being overly accommodative. Alternatively, it can cause inflation to decelerate by being restrictive. The monetary authorities choose to keep short-term interest rates slightly below their equilibrium levels in the early years of the trend projection, causing a slow but steady increase in inflation. Eventually, by 2018, the inflation rate stabilizes at about 3.5%.

Bond yields will generally move parallel to the funds rate over the forecast interval, but run somewhat higher. The yield on ten-year treasuries stays below 6.0% through 2007. Thereafter, the combination of higher short-term rates and increased government borrowing pushes up the ten-year bond rate to 8.1% by 2029. The forecast implies a real fed funds rate of about 2.5% and a real long-term bond rate of 4.9%.

Foreign Assumptions

The major U.S. industrialized trading partners are assumed to follow a growth pattern similar to that in the United States, with the pace of growth averaging 2.4% over the forecast period, down from an average 2.6% over the past 25 years. This slowdown reflects demographic forces similar to those operating in the United States. The developing countries that trade with the United States will grow 4.3%, down 0.2 percentage point from the past 25 years.

The dollar will have to depreciate steadily against foreign currencies throughout the forecast period in order to keep the U.S. current account deficit from growing too fast. Over the forecast period, the real U.S. trade-weighted dollar relative to industrialized country currencies depreciates 1.2% annually.

Long-Term Forecast Summary

Real GDP. The trend projection assumes that the U.S. economy experiences no major mishaps between now and 2029. The projection is identical with our February 2004 baseline forecast through 2014, and represents Global Insight's best estimate of the economy's path over that period. Beyond 2014, the projection

should be interpreted as the mean of all possible "near-full-employment" paths the economy could follow. The smooth-growth characteristics of the trend projection make it most useful for tasks largely impervious to short-term cyclical fluctuations, such as planning capacity additions and evaluating new markets. This projection is also the best base from which to evaluate the effects of various assumptions about key exogenous elements, such as fiscal policy or energy prices, on the overall economic outlook.

Annual real GDP growth averages 3.0% in 2003–29, a hair lower than the 3.1% rate of the past 25 years. The economy's underlying growth rate will slow after 2011, as baby boomers begin to retire, slowing labor force growth. Potential output growth should hold up fairly well in the future, with greater business fixed investment and R&D spending offsetting the slowdown in labor force growth. Eventually, though, the effects of weaker labor force growth become dominant and, in a sense, self-perpetuating. As output growth drops off, business fixed investment rises more slowly, limiting capital stock growth and thus future output gains.

Employment. Slower long-run increases in the labor force indicate more moderate long-run employment growth in the future. Total civilian employment will rise at an average annual rate of 1.3% from 2003 to 2029. Total establishment employment will rise from 129.9 million in 2003 to 179.9 million in 2029, an increase of 38%. Manufacturing's share of total employment will continue to decline over the forecast period, falling to 7.2% in 2029, from 11.2% in 2003. The broad service sector will generate an increasing share of employment growth in the forecast period, although the federal government's share of employment will decline during the forecast period.

Inflation. Over the long run, inflation is a monetary phenomenon. Its future course will be determined by policies implemented by Alan Greenspan and his successors. Since we do not know who his successors will be, we assumed the Fed would try to stabilize the inflation rate in the second half of the forecast.

The CPI is expected to average 2.9% annual increases in 2003–29, somewhat less than the 4.4% average in 1977–2003. The broader-based GDP deflator will also rise 2.9% per year.

Consumption. Expenditures, in the long term, are primarily determined by the growth of real permanent income, demographic influences, and changes in relative prices. The share of personal consumption expenditures in GDP will stabilize at about 69% of GDP. Real consumption expenditure growth will average 2.8% per year over the forecast. In per capita terms, growth will advance about 2.0% per year, down 0.2 percentage point from the 1977–2003 rate. The share of consumption devoted to services will rise, mainly because of rising health expenditures, while that for goods will fall over the forecast period.

The long-term outlook for auto and light truck sales calls for a slowdown in the rate of increase relative to past performances. Vehicle sales growth will average close to 1.2% over the next 25 years. Light-vehicle sales are forecasted to reach 22.8 million units by 2029. Although the number of vehicles per person has in-

creased significantly in the past 20 years, the United States is approaching a saturation point in the rate of vehicle ownership. Future growth in vehicle sales will be primarily driven by growth in population and demand for replacement vehicles. Automobile sales should be relatively strong throughout the projection period, averaging 8.5 million units per year.

Energy conservation efforts will continue. This stems partly from a stock/flow phenomenon: despite the trend toward minivans and sport/utility vehicles, for example, the average new vehicle is still more fuel-efficient than the existing stock. Gasoline usage per vehicle should fall for several more years, even if relative energy prices remain flat. Similar considerations apply to business capital and housing stocks. The ongoing employment shift from manufacturing to services also implies lower energy usage per unit of output.

Real personal disposable income, which climbed 3.1% in 1970–2003, will rise 3.1% annually over the next 25 years. This does not take into account the rising volume of withdrawals from existing retirement plans.

Housing. Household growth clearly depends on population growth, but real incomes, employment, the age distribution of the population, and societal values also influence it. Net additions to the housing stock are closely linked to household growth, which is the primary driver of housing starts. Many analysts tend to overlook another key factor for housing starts: the geographic location of the demand for net additions.

The 25–34-age cohort is key for the demand for new housing. This is the age group where individuals typically purchase their first home. The demand for new housing was boosted by the large gains in this age group in the late 1960s and 1970s, as the baby-boom generation entered the housing market. Unfortunately for the housing sector, the baby-boom generation began to pass through this age bracket in the mid-1980s, limiting the demand for additions to the housing stock. The number of households in this cohort will begin a modest increase after 2005. The overall headship rate will gradually increase toward older segments due to the shift in the age composition.

The demographic demand for housing will be higher over the next 25 years than over the past 25 years. Thus, housing starts are projected to average 1.7 million units annually in 2003–29, above the 1.6 million average for 1971–2003. Meanwhile, the housing stock will climb from 110.5 million units in 2003 to 140.7 million units in 2029.

Business Fixed Investment. Good profitability and solid demand growth should keep investment healthy over the next 25 years. The share of GDP devoted to business fixed investment will hover around 10.0–14.0% of GDP through most of the forecast period. The effective capital stock (in 2000 dollar terms) is projected to increase 4.4% annually, above the average growth rate recorded for 1970–2003. Inventory investment will remain a small percentage of GDP. Although inventories have played significant roles during past business cycles, inventory investment represents an average in the stable growth scenario and is thus artificially smooth. Capital inflow will contribute to net domestic investment through-

out the forecast period, although federal deficits clearly hurt it in the later years of the forecast. The government saving projection assumes that state and local governments continue to run modest operating surpluses.

The composition of investment will continue to change in the forecast period; structures' share of investment will decline modestly, while equipment's share rises. This is a continuation of a long-standing trend, and is a direct result of declining relative prices for equipment and software.

International Trade. A decline in the dollar relative to industrialized-country-currencies, combined with modest unit labor cost growth, will stimulate U.S. exports abroad and result in an eventual improvement in the U.S. current account balance. Global Insight projects that real exports will expand at an average annual rate of 5.8% over the entire forecast period. Real imports, meanwhile, will grow at an average annual rate of 6.5%.

FORECAST TABLES

Seminole Electric
Coal Prices (FOB CSX)
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb	Price Deflator (2003=1.0)
1998	22.80	19.90	25.77	22.74		0.913
1999	22.35	18.81	24.30	20.84		0.926
2000	22.19	17.51	24.70	22.25	14.75	0.946
2001	32.57	29.93	46.71	36.31	14.03	0.969
2002	26.79	23.34	28.96	27.75	9.45	0.984
2003	26.10	22.09	34.00	28.93	14.10	1.000
2004	33.64	29.41	58.50	50.12	12.35	1.019
2005	30.00	29.10	60.26	51.07	16.92	1.035
2006	26.45	23.52	53.03	39.15	9.33	1.051
2007	26.89	23.10	47.50	27.94	9.39	1.071
2008	27.30	23.91	43.61	28.53	9.53	1.093
2009	27.55	25.09	43.04	29.58	10.63	1.116
2010	27.83	26.36	43.04	30.60	12.13	1.142
2011	28.22	27.46	43.96	31.13	13.41	1.170
2012	28.77	28.21	45.13	31.39	14.19	1.198
2013	29.39	28.79	46.26	31.62	14.97	1.226
2014	30.06	29.36	47.22	31.86	15.87	1.256
2015	30.75	29.96	47.94	32.11	16.85	1.287
2016	31.47	30.56	49.04	32.36	18.22	1.319
2017	32.21	31.19	50.36	32.61	19.30	1.352
2018	32.98	31.84	51.70	32.86	20.38	1.387
2019	33.78	32.51	53.07	33.12	21.47	1.422
2020	34.61	33.20	54.47	33.39	22.83	1.459
2021	35.48	33.92	55.95	33.66	23.51	1.498
2022	36.36	34.64	57.45	33.91	24.03	1.537
2023	37.26	35.38	58.99	34.18	24.49	1.577
2024	38.19	36.14	60.57	34.45	24.88	1.618
2025	39.14	36.92	62.21	34.73	25.30	1.661
2026	40.12	37.72	63.90	35.01	25.73	1.705
2027	41.13	38.54	65.64	35.30	26.17	1.750
2028	42.18	39.38	67.44	35.60	26.61	1.797
2029	43.27	40.26	69.31	35.92	27.06	1.846
2030	44.39	41.17	71.25	36.24	27.52	1.896

Seminole Electric
Coal Prices (FOB CSX)
($2003 Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	24.98	21.80	28.23	24.91	
1999	24.14	20.32	26.24	22.50	
2000	23.45	18.51	26.10	23.52	15.59
2001	33.62	30.89	48.22	37.49	14.49
2002	27.24	23.73	29.45	28.21	9.60
2003	26.10	22.09	34.00	28.93	14.10
2004	33.01	28.86	57.42	49.19	12.12
2005	28.99	28.12	58.23	49.35	16.35
2006	25.17	22.38	50.46	37.25	8.88
2007	25.10	21.57	44.35	26.09	8.76
2008	24.97	21.88	39.90	26.10	8.72
2009	24.69	22.49	38.57	26.51	9.53
2010	24.38	23.09	37.71	26.80	10.63
2011	24.12	23.47	37.58	26.61	11.46
2012	24.02	23.56	37.68	26.21	11.85
2013	23.98	23.49	37.74	25.80	12.22
2014	23.94	23.38	37.61	25.38	12.64
2015	23.90	23.29	37.26	24.96	13.10
2016	23.86	23.18	37.19	24.54	13.81
2017	23.83	23.07	37.24	24.12	14.27
2018	23.79	22.96	37.29	23.69	14.70
2019	23.75	22.86	37.31	23.28	15.09
2020	23.72	22.75	37.33	22.89	15.64
2021	23.69	22.65	37.36	22.47	15.70
2022	23.66	22.54	37.38	22.06	15.63
2023	23.63	22.44	37.41	21.67	15.53
2024	23.60	22.33	37.43	21.29	15.38
2025	23.57	22.23	37.46	20.91	15.24
2026	23.54	22.12	37.48	20.54	15.10
2027	23.51	22.02	37.51	20.17	14.95
2028	23.48	21.92	37.53	19.81	14.81
2029	23.44	21.82	37.56	19.46	14.66
2030	23.41	21.72	37.58	19.12	14.52

Florida
Delivered Coal Prices
(Current Dollars per Ton)

Year	Illinois Basin		Central	Pittsburg
	Medium Sulfur	High Sulfur	Appalachia	Seam
	11,000 Btu/LB	12,000 Btu/Lb	12,400 Btu/Lb	13100 Btu/Lb
	from Farmersbu	from Providence	from Pike Count	from Waynesburg,
	Indiana	Kentucky	Kentucky	Pennsylvania
2000	39.10	36.72	40.97	45.05
2001	49.80	49.49	63.29	59.54
2002	43.99	42.41	45.51	50.94
2003	43.82	41.56	51.05	52.82
2004	51.79	49.05	75.97	74.60
2005	48.45	48.92	78.01	75.95
2006	45.19	43.53	71.06	64.41
2007	45.97	43.30	65.87	53.68
2008	46.73	44.34	62.30	54.73
2009	47.35	45.82	62.09	56.27
2010	48.00	47.36	62.45	57.79
2011	48.81	48.75	63.77	58.89
2012	49.74	49.83	65.31	59.67
2013	50.76	50.75	66.82	60.44
2014	51.85	51.66	68.18	61.24
2015	52.96	52.59	69.31	62.06
2016	54.12	53.53	70.84	62.91
2017	55.33	54.53	72.60	63.77
2018	56.57	55.60	74.40	64.66
2019	57.86	56.71	76.24	65.58
2020	59.19	57.84	78.12	66.53
2021	60.57	59.01	80.09	67.49
2022	61.98	60.20	82.10	68.45
2023	63.42	61.41	84.16	69.44
2024	64.88	62.65	86.26	70.45
2025	66.41	63.93	88.44	71.49
2026	67.96	65.24	90.68	72.55
2027	69.57	66.58	92.99	73.63
2028	71.22	67.96	95.37	74.75
2029	72.94	69.39	97.86	75.92
2030	74.70	70.85	100.41	77.11

NOTE: All transportation rates are assumed to be from the CSX origin points listed above

Florida
Delivered Coal Prices
(Current Dollars per Ton)

Year	Illinois Basin		Central Appalachia	Pittsburg Seam
	Medium Sulfur 11,000 Btu/LB from Farmersbu Indiana	High Sulfur 12,000 Btu/Lb from Providence Kentucky	12,400 Btu/Lb from Pike Couni Kentucky	13100 Btu/Lb from Waynesburg, Pennsylvania
2000	41.32	38.81	43.30	47.61
2001	51.41	51.09	65.33	61.46
2002	44.73	43.11	46.27	51.79
2003	43.82	41.56	51.05	52.82
2004	50.83	48.14	74.57	73.22
2005	46.82	47.27	75.39	73.40
2006	43.00	41.42	67.61	61.29
2007	42.93	40.43	61.50	50.12
2008	42.75	40.57	57.00	50.07
2009	42.43	41.06	55.64	50.43
2010	42.05	41.49	54.71	50.63
2011	41.72	41.68	54.52	50.34
2012	41.53	41.60	54.53	49.82
2013	41.41	41.40	54.51	49.30
2014	41.29	41.14	54.30	48.77
2015	41.16	40.88	53.88	48.24
2016	41.04	40.59	53.72	47.70
2017	40.92	40.33	53.70	47.17
2018	40.80	40.10	53.65	46.63
2019	40.68	39.87	53.60	46.11
2020	40.56	39.64	53.53	45.59
2021	40.44	39.40	53.48	45.06
2022	40.33	39.17	53.42	44.54
2023	40.21	38.94	53.36	44.03
2024	40.10	38.72	53.31	43.54
2025	39.98	38.49	53.25	43.04
2026	39.87	38.27	53.20	42.56
2027	39.75	38.05	53.14	42.08
2028	39.64	37.83	53.08	41.60
2029	39.52	37.60	53.03	41.14
2030	39.41	37.38	52.97	40.68

NOTE: All transportation rates are assumed to be from the CSX origin points listed above and delivered into the Palatka area

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Dollars per Million Btu)

Year	Henry Hub	(Current) FGT Bidweek	FGT Cash	Deflator (2003=1.0)	Henry Hub	(2002$) FGT Bidweek	FGT Cash
1998	2.11	2.09	2.00	0.913	2.31	2.29	2.19
1999	2.27	2.26	2.21	0.926	2.45	2.44	2.39
2000	3.88	3.89	4.22	0.946	4.10	4.11	4.46
2001	4.26	4.26	3.81	0.969	4.39	4.40	3.93
2002	3.22	3.24	3.33	0.984	3.27	3.29	3.38
2003	5.38	5.39	5.49	1.000	5.38	5.39	5.49
2004	6.14	6.14	6.12	1.019	6.03	6.03	6.01
2005	6.31	6.31	6.24	1.035	6.10	6.10	6.03
2006	6.03	6.03	5.95	1.051	5.74	5.74	5.66
2007	5.15	5.16	5.06	1.071	4.81	4.81	4.73
2008	4.60	4.60	4.55	1.093	4.20	4.21	4.16
2009	4.72	4.73	4.68	1.116	4.23	4.23	4.20
2010	4.90	4.91	4.87	1.142	4.29	4.30	4.26
2011	5.04	5.04	5.01	1.170	4.31	4.31	4.28
2012	5.17	5.18	5.14	1.198	4.32	4.32	4.29
2013	5.34	5.35	5.31	1.226	4.36	4.36	4.33
2014	5.47	5.47	5.44	1.256	4.35	4.36	4.33
2015	5.65	5.65	5.63	1.287	4.39	4.39	4.38
2016	5.81	5.81	5.80	1.319	4.40	4.41	4.39
2017	6.00	6.00	5.99	1.352	4.44	4.44	4.43
2018	6.04	6.05	6.04	1.387	4.36	4.36	4.35
2019	6.27	6.27	6.27	1.422	4.41	4.41	4.41
2020	6.48	6.48	6.50	1.459	4.44	4.44	4.46
2021	6.67	6.67	6.69	1.498	4.45	4.45	4.47
2022	6.86	6.86	6.88	1.537	4.46	4.47	4.48
2023	7.06	7.06	7.08	1.577	4.47	4.48	4.49
2024	7.26	7.26	7.28	1.618	4.49	4.49	4.50
2025	7.46	7.47	7.49	1.661	4.49	4.50	4.51
2026	7.68	7.68	7.70	1.705	4.50	4.50	4.52
2027	7.90	7.90	7.92	1.750	4.51	4.51	4.53
2028	8.12	8.12	8.15	1.797	4.52	4.52	4.53
2029	8.35	8.35	8.38	1.846	4.52	4.52	4.54
2030	8.58	8.58	8.61	1.896	4.53	4.53	4.55

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	NOMINAL			*CONSTANT 2003 DOLLARS*		
	0.7%	**1.0%**	**3.0%**	**0.7%**	**1.0%**	**3.0%**
1995	15.18	14.69	13.77			
1996	18.04	17.47	15.58			
1997	16.59	16.15	14.41			
1998	12.85	12.14	9.69			
1999	15.99	15.33	14.28			
2000	27.54	26.27	20.72	29.10	27.77	21.90
2001	22.90	21.68	17.12	23.64	22.39	17.67
2002	23.41	22.32	20.50	23.81	22.69	20.84
2003	29.04	28.02	23.93	29.04	28.02	23.93
2004	30.29	29.20	25.92	29.73	28.66	25.44
2005	33.69	32.50	27.49	32.56	31.40	26.57
2006	30.48	29.40	24.52	29.01	27.97	23.33
2007	31.07	29.96	25.14	29.01	27.97	23.48
2008	30.70	29.61	24.71	28.09	27.09	22.61
2009	30.78	29.68	24.78	27.59	26.60	22.21
2010	30.75	29.66	24.76	26.94	25.98	21.69
2011	30.45	29.37	24.51	26.03	25.10	20.96
2012	30.20	29.12	24.31	25.21	24.31	20.30
2013	30.49	29.41	24.55	24.88	23.99	20.03
2014	31.55	30.42	25.39	25.12	24.23	20.22
2015	32.75	31.58	26.36	25.45	24.54	20.49
2016	33.94	32.73	27.32	25.74	24.82	20.72
2017	35.13	33.88	28.28	25.99	25.06	20.92
2018	36.33	35.03	29.24	26.20	25.26	21.09
2019	37.52	36.18	30.20	26.38	25.44	21.24
2020	38.72	37.33	31.17	26.53	25.59	21.36
2021	39.94	38.51	32.15	26.67	25.71	21.46
2022	41.15	39.69	33.13	26.78	25.82	21.56
2023	42.37	40.86	34.11	26.87	25.91	21.63
2024	43.59	42.04	35.09	26.94	25.98	21.69
2025	44.81	43.21	36.07	26.98	26.02	21.72
2026	46.08	44.44	37.09	27.03	26.07	21.76
2027	47.35	45.66	38.11	27.06	26.09	21.78
2028	48.61	46.88	39.13	27.06	26.09	21.78
2029	49.88	48.10	40.15	27.03	26.06	21.76
2030	51.15	49.32	41.17	26.98	26.02	21.72

DSTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	NOMINAL		CONSTANT 2003 DOLLARS	
	Posted Price at Tampa, FL	Spot Price at Gulf Coast	Posted Price at Tampa, FL	Spot Price at Gulf Coast
1995	50.68	47.48		
1996	63.75	58.98		
1997	58.57	54.10		
1998	42.17	38.19		
1999	50.99	47.07		
2000	88.36	81.14	93.39	85.75
2001	75.97	68.91	78.43	71.14
2002	70.19	65.64	71.36	66.74
2003	87.76	80.59	87.76	80.59
2004	114.51	110.18	112.39	108.14
2005	123.33	118.93	119.18	114.93
2006	98.19	93.72	93.43	89.18
2007	97.01	92.57	90.58	86.43
2008	94.97	90.60	86.89	82.89
2009	95.23	90.82	85.35	81.39
2010	95.17	90.74	83.37	79.49
2011	94.27	89.85	80.59	76.81
2012	93.51	89.10	78.07	74.39
2013	94.46	89.98	77.06	73.41
2014	97.74	93.08	77.84	74.13
2015	101.49	96.62	78.88	75.10
2016	105.22	100.14	79.79	75.94
2017	108.95	103.67	80.58	76.67
2018	112.69	107.19	81.26	77.30
2019	116.42	110.71	81.85	77.84
2020	120.16	114.24	82.35	78.29
2021	123.98	117.83	82.78	78.68
2022	127.81	121.43	83.16	79.01
2023	131.63	125.03	83.47	79.28
2024	135.46	128.63	83.71	79.49
2025	139.29	132.23	83.86	79.61
2026	143.22	135.97	84.02	79.76
2027	147.16	139.70	84.09	79.83
2028	151.10	143.44	84.10	79.84
2029	155.04	147.18	84.01	79.75
2030	158.98	150.92	83.86	79.61

2004 BASE CASE GAS PRICE FORECAST, April 21, 2004

		PAYNE CREEK (7)				Reliant - Constellation - New Units							Calpine Osprey				Hardee Power Station	
		Up to 57 K Dth/day		Over 57 K Dth/day		New Units (CC) firm pricing negotiated amount/day							Up to 44 K Dth/day		Over 44 K Dth/day			
	Gas Price into Pipe $/Dth	Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	FGT Trans Use & Fuel $/Dth	FGT Delvd Price $/Dth	GS Trans Use & Fuel $/Dth	GS Delvd Price $/Dth	Generic CC's: w/o Firm Transp. Included $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth
	(1)	(2)		(3)		(4)			(3)				(5)				(6)	
	FGT Compressor Fuel %:				3.0%	GS Compressor Fuel %:			2.0%						PGS Compressor Fuel %:			3.0%
	FGT Usage Fees $/Dth:				$0.04	GS Usage Fees $/Dth:			$0.02						PGS Usage Fees $/Dth:			$0.041
	FGT Mkt Swing Trans:				$0.78	GS Mkt Swing Trans:			$0.78						PGS Mkt Swing Trans:			$0.48
	Transportation Basis - HHub:				$0.15													
Year																		
2004	$5.94	$0.34	$6.27	$1.11	$7.05	$1.12	$7.05	$1.05	$6.99	$6.26	$1.12	$7.05	$0.29	$6.23	$1.05	$6.99	$0.85	$6.79
2005	$5.20	$0.32	$5.52	$1.09	$6.29	$1.10	$6.30	$1.04	$6.24	$5.51	$1.10	$6.30	$0.28	$5.48	$1.04	$6.24	$0.83	$6.03
2006	$4.80	$0.31	$5.11	$1.08	$5.88	$1.08	$5.88	$1.03	$5.83	$5.09	$1.08	$5.88	$0.27	$5.07	$1.03	$5.83	$0.82	$5.62
2007	$4.50	$0.30	$4.80	$1.07	$5.57	$1.07	$5.57	$1.02	$5.52	$4.79	$1.07	$5.57	$0.26	$4.76	$1.02	$5.52	$0.81	$5.31
2008	$4.40	$0.30	$4.70	$1.07	$5.47	$1.07	$5.47	$1.02	$5.42	$4.68	$1.07	$5.47	$0.26	$4.66	$1.02	$5.42	$0.81	$5.21
2009	$4.31	$0.30	$4.61	$1.06	$5.37	$1.07	$5.38	$1.02	$5.33	$4.59	$1.07	$5.38	$0.26	$4.57	$1.02	$5.33	$0.80	$5.11
2010	$4.31	$0.30	$4.61	$1.06	$5.37	$1.07	$5.38	$1.02	$5.33	$4.59	$1.07	$5.38	$0.26	$4.57	$1.02	$5.33	$0.80	$5.11
2011	$4.53	$0.30	$4.83	$1.07	$5.60	$1.07	$5.60	$1.02	$5.55	$4.82	$1.07	$5.60	$0.26	$4.79	$1.02	$5.55	$0.81	$5.34
2012	$4.70	$0.31	$5.01	$1.08	$5.78	$1.08	$5.78	$1.03	$5.73	$4.99	$1.08	$5.78	$0.27	$4.97	$1.03	$5.73	$0.82	$5.52
2013	$4.90	$0.31	$5.21	$1.08	$5.98	$1.09	$5.99	$1.03	$5.93	$5.20	$1.09	$5.99	$0.27	$5.17	$1.03	$5.93	$0.82	$5.72
2014	$5.07	$0.32	$5.39	$1.09	$6.16	$1.09	$6.16	$1.03	$6.10	$5.37	$1.09	$6.16	$0.27	$5.34	$1.03	$6.10	$0.83	$5.90
2015	$5.29	$0.32	$5.61	$1.09	$6.38	$1.10	$6.39	$1.04	$6.33	$5.60	$1.10	$6.39	$0.28	$5.57	$1.04	$6.33	$0.83	$6.12
2016	$5.46	$0.33	$5.79	$1.10	$6.56	$1.10	$6.56	$1.04	$6.50	$5.77	$1.10	$6.56	$0.28	$5.74	$1.04	$6.50	$0.84	$6.30
2017	$5.66	$0.33	$5.99	$1.11	$6.77	$1.11	$6.77	$1.05	$6.71	$5.98	$1.11	$6.77	$0.29	$5.95	$1.05	$6.71	$0.85	$6.51
2018	$5.88	$0.34	$6.22	$1.11	$6.99	$1.12	$7.00	$1.05	$6.93	$6.21	$1.12	$7.00	$0.29	$6.17	$1.05	$6.93	$0.85	$6.73
2019	$6.12	$0.34	$6.46	$1.12	$7.24	$1.12	$7.24	$1.05	$7.17	$6.45	$1.12	$7.24	$0.29	$6.41	$1.05	$7.17	$0.86	$6.98
2020	$6.36	$0.35	$6.71	$1.13	$7.49	$1.13	$7.49	$1.06	$7.42	$6.70	$1.13	$7.49	$0.30	$6.66	$1.06	$7.42	$0.87	$7.23
2021	$6.60	$0.36	$6.96	$1.13	$7.73	$1.14	$7.74	$1.06	$7.66	$6.95	$1.14	$7.74	$0.30	$6.90	$1.06	$7.66	$0.88	$7.48
2022	$6.86	$0.36	$7.22	$1.14	$8.00	$1.15	$8.01	$1.07	$7.93	$7.22	$1.15	$8.01	$0.31	$7.17	$1.07	$7.93	$0.88	$7.74
2023	$7.12	$0.37	$7.49	$1.15	$8.27	$1.15	$8.27	$1.08	$8.20	$7.48	$1.15	$8.27	$0.32	$7.44	$1.08	$8.20	$0.89	$8.01
2024	$7.40	$0.38	$7.78	$1.16	$8.56	$1.16	$8.56	$1.08	$8.48	$7.77	$1.16	$8.56	$0.32	$7.72	$1.08	$8.48	$0.90	$8.30
2025	$7.69	$0.38	$8.07	$1.17	$8.86	$1.17	$8.86	$1.09	$8.78	$8.07	$1.17	$8.86	$0.33	$8.02	$1.09	$8.78	$0.91	$8.60
2026	$7.98	$0.39	$8.37	$1.18	$9.16	$1.18	$9.16	$1.09	$9.07	$8.37	$1.18	$9.16	$0.33	$8.31	$1.09	$9.07	$0.92	$8.90
2027	$8.29	$0.40	$8.69	$1.19	$9.48	$1.19	$9.48	$1.10	$9.39	$8.69	$1.19	$9.48	$0.34	$8.63	$1.10	$9.39	$0.93	$9.22
2028	$8.62	$0.41	$9.03	$1.20	$9.82	$1.20	$9.82	$1.11	$9.73	$9.03	$1.20	$9.82	$0.35	$8.97	$1.11	$9.73	$0.94	$9.56
2029	$8.95	$0.41	$9.36	$1.21	$10.16	$1.21	$10.16	$1.11	$10.06	$9.37	$1.21	$10.16	$0.35	$9.30	$1.11	$10.06	$0.95	$9.90
2030	$9.30	$0.42	$9.72	$1.22	$10.52	$1.22	$10.52	$1.12	$10.42	$9.73	$1.22	$10.52	$0.36	$9.66	$1.12	$10.42	$0.96	$10.26

NOTES:

(1) 2004 - 2030 is forecast as provided by Global Insight in December 2003, Henry Hub price. Confirmed by Mike Allen, March 17, 2004. **2004-2010 were adjusted by Mike Allen, approved by RJM/LTM to reflect the current pricing conditions, blending into the long-term Global Insight nat gas forecast.**

(2) The charges for up to 57,000 Dth/day are based on 25,000 Dth/day of FGT firm capacity with 3.0% compressor fuel and $.04/Dth usage charge, and 32,000 Dth/day of Gulfstream firm capacity with 2.0% compressor fuel and $.02/Dth usage charge.

(3) The charges for daily bundled volumetric transportaion assume Gulfstream volumetric daily market interruptable capacity will set market prices on both Gulfstream and FGT. Compressor fuel is assumed to be 2.0% and daily market transportation is a weighted average of estimated $0.78/Dth in the summer and in the shoulder months.

(4) Provides for the facility to be located on either the FGT or the Gulfstream pipelines with firm. capacity to be reserved on either Gulfstream or FGT.

(5) Assumes transportation is provide by a firm contract for 44,000 Dth/day. Assumes the facility will be located on the Gulfstream pipeline with 2.0% compressor fuel and $0.02 usage charge. Use $0.70/Dth for the reservation cost of firm transportation.

(6) The FGT compressor fuel charge for HPS is 3.0%. Variable transportation is the current PGS shoulder month price of $0.48/Dth applied to all 12 months recognition that the majority of energy is consumed during the shoulder months.

(7) The Payne Creek fixed annual reservation charge is calaculated as follows:

2004

FGT 25,000 x 366 x $0.7852 = $6,937,703
GST 32,000 x 366 x $0.570 = $6,675,840
Total = $13,613,543

2005 - 2009

FGT 25,000 x 365 x $0.7959 = $7,262,659
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $13,920,259

2010 and beyond

FGT 25,000 x 365 x $0.8357 = $7,625,763
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $14,283,363

Global Insight

Energy Price Forecast

Prepared for
Seminole Electric Company

December 2003

GLOBAL INSIGHT, INC.
24 HARTWELL AVE., LEXINGTON, MA 02421

Contributors

Mary Novak
Managing Director, Energy Services & Oil
(781) 301-9011
Fax: (781) 301-9402

Jim Osten
Principal, Natural Gas
(781) 301-9120
Fax: (781) 301-9402

Margaret Rhodes
Manager, Energy Forecasting, Power & Coal
(781) 301-9105
Fax: (781) 301-9402

John Dean
Consulting Economist, Coal and Nuclear
(301) 815-5470
Fax: (301) 815-5470

Hongyan Lin
Economist, Oil
(781) 301-9065
Fax: (781) 301-9402

Yanqun Shi
Economist, Natural Gas
(781) 301-9029
Fax: (781) 301-9402

Junya Tanizaki
Economist, Power & Coal
(781) 301-9114
Fax: (781) 301-9402

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EXECUTIVE SUMMARY

Petroleum

The price outlook for coming months could have at least as much to do with market perceptions as with underlying fundamentals.

There are signs that the market currently lacks a sense of direction, with small changes in reported weekly U.S. stocks precipitating large price movements and with OPEC ministers publicly advancing a range of mutually contradictory options for their December 4 meeting.

Market perceptions of stock levels will be a critical factor, and once again the "missing barrels" problem is emerging. This is when a large discrepancy becomes apparent between the view of global stocks indicated by the large "top-down" aggregates of supply and demand, and that indicated by "bottom-up" statistics on reported stocks in OECD countries. Currently, the top-down picture suggests a substantial easing in the global supply position, such that by early next year stocks should be reaching levels that could drive prices right down toward the bottom of the OPEC price band. Bottom-up figures, however, do not yet show this stock build, and U.S. crude and gasoline stocks still look very tight. Unfortunately, the scope for error in both estimates is large.

OPEC ministers have to decide which view to take at their meeting on December 4. Their difficulties are exacerbated by capacity increases from members Nigeria and Algeria, due on stream early next year; neither member is in a mood not to use new production. In addition, ministers are in disagreement about relative priorities between prices and market share. Finally, there is the problem of timing. OPEC cannot respond quickly to changes in market perceptions and mood, either in terms of meetings or more importantly because the bulk of its supply is six weeks from its main markets.

Natural Gas

The November forecast shows some weakening from the $5 plateau for natural gas prices during 2003-4. U.S. supply is increasing in 2003 as a result of a very high rate of LNG imports and a small recovery in the Gulf of Mexico. The economy is expected to rebound with about 4% economic growth in 2004 and 2% demand growth. LNG imports will increase again in 2004 but Canadian supply may continue to decline. Thus US supply growth will have to continue in order for this demand forecast to be realized. In the forecast, a tight supply and demand balance continues to exert pressures on natural gas prices.

Natural gas demand is about 4 Bcfd below the level predicted in forecasts from prior years. Thus, the North American supply and demand balance is much tighter

than in 2002. The high natural gas prices have caused "Demand Destruction." Global Insight has undertaken a major study of the Demand Destruction process for the industrial sector. Much of the impact on industry has been in the chemical sector where many ammonia plants have been shut down along with several methanol and ethylene plants. Recently, several ammonia plants came back on line to meet fertilizer demand for next spring.

The storage situation looks very normal. Weather forecasts are mixed but only a few forecasters are predicting colder than normal weather this winter and than only for the Northeast in the early winter. Global Insight expects that storage draw will be high this winter and that end of March working gas will be below normal. Henry Hub prices average $4.75 in 2004.

PETROLEUM OUTLOOK

Short-term Highlights

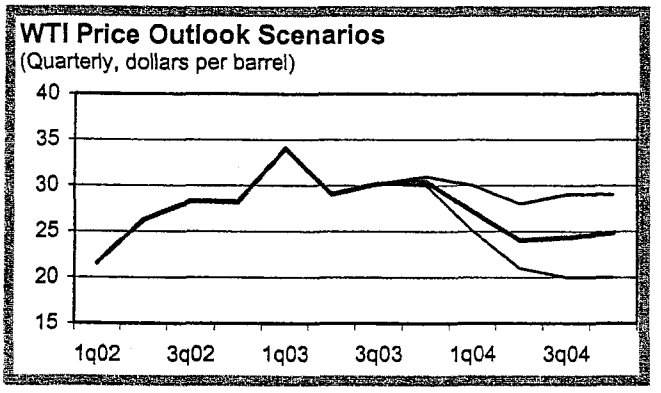
In November, the price of WTI rose while that of Brent fell, an indication of different forces operating on the different markers, but also of the uncertainly and lack of direction mentioned in last month's report.

Indeed, developments over the past month have only added more uncertainty to the picture. The crude market has been tight in the face of surging Chinese demand for crude, and market analysts have been marking up their estimate of Chinese demand for next year. Given the difficulties both of projecting the scale and incidence of Chinese economic growth and of making sense of opaque Chinese oil market statistics, such estimates could well see further adjustments, probably upwards. OPEC's December 4 meeting has added further uncertainty. The OPEC basket price has been mostly above the top of its $22-28/barrel (bbl) band, and ministers decided to make no further change to quotas at this stage but to meet again in Algiers on February 10. This could be too late, however, leaving OPEC running to catch up as prices fall. The cartel's output did not decline by much, if at all, in November, as members cashed in on high prices and firm Chinese demand, and little further reduction should now be expected through February. Moreover, Iraqi output continues to surprise, rising by more than expected most months. All indications of supply and demand analysis therefore point to a substantial stock build through the first quarter and beyond, which will now require OPEC to make very deep cuts if it wishes to avoid a price collapse that takes prices below the bottom of its band.

We have factored two large cuts in the first half of next year into our balance, but with stocks still rising inexorably, we continue to project a price fall, though slightly later than previously, with the steepest drop occurring over February/March. In addition, although the December 4 decision points to an even greater stock build, paradoxically it may assist OPEC. The even sharper price decline that may result, with the prospect of further falls if no action is taken, could focus minds enough to generate the scale of cuts that may prove necessary.

The outlook remains even more than usually uncertain, however. Prices have already remained high for longer than we expected, largely due to stronger underlying demand and continuing low stocks in the United States. It is possible that supply and demand balances are still too optimistic about next year's non-OPEC increases while understating the possible impact of economic recovery and surging Chinese demand. OPEC members also remain very committed to high prices, recently making much of the loss of purchasing power of their dollar-denominated earnings. Prices remaining close to $30/bbl for WTI are still conceivable.

On the other hand, if prices do begin to slide in the face of rising forward stock cover, OPEC discipline could break down as members revert to historical patterns of behavior, each individually increasing output in an attempt to maintain revenue, thus perpetuating the downward cycle of prices. Alternatively, Saudi Arabia could find it intolerable to make the scale of cut that could be required of it in order to defend prices, especially in the face of poor quota compliance, and refuse to make such a cut. This could drive the price of the OPEC basket below $20/bbl or even much lower.



Recent Developments

It is very difficult to draw any clear message from the movement of the main markers during November, as they responded to different forces. Compared with the average for October, WTI and Dubai rose, while Brent fell and the OPEC basket price scarcely changed.

Marker Crude Prices (Dollars/bbl)

	September	October	November
WTI	28.25	30.30	30.93
Brent	27.08	29.65	28.76
Dubai	25.24	27.24	27.54
OPEC basket	26.15	28.40	28.48

WTI was driven up by a combination of worries about low U.S. product stocks, various international events, and hedge funds that built the second highest ever net long position. Dubai was supported by continuing robust demand from the Far East, particularly China. Brent was pressured by a 250,00 barrels per day (b/d) increase in supplies of Russian Urals from the newly expanded Baltic Pipeline System through the Baltic terminal of Primorsk, and by high freight rates that made it difficult to make the arb to the United States work.

Late in the month, profit taking by the hedge funds and a reported easing of concern about the U.S. product position took $2.50/bbl off WTI in one day. The other markers fell in sympathy, albeit by less. Covering of short positions in advance of the U.S. Thanksgiving long weekend halted the fall. It is noteworthy that this is

the second successive month during which the OPEC basket price has exceeded the top of the $22-28/bbl price band. Because prices did not exceed $28//bl for 20 *consecutive* trading days, however, OPEC ministers did not have to face the potentially embarrassing position of having to simultaneously discuss a cut and also consider an "automatic" 500,000 b/d increase in output.

Market signals were as mixed as those from the price movements of the marker crudes. There were signs both of strength and of forthcoming weakness. Chinese demand is evidently very strong, with product shortages and rationing reported, and the shortage of fuel oil import licenses meant that there was a strong demand for heavier crudes from the Middle East and West Africa. The surge in demand seems very recent, reflected in the doubling of freight rates for very large crude carriers (VLCCs) from the Arabian Gulf to the East since the end of October. The IEA also recognized this feature in its latest views, adding 300,000 b/d to its estimate of Chinese demand in the fourth quarter, and 200,000 b/d on average throughout 2004. Competition between China and the United States for available supplies is seen by some as one factor underlying recent market strength. On the other hand, OPEC production in October was up by around 300,000 b/d on September, according to all secondary sources, and although no November estimates are yet available, all the indications suggest that the intended cut of 0.9 million barrels per day (mb/d) (which would actually have needed to be nearer 1.3 mb/d to reach the new quota) did not occur. Instead, it seems that non-Gulf members continued with their normal behavior of maximizing output, while the Gulf members, who might have been expected to observe the cut, decided to cash in on high prices and strong Chinese demand. If all the movements to China and elsewhere in the East go into meeting current demand, global balances will be little affected, but if some of the strong demand proves to have been partly due to precautionary stock building in advance of the November 1 cut and in anticipation of a further cut resulting from OPEC's December 4 meeting, then it may result in reduced demand a month or two hence. By late November, perceptions were that OPEC would make no change to quotas on December 4, so this factor had little impact on market sentiment.

Demand and Supply Fundamentals

Economics

Most regions of the world are now showing signs of recovery, although in some regions, such as Europe, these recoveries are still quite tentative. However, there are signs that the U.S. economy has again become the global growth locomotive. Almost all regions of the world are counting on strong export growth as a major contributor to their recoveries. This will do nothing to correct the large current account imbalances in the world economy—indeed, it could actually make matters worse. Moreover, as the U.S. dollar continues its long slide, strong U.S. GDP growth may not translate into strong U.S. import growth. Thus, the rest of the

world will either continue to see sluggish expansion, or face greater pressure to boost domestic demand.

Real GDP Growth, World and Major Seven Economies
Year-on-year percent change

	2003		2004			
	Q3	Q4	Q1	Q2	Q3	Q4
US	3.3	3.9	4.5	4.6	4.1	4.1
Canada	1.4	2.0	2.3	3.3	3.9	3.9
France	-0.2	0.4	0.5	1.3	1.5	1.8
Germany	0.0	0.3	0.8	1.2	1.4	1.6
Italy	0.2	0.0	0.5	1.0	1.5	1.9
UK	1.9	2.2	2.9	3.0	2.8	2.5
Japan	2.2	1.9	1.7	1.1	1.5	1.5
World	2.2	2.6	3.1	3.2	3.1	3.2

For the U.S. current deficit to be brought under control, the country's mix of growth needs to shift from domestic demand to net export, while the reverse needs to happen in the rest of the world. The evidence of the global recovery, so far, suggests that this shift is occurring at a very slow rate.

The U.S. expansion is still being driven by strong growth in domestic demand, and trade remains a persistent drag on the economy. With the dollar expected to fall further, net exports will begin to make a small contribution to growth by 2005. In the meantime, though, America's direct contribution to world economic growth will increase from 36% in 2002 and 2003 to 39% next year before settling back to 32% in 2005-06.

The recovery in the Eurozone is still relatively weak, and remains too dependent on exports for a region that could play a role as a global growth locomotive. But in a mirror image of the United States, as the euro continues to strengthen over the next few years, net exports will begin to act as a drag on growth. The United Kingdom has made the strongest contribution to global growth of the Big 4 Western European economies in recent years, and should continue to do so. Moreover domestic demand has been the major source of its growth.

Growth in Japan has accelerated a little over the past year, but unfortunately exports have played a disproportionately large part in this upturn. Going forward, however, net exports are expected to become a drag on growth, as the yen continues to appreciate, relative to both the dollar and the euro. The rest of Asia has been expanding strongly and will contribute as much as 25% of world growth in the near to medium term. But net exports have played a very large role in Asia's better-than-average performance. This is partly due to the rapid rise in intra-regional trade, and partly to exchange rate policies in the region designed to prevent too rapid an appreciation relative to the U.S. dollar.

Among the other emerging regions, Latin America, the Middle East, and Africa are all enjoying export led expansions, while growth in Emerging Europe is more balanced.

Demand

Upward revisions to demand estimates for China and the Middle East mean that global demand this year is now estimated to grow by 1.3 mb/d compared with 2002, an increase of 0.2 mb/d compared with last month's estimate. Demand has similarly been adjusted upwards for the same regions for next year, leaving the 2004 versus 2003 increase at 1.0 mb/d.

In China, GDP growth this year is now estimated at 8.3% by Global Insight, an increase from last month's 7.6%, but slowing slightly to 7.9% next year. Oil demand is estimated to increase by 10% this year and also more modestly next year, by closer to 6%. The rapid oil consumption growth has been driven by expansion of demand in three areas. First, transportation demand is increasing, with rapid gains in car ownership, and the need for transporting goods that is an inevitable part of economic growth anywhere. Second, the petrochemical industry's output is growing rapidly, supported by strong domestic and export demand for plastics. Third, power generation in many coastal areas, where growth is at its most rapid, remains largely dependent on oil, because of the difficulties of moving coal from north China where domestic sources are located, to the south where electricity demand is climbing rapidly, driven both by economic expansion and the building of new air-conditioned apartment blocks.

Plainly, there are questions about the sustainability of such heady rates of expansion, but it is worth noting that GDP growth has averaged 9.6% over the past decade, and that today's growth rates are not much more than half those achieved in the early 1990s.

Upward adjustments to Middle East demand growth result primarily from Iraq, due to military fuel use at higher-than-expected levels as a result of the security situation, and rapid growth in gasoline and diesel demand to run the large number of secondhand vehicles that have been imported from all around the region.

Non-OPEC Production

Latest estimates now suggest that year-on-year third-quarter growth was less than previously thought, at 1.2 mb/d compared with 1.6 mb/d as previously assessed. Fourth-quarter year-on-year growth is also lower, by 0.2 mb/d to 1.4 mb/d. The full year 2003 is now assessed at 0.1 mb/d lower, with a similar reduction for 2004. Nevertheless, despite reductions, third quarter output still advanced by 700,000 b/d from the second quarter, and the fourth quarter is expected to show a rise of 1.1 mb/d versus the third.

The reductions to both history and forecasts arise primarily in the North Sea and in North America. The U.K. sector of the North Sea has suffered a series of production problems this year and it is now apparent that these had a greater impact on the third quarter than previously estimated, while in Norway production has been running below expectations, thus reducing the estimate for next year. In North America, U.S. NGL and lower-48 production have disappointed of late, while in Canada scheduled and unscheduled maintenance has cut output.

On the other hand, Russian output has continued to exceed expectations, and continues to show year-on-year increases of around 850,000 b/d, although November was slightly down on October's record high. In addition, the expansion to the Baltic Pipeline System to Primorsk was completed ahead of schedule, in November, taking capacity on that line up from around 250,000 b/d to some 600,000 b/d, with further expansions due, to 840,000 b/d in the second quarter of 2004 and to 1.2 mb/d in 2005. At this stage, it is not clear whether the incremental export capacity will become a net addition or will partially substitute for other routes. Moreover, Primorsk is ice-prone during the winter, so additions to extra-FSU supply remain uncertain.

Significant additions are also expected next year from West Africa (around 0.4 mb/d), as production builds from new fields recently started in Chad and Equatorial Guinea, and as new fields start up in Angola. Lesser increases are expected in Latin America (Brazil and Ecuador).

OPEC Production

OPEC-10 production during October is estimated at 25.6 mb/d, an increase of some 0.2 mb/d from an upwardly revised September, as high prices encouraged extra output in advance of the cut scheduled for November 1. OPEC-10 production was thus some 0.2 mb/d over the prevailing quota. In addition, Iraq added around 0.2 mb/d, a smaller increase than over June to September. No estimates are yet available for November output, but indications are that few, if any, members implemented the scheduled cut, as high prices and robust demand from the Far East proved too great a temptation. Reports indicate that some Arabian Gulf members have indicated December volumes to customers that show little reduction on November, while we would not have expected non-Gulf members to be making cuts anyway.

Although Iraqi output rose by only 0.2 mb/d in October, interpreted by some as indicating the possible arrival of a plateau due to production and export capacity constraints, initial reports are that November showed another sharp increase, with total production at 2.0 mb/d and exports at 1.5 mb/d. This implies an increase of some 350,000 b/d versus October, the largest month-on-month increase yet achieved.

On December 4, OPEC ministers decided to roll over the current quotas and to meet again in Algiers on February 10.

	Quota Jun-Oct 2003	Production Oct 2003	Production vs. Quota	New quota From 1 Nov	Estimated Sustainable Capacity* (IEA Oct 03)	Spare Capacity
Algeria	0.811	1.15	0.34	0.782	1.20	0.05
Indonesia	1.317	1.00	-0.32	1.270	1.10	0.10
Iran	3.729	3.80	0.07	3.597	3.85	0.05
Kuwait	2.038	2.24	0.20	1.966	2.30	0.06
Libya	1.36	1.45	0.09	1.312	1.50	0.05
Nigeria	2.092	2.25	0.16	2.018	2.50	0.25
Qatar	0.658	0.74	0.08	0.635	0.80	0.06
Saudi Arabia**	8.256	8.51	0.25	7.963	9.50	0.99
UAE	2.217	2.22	0.00	2.138	2.40	0.18
Venezuela	2.923	2.24	-0.68	2.819	2.35	0.11
OPEC 10	**25.401**	**25.60**	**0.20**	**24.50**	**27.50**	**1.90**
Iraq		1.60			1.60	0.00
Total OPEC		**27.20**			**29.10**	**1.90**

* Capacity figures are levels achievable within 30 days and sustainable for 90 days.

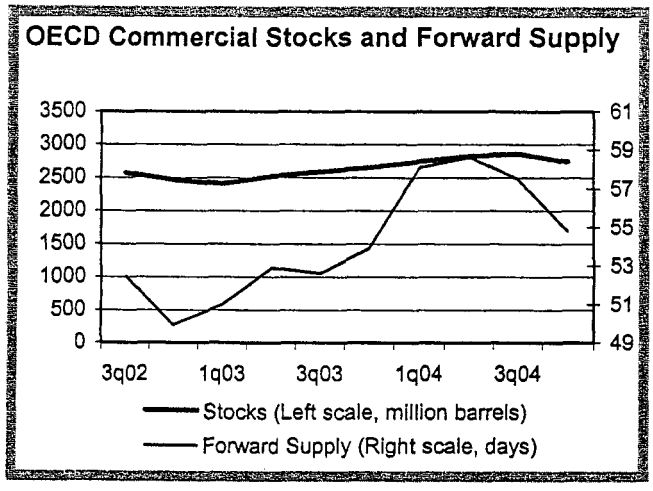
** Saudi Arabia can add a further 1 mb/d of capacity within 90 days

Market Balance

Total OECD Commercial Inventories

Latest data for total OECD commercial inventories show virtually no change versus last month's estimates for the first half of the year. The first report of end-third-quarter bottom-up stocks indicates a build of nearly 0.8 mb/d. In addition, government-held stocks in OECD regions also increased by around 160,000 b/d in the third quarter, mostly accounted for by the ongoing rise in the U.S. Strategic Petroleum Reserve (SPR), giving a total build in OECD regions of 0.9 mb/d. This compares with an estimated top-down global build of around 1.3 mb/d. OPEC output rose a little between the second and third quarters, so volumes of oil afloat will have risen slightly, thus implying perhaps 0.3-0.4 mb/d of stock build in non-OECD areas. This seems reasonable.

In terms of days' cover, the end-third-quarter number now works out to 52.6 days, a small reduction on the end-second-quarter number but, more crucially, significantly lower than previously expected. This is now explicable in terms of the latest third-quarter estimates of slightly weaker supply but stronger demand than previously allowed for, and resolves the discrepancy referred to last month.



Atlantic Basin Inventories

We commented last month that November might see crude stocks rising, falling, or staying flat, all depending on the extent of U.S. refiners' pre-booking of supplies, and on the volume of movements to the East. While we cannot know how much the two were connected, it is now clear that U.S. crude imports fell during November to average only 9.65 mb/d, 0.3 mb/d below October, while movements to the East continued at very high levels. Thus, as average U.S. refinery runs declined less than imports, stocks fell again, ending the month (weekly data to November 28) at 284 million bbls, thus again setting a record low for the month, the pattern of the first eight months of the year but briefly interrupted in September and October.

Gasoline stocks remain very low. At end-November they were at 197 million bbls, up 6 million bbls from end October. While this was not quite the lowest level of recent years in absolute terms, it was certainly the lowest, and by a large margin, in terms of days' cover because of the strength of recent demand. Building gasoline stocks, rather than distillate, is going to be the major concern of refiners over the winter, as recent experience plus strong economic recovery suggest next year could prove a "bumper" driving season.

Total distillate stocks moved sideways in November, falling by 1 million bbls to 131 million bbls, with the fall shared between heating oil and road diesel grades. Heating oil stocks remain below normal levels for the time of year, but should be able to rise further during December before beginning the normal seasonal decline in January. Stocks should now be adequate for the winter, but exceptionally cold weather could still cause problems. In this context it is pertinent to mention that jet fuel consumption has been rising again. While consumption is still well down on pre-September 11, 2001 levels, so are production and yields as refiners have switched out of kerosene manufacture into distillate. Stocks of kerosene have been very low since September 2001, but this has not been seen as a problem. If demand is beginning to recover, however, refiners will need to respond, and will have to switch some production back from distillate. Should cold weather and a

revival of kerosene demand coincide, which is unlikely but not impossible, the total middle distillate position could become quite tight.

European crude stocks rose slightly during October according to preliminary (Euroilstock) data. Stocks remain toward the upper end of the historical range. Good margins for the time of year, on the back of high product prices, despite high crude prices, are expected to have resulted in high rates of refinery output throughout during October and November. This will have had the effect of reducing the days' cover figure toward the middle of the historical range, lower than it was earlier in the year but still not a cause of concern.

Gasoline stocks remain close to the bottom of the historical range, although preliminary data indicate the end-October level rising above the levels of October 2002 and October 2001. This is the first time since October last year that gasoline stocks have exceeded year-earlier levels. In terms of days' cover, the end-September position appears high, and an estimate of the end-October position would indicate something higher still. Prices, which remain very high for the time of year, seem therefore to be responding to the absolute level rather than the adequacy of cover.

Gasoil stocks remain in the middle of the historical range, both in absolute and days' cover terms. Despite the U.S. appetite for Russian imports, and the increased movements out of the Rotterdam area as the Rhine River water levels have risen, stocks have been maintained at adequate levels, mostly by high refinery production—gasoil yields have been either at or close to record levels this year.

Prospects for the Global Balance

OPEC ministers' decision to make no immediate changes to quotas but to meet again on February 10 is both an obvious and a strange one. Obvious, in that while prices are so high, with the OPEC basket price mostly above the top of its band, it would have been politically very difficult to make a cut to supply, even though ministers are tending to argue that high prices reflect market uncertainty and tight products markets rather than a tight crude position. Strange in that they have deferred the decision by two months, rather than one month, at a critical time during which prices could face severe downward pressure.

It now looks as if OPEC-10 output will scarcely fall at all during the fourth quarter, as members cash in on high prices and strong Chinese demand. This policy could well continue into January. In addition, despite the ongoing security problems in Iraq, output continues to expand at a faster rate than most have expected. Export infrastructure could become a constraint during the second quarter of next year, but probably not before then. Total OPEC output therefore could be 1 mb/d higher in the fourth quarter than in the third, whereas we had previously only assumed a rise of 0.1 mb/d. In addition, first-quarter 2004 output will now also be

higher than we had previously assumed, as no cut in quotas is now likely to be effective before March 1.

Upward amendments to estimates of demand and small downward estimates to supply had made the balance look much less oversupplied than appeared to be the case a month ago. OPEC's latest decision, however, has changed everything again. OPEC ministers are very concerned about a fall in prices in the second quarter, but by deciding to continue producing at current levels probably until February, they are potentially provoking an even greater price problem through oversupply.

Total OECD days' cover looks set to rise to 54 days by the end of the fourth quarter. If production from the OPEC-10 continues at current levels through February while Iraq's output steadily increases, a massive cut is going to be needed at the February meeting to keep stock cover levels from rising to very high levels indeed. OPEC has never been very good at making very large cuts in one go, however, because of the difficulties of agreeing on the split. To illustrate the problems facing OPEC, for this report we have assumed a cut of 2.5 mb/d from the OPEC-10 effective March 1 (bigger than any single cut the cartel has made in recent years), and a further cut of 1.5 mb/d effective May 1. This would imply OPEC-10 output of less than 22 mb/d by the end of the second quarter, which in turn probably implies Saudi Arabian output not much above 5 mb/d, possibly less than immediately before the invasion of Kuwait in 1990. Nevertheless, OECD stocks still look close to 58 days' cover through the first half of next year. At this stage, we have not modified the balance for the second half of next year.

Crude Price Forecast

Base Case

Although a plunge in prices may not now occur as soon as previously projected, latest developments seem to make a fall even more inevitable due to rising stocks. Paradoxically, however, these developments may ultimately serve to put a slightly higher floor under crude prices than previously assumed, if rising stocks and rapidly falling prices emphasize the need to take drastic action and promote a willingness to make deeper cuts than might otherwise have been considered acceptable. Saudi Arabia has continued to defend the principle of $25/bbl so steadfastly that it would now be almost impossible for it not to defend at least the $22/bbl floor, even if that required the kingdom itself to make much deeper cuts than it has had to contemplate since 1985-86. Hence, we are now showing prices sliding over December and January and then falling more sharply in February and March as the potential stock overhang of the second quarter looms more threateningly. However, we have raised the bottom of the trough a little.

Short-Term Marker Crude Price Forecast (Dollars per Barrel)

	Nov	Dec	Jan	Feb	Mar	Apr	May

WTI	31.06	30.00	29.00	27.25	25.00	23.50	24.25
Brent	28.73	28.00	27.00	25.00	23.00	21.75	22.50

Rarely in recent years has the outlook been so difficult to forecast. Supply/demand analysis points to a major overhang, and possibly prices below $20/bbl. But non-OPEC disappointments and strong Chinese demand could quickly, and drastically, change this outlook. OPEC's determination to support prices and recent history make it difficult to imagine that action would not be taken to defend prices if they began to plummet. But OPEC's all-too-often natural response to falling prices is not to band together and agree to deep cuts with improved compliance, but to act separately and individually and seek to bolster individual revenues by increasing rather than reducing output. We find it difficult to conceive that the balance could change by so much as to prevent stocks building to high levels during the first quarter, and thus we continue to project a price decline as a base case. Nevertheless, we are acknowledging the presence of the other major factors by raising the low point. A different weighting of the various factors could, however, produce alternative outcomes.

Alternative Cases

High-price scenario: The high price scenario could develop as a result of one or several of the key assumptions in the base case proving wrong, including:

- Stronger demand growth, possibly through more robust economic recovery, surging Chinese demand, a cold winter, or special factors such as high gas prices in the United States or continued nuclear problems in Japan.

- In the United States, strong product demand and difficulties in obtaining crude in competition with Asia continue to hinder a crude stock build.

- Delays and disappointments in non-OPEC production and willingness, currently unexpected, on the part of non-OPEC producers to cut output or restrain increases and share in supporting price.

- Renewed problems and sabotage in the south of Iraq, as well as the north, slowing or even reversing the build up of production, as well as renewed turmoil and production interruptions in Venezuela and Nigeria.

- Better-than-expected OPEC discipline and greater willingness to make the deep cuts necessary, including those members with new capacity being prepared to defer start-ups. This could possibly be accompanied by an upward revision to the price band, as members decide to defend prices and accept the inevitable further sacrifices in market share.

In this case, stocks would build more slowly, and if markets continue to perceive tightness because their attention is focused on the one component in stocks that is proving slow to build—U.S. crude—then prices might remain high long enough for OPEC to take the necessary measures to bring supply and demand into better balance.

Low-price scenario: A low price scenario could result from:

- OPEC indiscipline and very public disagreements over quotas, and unwillingness to make cuts without non-OPEC support, which is not forthcoming.
- Weaker demand as the global economy fails to achieve the projected recovery, partly as response to recent high oil prices, and/or winter weather is very mild.
- Reduced Chinese buying of (heavy) crude after January 1 and buying of fuel oil instead, with stocks of other products built during the fourth quarter.
- More rapid buildup of non-OPEC production as new fields exceed expectations and as Russia finds creative ways to bypass the bottleneck of the pipeline system, as it did this year.
- A rapid change in market perceptions, probably as a result of lower refinery runs in the United States allowing crude stocks to build, thereby allowing market attention to focus on the underlying buildup of global stocks.
- A change of heart on the part of the U.S. administration, permitting a release of stock from the SPR, or more likely a decision to halt the build temporarily.

In this situation, market perceptions could change rapidly and prices fall sharply, although probably not before late January, and could remain low through much of the first half of next year, possibly even through the full year. OPEC members would find such a time very painful, but without the support of non-OPEC producers, their scope to change things will be very limited.

Although in this low-price scenario we have shown WTI falling to $20/bbl in the second quarter, implying an OPEC basket price around $18/bbl, there is still an outside possibility that prices could collapse totally. If OPEC discipline breaks down completely and members once again demonstrate that they have failed to learn the lessons of history and increase output to try to maintain revenue in the face of a falling price, then a repeat of 1998/99, albeit unlikely, cannot be totally ruled out.

U.S. Product Prices

Gasoline

November gasoline demand continued the trend of earlier months, posting a strong year-on-year gain of 1.75%, or around 150,000 b/d according to weekly data. Returning to the pre-2001 pattern, November consumption was down on October, but December is expected to show a rise on November, which would bring annual demand close to 9 mb/d, an increase of a little over 100,000 b/d on last year. This would be only half the annual increase recorded last year, since the earlier part of this year showed little rise. Consumption next year is expected to climb strongly on the back of robust economic growth generally and consumer spending in particular.

Record-high November refinery runs contributed to near-record refinery output of gasoline at 8.68 mb/d (marginally lower than last year's all-time high of 8.74 mb/d when the gasoline yield was 1% higher). Imports were also high, so stocks rose some 6 million barrels to 197 million barrels, still well below the average of the previous five years. Expected high consumption levels in coming months pull down the days' cover figure, moreover, and this remains at record low levels, as it has every month since April. Although at this time of year refiners ought to be able to focus on heating oil manufacture, it is gasoline that is of greatest concern.

According to our estimates, even if refinery runs over December and January come in well above the levels of the past couple of years, and both gasoline yields and imports are high, still gasoline stocks are unlikely to rise above 200 million barrels before February. Even then, days' cover figures would most likely continue at record lows. Moreover, low gasoline stocks and high prices in Europe, plus high freight rates, mean that the arbitrage may not often be open. Added to this are the complicating effects of new specifications as the New York Harbor market adjusts to New York and Connecticut's banning of MTBE from January 1 and as new lower sulfur limits are introduced nationally.

Gasoline prices seem set to continue both high and volatile at least till early summer. Three of the past four years have seen price spikes by April, resulting in ultra-high early spring prices in 2000, 2001, and 2003. While we are not currently projecting a repeat of such a surge, the position this time looks as tight as any of those years, making a repeat highly possible. The height of such price spikes, however, has more to do with market sentiment than fundamentals, and is thus effectively impossible to call in advance.

Distillate

Early winter total distillate demand has been moderately high despite relatively mild temperatures so far (October cooler than usual, November warmer). Weekly data suggest total demand in November was nevertheless 4.0 mb/d, a new record high for the month. Total distillate stocks are in the middle of the five-year range,

at 131 million barrels at the end of November, but heating oil stocks are toward the lower end of the range while diesel is at close to record highs. Such stock levels should be adequate for the winter provided the weather is normal, and provided yields and imports can be kept high. In theory, this should not be as difficult as for gasoline, since European gasoil stocks are much higher than those of gasoline and globally there is still a structural middle distillate surplus. Nevertheless, European middle distillate prices have been very high recently. Russian exports, moreover, remained low in November and cannot be safely assumed to make up U.S. shortages in the same way as last year.

Hence, we continue to expect prices at the top end of the historical range relative to crude for both diesel and distillate. Should the weather turn colder than usual or Russian Baltic exports be unusually hindered by ice, as last winter, the whole Atlantic Basin middle distillate position could become quite tight and prices could both spike and average much higher. Another factor that could exacerbate the situation is the recovery of kerosene demand that has been seen since the early summer. If rising demand forces refiners to focus on rebuilding kerosene stocks, it would be at the expense of distillate manufacture. European kerosene prices have recently been approaching new record highs relative to crude, so for a time uncommitted cargoes are most likely to head for Europe, making it more difficult for the United States to attract imports until prices moderate.

Residual Fuel

With storage nearing peak levels and a mild winter so far, natural gas prices have been moderate, so resid consumption has remained low for the past three months, at around 700,000 b/d. With the need to build stocks of lighter products, refiners have taken advantage of relatively weak resid demand and minimized resid output, which has been plumbing new lows; the resid yield fell to 3.7% in November. With no indications yet that the winter will be other than normal, resid demand is expected to remain relatively weak, although some substitution for gas in power stations is possible.

Crude supply developments could affect relative price among the various fuel oil grades. If producers of light low-sulfur crudes, notably Nigeria and Algeria, continue to raise output, regardless of quotas, then many of those extra barrels will find their way to the United States as both their high gasoline yields and low-sulfur content will make them especially attractive to U.S. refiners in current circumstances. Both countries also produce low-sulfur fuel oil, albeit in limited quantities, so could increase the supply of 0.3%S material. On the other hand, if OPEC makes further cuts to output in February, and in particular if Saudi Arabia is forced to make large cuts, then it may choose to let the cuts fall disproportionately on the heavier, lower netback, grades. This could hit the supply both of feedstock to Gulf Coast cokers and of high-sulfur fuel oil. At this stage, because of all the uncertainty over possible maneuverings within OPEC, we have not sought to reflect the potential impact of such developments onto fuel oil prices.

Broadly, fuel oil prices are expected to follow seasonal patterns, with prices relative to crude weakening in the first quarter but then recovering a little into the middle of the year as air-conditioning demand for electricity kicks in.

Long-term Outlook

Our long-term forecast depends on steadily increasing global demand from economic expansion, coupled with OPEC's keeping oil markets adequately, but not over, supplied. Through 2025, the Global Insight economic forecast projects global growth of approximately 3% annually. This is an essential assumption in the oil price forecast, as economic growth directly influences oil demand. Global oil demand is projected to grow at around 2% annually. Principal demand growth areas coincide with those expected to grow robustly in economic terms, namely, Asia and Latin America. It should be noted that a key underlying assumption in the demand forecasts is that a global emissions-reduction pact is not implemented within the forecast period. If such an agreement were to be reached, oil demand growth would likely be restrained, thereby producing a lower price path than currently projected.

The relatively strong global demand for energy, however, will not necessarily translate into higher prices, as growing demand is expected to be met by commensurate increases in production. The recent increase in oil prices will encourage OPEC and non-OPEC producers to increase their production capacity. OPEC's spare capacity is approximately 5 million b/d as a result production cuts, while the high price environment over the past few years has encouraged drilling by non-OPEC producers. Recent advancements in oil exploration and extraction technology should ensure that production capacity matches demand growth, even as global demand rises above 100 million b/d. However, steady prices will be required to fund the massive capital expenditures that will be necessary in order to extract and transport the oil.

In the base-case scenario, non-OPEC supply is seen as growing by slightly less than 2% per year through 2020, as production expansion in the Caspian, Russia, offshore West Africa, and offshore Brazil offset declines in the mature areas such as the United States and the North Sea. OPEC production is estimated to increase by about 2.5% per year over the same period. It is expected that the OPEC members with the largest reserves will have the greatest production gains—notably, Saudi Arabia, Iran, and Iraq—assuming sanctions eventually cease. Under the base-case price scenario, the average spot price of WTI should grow to above $27 by 2025 (in real constant 2002 dollars).

NATURAL GAS OUTLOOK

Key Issues

U.S. natural gas markets are facing an imbalance in supply and demand that can only be resolved by significantly higher prices than existed in the past decade. If trends of the past year continue, conventional natural gas production will at best remain flat and will most likely decline in both the United States and Canada. With demand for natural gas increasing across most sectors, higher prices will result to balance the market. In most cases, it will be energy intensive industries that reduce consumption of gas. Smaller adjustments will take place in other sectors.

Many new supply sources will be required to meet demand. The size and timing of these new supply sources help to define the likely path of natural gas prices. The timing of Alaskan gas supplies is a key assumption in the forecast, because it will come in a very large increment and thus require a large scale reordering of the gas market at the time it enters the market. LNG is likely to be the marginal source of supply for the United States over the forecast period. Conventional supply is not expected to grow. Alaska and Arctic gas come in very large and discrete increments. Thus in most years, growth in natural gas demand will have to be met by increases in LNG imports. This is not easy to accomplish. Significant increases in LNG imports require long lead times to arrange liquefaction plants, tankers and terminals. Further, it is not profitable to operate LNG facilities at low levels of utilization. Once committed, LNG facilities are likely to operate above 90% of capacity, leaving little room to swing with markets. Given long lead times, LNG projects will reflect prior expectations of the supply and demand balance that may or may not be realized.

Whether expectations of the supply and demand balance are realized or not will have a significant impact on prices. If expectations are realized in a timely manner, then supply and demand will remain close to balance and prices will tend to reflect long-run marginal costs. If natural gas consumers expand based upon specific expectations for supply developments, then imbalances could occur if such expectations are not realized.

Key issues for the long-term supply forecast are where will the gas come from and what will it cost. At present, 85% of U.S. gas is from the Lower 48 states—down from 97% in 1986. Fields in conventional areas are maturing. New supplies will have to come from unconventional sources, such as the deep water, coalbed methane, liquefied natural gas (LNG), deep drilling, Mackenzie Delta, and Alaska. Although there is substantial uncertainty about what these supplies will cost, the supply cost for the largest incremental supplies of natural gas available to the United States is expected to exceed $3 per million Btu.

On the consumption side, three questions exist: How fast will power generation grow? How much new generation will be gas? Will gas-intensive industries move offshore? Initiatives by the Bush administration to weaken the interpretation of the Clean Air Act's new source review requirements could cause a substantial increase in coal generation and dampen the growth in gas consumption. On the other hand, the potential for limits on carbon emissions or tightening of environmental regulations could severely limit the growth in coal generation. Since gas is the marginal fuel for power generation, changes in the share and size of the generation market will have a major impact on gas consumption.

Strong growth in natural gas consumption for power generation, 4.8% over the 2002 to 2007 period, is projected to be the major driver of natural gas consumption. Industrial consumption growth will average only 0.2% per year during these five years. High natural gas prices will cause gas-intensive industries to be located outside North America and cause industries to improve their energy efficiency. Total natural gas consumption is expected to grow at only 1.6% per year to 2007. The fact that gas is on the margin for power generation also means natural gas consumption is likely to be more volatile. This volatile consumption in conjunction with a just-in-time inventory approach to natural gas supply make it likely that natural gas price volatility will continue to be high in the future.

Natural Gas Prices

Natural gas prices have gone in two different directions in October, with the future market spiraling upwards towards $6.00 before falling towards cash market values in the $4.50 range. The most likely explanation for this movement is the closing out of short positions that were based on a more pessimistic view on storage than the now near-normal levels in October. Global Insight expects that end-October storage will reach 3.1 trillion cubic feet (Tcf) in the EIA weekly survey, with ultimate revisions to be above 3.15 Tcf in the monthly report. Storage should be above year-ago levels by November. Consequently, the Global Insight price forecast for November is about $4.50 for Henry Hub, though December is expected to be above $5.00.

Degree-days are the wild card for price and storage projections every winter. Weather forecasts are mixed for this winter, with the National Oceanic and Atmospheric Administration (NOAA) projecting a warmer-than-normal southwest, but not making a call for any other region. NOAA forecasts whether it is probable that temperatures will depart from normal. When there is no clear indication of either warmer or colder temperatures, then average or normal temperatures are most likely. Other forecasts, such as the Old Farmers Almanac, suggest that the Northeast will be colder than normal for the first half of winter, and then warmer than normal for the second half. Several weather forecasting firms are expecting a warmer-than-normal winter. One area of consensus is a warmer-than-normal west coast winter, with above-average precipitation in the Pacific North West.

Normal weather this winter would result in heating degree-days about 2% less than last winter. Global Insight customarily uses normal weather to forecast prices, which appears to be a reasonable assumption for 2003–04. Global Insight assumes a normal winter, with the caveat that winter weather is difficult to forecast, but often surprises.

Storage draw this winter will be large. Last winter, even though degree-days were near normal, storage draw was a record of nearly 2.4 Tcf from October 31 to March 31. This coming winter, storage draw of 2.2 Tcf is expected. By comparison, the 2001–02 winter had 5% warmer temperatures and a storage draw of only 1.6 Tcf. The high storage draw is required to accommodate power generation consumption of natural gas during the peak winter season. Electricity demand is expected to increase as a result of the economic forecast of near 4% growth. Thus, the forecast of prices over $5 from December 2003 to March 2004 reflects normal weather, a strong economic rebound, and a rapid drawdown of working gas in storage.

Supply and demand trends are mixed. The supply and demand balance remains bearish, as indicated by the weekly EIA storage reports. Global Insight calculates a 3–4-billion-cubic-feet-per-day (Bcfd) loosening of the balance, compared with last year. Part of the change of the supply and demand balance is related to demand destruction from the high prices last spring.

Supply trends have turned more positive for the second half of 2003. State production trends show a 0.5–1.2-Bcfd increase in natural gas production for 2003, most from Wyoming. Also, LNG imports have reached the 1.7-Bcfd level in the third quarter, up a full 1 Bcfd from 2002 levels. However, imports from Canada are down.

The supply situation for 2004 appears tight. Canadian supply for 2004 is expected to continue to decrease by Trans Canada Pipelines. TCPL mainline volumes are expected to decrease by 0.3 to 1.0 Bcfd during 2004 which implies that pipeline imports could be pressured down. Part of the supply increase in 2003 came from the Gulf of Mexico. However, the reported increase in Gulf-of-Mexico production is still below 2001 levels, though above those of 2002. Also, offshore production data are preliminary. Finally, LNG imports have little room left to climb until new sources are constructed. Thus, projected demand growth for 2004 will be constrained by the availability of gas supply.

Demand is expected to be down by about 1 Bcfd in 2003. Thus, the fundamentals suggest about a 2-Bcfd increase in supply and a 1-Bcfd decrease in demand for a 3-Bcfd looser market in 2003. However, most of this relative change was caused by high prices, and prices continue to be higher in 2003 than in 2002.

The explanation for higher prices during a period of a loosening market is that the supply and demand indicator is reflecting necessary rebuilding of storage and the demand reduction only occurred because of demand destruction associated with

high prices. Using relative storage changes as a gauge of market tightness is an interesting but inexact indicator of underlying market fundamentals.

Short-Term Prices

Natural gas prices reflect supply and demand balances. For 2003, demand was constrained by high prices. Thus while supply has been tight, storage was rebuilt by the reduction in demand. For 2004, a strong economy and decreasing imports of Canadian gas imply a continued high prices though likely a $1 lower than those that prevailed during 2003. It is still possible that natural gas markets will tighten this winter. With normal weather and relatively high storage levels, storage withdrawals should be less than last year's, even with strong economic growth. Global Insight expects that storage withdrawals will be below last year's rate by about 1 to 2 billion cubic feet per day (Bcfd) on a weather-adjusted basis. This is a slightly looser market than last winter, but a tighter market than the five-year average.

Demand indicators are turning positive. The economy is expected to grow strongly in 2004, with a recovery already underway. Energy-intensive industry recovers with the overall economy, but a t a slower rate. Electricity demand growth of 2% is forecast for 2004, though recent trends, reported by the Edison Electric Institute, show a 1% decline in power generation in the second quarter and a flat power generation in the third quarter of 2003.

Natural gas demand for 2003 is expected to be about 22.2 trillion cubic feet (Tcf), down from 22.5 Tcf in 2002. There have been several revisions of demand data for 2003, while 2002 demand has been slightly revised upwards. The overall effect of the demand revisions are to lower 2003 demand. Energy-intensive industrial production is down for 2003. However, a strong economic recovery for 2004 pushes demand up by 2%.

For 2003, the closure of several ethylene plants and numerous ammonia plants will decrease industrial natural gas demand this year. High prices and weak industrial production indicate lower industrial demand. A detailed forecast by industry suggests that demand decreases will be broad based as well. Production of major petrochemicals was reported as up by 1% in the second quarter of 2003. Thus, most of the reduction in gas demand occurs in the industrial sector in the Global Insight forecast.

Output of the ammonia and methanol industries is down by over one-third in 2003. These industries normally consume over 2 billion cubic feet per day (Bcfd) of natural gas, including feedstock. About 4 ammonia plants were reported to resume production in October. Thus the demand for natural gas may be increasing and the output of energy intensive industry increasing as forecast.

Oil demand did not increase after June, despite the high gas prices. Thus, some industrial and electric power demand for natural gas may have returned from fuel

oil during this period. There was over 4 Bcfd of fuel oil demand increase in January 2003, indicating significant interfuel substitution.

Electricity production is reported to be up by about 1.6% year to date by the Edison Electric Institute, with all of the increase in the first quarter of 2003. Thus, power generation use of natural gas is also likely to be flat or decreasing for 2003, despite all of the new gas units coming on-line.

Residential and commercial demand were very high in the first quarter of 2003, and could show increases for the year as a result. Demand during the rest of the year is likely to trail year-ago levels, reflecting high prices and weak economic growth. Overall, it will be a close match between 2003 and 2002 demand levels, with weather-related gains in the first quarter of 2003 being offset by reductions in industrial demand during the remainder of the year.

U.S. production is expected to increase in 2004, and in fact is likely to be increasing in 2003. Also, LNG imports will rise from 0.7 Bcfd in 2002 to 1.6 Bcfd in 2003 and then increase again to over 2 Bcfd for 2004. Offsetting part of the supply growth is a decline in gas imports from Canada. TCPL expects that its mainline volumes will be from 0.3 Bcfd to 1.0 Bcfd below 2003 levels next year. Canadian production fell 0.5 Bcfd in 2003, and is expected to be flat or down in 2004.

The state production report, compiled by the EIA, shows natural gas production rising about 2%, or 0.4 trillion cubic feet at an annual rate. Also, the rate of decrease, reported via the compilation of company data, is faltering. Thus, natural gas production is increasingly pointing to an increase for 2003. Wyoming and the Gulf of Mexico are the major sources of increases in the EIA data.

Much of the increase is from Wyoming and predates the Kern River expansion. Thus, Wyoming production could be up by over 1 billion cubic feet per day (Bcfd) in 2003. With a full year of Kern River and the new Northwest Pipeline Rocky Mountain expansion, Wyoming production could grow by a further 0.5 Bcfd, to 1.0 Bcfd in 2004.

Wyoming production is up by 0.8 Bcfd for the first quarter of 2003, reflecting, in part, the pent-up supply from coal bed methane and development drilling in the foothills that depressed prices last summer. A cold winter and startup of the Trailblazer pipeline contributed to the price recovery and production increase. Wyoming's production increase will be further augmented in the reports starting in May 2003 that reflect the expansion of Kern River pipeline.

The Minerals Management Service provides a preliminary estimate of offshore production to the EIA. Final data for the offshore are only available through early 2002. Thus, there can be substantial revisions. However, data for the first quarter of 2003 show an increase of about 0.9 Bcfd due partly to the deep trough that production fell to in 2002. From 14 Bcfd for 2001, production fell to 12.2 Bcf for the first quarter of 2002, and is now reported at 13.1 Bcfd for 2003. The timing of Canyon Express (0.5 Bcfd) in late 2002 and Na Kika (0.3 Bcfd) and other projects

(0.3–0.4 Bcfd) in 2003 could explain the increase in 2003. Whether the offshore production increase is sustainable is still uncertain.

The production forecast has been revised upwards to show an increase in 2003 and 2004. Company reports still show a decrease in production for 2003. It is possible that revisions in state and MMS data will lower production estimates for 2003. There are no big projects expected in 2004 that will have the impact of the Kern River Expansion in 2003. The next big Rocky Mountain expansion will be in 2005 with the Cheyenne pipeline to Kansa with capacity of over 0.7 Bcfd.

The natural gas industry exceeds $100 billion in size and is as complex in its structure and regulation as any other industry. Like a giant ship at sea, turning the industry to a new direction takes time. Imbalance between supply and demand is not going to disappear quickly. With supply expected to decline while demand is influenced by the economic recovery, gas prices will be volatile. During March 2003, the volatility index for Henry Hub prices reached 300%, compared with 100% during the winter of 2000–01. Thus, day-to-day price changes this year, especially during extreme weather, could reach unprecedented levels of volatility.

Long-Term Prices

Long-term natural gas prices will be driven by the interacting forces of the marginal cost of increasing supply and the demand response to price changes. The key driver will be the supply costs of the marginal source. Supply costs are based upon analysis of recent plays and also the relationship of drilling activity to price changes and are expressed in 2002 dollars per million Btu. In 2002, supply costs were thought to be in the $2 to $4 range for U.S. natural gas. It is evident that supply costs have increased in the last year and will likely increase further. Despite high prices in existence for most of the past three years, natural gas production has declined. In general, prices at which total U.S. drilling activity and production decline are below the supply cost. During 2001, prices that average above $4 were sufficient to increase drilling activity and U.S. production. In 2002, a price of $3.20 for Henry Hub was insufficient to sustain production at 2001 levels. So far in 2003, prices over $5 have increased drilling activity but have only been associated with production increases in the Rocky Mountains. Thus the estimates of domestic supply costs for 2003 are significantly higher than in 2002. The supply costs for Alaskan gas and LNG, though based upon recent information, are comparable to previous estimates. Alaskan supply costs reflect pipeline tariffs for a $15 to $17 billion project with prices delivered to Chicago of $3.20 to $4.00. LNG supply costs remain in the $2.85 to $3.50 range for the Gulf Coast and $3 to $3.50 for the West Coast. These supply costs are a measure of the minimum long-term price at the exit of an LNG terminal required to justify development of the entire value chain. Supply costs for the Canadian Arctic and East Coast Canada are less certain, because of lack of information.

In this forecast, it is LNG and Arctic gas that provide for growth while domestic production is expected to remain below 20 trillion cubic feet (tcf) for an extended

period before eventually decreasing. Because Arctic gas will enter the market in large, discrete amounts, LNG will be on the margin for most of the forecast period and will thus have a very important role in setting prices. In a theoretical long-run equilibrium situation, natural gas prices will tend to be set by the long run cost of marginal supplies. It is more likely, however, that long-run prices will be set by marginal costs plus a premium. Two elements of the market are likely to keep the forecast prices above these long run marginal costs. First, natural gas markets operate at a high frequency with daily and monthly transactions. Annual natural gas prices are an average of daily and monthly prices that include many peaks and troughs. There is a pronounced seasonality of natural gas prices that reflects weather patterns and the cost of storage. Also, prices can peak strongly during periods of cold winter weather leading to low storage or during summer heat waves. Troughs in prices often occur in the reverse circumstances. Second, the expected rapid growth in the need for additional LNG imports means that supply is likely to be chronically capacity-limited.

Over the course of a year, supply and demand must balance, though because of storage, this is not a constraint for any particular day or month. Thus during a period of general supply tightness, the average annual price would reflect high prices for seasonal peaks, while during years of slack supply prices could be driven down to the supply cost. LNG supply costs represent a normal return when operating at close to 100% of capacity. Thus LNG supply costs are a measure of the lower price in the market rather than the average price. That LNG will be on the margin doesn't mean that seasonal price variations will disappear. Rather, most LNG producers will be able to obtain some rent in the U.S. market from the occasional seasonal peaks

Conditions That Could Produce Lower or Higher Long-Term Prices: Natural gas prices could be sustained at a higher level than in our baseline projection in several ways. The most likely source of higher prices would be more rapid deterioration in conventional U.S. gas supply and thus even greater requirements for LNG imports. Since a period of from three to eight years is necessary to plan and construct an LNG chain, a more rapid deterioration of supply would be difficult to offset in a timely manner. Higher prices could also result from unmet expectations for major new supply increases from Alaska, the Arctic and eastern Canada. For instance, if the Alaskan pipeline project, which would add about 4.5 Bcfd of incremental supply when completed, were initiated but delayed further, there could be a sustained period of unmet demand and high prices. Finally, higher prices could be caused by more rapid demand growth resulting from a more dismal outlook for power generation from coal, nuclear, or renewable energy.

Alternatively, long-term prices could be lower than projected if increases in access to U.S. resources and more favorable supply costs increase the domestic production of natural gas. Prices could also be weakened by lower demand trends resulting from more aggressive use of nuclear, coal and alternative power sources or from large-scale efficiency programs in the residential and commercial sectors.

In these cases, less LNG supply would be required, so if LNG projects were developed along the lines of the baseline projection, an oversupply situation could arise.

With the worldwide LNG market likely to continue to expand, it is worthwhile to explore the question of whether a natural gas cartel could effectively control that market in the manner than OPEC manages the world oil market. Such a cartel is implausible in Global Insight's view. A natural gas cartel would require close coordination with OPEC so that oil and gas prices were non-competing while also including many large non-OPEC producers who heretofore have not been willing to coordinate oil supplies. Natural gas markets tend to be continental in nature and feature pipeline versus LNG competition such as in Europe. The major players in European natural gas markets are Russia and Norway, who have systematically increased oil production as OPEC members have reduced supplies to support prices. Thus coordinating OPEC oil policy with natural gas producers who have resisted coordination of oil supply is very unlikely.

While a world crude oil cartel has existed for nearly 40 years, it consists of mostly Middle East oil producers that have much in common and are very dependent on oil revenues for national finances. Natural gas producers are a much more eclectic group. Russia has the largest gas reserves in the world and is a major exporter to Europe competing with Norway and Algeria in this market. Russia has about 1,700 tcf of gas reserves, equivalent to over 80 years of U.S. consumption. Qatar and Iran rank second to Russia in gas reserves at about an equivalent to 40 years of U.S. consumption. Other members of OPEC such as Indonesia, Nigeria and the UAE have LNG projects. As a group, OPEC nations supply over 80% of LNG production, but only about 30% of world gas trade including pipelines. The competition of pipeline gas with LNG is a very significant obstacle to a natural gas cartel. Also, there are many aspiring entrants to the LNG market such as Trinidad, Egypt, Equatorial Guinea, Russia, Norway, and Bolivia, who are not members of OPEC.

Natural Gas Demand

Near-Term Demand Is Being Restrained By High Prices: Natural gas demand is expected to be lower this year than last a consequence of higher prices resulting from the decline in supply and rebuild of storage. Natural gas demand growth has averaged about 2% per year growth in the past decade. This year, demand will be constrained by the availability of supply. With U.S. production declining and imports from Canada also down, demand will have to decrease by an equivalent amount: about 2 billion cubic feet per day (Bcfd). Further adjustments will have to be made for rebuilding working gas in storage. If year-end working gas reaches 2.3 trillion cubic feet (tcf) as in 2002, the required change in demand will approximately equal the change in supply on an annual basis. Since demand growth was substantial during the cold first quarter, the decrease in demand will be concentrated in the second half of 2003. In 2003, electricity demand is also following this pattern with strong weather-driven growth early in the year followed by

minimal year-over-year growth in the second half of this year, when projected normal summer and winter temperatures would be considerably milder than temperatures a year ago.

The power sector will be a wild card in the demand for gas. With an enormous increase in natural gas-fired generating capacity added in 2001–03, power generation use of natural gas should soar. Also, tightening nitrogen oxide emission standards will increase the demand for natural gas. With high gas prices this year, though, some switching from gas to fuel oil at dual-fired generating stations is likely to offset some of the demand increase coming from new gas-based plants. Inter-fuel substitution had a potential of 9 Bcfd in the 1990s before the retirement or conversion of old oil plants. Many of the new natural gas plants cannot or will not use fuel oil. Thus inter-fuel substitution capability is less than one half of what it was. Also, the supply of distillate fuel oil is limited with low inventories and dependence upon imports. With natural gas prices higher than distillate fuel oil prices, most of those who can use fuel oil likely are already doing so. Sudden increases in fuel oil demand are one way to measure inter-fuel substitution. For several winter months in 2003, fuel oil demand was the equivalent of about 3 Bcfd ahead of year-ago trends. Even though part of the increase is related to economic growth and a cold winter, there must be significant substitution of fuel oil for natural gas. This rate of increase in fuel oil demand is probably close to the maximum of displacement of natural gas by oil, at least without further investment and regulatory relief. Many power plants are limited as to the number of days that they can burn oil. Also, restrictions on NOx emission, which are being tightened this summer, will also reduce the potential for interfuel substitution.

Industrial natural gas demand is suffering. Even with a modest economic recovery, output of energy intensive industry is declining for the second and third quarters of 2003. The closure of fertilizer plants is one indication of demand destruction and the constraints that high gas prices place on industrial output. Industrial natural gas consumption should decrease in 2003 because of demand destruction and inter-fuel substitution. Residential and commercial demand will not experience the recent high prices until rate adjustments and cost passthroughs occur, most prominently in the second half of 2003.

Long-Term Demand Growth Is Expected In All Sectors. In the long term, natural gas demand growth is expected to occur in every sector. Core sectors already have a high market share of natural gas for such uses as space heating, water heating, cooking and clothes drying. The main competitor to natural gas in the core sectors is electricity. Industrial sector natural gas demand has more competition as the boiler fuel market can be met from sources as diverse as byproduct fuels, coal and petroleum. Also, long-term price driven demand destruction can be divided into several stages:

- Conservation: Initial reaction to prices including temporary changes in energy usage

- Efficiency: Longer term adjustment to prices including permanent changes in energy usage
- Shutdown: Temporary or permanent reduction in output
- Relocation or Displacement: New investment in energy intensive industries in overseas location and/or importation of energy intensive components

The chemical industry is at the forefront of demand destruction in the current outlook. High natural gas prices are not reflected in chemical product prices. While the chemical industry has requested changes to U.S. domestic energy policies, these are difficult to enact as they lead to higher costs to other segments of industry and to gas consumers. For example, a restriction on the use of ethane as a fuel would limit ethane to use in ethylene plants but would result in a lower value for natural gas plant output and possibly higher prices of natural gas.

Requests that renewed priority be given to energy conservation and improvements in efficiency may have a more sympathetic audience among state regulators. State governments regulate local distribution companies and can control the amount of spending on efficiency programs. The federal government can mandate efficiency standards for common appliances that, over time, could have substantial impact on energy demand—although standards for most of the major appliances already exist. The chemical industry can also pursue improvements in its own processing. In the past, many conservation and demand side measures have been adopted with limited results. Conservation efforts are usually initiated by periods of high prices and are seldom sustained during periods of low prices. Efficiency improvements are long lead-time items and require substantial investment by consumers and suppliers.

Industrial Sector Adjustments to High Gas Prices: Most energy-intensive U.S. industries face competitive world markets and have difficulty passing through high costs of natural gas. Adaptive strategies include importing the most energy intensive components, investing in energy efficiency, increasing use of waste or scrap materials that require less energy inputs and switching production to higher valued items.

In the current outlook, new ethylene plants are expected to be based on naphtha such that the supply of both ethylene and propylene is increased. The off-gas stream from the naphtha crackers is sufficient to fuel the plants and thus little natural gas is required as fuel for other than ethane based plants. However, naphtha is a high-cost source of ethylene, especially compared with Middle East sources. The United States becomes a net importer of petrochemicals as the Middle East captures most new investment in ethylene and derivatives.

Most ammonia and methanol plants are shutdown in the United States. Most U.S. ammonia is used for nitrogen fertilizers for crops such as corn. Thus demand for ammonia will grow especially if more corn is used to make ethanol as MTBE is phased out of reformulated gasoline. As demand grows, ammonia production

moves offshore to low cost gas sources such as Trinidad and Qatar. The expected phase-out of MTBE is expected to reduce U.S. demand for methanol by about 40%. Thus not all if the currently shutdown methanol production will be re-opened or replaced. Methanol production could move to areas of large stranded gas reserves such as Australia where a 5 million ton plant has been proposed.

Steel production is expected to grow slowly as adjustments are made to reduce energy consumption. One option is to import raw steel to U.S. plants for rolling and transformation to products. Most energy is used in creating raw steel, so the U.S. iron and steel industry could reduce energy consumption substantially.

Production of raw aluminum is not expected to keep up with demand. Aluminum ingots can be produced from scrap or imported rather than being produced from raw materials. While overall consumption of aluminum products increase, energy consumption could decrease.

Paper production includes several alternative processes, each with varying energy requirements. Most paper making uses waste from production to displace some or most requirements for purchased fuels. At recent natural gas prices, some trends towards more energy efficient processes, higher use of waste paper and substitution of own fuel or other fossil fuels for natural gas are expected.

Energy efficiency increases vary by process. Most traditional technologies have the potential to improve efficiency by 10% to 20% over the forecast horizon. New technologies could have much higher efficiency, as much as 50% improvement for many significant uses of natural gas during the 2002 to 2030 period.

Natural Gas Supply

Near-Term Gas Markets Are Struggling to Rebalance. Federal Reserve Chairman Greenspan noted that there is a small imbalance in natural gas supply and demand. Global Insight estimates that the North American supply and demand imbalance is equivalent to about 6% of what the market would have been. Supply decreases, higher required storage rebuild, and economic expansion all contributed to the imbalance. Compared with 2002, natural gas production in the United States is expected to decrease by about 1 billion cubic feet per day (Bcfd), while Canadian production is down about 0.7 Bcfd. Storage rebuild will account for about a 3-bcfd increase in gas disposition in the United States for April–December. Canadian storage will have to be rebuilt at a higher rate as well to overcome a 130-bcf deficit, versus a year ago, as of mid-June. Increased imports of LNG will be partially offset by increased exports to Mexico. Thus, the North American supply and demand balance is about 5 Bcfd tighter during 2003, compared with 2002. Oil consumption is running the equivalent of several Bcfd above year-ago levels and is ameliorating the imbalance. Nevertheless, natural gas prices will have to remain above fuel oil prices to continue inter-fuel substitution. Power sector demand could be weaker this year if second-half temperatures are normal, as compared with the extreme temperatures in that period a year ago. Even so,

some demand destruction will be required to close the remaining imbalance in the gas market, resulting in gas prices above oil prices.

U.S. gas production is down about 2% or 1 Bcfd in the first quarter of 2003, according to company reports. Natural gas liquid production was also down about the equivalent of 0.6 Bcfd in the first quarter of 2003. Wet gas production includes the liquids, while dry gas production does not. Thus, the gas supply delivered to pipelines (dry gas) likely included more liquids. During past periods of high gas prices, natural gas liquids left in the gas stream have contributed as much as 2 Bcfd equivalent to supply. The increase in Texas gas well production during the first quarter of 2003 likely includes some of the liquids left in the gas stream.

LNG imports have risen significantly in 2003, as the second and third trains in Trinidad have added to available supply. LNG imports are expected to grow from 0.7 Bcfd in 2002 to 1.3 Bcfd this year, as almost all of the Trinidad supplies are shipped to the United States. Moreover, the Cove Point import terminal is expected to open in July 2003 and add 1 Bcfd to import capacity. Total U.S. LNG import capacity will be about 2.6 Bcfd when Cove Point comes on-line, setting the stage for further LNG import growth in 2004.

Is U.S. natural gas production increasing or decreasing? U.S. natural gas production has changed very slowly over the past decade, with small increases until recently. In 2002, U.S. production declined to 52.2 billion cubic feet per day (Bcfd), down by 0.9 Bcfd from 2001 levels. So far in 2003, production trends are mixed, with the EIA and Texas gas well production showing small increases while surveys continue to show decreases. According to surveys of large companies, U.S. production declined by nearly 1 Bcfd in the first quarter from year-ago levels.

Total Federal Gulf of Mexico production decreased by 1.3 Bcfd between 2001 and 2002, from 13.8 Bcfd to 12.5 Bcfd. A portion of the production decline was due to hurricanes last fall. Also, while deepwater production was increasing, shallow water production fell from about 10 Bcfd to under 9 Bcfd in 2002. With several companies pulling out of the shallow Gulf and with a lackluster market for offshore drilling rigs, it is probable that the drop in shallow water production is accelerating. Thus, overall Gulf of Mexico will decrease again in 2003, probably by about 1 Bcfd.

Existing deepwater production has experienced significant decline rates. These projects are typically designed to produce most of the gas in the first several years. Thus, the decline in existing deepwater production could be above 1 Bcfd as well. New deepwater projects are expected to add about 1 Bcfd to supply during 2003. Thus, production from the deepwater region will remain constant during 2003, but not offset the decline in shallow water supplies. Overall, the Gulf of Mexico gas production will be around 11.5 Bcfd for 2003, down 1 Bcfd from 2002. Continued declines in Gulf of Mexico production are indicated for 2004.

Production is increasing in the Rocky Mountains. Based on pipeline expansions, Rocky Mountain takeaway capacity will increase by over 2 Bcfd from 2003 to

2005, including Kern River. Thus, production should increase by about 0.7 Bcfd in 2003 and 2004. The Rocky Mountain increase is not enough to offset the production declines in the Gulf of Mexico. Further, onshore production outside of the Rocky Mountains is expected only to hold its own. Small changes in Texas (up), Mid-continent (down), and California (down) will likely offset one another. Thus, the trend for U.S. gas production is small decreases in 2003 and most likely 2004.

Drilling activity has increased over year-ago levels, but is still lagging the boom year of 2001. Also, despite a tripling of gas well drilling in the last decade, gas production has still declined. It is clear that future supply additions in the United States will be difficult given the rapid decline rate of existing production and the minimal production response to heightened levels of drilling activity.

Natural gas imports from Canada have decreased in 2003. With gas supply in Western Canada dropping by up to 0.8 billion cubic feet per day (Bcfd) so far this year, supply to the United States is also going to decline. Most of the decrease in gas imports has occurred in the western United States, where the Kern River pipeline expansion has added to California supply.

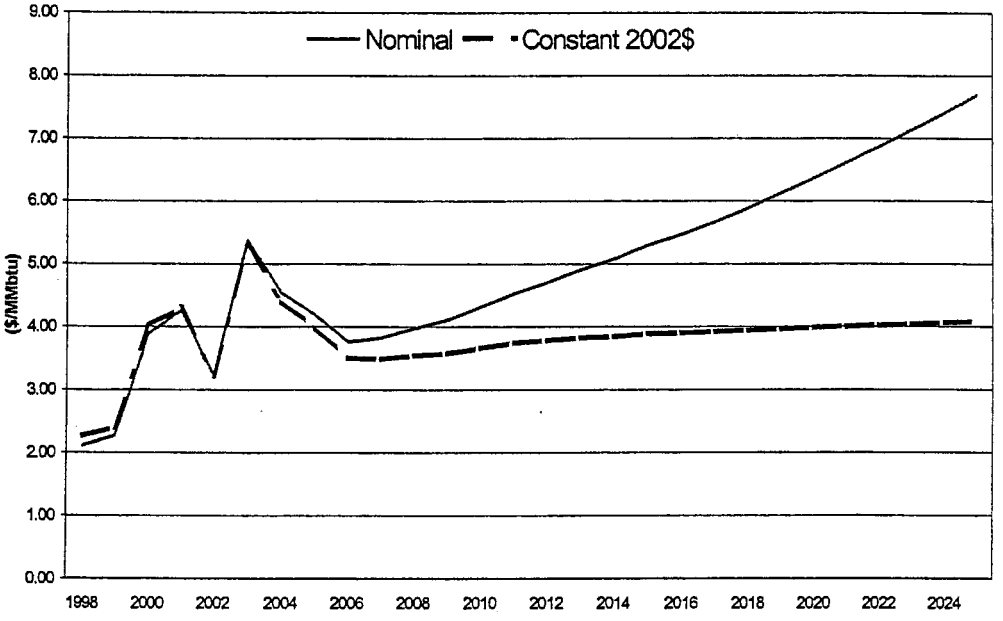
With U.S. natural gas prices far above European levels, there should be LNG cargoes diverted to the United States this year. LNG imports during the first part of 2003 have been running above 1 Bcfd, up from about 0.7 Bcfd for 2002. LNG will contribute to supply increases in 2003 and 2004, though the biggest gains will come with expansions planned for 2005–06 and new projects for 2006–07. LNG imports could average 1.3 Bcfd for 2003 and reach 2 Bcfd during 2004 and 2005.

Long-Term Supplies Will Include Rising LNG Imports. The baseline natural gas supply outlook is for essentially flat lower-48 production levels throughout the forecast period. This is a downward revision from our prior long-term forecasts based upon the recent declines in production throughout North America and the continuing lack of response in supply levels to drilling activity. Increases in the Rocky Mountains and frontier regions are likely to offset small production declines in traditional areas. Shallow water offshore production in the Gulf of Mexico is expected to continue to decline. Production forecasts are based upon an analysis of resources, supply costs (discussed above), and production trends by basin in Canada and the United States.

The long-term outlook assumes that expanding LNG imports routinely fill the growing gap between domestic demand and domestic supply. LNG is the marginal supply source and as such is a major determinant of prices. North America has always been nearly self sufficient in natural gas, with LNG making up only 2% of the market for 2003. While the share of LNG will grow, domestic production will account for the majority of supply throughout the forecast horizon. Thus it is likely that for many U.S. regions, domestic production will—at least at times—remain the swing supply source. Thus the long run marginal cost of LNG will set a floor price for natural gas while domestic supply conditions determine the peak and seasonality of prices.

Resource estimates used in the domestic production analysis are based upon the 1992 and 1999 National Petroleum Council studies and the 2002 assessment by the Potential Gas Committee. Also, assessments by the Minerals Management Service for the offshore and the National Energy Board for Canada are referred to. The total resource base does not necessarily translate into supply because of various restrictions on access. In the current outlook, access to Rocky Mountain resources is assumed to increase over time. Moratoriums on development of various offshore regions already extend to 2012 under current federal executive orders, and these are not rescinded in the Base Scenario.

Natural Gas Spot Prices



Short-term Coal Outlook

In our view, coal markets are positioned in an unsustainable split with some Eastern prices, reaching heights not seen since late 2001, with western prices, notably those in the Powder River Basin, showing little movement. Compliance coal in Central Appalachia is close to $40/ton, and with Pittsburgh seam capacity in Northern Appalachia somewhat constrained at present, prices there for the mid- and even high-sulfur coals are following that same direction, albeit several dollars lower.

In the Midwest and West, prices escalated rapidly in both the Illinois and Uinta Basins in December, but now seem to be stalling (and falling slightly in the Uinta Basin), waiting to see what happens next. PRB prices remain hovering at levels we have not seen since the fall of last year, as yet showing no major response to activity in the East. Similarly, petcoke prices have been demonstrating considerable restraint, even in the face of skyrocketing international coal prices.

While a look at OTC markets implies this situation will continue through the year, we do not believe that outlook is sustainable. If coal prices in the East were to remain at their current levels throughout 2004, then we would expect that prices in the West (including, and particularly, the PRB) would rise significantly. The rationale for continued high pricing in the East is strong; the economy is finally growing, natural gas prices are high, and imported coal prices, driven by international freight rates, are in the stratosphere.

In spite of these convincing arguments, our outlook at this time is for prices to begin falling modestly in the East in the spring. Natural gas prices should be weakening considerably by then (although, on a relative basis, still high above the $4 mark). Moreover, coal buyers are in much better control of their inventory situation at present; therefore, while they can not sit and wait out the market forever, they are not in a desperate-buying mode either.

There are two less immediate but extremely important coal developments worthy of comment. The first relates to the growing consolidation of the industry. With Peabody purchasing some of the RAG mining operations, questions are being raised whether or not Peabody will end up with most of that company's assets. That would consolidate competition not only in the PRB, but in the very important Pittsburgh seam as well. With the Arch proposed purchase of Triton now under anti-trust scrutiny, many observers question whether the federal government would allow an Arch-Peabody-Kennecott triumvirate to rule the PRB. Yet, the feds have allowed stranger things to happen, so we would not close the door on that possibility yet. Whatever the outcome, coal ownership trends continue to

point to a highly consolidated top echelon of companies wielding formidable market power, with a large but financially weak second layer of firms underneath unable to impact coal production significantly on their own.

The second development worth noting for coal markets is the wrench thrown: the New Source Review policy of the Bush administration by the courts in issuing a stay against the implementation of EPA's new "routine maintenance" rulemaking. The Bush EPA plan was to effectively provide coal powerplants wide latitude to make significant changes without triggering the immediate need to install pollution-control equipment. For coal markets, this meant that many plants could continue to use or convert to the use of low sulfur coals for the next four to six years before encountering strong pressure to install scrubbers—an attractive option to use PRB coal despite the capital costs required to convert from Midwest or Eastern coals. Through its administrative powers, the Bush administration has been highly successful in pursuing this policy by both delaying any final resolution of the NSR question as well as ceasing enforcement where possible of Clinton-era suits and investigations. On the other hand, in proposing a NSR interpretation that clearly pushes the envelope without making the effort to fully support it with substantive analysis, the Bush administration has opened the door for the courts to reject it (regardless of its merits). As a result, until a court decision is made (and if the Bush policy were to be overturned by the courts), a high degree of uncertainty remains for coal producers and coal-burning power companies alike in their effort to map out even near-term strategies. Indeed, even the largely pro-coal state of Ohio has suspended implementation of this NSR routine maintenance policy until the courts render a final decision.

Coal Production

At the time of this writing, we appear to have experienced a 20-million-ton decline in production in 2003, from 2002. However, the silver lining is that more than half of that reduction was directly attributable to stockpile corrections. With inventories unlikely to play a major role in 2004, and the economy showing some strong signs of revitalization, we are looking for virtually all that shortfall to be recaptured in 2004.

The **East** dipped badly in production in the third quarter of 2003, raising strong fears that concerns over deterioration in Central Appalachia were more than justified. Fourth-quarter output has rebounded dramatically, however, to levels not seen since the second quarter of 2002. The East took a hard hit in 2003 from both inventory adjustments and imports penetrating into the East's market area. However, we expect some solid improvement in 2004 as demand rises, despite the ever-present competition from foreign coals.

The **Interior** region lost about 1% of its production in 2003, and should lose another half a percent in 2004 as SO2 concerns intensify. This region's numbers could be buoyed, however, by concern over high prices coming out of the East and roadblocks put up by the courts against expanding the use of western coal.

We look for coal buyers in the Midwest to be highly protective of the Interior market, given the high level of uncertainty pervading other supply regions.

Production in the **West** came on much stronger in the fourth quarter of 2003 than what we had anticipated, reaching over 140 million tons for the first time (in a quarter) this year. Despite the court's recent stay in implementing the Bush administration's routine maintenance provisions of New Source Review, we look for continued penetration in the East and Midwest this year due to the highly competitive nature of this region's coal.

TOTAL PRODUCTION (Millions of Tons)

	Q1	Q2	Q3	Q4	Total	% Change
2001	283.8	279.4	279.7	284.8	1,127.7	5.04%
2002	282.6	266.7	270.9	274.1	1,094.3	-2.96%
2003	264.1	267.2	267.9	274.4	1,073.6	-1.89%
2004	274.0	271.4	274.8	274.1	1,094.3	1.92%

APPALACHIAN PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2001	111.6	109.8	105.0	106.3	432.8	3.19%
2002	108.1	98.5	95.2	95.2	397.0	-8.28%
2003	95.4	95.5	92.2	96.9	379.9	-4.30%
2004	96.3	95.7	96.7	96.4	385.1	1.36%

INTERIOR PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2001	36.8	37.2	37.7	35.3	147.0	2.44%
2002	36.9	37.3	36.7	35.9	146.9	-0.11%
2003	36.1	37.0	36.1	36.2	145.4	-0.98%
2004	36.4	35.7	36.5	35.9	144.6	-0.60%

WESTERN PRODUCTION

	Q1	Q2	Q3	Q4	Total	% Change
2001	135.4	132.4	137.0	143.1	547.9	7.29%
2002	137.6	130.8	138.9	143.1	550.4	0.47%
2003	132.5	134.7	139.7	141.3	548.3	-0.39%
2004	141.2	140.0	141.6	141.8	564.6	2.98%

Coal Region Definitions: *Appalachia*—Northern Appalachia (Pennsylvania, northern West Virginia, Maryland), Ohio, Central Appalachia (southern West Virginia, eastern Kentucky, northern Tennessee, Virginia), Southern Appalachia (Alabama and southern Tennessee). *Interior*—Illinois Basin (Illinois, Indiana, western Kentucky), Central Interior (Iowa, Kansas, Missouri, Oklahoma), Lignite (Texas, Arkansas, Louisiana). *West*—Powder River Basin (northern Wyoming, southern Montana), Northern Lignite (Montana and North Dakota), Green River Basin (northwestern Colorado, southwestern Wyoming), Hanna Basin (south-central Wyoming), Uinta Basin (Utah, western Colorado), Raton Basin (northeastern New Mexico, southern Colorado), Four Corners (northeastern Arizona, northwestern New Mexico, southeastern Colorado), Northwest (Washington and Alaska).

The Stock Situation

Our assessment of inventory levels is that stocks have, for the moment, ceased to be the volatile issue that has upended coal markets for so many years. Recent data suggest that the annual summer (2003) stock drawdown was just slightly less than we had anticipated, still leaving markets relatively free of concerns over whether inventories are too high or too low. We anticipate that several million tons were added to the stockpile levels in the fourth quarter of last year, leaving buyers in the position of making relatively few adjustments in 2004. All of this is dependent on the assumption that we do not experience dramatic weather extremes or coal supply shortages, but for the moment at least, coal buyers and sellers should be able to concentrate on market fundamentals for this year without worrying about how much coal is sitting on the ground.

Coal Stocks (Million Tons)

				—Forecast—	
Sep 2003	Sep 2002	% Change	EOY 2003	EOY 2004	% Change
172.9	179.5	-3.2%	179.8	178.3	-0.8%

Exports & Imports

U.S. steam coal exports continue to show unexpected strength in the face of rapidly escalating global thermal coal prices. For 2004, we are expecting international steam prices to remain high for the better part of the year, as freight rates show little sign of subsiding and new vessel construction is unlikely to keep pace with expanded demand, as most of the world economies improve. China, which played a major role in 2003's freight market rise (which led to coal price increases), is now taking steps to moderately cool its economy in the face of energy shortages and industrial overload. Expected economic growth elsewhere in the world could offset the Chinese efforts, however, as many economies are looking to expand after years of stagnation. All this should translate into a strong year for U.S.-met shipments, and our forecast anticipates U.S. steam exports will be strong through the third quarter of next year. Even this improved outlook could be overly conservative in the face of some concerns that global freight rates could remain at high levels for as long as two years.

U.S. Exports and Imports (Million Tons)

Estimated Forecast

	YTD 10/03	YTD 10/02	% Change	2003	2004
US Exports-Total	35.9	34.0	5.9%	43.2	42.6
US Imports	20.9	13.9	+50.9%	25.3	27.4

Source: U.S. Department of Energy and National Mining Association

Foreign coal imports into the United States had already broken the 2001 record by October of last year, despite the rise in international coal prices. Unless U.S. domestic coal prices decline to unexpectedly low levels, however, we foresee another banner year in 2004 for foreign coal purchases. With coal markets in the East remaining at elevated levels, and with domestic coal availability more often in doubt, U.S. coal buyers are expected to continue buying from all markets in order to leverage themselves. The recent purchase by Kinder Morgan of two terminals in Florida, rumored to be for importing coal, is further evidence of this likelihood.

Long Term Coal Outlook

The recent rise in real coal prices will be reversed in the long-term forecast. U.S. delivered coal prices will decline in real terms over the forecast period as more pressure is brought to bear on the fuel component of the electric power industry. This pressure to provide both cheaper and less polluting fuel will force overall delivered coal prices to the electric power industry to decline in real terms so that coal can retain as much of its market share as possible.

The overall decline in delivered steam coal prices to the electric power industry will come from a number of sources. Continued efficiency improvements in the mining sector and competition with more efficient natural gas-fired generation stations will continue to promote real coal price declines. In the last ten years, the greatest drops in price came from transportation cost reductions and long-term contract expirations. The transportation cost reductions stemmed from the consolidation in the rail industry that has left four large regional rail lines that promise some, but no longer significant, price declines due to efficiency improvements. The early high-cost, long-term contracts without adjustment clauses from the late 1970s and 1980s have expired, also contributing to the delivered cost decline. With their expiration, average minemouth coal prices have fallen markedly since their peak in the mid-1980s; but the majority of the price reductions from this source have already occurred. Coal contracts of 20 years at a fixed price no longer exist. Most contracts are for three to five years and have a market clause. Thus, contract prices are becoming more sensitive to current market conditions.

Emission allowance prices are expected to strengthen when the inventory of excess allowances from past years is depleted. This could happen as early as 2004-05 when utilities will be adding more scrubbers for sulfur removal as well as SCRs for NOx removal. Higher allowance prices mean higher costs of using coal.

Outlook for Petroleum Coke

- The strike in Venezuela that started in December, 2002 disrupted supplies of petroleum coke but it's effects subsided in 2003 as petroleum production was restored. Initially, it resulted in a slightly higher international call for coal as petroleum coke prices soar, but the need for replacement coal was highly dispersed. As a result, there was not a significant impact on coal markets these from developments. Petcoke markets are quite another thing, however, and prices for low grade, high sulfur product reached into the mid-$20's in early 2003 before subsiding.

- Petroleum coke supply is expected to increase with the new heavy oil projects in Venezuela with over 500,000 barrels per day of coking capacity. Also, new cokers are going into refineries in the US that use heavy oil from Mexico and Venezuela. North and South America provide over two thirds of the worlds petroleum coke supply of 60 million tons. World supply is expected to increase to 70 million tons as the new coking projects are added. The installation of significantly greater coking capacity in refineries in the 2001-2004 period will provide a huge boost to petroleum coke availability that will tip the balance in favor of supply over demand.

- Petroleum coke is used as a blend with steam coal by many utilities, but comprises only a small percentage of utility fuel consumption. Coal plants with scrubbers, with the new fluidized bed technology or with gasification can use petroleum coke. Increasing coke production - resulting from increasing residual fuel conversion and falling delivered prices- is making this product attractive to some utilities. Generally, petroleum coke prices have to be priced very competitively on a delivered basis to attract utilities.

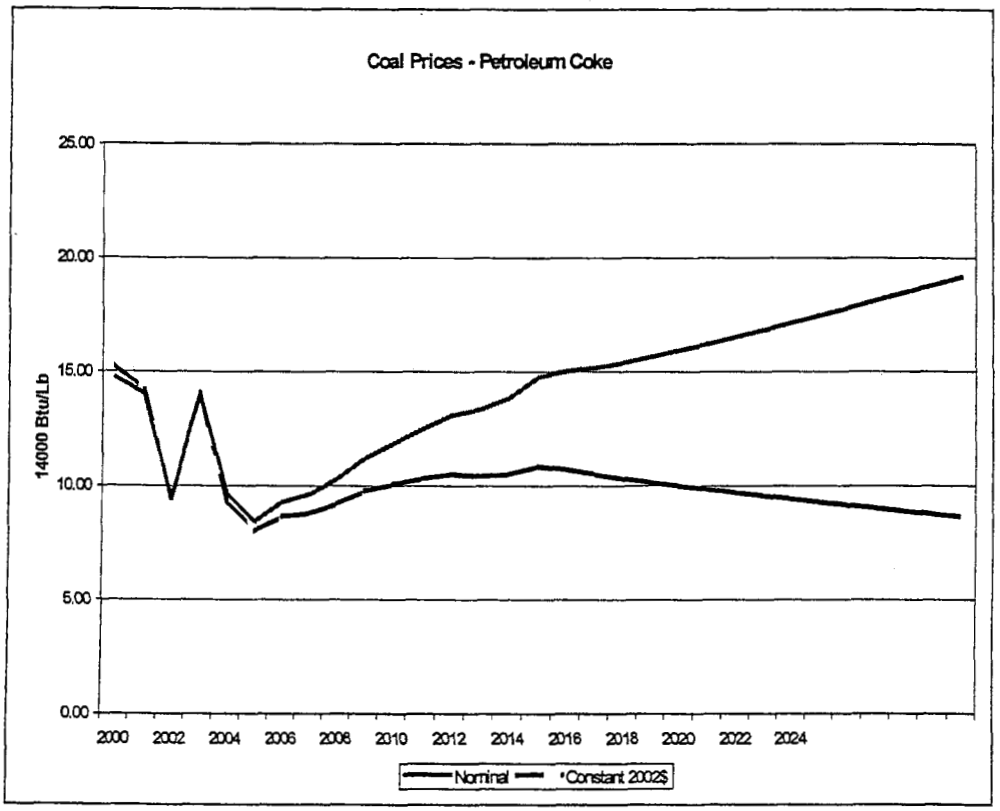
- Petroleum coke prices have a ceiling value placed by steam coal but have no floor value. As refiners produce more petcoke, their marketing strategies may evolve from viewing petcoke as a byproduct to be discarded and more to a product that can be priced competitively in a growing market.

- When residual fuel is converted to petroleum coke, the sulfur and metals in the residual fuel are concentrated in the petroleum coke. As long as transportation costs do not remove the current price advantage that coke has over coal, high-sulfur coke can be burned economically with coal, particularly in plants already equipped with scrubbers, although coke's fuel properties are somewhat different from those of coal.

- Green coke is the form of coke used as fuel. Less than 10 percent of the fuel-quality green coke produced domestically is burned as fuel domestically, and this amount used for utility fuel represents only 5 percent of to-

tal petroleum coke demand. Petroleum coke is generally blended with coal in pulverized coal plants or gasification units.

- The price of coke continues to decrease despite volatility in coal, oil and natural gas prices. The average delivered cost of petroleum coke to utilities in 1999 was 65.4 cents per million Btu and declined to 58.5 cents in 2000. The average delivered price of coal was 120 cents per million Btu in 2000, down from 121.6 cents in 1999. Petroleum coke prices are especially competitive with coal prices in Florida since the state is near the large coke-producing refineries on the Gulf Coast, and more distant from coal producing regions.



U.S. ECONOMIC OUTLOOK[1]

Real GDP

The trend projection assumes that the U.S. economy experiences no major mishaps between now and 2028. The projection is identical with our February 2003 baseline forecast through 2013, and represents Global Insight's best estimate of the economy's path over that period. Beyond 2013, the projection should be interpreted as the mean of all possible "near-full-employment" paths the economy could follow. The smooth-growth characteristics of the trend projection make it most useful for tasks largely impervious to short-term cyclical fluctuations, such as planning capacity additions and evaluating new markets. This projection is also the best base from which to evaluate the effects of various assumptions about key exogenous elements, such as fiscal policy or energy prices, on the overall economic outlook.

Annual real GDP growth averages 3.0% during 2001–27, about the same average achieved during 1976–2001. The economy's underlying growth rate will slow after 2011 as baby boomers begin to retire, slowing labor force growth. Potential output growth should hold up fairly well in the future, with greater business fixed investment and R&D spending offsetting the slowdown in labor force growth. Eventually, though, the effects of weaker labor force growth become dominant and, in a sense, self-perpetuating. As output growth drops off, business fixed investment rises more slowly, limiting capital stock growth and thus future output gains.

Employment

Employment. Slower long-run increases in the labor force indicate more moderate long-run employment growth in the future. Total civilian employment will rise at an average annual rate of 1.2% from 2002 to 2013 and will moderate to an average growth rate of 0.2% for the rest of the forecast period. Total establishment employment will rise from 130.8 million in 2002 to 168.8 million in 2028, an increase of 29%. This growth is significantly slower than the astonishing gain of 48.3 million (63%) recorded in the previous 25 years. Manufacturing's share of total employment will continue to decline over the forecast period, falling to 10.0% in 2028 from 12.8% in 2001. The broad service sector will generate an increasing share of employment growth in the forecast period, although the share of employment accounted for by the federal government will decline during the forecast period.

Inflation

Over the long run, inflation is a monetary phenomenon. Its future course will be determined by policies implemented by Alan Greenspan and his successors. Since we do not know who his successors will be, we assumed the following in the 25-year

[1] Global Insight's Long-term US Economic Outlook, Winter 2003, published February 2003.

forecast: The Fed will attempt to keep inflation contained over the first ten years of the forecast period. In the second half of the forecast period, as baby boomers start retiring, labor markets will tighten, putting pressure on wages. We assume that the Fed will allow inflation to creep up rather than slow the economy—possibly inducing a recession—to keep inflation checked. The CPI is expected to average 3.0% annual increases between 2002 and 2028, somewhat less than the 4.0% average from 1947 to 2000. The broader-based GDP deflator will rise 1.1% per year. The acceleration of inflation over the projection period reflects a more accommodative Federal Reserve attitude in response to pressures created by the aging population.

Consumption

Expenditures, in the long term, are primarily determined by the growth of real permanent income, demographic influences, and changes in relative prices. The share of personal consumption expenditures in GDP will rise slightly over the forecast interval, and should account for 72% of the overall economy by the end of the forecast horizon. Real consumption expenditure growth will average 3.0% per year over the forecast period.

With total output growth easing, real consumer spending gains will slow from 3.2% annually in 1973–2000 to 3.0% during 2002–28. In per capita terms, growth will advance about 2.2% per year, 0.2% below the 1975–2000 rate. Most consumption categories are expected to slow, except for health-care spending, which will pick up again after 2012.

The share of consumption devoted to services will rise, mainly because of rising health expenditures, while that for goods will fall over the forecast period.

The long-term outlook for auto and light truck sales calls for a slowdown in the rate of increase relative to past performance. Vehicle sales growth will average close to 1.0% over the next 25 years. Light-vehicle sales are forecasted to reach 21.8 million units by 2028. Although the number of vehicles per person has increased significantly in the past 20 years, the United States is approaching a saturation point in the rate of vehicle ownership. Future growth in vehicle sales will be primarily driven by growth in population and demand for replacement vehicles. Automobile sales should be relatively strong throughout the projection period, averaging 8.6 million units per year.

According to Global Insight's Energy Service, real energy-intensive consumption (gasoline, fuel oil, coal, electricity, and natural gas) should increase 1.8% per year through 2028, compared with 1.5% annual gains since 1970. Energy conservation efforts will continue. This stems partly from a stock/flow phenomenon: despite the trend toward minivans and sport/utility vehicles, for example, the average new vehicle is still more fuel-efficient than the existing stock. Gasoline usage per vehicle should fall for several more years, even if relative energy prices remain flat. Similar considerations apply to business capital and housing stocks. The ongoing employment shift from manufacturing to services also implies lower energy usage per unit of output.

Real personal disposable income, which climbed 3.1% in 1970–2000, will rise 2.9% annually over the next 25 years. This does not take into account the rising volume of withdrawals from existing retirement plans.

Housing

Household growth clearly depends on population growth, but real incomes, employment, the age distribution of the population, and societal values also influence it. Net additions to the housing stock are closely linked to household growth, which is the primary driver of housing starts. Many analysts tend to overlook another key factor for housing starts: the geographic location of the demand for net additions.

The 25–34-age cohort is key for the demand for new housing. This is the age group where individuals typically purchase their first home. The demand for new housing was boosted by the large gains in this age group in the late 1960s and 1970s, as the baby-boom generation entered the housing market. Unfortunately for the housing sector, the baby-boom generation began to pass through this age bracket in the mid-1980s, limiting the demand for additions to the housing stock. The number of households in this cohort will begin a modest increase after 2005. The overall headship rate will gradually increase toward older segments due to the shift in the age composition.

The demographic demand for housing will be higher over the next 25 years than over the past 25 years. Thus, housing starts are projected to average 1.7 million units annually from 2002 to 2028, above the 1.5 million average for 1971–2000. Meanwhile, the housing stock will climb from 113.0 million units in 2002 to 144.1 million units.

Business Fixed Investment

Good profitability and solid demand growth should keep investment healthy over the next 25 years. The share of GDP devoted to business fixed investment will hover between 10.0% and 13.0% of GDP through most of the forecast period. The effective capital stock (in 1996 dollar terms) is projected to increase 4.4% annually, just above the average growth rate recorded for 1971–2001. Inventory investment will remain a small percentage of GDP. Although inventories have played significant roles during past business cycles, inventory investment represents an average in the stable growth scenario and is thus artificially smooth. Capital inflow will contribute to net domestic investment throughout the forecast period, although federal deficits clearly hurt it in the later years of the forecast. The government saving projection assumes that state and local governments continue to run modest operating surpluses.

The composition of investment will continue to change in the forecast period; structures' share of investment will decline modestly, while equipment's share rises. This is a continuation of a long-standing trend, and is a direct result of declining relative prices for equipment and software.

International Trade

A decline in the exchange rate, combined with modest unit labor cost growth, will stimulate U.S. exports abroad and result in an eventual improvement in the U.S. current account balance. Global Insight projects that real exports will expand at an average annual rate of 5.2% over the entire forecast period. Real imports, meanwhile, will grow at an average annual rate of 6.5%.

APPENDIX TABLES

Forecast Tables

Table 1: Distillate Fuel Prices-Monthly
Table 2: Distillate Fuel Prices-Annual
Table 3: Residual Fuel Prices-Monthly
Table 4: Residual Fuel Prices-Annual
Table 5: Natural Gas Prices-Monthly
Table 6: Natural Gas Prices-Annual
Table 7: Coal Prices-Annual-FOB CSX
Table 8: Coal Prices-Annual-Florida Delivered
Table 9: Implicit Price Deflator-Annual

Data Definitions

Background: *Discussion of Location, Contracts, Delivery Routes, and Embedded Costs in the measurement of Fuel Prices as Prepared by Global Insight.*

Note on Taxes: Since the Superfund tax of 9.7 cents per barrel expired as of December 31, 1995, the spot price forecasts do not include any special taxes as well.

PETROLEUM

All petroleum product spot price history is from Platts. Platts defines the fuel specifications unless otherwise noted.

Distillate:

- ***This definition applies to tables 1-2:*** The Gulf Coast annual average price is calculated from the monthly average of spot cargoes transacted. Cargo assessments assume reasonably prompt arrival, typically 5-15 days away. Volumes are at least one vessel with 150,000 barrels of product, except where vessel size restrictions are in effect.

Specifications: 0.2% sulfur (at New York Harbor; up to 0.5% sulfur outside New York), 40 cetane, 34° API gravity, 130° F minimum flash point. These are the specifications for "normal" New York distillate; low sulfur distillate is 0.05% sulfur and 42 cetane, essentially equivalent to on-highway diesel. Since prices are generally quoted in cents per gallon, these prices were multiplied by 0.42 to arrive at a price in dollars per barrel. The standard DOE/EIA conversion factor of 5.825 mmBtu per barrel of distillate was used to calculate the price in dollars per mmBtu.

The Tampa spot price is based upon assessments of the terminal price at this location. The annual average price is an arithmetic average of the monthly average prices.

Residual Fuel:

- ***This definition applies to tables 3-4:*** Annual average price calculated from the monthly average of spot cargoes for the Gulf Coast. Cargoes can originate anywhere from Corpus Christi, Texas to the Mississippi. Platt's prices reflect cargoes lifting within 7 to 14 days or for New York Harbor, cargoes arriving within 5 to 15 days. Volumes are at least one vessel with 150,000 barrels of product, except where vessel size restrictions are in effect. Historical data for Gulf Coast cargoes includes 0.7%, 1%, 2.2%, and 3.5% sulfur. Historical data for the 0.7% sulfur residual fuel oil has been discontinued by Platt's. Analysis of this data shows that the Gulf Coast 1% sulfur price averages about $2 per barrel less than the New York Harbor price, reflecting a normal transportation premium. Also, analysis of the delivered cost of residual fuel oil to Florida utilities shows that they essentially pay the Gulf Coast spot price. The standard DOE/EIA conversion factor of 6.287 mmBtu per barrel of residual fuel is used to calculate the price in dollars per mmBtu. The specifications for 1.0% residual fuel are gravity 10.5 API, viscosity 225 ssf, maximum sulfur 1.0 %.

PETROLEUM COKE

- ***This definition applies to table 7:*** The petroleum coke price is obtained from JD Energy, Coal Monthly for Gulf Coast FOB with an energy content of 14000 Btu per pound. Also, the *Cost and Quality of Fuels for Electric Utility Plants* publication of the DOE/EIA is referenced where prices are reported for individual plants.

NATURAL GAS PRICES

Henry Hub Prices:

- ***This definition applies to tables 5-6:*** Global Insight uses the *Inside FERC Gas Market Report* (IFGMR) for spot natural gas prices. Spot prices are reported in dollars per million Btu. Bidweek index prices representing 30-day transactions are used for the monthly price. Annual prices are averages of the monthly prices. Spot price forecasts are prepared for specific locations for which several are in the Gulf Coast. The spot prices reported for the Gulf Coast region include the Henry Hub cash index, the average delivered to pipeline price for Louisiana and the average price for the entire Gulf Coast including Texas and Louisiana. The index value is calculated by IFGMR staff from information provided by participants in the spot market.

Florida Gas Transmission Zone 2:

- ***This definition applies to tables 5-6:*** Global Insight uses the Inside FERC Gas Market Report for bidweek prices and Gas Daily for daily cash prices. Both the Bidweek and the average monthly cash prices are provided. Florida Gas Transmission zone 2prices reflect market conditions in Mississippi, Alabama and the Mobile Bay region.

COAL PRICES

This definition applies to tables 7-8: Coal prices are reported in dollars per ton and in dollars per million Btu.

Purchase Locations:

The specific coal grades provided in the fuel price analysis reflect purchases at the minemouth by production basins: Northern Appalachia, Central Appalachia, Illinois Basin and the Powder River Basin. The center of Northern Appalachian coal production is the Pittsburgh seam south of Pittsburgh, PA in the Monongahela Valley. The Central Appalachian production basin is centered around the Big Sandy River with southern West Virginia to the northeast and eastern Kentucky to the southwest. The Illinois basin includes the states of Illinois and Indiana and the western portion of Kentucky. The Powder River Basin is located in the northeast corner of Wyoming and Southeastern Montana.

Type of Contracts:

Coal is purchased for delivery to coal-fired power plants under either a spot or contract agreement. Spot purchases can be for scheduled deliveries up to a year in length. Contract purchases last longer than one year, generally anywhere from three to five years in length. Current contracts have price adjustment clauses included that will allow for a periodic re-negotiation of the contract price based upon the changing market price. Some older coal delivery contracts that were instituted in the late 1970's and early 1980's are still in existence. These older contracts last upwards of twenty years with no clause for price adjustment. As a rule, these contracts will be significantly above the spot market price or new contract price.

Delivery Routes:

Rail lines to Florida include CSX and Norfolk Southern. CSX and Norfolk Southern serve the Northern and Central Appalachian basins and the Illinois basin.

For rail delivery from Northern Appalachia, the coal will most likely originate from mines with access to CSX and move to Baltimore. Central Appalachian coal is likely to move on Norfolk Southern to Norfolk and then to other destinations. The coal in either producing region could also originate from mines served by the other railroad with a transfer, but this would incur an added transshipment cost.

Either Burlington Northern Santa Fe or Union Pacific must first transport coal originating from the Powder River Basin. A third railroad, Dakota, Minnesota, & Eastern will soon gain access to the Powder River basin with an eastern terminus on the Mississippi River. The coal shipments would then be transferred to CSX lines for delivery. The logistical problems of rail shipment of bulk commodities across the Mississippi River and into South Atlantic would make the cost of such transportation relatively expensive.

IMPLICIT PRICE DEFLATOR

- ***This definition applies to real dollar values:*** The implicit price deflator is the chained price index for the U.S. gross domestic product. The base year is set to 2002, i.e. the deflator in 2002 = 1.000. The deflator is used to transform nominal price forecasts into forecasts stated in constant, or real, 2002 dollars.

Table 1

DISTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	Posted Price at Tampa, FL	Spot Price at Gulf Coast
Jan-99	35.23	31.47
Feb-99	32.77	28.79
Mar-99	40.24	36.61
Apr-99	47.39	41.11
May-99	45.78	40.17
Jun-99	44.03	41.77
Jul-99	51.14	48.53
Aug-99	56.69	53.69
Sep-99	62.56	58.61
Oct-99	60.88	56.79
Nov-99	66.56	62.46
Dec-99	68.58	64.80
Jan-00	77.56	72.33
Feb-00	85.99	75.51
Mar-00	84.95	72.82
Apr-00	78.05	69.05
May-00	81.92	73.24
Jun-00	81.27	76.32
Jul-00	82.14	76.75
Aug-00	91.18	87.02
Sep-00	102.74	97.14
Oct-00	99.14	94.19
Nov-00	101.65	96.73
Dec-00	93.74	82.56
Jan-01	104.48	84.48
Feb-01	88.58	76.78
Mar-01	75.30	69.40
Apr-01	80.14	73.35
May-01	83.21	75.44
Jun-01	80.71	74.45
Jul-01	72.00	68.29
Aug-01	75.17	72.02
Sep-01	76.48	70.35
Oct-01	64.87	60.56
Nov-01	57.10	52.68
Dec-01	53.63	50.26
Jan-02	54.89	51.08
Feb-02	55.54	51.90
Mar-02	65.01	61.36
Apr-02	68.30	64.67
May-02	69.51	64.40
Jun-02	66.11	62.51
Jul-02	69.48	65.89
Aug-02	72.03	68.53
Sep-02	79.95	76.15
Oct-02	81.95	75.95
Nov-02	76.12	70.61
Dec-02	83.37	79.83

Table 1

DISTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	Posted Price at Tampa, FL	Spot Price at Gulf Coast
Jan-03	91.46	88.02
Feb-03	115.21	105.65
Mar-03	105.32	88.40
Apr-03	86.47	72.54
May-03	79.65	70.60
Jun-03	77.55	73.98
Jul-03	80.70	76.72
Aug-03	83.72	79.92
Sep-03	75.91	71.80
Oct-03	83.66	79.98
Nov-03	84.69	81.20
Forecast		
Dec-03	86.29	80.35
Jan-04	82.71	77.10
Feb-04	77.20	72.09
Mar-04	70.75	66.23
Apr-04	65.81	61.74
May-04	66.43	62.30
Jun-04	64.28	60.35
Jul-04	65.30	61.28
Aug-04	67.71	63.46
Sep-04	70.32	65.84
Oct-04	71.41	66.83
Nov-04	71.44	66.85
Dec-04	71.51	66.92
Jan-05	69.78	65.34
Feb-05	67.16	62.96
Mar-05	66.96	62.78
Apr-05	69.18	64.80
May-05	67.37	63.15
Jun-05	64.97	60.97
Jul-05	66.23	62.12
Aug-05	70.15	65.69
Sep-05	75.64	70.67
Oct-05	74.86	69.97
Nov-05	74.62	69.74
Dec-05	75.02	70.11
Jan-06	70.26	65.78
Feb-06	68.09	63.81
Mar-06	68.35	64.05
Apr-06	71.11	66.55
May-06	69.72	65.29
Jun-06	67.70	63.46
Jul-06	69.01	64.64
Aug-06	73.08	68.35
Sep-06	78.78	73.52
Oct-06	77.96	72.78
Nov-06	77.70	72.54
Dec-06	78.11	72.91

Table 2

DISTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	NOMINAL		CONSTANT 2002 DOLLARS	
	Posted Price at Tampa, FL	Spot Price at Gulf Coast	Posted Price at Tampa, FL	Spot Price at Gulf Coast
1995	50.68	47.48	57.17	53.56
1996	63.75	58.98	70.54	65.26
1997	58.57	54.10	63.57	58.72
1998	42.17	38.19	45.22	40.94
1999	50.99	47.07	53.89	49.75
2000	88.36	81.14	91.47	84.00
2001	75.97	69.00	76.83	69.78
2002	70.19	66.07	70.19	66.07
2003	87.55	80.76	86.23	79.54
2004	70.41	65.91	68.33	63.97
2005	70.16	65.69	66.76	62.51
2006	72.49	67.81	67.59	63.22
2007	74.94	70.26	68.40	64.13
2008	76.46	71.72	68.23	64.01
2009	78.04	73.25	67.99	63.81
2010	80.68	75.77	68.52	64.35
2011	83.77	78.71	69.23	65.05
2012	86.97	81.76	69.92	65.73
2013	91.77	86.33	71.70	67.45
2014	96.06	90.41	72.80	68.52
2015	100.57	94.71	73.92	69.62
2016	105.05	98.99	74.93	70.61
2017	109.21	102.97	75.52	71.20
2018	113.54	107.11	76.02	71.71
2019	118.42	111.78	76.71	72.40
2020	123.39	116.53	77.32	73.02
2021	128.37	121.30	77.81	73.53
2022	133.72	126.43	78.39	74.12
2023	139.39	131.87	79.06	74.79
2024	145.57	137.78	79.88	75.61
2025	151.23	143.22	80.28	76.03
2026	157.58	149.30	80.90	76.65
2027	164.12	155.56	81.50	77.25
2028	171.01	162.17	82.18	77.93
2029	178.66	169.50	83.07	78.81
2030	185.63	176.18	83.51	79.26

Table 3

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	SULFUR CONTENT		
	0.7%	1.0%	3.0%
Jan-99	11.08	10.23	8.25
Feb-99	9.77	8.97	7.55
Mar-99	11.58	10.78	10.13
Apr-99	14.04	13.24	12.83
May-99	14.39	13.85	12.73
Jun-99	14.39	13.79	13.40
Jul-99	16.49	15.88	15.09
Aug-99	19.36	18.76	17.70
Sep-99	20.57	19.97	19.05
Oct-99	20.24	19.65	18.46
Nov-99	21.15	20.55	18.22
Dec-99	18.86	18.26	17.92
Jan-00	20.03	19.43	19.22
Feb-00	22.19	21.59	20.95
Mar-00	23.80	23.20	21.61
Apr-00	23.18	22.43	18.78
May-00	26.12	25.04	21.27
Jun-00	28.89	27.89	22.74
Jul-00	27.78	26.53	20.50
Aug-00	28.89	27.71	20.28
Sep-00	32.49	31.49	23.60
Oct-00	32.47	31.47	23.02
Nov-00	33.45	30.64	20.45
Dec-00	31.18	27.88	16.24
Jan-01	30.09	28.09	18.79
Feb-01	26.86	25.35	20.68
Mar-01	25.09	24.31	18.59
Apr-01	25.11	24.11	14.90
May-01	24.69	23.74	16.77
Jun-01	22.96	21.96	17.72
Jul-01	21.46	20.63	17.36
Aug-01	21.38	20.34	17.54
Sep-01	23.16	22.19	19.79
Oct-01	19.34	18.39	15.36
Nov-01	16.83	15.96	13.59
Dec-01	17.78	16.73	14.74
Jan-02	16.40	15.42	14.82
Feb-02	16.44	15.45	15.24
Mar-02	20.42	19.37	19.20
Apr-02	23.46	22.54	21.93
May-02	24.03	23.04	21.94
Jun-02	24.49	23.50	21.38
Jul-02	23.25	22.25	21.86
Aug-02	25.24	24.27	22.80
Sep-02	26.45	25.45	24.81
Oct-02	28.57	27.58	23.19
Nov-02	24.92	23.77	18.76
Dec-02	27.28	26.20	22.41

Table 3

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	SULFUR CONTENT		
	0.7%	1.0%	3.0%
Jan-03	32.03	30.96	29.73
Feb-03	35.66	34.68	27.76
Mar-03	34.05	33.16	22.78
Apr-03	25.60	24.72	19.59
May-03	26.73	25.81	21.16
Jun-03	28.32	27.39	22.35
Jul-03	30.39	29.44	25.64
Aug-03	29.30	28.34	25.96
Sep-03	25.72	24.80	22.42
Oct-03	28.66	27.74	24.47
Nov-03	28.22	26.93	24.00
Forecast			
Dec-03	28.47	27.11	21.77
Jan-04	26.24	24.88	19.77
Feb-04	22.17	21.11	17.81
Mar-04	21.05	20.06	17.02
Apr-04	20.93	20.04	16.77
May-04	22.20	21.32	17.81
Jun-04	21.99	21.07	17.59
Jul-04	21.80	20.88	17.01
Aug-04	21.79	20.84	17.68
Sep-04	23.19	22.23	19.18
Oct-04	24.05	23.12	19.83
Nov-04	23.35	22.43	18.75
Dec-04	23.88	22.59	18.14
Jan-05	22.74	21.37	16.98
Feb-05	20.30	19.23	16.23
Mar-05	20.85	19.86	16.85
Apr-05	21.93	21.04	17.60
May-05	22.50	21.61	18.06
Jun-05	22.21	21.28	17.77
Jul-05	22.09	21.16	17.25
Aug-05	22.15	21.20	17.98
Sep-05	23.42	22.46	19.38
Oct-05	24.12	23.20	19.90
Nov-05	23.50	22.58	18.88
Dec-05	23.88	22.59	18.14
Jan-06	22.88	21.52	17.10
Feb-06	20.56	19.49	16.45
Mar-06	21.25	20.26	17.19
Apr-06	22.50	21.61	18.08
May-06	23.23	22.35	18.67
Jun-06	23.08	22.15	18.50
Jul-06	22.95	22.02	17.95
Aug-06	23.01	22.06	18.71
Sep-06	24.33	23.37	20.16
Oct-06	25.06	24.13	20.70
Nov-06	24.41	23.49	19.64
Dec-06	24.78	23.49	18.87

Table 4

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	NOMINAL			CONSTANT 2002 DOLLARS		
	0.7%	1.0%	3.0%	0.7%	1.0%	3.0%
1995	15.18	14.69	13.77	17.12	16.57	15.53
1996	18.04	17.47	15.58	19.96	19.33	17.24
1997	16.59	16.15	14.41	18.01	17.53	15.64
1998	12.85	12.14	9.69	13.78	13.01	10.39
1999	15.99	15.33	14.28	16.90	16.20	15.09
2000	27.54	26.27	20.72	28.51	27.20	21.45
2001	22.90	21.82	17.15	23.15	22.06	17.35
2002	23.41	22.40	20.69	23.41	22.40	20.69
2003	29.43	28.42	23.97	28.98	27.99	23.61
2004	22.72	21.71	18.11	22.05	21.07	17.58
2005	22.47	21.47	17.92	21.39	20.43	17.05
2006	23.17	22.16	18.50	21.60	20.66	17.25
2007	24.01	22.96	19.17	21.91	20.96	17.50
2008	24.51	23.44	19.57	21.87	20.92	17.46
2009	25.03	23.94	19.98	21.80	20.86	17.41
2010	25.89	24.76	20.67	21.99	21.03	17.56
2011	26.89	25.72	21.47	22.23	21.26	17.75
2012	27.94	26.72	22.31	22.46	21.48	17.93
2013	29.50	28.21	23.55	23.04	22.04	18.40
2014	30.89	29.55	24.67	23.41	22.39	18.69
2015	32.36	30.95	25.84	23.79	22.75	18.99
2016	33.82	32.35	27.00	24.12	23.08	19.26
2017	35.18	33.65	28.09	24.33	23.27	19.42
2018	36.59	35.00	29.22	24.50	23.44	19.56
2019	38.19	36.53	30.49	24.74	23.66	19.75
2020	39.81	38.08	31.79	24.95	23.86	19.92
2021	41.45	39.64	33.09	25.12	24.03	20.06
2022	43.20	41.32	34.49	25.32	24.22	20.22
2023	45.05	43.10	35.97	25.55	24.44	20.40
2024	47.08	45.03	37.59	25.83	24.71	20.63
2025	48.93	46.81	39.07	25.98	24.85	20.74
2026	51.01	48.79	40.73	26.19	25.05	20.91
2027	53.15	50.84	42.44	26.40	25.25	21.08
2028	55.41	53.00	44.24	26.62	25.47	21.26
2029	57.91	55.39	46.24	26.93	25.76	21.50
2030	60.20	57.58	48.07	27.08	25.90	21.62

Table 5

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-98	2.27	2.28	
Feb-98	2.04	2.01	2.17
Mar-98	2.26	2.25	2.19
Apr-98	2.33	2.29	2.38
May-98	2.27	2.25	2.09
Jun-98	2.03	2.01	2.06
Jul-98	2.36	2.36	2.06
Aug-98	1.93	1.92	1.75
Sep-98	1.63	1.61	1.91
Oct-98	2.07	2.03	1.79
Nov-98	2.00	1.99	2.02
Dec-98	2.12	2.10	1.64
Jan-99	1.80	1.79	1.80
Feb-99	1.81	1.78	1.72
Mar-99	1.64	1.62	1.75
Apr-99	1.88	1.89	2.12
May-99	2.35	2.35	2.20
Jun-99	2.23	2.23	2.24
Jul-99	2.28	2.27	2.23
Aug-99	2.62	2.62	2.73
Sep-99	2.90	2.90	2.47
Oct-99	2.55	2.54	2.67
Nov-99	3.06	3.03	2.30
Dec-99	2.14	2.14	2.31
Jan-00	2.36	2.35	2.36
Feb-00	2.61	2.63	2.61
Mar-00	2.61	2.63	2.74
Apr-00	2.88	2.90	2.98
May-00	3.08	3.08	3.55
Jun-00	4.37	4.41	4.21
Jul-00	4.36	4.38	3.88
Aug-00	3.83	3.83	4.32
Sep-00	4.62	4.62	4.96
Oct-00	5.29	5.29	4.92
Nov-00	4.50	4.51	5.39
Dec-00	6.02	6.03	8.70

Table 5

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-01	9.91	9.94	8.00
Feb-01	6.22	6.27	5.37
Mar-01	5.03	5.05	5.01
Apr-01	5.35	5.34	5.08
May-01	4.87	4.86	3.90
Jun-01	3.73	3.74	3.42
Jul-01	3.16	3.21	2.99
Aug-01	3.19	3.18	2.87
Sep-01	2.34	2.35	2.11
Oct-01	1.86	1.86	2.40
Nov-01	3.16	3.13	2.27
Dec-01	2.24	2.26	2.31
Jan-02	2.61	2.61	2.19
Feb-02	2.03	2.06	2.23
Mar-02	2.39	2.41	2.96
Apr-02	3.41	3.44	3.42
May-02	3.36	3.40	3.55
Jun-02	3.37	3.42	3.29
Jul-02	3.26	3.30	3.07
Aug-02	2.95	3.01	3.14
Sep-02	3.27	3.30	3.58
Oct-02	3.72	3.72	4.13
Nov-02	4.13	4.21	3.95
Dec-02	4.13	4.20	4.52
Jan-03	4.96	4.94	6.30
Feb-03	5.66	5.68	7.71
Mar-03	9.11	8.85	6.24
Apr-03	5.14	5.15	5.29
May-03	5.12	5.13	5.75
Jun-03	5.95	5.98	5.71
Jul-03	5.30	5.49	5.00
Aug-03	4.69	4.73	4.98
Sep-03	4.93	4.96	4.57
Oct-03	4.43	4.43	4.60
Nov-03	4.45	4.48	4.44
Dec-03	4.86	4.86	5.02

Table 5

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-04	5.03	5.03	5.02
Feb-04	4.96	4.95	5.10
Mar-04	5.11	5.10	4.78
Apr-04	4.57	4.55	4.33
May-04	4.23	4.22	4.03
Jun-04	3.99	4.01	4.11
Jul-04	4.26	4.30	4.24
Aug-04	4.30	4.32	4.28
Sep-04	4.34	4.36	4.29
Oct-04	4.34	4.35	4.41
Nov-04	4.52	4.51	4.65
Dec-04	4.75	4.75	4.73
Jan-05	4.68	4.68	4.63
Feb-05	4.55	4.54	4.37
Mar-05	4.22	4.20	4.00
Apr-05	3.87	3.86	3.84
May-05	3.87	3.86	3.89
Jun-05	3.97	3.99	4.02
Jul-05	4.12	4.15	4.09
Aug-05	4.15	4.17	4.14
Sep-05	4.19	4.22	4.15
Oct-05	4.19	4.20	4.22
Nov-05	4.29	4.28	4.20
Dec-05	4.19	4.19	4.27
Jan-06	4.32	4.32	4.09
Feb-06	3.94	3.93	3.77
Mar-06	3.66	3.64	3.56
Apr-06	3.52	3.51	3.51
May-06	3.57	3.56	3.48
Jun-06	3.53	3.54	3.51
Jul-06	3.59	3.62	3.49
Aug-06	3.53	3.55	3.72
Sep-06	3.93	3.95	3.81
Oct-06	3.83	3.83	3.68
Nov-06	3.68	3.67	3.89
Dec-06	4.06	4.06	4.16

Table 5

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-07	4.20	4.20	3.88
Feb-07	3.68	3.67	3.61
Mar-07	3.58	3.56	3.58
Apr-07	3.61	3.60	3.62
May-07	3.68	3.68	3.61
Jun-07	3.66	3.67	3.64
Jul-07	3.72	3.76	3.62
Aug-07	3.66	3.68	3.87
Sep-07	4.07	4.10	3.96
Oct-07	3.97	3.98	3.82
Nov-07	3.81	3.81	4.04
Dec-07	4.22	4.22	4.31
Jan-08	4.35	4.35	4.04
Feb-08	3.82	3.81	3.78
Mar-08	3.73	3.71	3.75
Apr-08	3.77	3.76	3.78
May-08	3.84	3.83	3.77
Jun-08	3.80	3.82	3.80
Jul-08	3.87	3.91	3.78
Aug-08	3.80	3.83	4.03
Sep-08	4.23	4.25	4.12
Oct-08	4.12	4.12	3.98
Nov-08	3.95	3.95	4.20
Dec-08	4.37	4.36	4.48
Jan-09	4.50	4.50	4.19
Feb-09	3.95	3.95	3.92
Mar-09	3.87	3.85	3.89
Apr-09	3.90	3.89	3.93
May-09	3.97	3.96	3.91
Jun-09	3.93	3.95	3.94
Jul-09	4.00	4.04	3.92
Aug-09	3.93	3.95	4.18
Sep-09	4.37	4.40	4.27
Oct-09	4.25	4.26	4.11
Nov-09	4.08	4.07	4.34
Dec-09	4.50	4.50	4.63

Table 6

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Dollars per Million Btu)

Year	(Current) Henry Hub	(Current) FGT Bidweek	(Current) FGT Cash	Deflator (2002=1.0)	(2002$) Henry Hub	(2002$) FGT Bidweek	(2002$) FGT Cash
1998	2.11	2.09	2.00	0.933	2.26	2.24	2.15
1999	2.27	2.26	2.21	0.946	2.40	2.39	2.33
2000	3.88	3.89	4.22	0.966	4.01	4.02	4.37
2001	4.26	4.26	3.81	0.989	4.30	4.31	3.85
2002	3.22	3.24	3.33	1.000	3.22	3.24	3.33
2003	5.37	5.39	5.47	1.015	5.29	5.31	5.38
2004	4.53	4.54	4.50	1.030	4.40	4.40	4.37
2005	4.19	4.20	4.15	1.051	3.99	3.99	3.95
2006	3.76	3.77	3.72	1.073	3.51	3.51	3.47
2007	3.82	3.83	3.80	1.096	3.49	3.49	3.46
2008	3.97	3.98	3.96	1.121	3.54	3.55	3.53
2009	4.11	4.11	4.10	1.148	3.58	3.58	3.57
2010	4.31	4.31	4.32	1.177	3.66	3.66	3.67
2011	4.53	4.53	4.55	1.210	3.74	3.75	3.76
2012	4.70	4.71	4.72	1.244	3.78	3.78	3.79
2013	4.90	4.90	4.92	1.280	3.83	3.83	3.84
2014	5.07	5.07	5.10	1.320	3.84	3.84	3.86
2015	5.29	5.29	5.32	1.361	3.89	3.89	3.91
2016	5.46	5.47	5.51	1.402	3.90	3.90	3.93
2017	5.66	5.67	5.72	1.446	3.92	3.92	3.96
2018	5.88	5.89	5.95	1.494	3.94	3.94	3.98
2019	6.12	6.13	6.19	1.544	3.96	3.97	4.01
2020	6.36	6.36	6.44	1.596	3.98	3.99	4.03
2021	6.60	6.61	6.69	1.650	4.00	4.01	4.05
2022	6.86	6.87	6.95	1.706	4.02	4.03	4.07
2023	7.12	7.13	7.22	1.763	4.04	4.05	4.09
2024	7.40	7.41	7.50	1.822	4.06	4.06	4.11
2025	7.69	7.69	7.79	1.884	4.08	4.08	4.13
2026	7.98	7.99	8.09	1.948	4.10	4.10	4.15
2027	8.29	8.30	8.40	2.014	4.12	4.12	4.17
2028	8.62	8.62	8.73	2.081	4.14	4.14	4.19
2029	8.95	8.96	9.07	2.151	4.16	4.17	4.22
2030	9.30	9.31	9.42	2.223	4.18	4.19	4.24

Table 7

Seminole Electric
Coal Prices (FOB CSX)
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	22.80	18.25	25.77	25.16	
1999	22.35	17.44	24.30	23.86	
2000	22.19	16.83	24.70	24.30	14.75
2001	32.57	27.36	46.71	40.88	14.03
2002	26.79	21.90	28.96	30.64	9.45
2003	26.10	21.83	34.01	31.43	14.10
2004	27.00	22.82	36.69	32.69	9.62
2005	25.54	22.37	35.59	30.13	8.40
2006	26.00	22.41	35.62	30.01	9.26
2007	26.49	22.99	35.81	30.27	9.61
2008	26.95	23.95	35.88	30.84	10.28
2009	27.30	25.09	36.06.	31.96	11.19
2010	27.20	26.40	36.40	32.97	11.83
2011	27.66	27.56	37.28	33.34	12.46
2012	28.31	28.24	38.42	33.51	13.06
2013	29.08	28.89	39.60	33.77	13.34
2014	29.93	29.57	40.68	34.14	13.84
2015	30.81	30.28	41.56	34.59	14.75
2016	31.70	30.98	42.74	34.99	15.02
2017	32.65	31.73	44.16	35.47	15.17
2018	33.66	32.53	45.65	35.94	15.37
2019	34.74	33.38	47.23	36.43	15.64
2020	35.87	34.26	48.84	36.93	15.93
2021	37.03	35.16	50.53	37.52	16.22
2022	38.24	36.09	52.28	38.15	16.52
2023	39.47	37.04	54.07	38.77	16.83
2024	40.75	38.01	55.93	39.39	17.14
2025	42.07	39.01	57.85	40.05	17.46
2026	43.43	40.03	59.85	40.72	17.79
2027	44.84	41.09	61.91	41.40	18.12
2028	46.29	42.17	64.04	42.09	18.46
2029	47.79	43.28	66.25	42.79	18.81
2030	49.34	44.42	68.53	43.51	19.16

Table 7

Seminole Electric
Coal Prices (FOB CSX)
($2002 Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	24.45	19.57	27.63	26.98	
1999	23.62	18.43	25.69	25.22	
2000	22.97	17.42	25.57	25.16	15.27
2001	32.94	27.67	47.24	41.34	14.19
2002	26.79	21.90	28.96	30.64	9.45
2003	25.70	21.50	33.50	30.95	13.88
2004	26.20	22.14	35.60	31.72	9.33
2005	24.30	21.29	33.86	28.67	7.99
2006	24.24	20.89	33.21	27.98	8.63
2007	24.18	20.98	32.69	27.63	8.77
2008	24.05	21.37	32.02	27.53	9.18
2009	23.78	21.86	31.42	27.85	9.75
2010	23.10	22.42	30.91	28.00	10.05
2011	22.86	22.78	30.81	27.55	10.29
2012	22.76	22.70	30.89	26.94	10.50
2013	22.72	22.57	30.94	26.39	10.42
2014	22.68	22.41	30.83	25.88	10.49
2015	22.64	22.26	30.55	25.42	10.84
2016	22.61	22.10	30.49	24.96	10.71
2017	22.58	21.94	30.53	24.53	10.49
2018	22.54	21.78	30.57	24.06	10.29
2019	22.51	21.62	30.59	23.60	10.13
2020	22.48	21.47	30.61	23.14	9.98
2021	22.45	21.31	30.63	22.74	9.83
2022	22.42	21.16	30.65	22.37	9.69
2023	22.39	21.01	30.67	21.99	9.54
2024	22.36	20.86	30.69	21.62	9.40
2025	22.33	20.71	30.71	21.26	9.27
2026	22.30	20.55	30.72	20.91	9.13
2027	22.27	20.40	30.74	20.56	9.00
2028	22.25	20.26	30.77	20.23	8.87
2029	22.22	20.12	30.80	19.90	8.75
2030	22.20	19.98	30.83	19.57	8.62

Table 8

Florida
Delivered Coal Prices
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb
2000	42.37	37.01	38.88	39.28
2001	52.96	47.75	61.04	56.01
2002	46.83	41.93	43.04	45.51
2003	46.55	42.28	48.38	46.61
2004	47.63	43.45	51.18	48.00
2005	46.35	43.18	50.21	45.57
2006	47.02	43.43	50.39	45.62
2007	47.70	44.20	50.72	46.02
2008	48.41	45.41	50.96	46.78
2009	49.07	46.86	51.36	48.12
2010	49.27	48.46	51.90	49.34
2011	50.03	49.93	53.00	49.94
2012	51.02	50.95	54.38	50.36
2013	52.14	51.95	55.80	50.89
2014	53.36	53.00	57.14	51.53
2015	54.58	54.06	58.27	52.24
2016	55.83	55.11	59.70	52.91
2017	57.16	56.25	61.39	53.67
2018	58.62	57.49	63.19	54.47
2019	60.16	58.80	65.08	55.30
2020	61.75	60.14	67.03	56.14
2021	63.39	61.52	69.05	57.09
2022	65.09	62.94	71.14	58.08
2023	66.82	64.38	73.29	59.07
2024	68.60	65.86	75.50	60.07
2025	70.45	67.39	77.79	61.12
2026	72.35	68.95	80.16	62.18
2027	74.30	70.55	82.61	63.27
2028	76.32	72.19	85.14	64.38
2029	78.39	73.88	87.75	65.51
2030	80.53	75.60	90.44	66.66

Table 8

Florida
Delivered Coal Prices
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb
2000	43.86	38.31	40.25	40.66
2001	53.56	48.29	61.73	56.65
2002	46.83	41.93	43.04	45.51
2003	45.84	41.64	47.65	45.90
2004	46.22	42.16	49.67	46.58
2005	44.11	41.09	47.78	43.37
2006	43.84	40.49	46.98	42.53
2007	43.54	40.35	46.29	42.00
2008	43.21	40.53	45.48	41.75
2009	42.75	40.82	44.74	41.92
2010	41.84	41.16	44.08	41.91
2011	41.35	41.27	43.80	41.28
2012	41.02	40.96	43.72	40.49
2013	40.74	40.59	43.60	39.76
2014	40.44	40.16	43.31	39.05
2015	40.12	39.73	42.83	38.40
2016	39.82	39.31	42.58	37.74
2017	39.53	38.90	42.45	37.11
2018	39.25	38.49	42.31	36.47
2019	38.97	38.09	42.16	35.82
2020	38.69	37.68	42.00	35.18
2021	38.42	37.29	41.85	34.60
2022	38.16	36.90	41.71	34.05
2023	37.90	36.52	41.57	33.50
2024	37.65	36.14	41.43	32.96
2025	37.39	35.77	41.29	32.44
2026	37.14	35.40	41.15	31.92
2027	36.90	35.04	41.02	31.42
2028	36.67	34.69	40.91	30.94
2029	36.45	34.35	40.80	30.46
2030	36.23	34.01	40.69	29.99

Table 9

IMPLICIT PRICE DEFLATOR
2002 = 1.000

1995	0.887
1996	0.904
1997	0.921
1998	0.933
1999	0.946
2000	0.966
2001	0.989
2002	1.000
2003	1.015
2004	1.030
2005	1.051
2006	1.073
2007	1.096
2008	1.121
2009	1.148
2010	1.177
2011	1.210
2012	1.244
2013	1.280
2014	1.320
2015	1.361
2016	1.402
2017	1.446
2018	1.494
2019	1.544
2020	1.596
2021	1.650
2022	1.706
2023	1.763
2024	1.822
2025	1.884
2026	1.948
2027	2.014
2028	2.081
2029	2.151
2030	2.223

BASE CASE GAS PRICE FORECAST, April 2003

		PAYNE CREEK (6)				Reliant Constalation & New Units w/daily trans		Calnine Osprey w/firm trans		Hardee Power Station	
		Up to 57 K Dth/day		Over 57 K Dth/day							
Year	Gas Price Into Pipe $/Dth	Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth	Vary Trans Use & Fuel $/Dth	Delvd Price $/Dth
	(1)	(2)		(3)		(3)		(4)		(5)	
2003	$5.46	$0.26	$5.73	$0.92	$6.38	$1.10	$6.56	$0.24	$5.70	$0.84	$6.30
2004	$4.28	$0.24	$4.52	$0.88	$5.16	$1.06	$5.34	$0.23	$4.50	$0.80	$5.08
2005	$3.95	$0.23	$4.19	$0.87	$4.83	$1.05	$5.01	$0.22	$4.17	$0.79	$4.75
2006	$3.79	$0.23	$4.02	$0.87	$4.66	$1.05	$4.84	$0.22	$4.01	$0.79	$4.58
2007	$3.91	$0.23	$4.14	$0.87	$4.78	$1.05	$4.96	$0.22	$4.13	$0.79	$4.70
2008	$4.06	$0.23	$4.29	$0.88	$4.93	$1.06	$5.11	$0.22	$4.28	$0.80	$4.86
2009	$4.15	$0.24	$4.39	$0.88	$5.03	$1.06	$5.21	$0.22	$4.38	$0.80	$4.95
2010	$4.30	$0.24	$4.54	$0.88	$5.18	$1.06	$5.36	$0.23	$4.53	$0.80	$5.10
2011	$4.56	$0.24	$4.81	$0.89	$5.45	$1.07	$5.63	$0.23	$4.79	$0.81	$5.37
2012	$4.76	$0.25	$5.00	$0.90	$5.65	$1.08	$5.83	$0.23	$4.99	$0.82	$5.57
2013	$4.92	$0.25	$5.17	$0.90	$5.82	$1.08	$6.00	$0.23	$5.15	$0.82	$5.74
2014	$5.05	$0.25	$5.30	$0.91	$5.95	$1.09	$6.13	$0.23	$5.28	$0.83	$5.87
2015	$5.24	$0.26	$5.50	$0.91	$6.15	$1.09	$6.33	$0.24	$5.48	$0.83	$6.07
2016	$5.40	$0.26	$5.67	$0.92	$6.32	$1.10	$6.50	$0.24	$5.64	$0.84	$6.24
2017	$5.56	$0.27	$5.83	$0.92	$6.48	$1.10	$6.66	$0.24	$5.80	$0.84	$6.40
2018	$5.76	$0.27	$6.02	$0.93	$6.68	$1.11	$6.86	$0.24	$6.00	$0.85	$6.60
2019	$5.93	$0.27	$6.20	$0.93	$6.86	$1.11	$7.04	$0.25	$6.17	$0.85	$6.78
2020	$6.12	$0.28	$6.39	$0.94	$7.06	$1.12	$7.24	$0.25	$6.37	$0.86	$6.98
	$6.36										
	$6.60										
	$6.85										
	$7.09										
	$7.35										

	FGT	GS	PGS
Compressor Fuel %:	3.0%	1.3%	3.0%
Usage Fees $/Dth:	$0.04	$0.02	$0.041
Mkt Swing Trans:	$0.78	$0.60	$0.48
Transportation Basis - HHub:	$0.15		

Year	Coal, Delvd Pitt Seam	Ill Hi Sulf
2003	1.655	1.691	1.704
2004	1.812	1.697	1.715
2005	1.791	1.673	1.644
2006	1.780	1.661	1.656
2007	1.778	1.656	1.684
2008	1.804	1.680	1.726
2009	1.855	1.731	1.777
2010	1.894	1.770	1.831
2011	1.910	1.786	1.880
2012	1.918	1.796	1.914
2013	1.930	1.810	1.948
2014	1.944	1.826	1.980
2015	1.962	1.846	2.015
2016	1.980	1.865	2.049
2017	2.000	1.888	2.087
2018	2.020	1.911	2.128
2019	2.039	1.935	2.170
2020	2.058	1.958	2.213
	2.081	1.986	2.259
	2.105	2.017	2.308
	2.128	2.048	2.357
	2.153	2.080	2.408
	2.179	2.114	2.462
	2.202		
	2.225		
	2.248		
	2.272		
	2.296		
	2.320		
	2.344		
	2.369		
	2.394		
	2.419		

NOTES:

(1) 2003 - 2025 is forecast as provided by Global Insight in April 2003, Henry Hub price.. Beyond that point, prices reflect escalation based on a 10-year average.

(2) The charges for up to 57,000 Dth/day are based on 25,000 Dth/day of FGT firm capacity with 3.0% compressor fuel and $.04/Dth usage charge, and 32,000 Dth/day of Gulfstream firm capacity with 1.3% compressor fuel and $.02/Dth usage charge.

(3) The charges for daily bundled volumetric transportaion assume Gulfstream volumetric daily market interruptable capacity will set market prices on both Gulfstream and FGT. Compressor fuel is assumed to be 3.0% and daily market transportation is a weighted average of estimated $0.60/Dth in the summer and in the shoulder months.

(4) Assumes all transportation is provide by a firm contract. Assumes the facility will be located on the Gulfstream pipeline with 1.3% compressor fuel and $0.02 usage charge. Use $0.70/Dth for the reservation cost of firm transportation.

(5) The FGT compressor fuel charge for HPS is 3.0%. Variable transportation is the current PGS shoulder month price of $0.48/Dth applied to all 12 months recognition that the majority of energy is consumed during the shoulder months.

(6) The Payne Creek fixed annual reservation charge is calaculated as follows:

2003

FGT 25,000 x 365 x $0.715 = $6,524,375
GST 32,000 x 365 x $0.570 = $6,657,600
Total =$13,181,975

2004

FGT 25,000 x 366 x $0.7852 = $6,937,703
GST 32,000 x 366 x $0.570 = $6,675,840
Total = $13,613,543

2005 and beyond

FGT 25,000 x 365 x $0.7959 = $7,262,659
GST 32,000 x 365 x $0.570 = $6,657,600
Total = $13,920,259

Global Insight Fuel Price Forecast
Petcoke Prices Per Ton, Prior to Shipping Costs

	commodity price		
	$19.72		
	$10.06		
	$9.43		
2006	$9.58		
2007	$9.77		
2008	$9.99		
2009	$10.24		
2010	$10.44		
2011	$10.66		
2012	$10.90		
2013	$11.19		
2014	$11.45		
2015	$11.73	Escalation	
2016	$12.03	1.0256	
2017	$12.35	1.0266	
2018	$12.69	1.0275	
2019	$13.03	1.0268	
2020	$13.38	1.0269	
2021	$13.74	1.0269	
2022	$14.12	1.0277	
2023	$14.52	1.0283	
2024	$14.93	1.0282	Avg
2025	$15.35	1.0281	1.0273
2026	**$15.77**		
2027	**$16.20**		
2028	**$16.64**		
2029	**$17.09**		
2030	**$17.56**		
2031	**$18.04**		
2032	**$18.53**		
2033	**$19.04**		
2034	**$19.55**		
2035	**$20.09**		

FUEL PRICE SERVICE

UTILITY FUEL PRICES FOR THE SOUTH ATLANTIC REGION

PREPARED FOR: SEMINOLE ELECTRIC COOPERATIVE, INC.

MARCH 2003

Analysis of Utility Fuel Prices in the South Atlantic Region

Prepared for: Seminole Electric

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Note: The short-term distillate and natural gas price forecasts were prepared in March 2003. The long-term forecasts represent Global Insight's latest long-term fuel price analysis, which was prepared in October 2002.

FORECAST HIGHLIGHTS

Petroleum

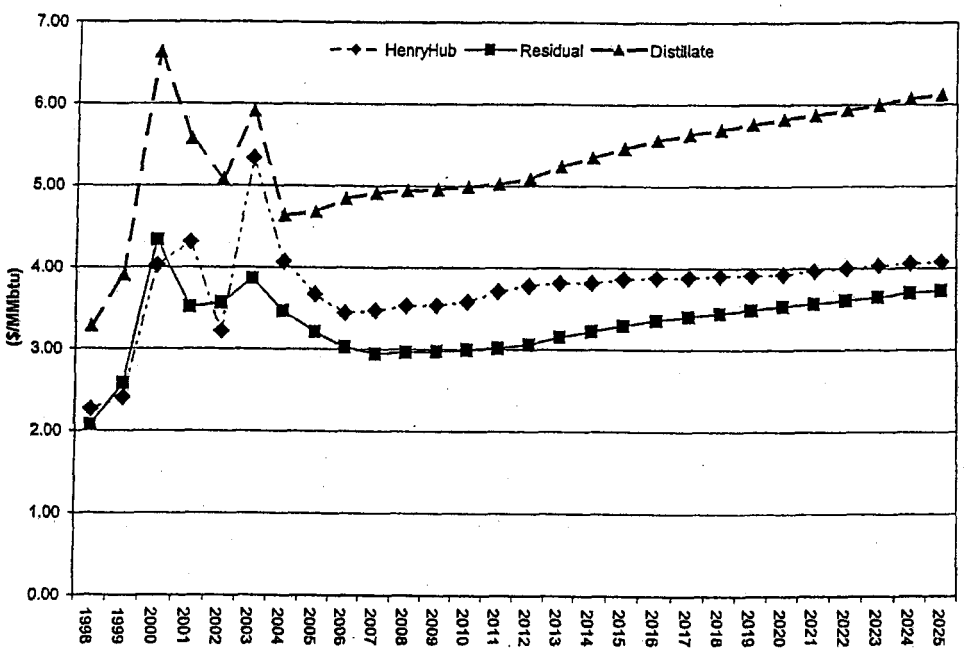
- The oil price forecasts were prepared in early March and war was included as an assumption in the base crude oil price scenario. War was assumed to commence in late March or early April; the fact that it started sooner does not compromise the forecast. The war assumption includes the notion that the war will be relatively "quick and clean." "Quick and clean" means that the war is expected to be over, or nearly over, in less than two months and that there is no damage done to oil infrastructure outside of Iraq. Prices spiked prior to the war in anticipation of a possible, large-scale supply disruption, but once it was clear that supply from other Middle East producers was secure, prices retreated.
- Lean oil stocks, particularly in the United States, will allow for a period of oversupply—indeed, it is necessary in order to return stocks to more-normal levels. A large stock build is expected in the second quarter, which will bring some price relief, but tight product markets, again, particularly in the U.S., will keep prices from falling too far.
- OPEC left quotas unchanged at its March 11 meeting; however, with Venezuelan production still recovering and the prospects of war halting Iraqi exports, the quotas are meaningless right now. Once the war is over, expect OPEC to convene and review market fundamentals, then begin to scale back output to avoid an extended period of oversupply.
- The onset of war, a pickup in demand in the second half of the year, and OPEC market management should keep prices supported for the rest of this year, and West Texas Intermediate (WTI) is now expected to average over $29/barrel in 2003 after averaging $26/barrel last year. Fundamentals are still bearish for 2004, so WTI is expected to dip below $25/barrel next year.
- Oil prices are expected to slowly decrease over the next couple of years as supply growth outpaces demand growth. The high oil price environment that has been present since mid-1999 has led to increased investment in non-OPEC supply. Those investments have begun to bear fruit, particularly in Russia, West Africa, Mexico, and the Caspian region. Production capacity is also rising within OPEC, and some of the cartel members are eager to exploit their new production capacity.
- Global economic growth is expected to average approximately 3% annually starting in 2004, which will eventually fuel the anticipated growth in oil demand. By 2005, oil prices should begin a slow ascent (measured in constant dollars) that is likely to continue throughout the forecast period. Prices will be supported by rising demand for oil, as well as OPEC's continued policy of output restraint, a strategy that will be necessary in order for the cartel to maintain their price objectives.

Natural Gas

- The March natural gas price forecast reflects a war with Iraq that lasts two months and leads to lower oil prices by the second half of 2003. Natural gas prices, however, will remain high this summer. The natural gas situation is worsening, as a cold winter has depleted storage inventories towards historical minimums in both Canada and the United States. Supply trends also worsened in the most recent reports, with Canadian production down over 0.3 billion cubic feet per day (Bcfd) for the first quarter of 2003, while U.S. production decreased further in fall 2002 than previously expected. Overall, Henry Hub cash prices are expected to average above $5 for 2003.

- The supply and demand indicator shows about a 3-Bcfd deterioration in the first quarter of 2003. Spot prices averaged close to $9 during early March, while eastern citygate prices were often over $10. While high prices earlier this winter resulted in interfuel substitution, low inventories of fuel oil have limited further use of oil. Consequently, demand destruction occurred in the industrial sector, as ammonia plants shut down and other industries reduced consumption of natural gas.
- Entering the spring and summer refill season, natural gas balances are far below normal. Consequently, North American storage will have to be rebuilt this summer at a rate of about 5 Bcfd above last year's. Most supply indicators remain negative, so a rebound in production will be delayed until at least the second half of 2003, if not until 2004. Less gas will be available for consumption than last year. Thus, there will be a squeeze on other consumers of natural gas, particularly industry. Consumption of natural gas will be limited by availability this summer, implying high prices.
- The base case oil price forecast is a major factor in determining the gas price forecast. Natural gas prices have to be high enough to cause fuel switching since there is not enough gas available to both meet demand and to rebuild storage. Also, prices are likely to reach high peaks and lead to demand destruction. A key near-term issue is whether natural gas prices will jump sharply as the U.S. economy recovers and productive capacity declines.

Fuel Price Trends For Florida
($/MMBtu)



Source Platt's oil prices, Inside Ferc Natural Gas Report Henry Hub

00242

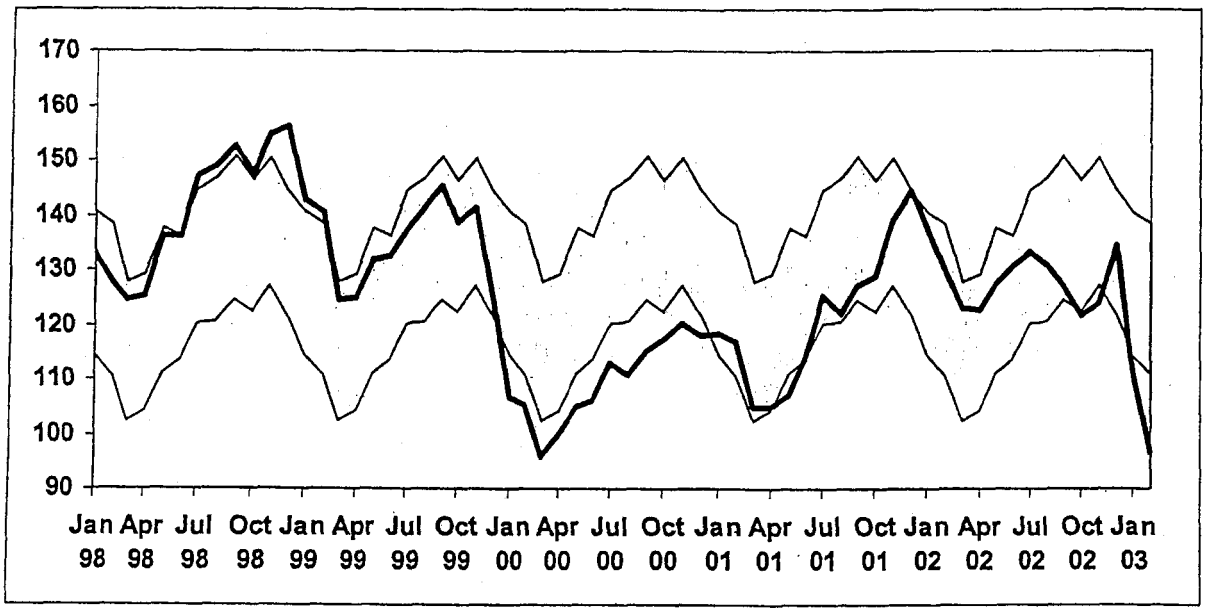
DISTILLATE FUEL

Weak demand and high stock levels applied a bearish tone to distillate prices for most of 2002, but a very cold start to winter coupled with surging crude prices returned distillate prices in the early part of 2003 to levels not seen since early in 2001. With so much turbulence in crude markets, crude prices are likely to remain high through at least the second quarter of 2003; distillate prices should remain supported as well, though not at he levels seen earlier this year.

The cold winter has raised U.S. distillate demand. In November and December, U.S. distillate demand averaged nearly 4 million b/d, about 8% higher than a year earlier. The trend continued in January and February, as distillate demand averaged 4.3 million b/d, about 13% higher than the year before. Predictably, heating degree days have been higher this year than last and have also been higher than normal. Heating degree days were about 29% higher than last year (September through March 21) and about 6% higher than normal for the same period. The higher demand levels and the rise in crude prices pushed distillate at the U.S. Gulf Coast to 106¢/gallon in February, a level that is believed to be a record.

The high price of crude oil, though, has slowed refinery runs. Although yields are normal, total output has been falling because of the reduced runs; distillate production ran at about 3.4 million b/d in January and February. Imports of distillate are up year over year, but the combination of production and imports has so far been lagging that of demand. As a result, distillate stocks are falling. Distillate stocks at the end of February had dropped to 96.5 million barrels, roughly 26 million barrels lower than a year earlier. Forward cover in February fell to 25.5 days, its lowest level ever. Forward cover will likely drop by another day in March, but with the end of winter coming, distillate demand should weaken and stocks should begin to recover. In addition, the high price of distillate in the United States has probably attracted many cargoes and thus imports should rise as well. Again, with demand weakening, the imports should find their way into stocks.

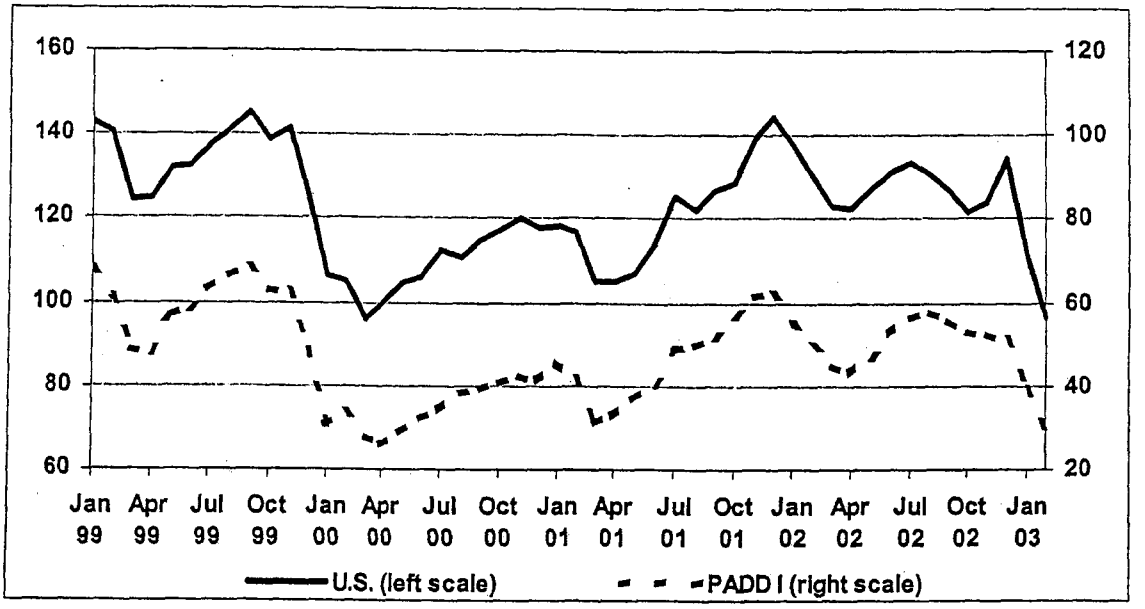
U.S. Distillate Stocks and Average Ranges
(Million barrels)



Source: U.S. Department of Energy.

00243

Distillate Stocks in the U.S. and PADD I
(Million barrels, monthly)



Source: U.S. Department of Energy.

U.S. distillate stocks at the end of February stood at about 96.5 million barrels, about 26 million barrels less than at the same time in 2001. Distillate stocks in PADD I were about 29.5 million barrels, nearly 20 million barrels less than at the end of February of 2002. In the Lower Atlantic region of PADD I, stocks were at 10 million barrels, nearly 3 million barrels less than the level a year ago.

Stocks spent the first half of 2002 at or near the top of the historical range. However, very weak refining margins caused refiners to cut back on distillate production, as refiners opted to produce as much gasoline as possible because of a slighter better rate of return. In fact, in some instances distillate was re-run through refineries to produce more gasoline. The net effect of reducing distillate supply was to cause drawdowns of distillate stocks at a time when inventories are normally building to ensure adequate supply during the winter heating season. The drawdowns moved distillate stocks out of the normal range late in 2002, with inventory levels returning to the low end of the range by the end of the year.

U.S. distillate inventories have been low before, but what makes this situation unique is the combination of the unrest in Venezuela and the heavy refiner maintenance that occurred in February.

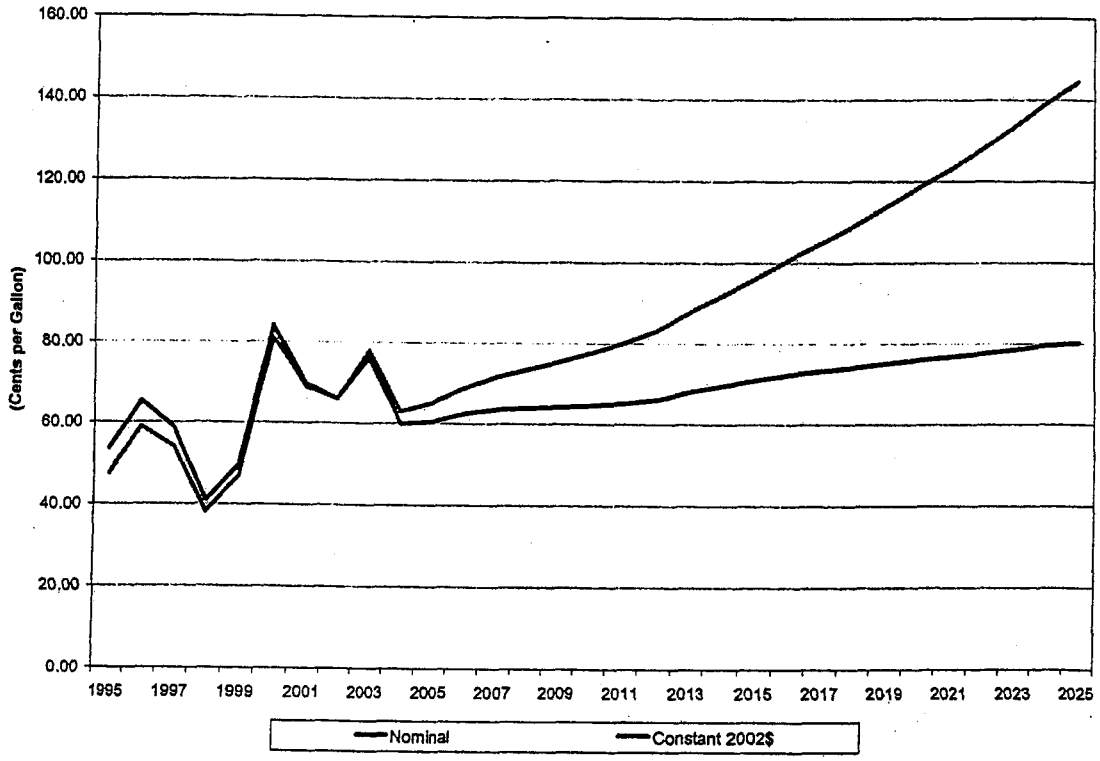
Because of the unrest in Venezuela, lower volumes of crude are making its way to the U.S. in the form of imports. This caused a run-up in crude prices, but the by-product of the price run-up and the lower import volumes are that margins have shrunk again and there is less crude available. Both of these factors caused refiners to consider lowering crude runs, which reduced output of oil products. In addition, up to 800,000 b/d of refining capacity was down during the month of February due to regular maintenance. Again, this resulted in lower volumes of product production.

In light of these facts, distillate stocks should stay at the low end of the normal range and perhaps even below the normal range, thus keeping firm support beneath distillate prices over the next few months, but distillate market fundamentals should gradually improve over the course of the second and third quarters, thus removing some of the upward price pressure. Gulf Coast distillate prices averaged 66¢/gallon in 2002. Because of the expected beginning-of-the-year strength in prices, Gulf Coast distillate prices are

expected to average moderately higher in 2003, with the forecast projecting a yearly average of 78¢/gallon.

Distillate prices in 2004 are expected to drop to a yearly average of 63¢/gallon, primarily because crude prices are expected to dip under the weight of oversupply. However, intervention by OPEC to keep supply in check and markets balanced is possible, thus the chance of slightly higher prices in 2004.

Distillate Prices - Gulf Coast
(Cents per Gallon)



RESIDUAL FUEL

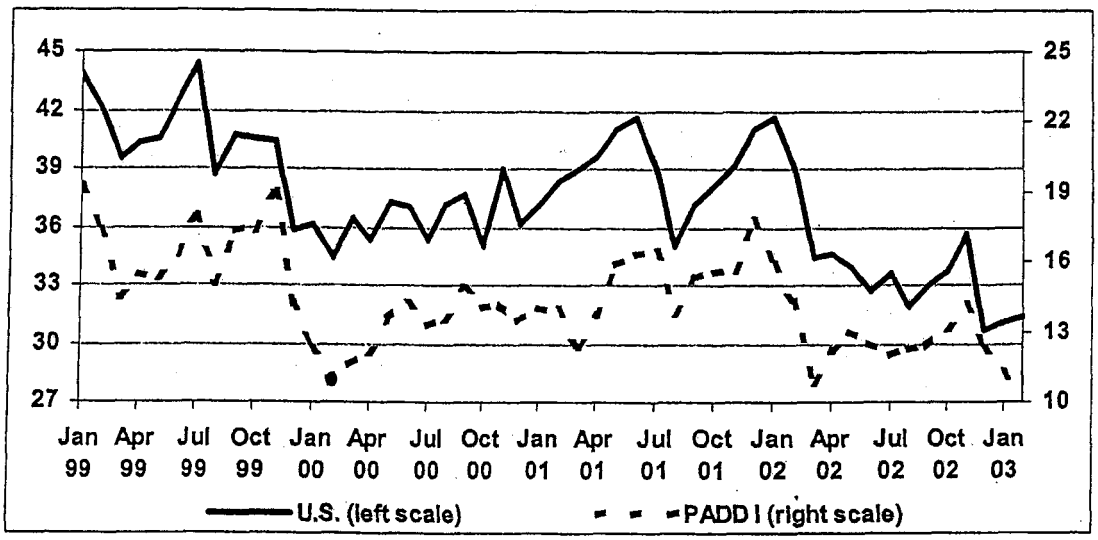
Changes in resid prices largely reflect changes in crude prices. Weak demand for resid in 2002 kept prices in check somewhat, but resid's rise from a low of $15.42/barrel (1% sulfur at the Gulf) in January 2002 to $34.68 in February 2003 reflected both the strength in the underlying crude prices that resulted from the often-chaotic global crude market and also an increase in demand.

Resid demand in 2002 shrank 20%, compared with demand in 2001. A return to more-normal pricing for natural gas removed the incentive to burn resid for power generation, but that dynamic changed somewhat in the early part of this year. The uptick in natural gas prices has spurred demand for resid. Demand in February was about 18% higher than in February 2002. Gulf Coast 1% sulfur spot resid in February was priced near $5.52/MMBtu, slightly less than Henry Hub natural gas prices.

Resid stocks have been below the normal range since May 2001, and while low stocks for other products causes concern, the drop in resid stocks has not—at least not yet. Estimated U.S. stocks of residual fuel at the end of February stood at about 31 million barrels, about 20 million barrels less than at the end of February 2002. Resid inventories have been below the normal range, but because demand was so weak, days of forward supply was above 50 days for most of 2002. With the recent rise in demand and drop in stocks, forward cover has suddenly slipped to 33 days—still not a cause for outright alarm, but certainly supportive for prices.

Natural gas prices are expected to remain relatively high for the rest of this year—Henry Hub natural gas prices are expected to average just over $5.00/MMBtu from April through December. Resid prices are expected to be below that of natural gas, thus resid demand should continue to be stronger than it was a year ago. Therefore, Global Insight expects the strength in resid prices to continue as well. Resid at the Gulf Coast (1% sulfur) is expected to average about $22/barrel over the last three quarters of this year, falling further in 2004 as crude prices decline. However, stronger prices could be reached if summer weather turns out to be hotter than normal and supply issues arise for natural gas.

Residual Fuel Stocks in the U.S. and PADD I
(Million barrels)

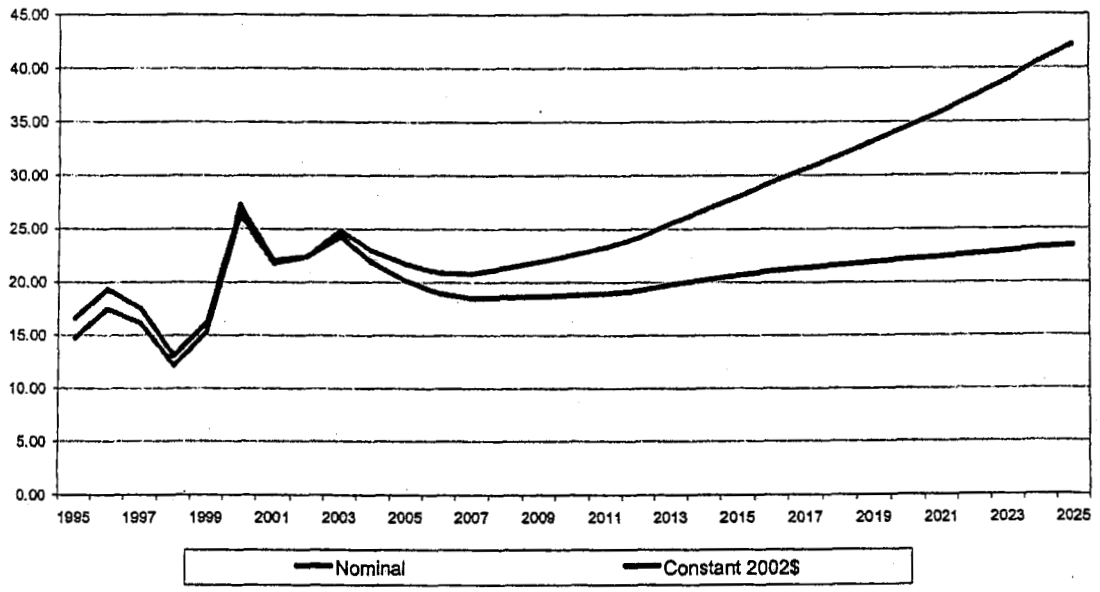


Source: U.S. Department of Energy.

From 2005 to 2020, residual fuel demand for electric generation in the U.S. is foreseen to fall by 2.1% annually. Total U.S. oil demand for electric generation is expected to rise by 2.5%, and distillate demand by 9% annually over the same interval. Thus, residual fuel will be displaced by distillate fuel over that period. Residual fuel production is expected to decline over that period as well. The outlook for prices is that they will track crude's eventual progress, but the downward pressure of falling demand will limit price growth. Residual fuel prices to electric utilities in the South Atlantic region will remain at a discount to distillate prices throughout the forecast.

00246

Residual Fuel Prices - Gulf Coast 1% Sulfur
(Dollars per Barrel)



00247

NATURAL GAS

The March natural gas price forecast reflects a war with Iraq that lasts two months and leads to lower oil prices by the second half of 2003. Natural gas prices, however, will remain high this summer. The natural gas situation is worsening, as a cold winter has depleted storage inventories towards historical minimums in both Canada and the United States. Supply trends also worsened in the most recent reports, with Canadian production down over 0.3 billion cubic feet per day (Bcfd) for the first quarter of 2003, while U.S. production decreased further in fall 2002 than previously expected. Overall, Henry Hub cash prices are expected to average above $5 for 2003.

The supply and demand indicator shows about a 3-Bcfd deterioration in the first quarter of 2003. Spot prices averaged close to $9 during early March, while eastern citygate prices were often over $10. While high prices earlier this winter resulted in interfuel substitution, low inventories of fuel oil have limited further use of oil. Consequently, demand destruction occurred in the industrial sector, as ammonia plants shut down and other industries reduced consumption of natural gas.

Entering the spring and summer refill season, natural gas balances are far below normal. Consequently, North American storage will have to be rebuilt this summer at a rate of about 5 Bcfd above last year's. Most supply indicators remain negative, so a rebound in production will be delayed until at least the second half of 2003, if not until 2004. Less gas will be available for consumption than last year. Thus, there will be a squeeze on other consumers of natural gas, particularly industry. Consumption of natural gas will be limited by availability this summer, implying high prices.

The base case oil price forecast is a major factor in determining the gas price forecast. Natural gas prices have to be high enough to cause fuel switching since there is not enough gas available to both meet demand and to rebuild storage. Also, prices are likely to reach high peaks and lead to demand destruction.

Base Case Key Assumptions:

- Short war (two months or less) starts in March.
- Minimal coalition casualties.
- No major oil disruption.
- Oil prices average $29 for the whole year.
- The dollar falls gradually, losing 4% of its value against industrial country currencies during 2003.
- Falling confidence and stock prices hamper growth, but rebound after successful conclusion of war.
- Tax cuts, plus additional $50 billion in defense spending help to sustain the recovery.
- 60% probability.

Natural gas prices will not fall this year as they did in 2001. During 2001, the economy was in recession and demand was falling. Also, a rapid increase in drilling activity caused production to increase. This year, economic recovery, growing demand for natural gas, and decreasing supply present an inconsistent picture for gas markets this year. If as expected, natural gas production continues to decline in the United States, then prices will remain above fuel oil and perhaps even higher than distillate prices. In the Base

Case, natural gas prices are expected to remain in the $5 range through the rest of 2003. Though there are some new supplies, such as Kern River and Cove Point, coming on-line this year, these will have small regional impacts rather than national implications. Canada has a similar supply and demand imbalance, and will be hard pressed to sustain current levels of exports to the United States. Canadian natural gas supply is down over 0.3 Bcfd in early 2003, despite record drilling activity. Mexican demand for U.S. gas is also growing. Thus, trade trends will, if anything, accentuate the problems facing the United States.

Upside risks to the forecast include oil issues such as the progress of the war in Iraq, the aftermath of the oil strike in Venezuela, and chaos in Nigeria. Oil inventories remain low, and so further disruption of world oil markets will have significant impacts on U.S. prices. The downside risk is a rebound in U.S. and Canadian supply. While Canadian drilling activity is running 70% over a year ago, U.S. drilling activity is up only 10% from year-ago levels and is more than 30% below the peak in 2001.

Near Term Prices

In the aftermath of extremely high prices in 2001, supply and demand trends quickly brought prices down. In 2001, supply was trending up and demand was trending down. This year, the trends are reversed—supply is decreasing and demand is increasing. Consequently, the expected increase in demand for 2003 will be constrained as storage is rebuilt. With economic growth of about 3.5% expected for fourth-quarter 2003, over fourth-quarter 2002, natural gas demand would normally grow about 1 trillion cubic feet (Tcf). Global Insight expects total consumption of natural gas to be slightly lower in 2003 than in 2002 because of the constraint imposed by declining U.S. production. Thus, about 3 billion cubic feet per day (Bcfd) of demand will have to shift to alternative fuels or be shut-in. Since much of first-quarter demand was met with storage withdrawals, the prospect for demand destruction is high for the remainder of 2003.

Fourth-quarter 2002 U.S. natural gas production is expected to be about 6% below the level in 2001. Even with U.S. drilling activity increasing, production is expected to be down in 2003 because of the lead-time necessary to turn around this trend. U.S. production will get a boost in the second half of 2003 from the start up of Kern River expansion and from numerous deepwater Gulf of Mexico projects, such as Na Kika. By 2004, U.S. production should be stabilized.

Imports of natural gas offer little prospect for an increase in supply this year. The source of most imports, Canada, is also experiencing decreasing production and a requirement to rebuild working gas inventories from historically low levels. Mexican imports of gas are increasing. LNG imports briefly reached 900 million cubic feet per day in fall 2002, a level that will be exceeded in 2003, but not by much. Thus, net imports of natural gas will hold close to 2002 levels.

Storage rebuild will require over 5 Bcfd of additional injections in April–October, compared with last year. With North American storage 1.2 Tcf below year-ago levels, storage rebuild will take priority for local distributors this summer. The situation is extreme. It is possible that storage rebuild will encounter physical limits and working gas in storage will reach October at less-than-optimal levels. Also, it is possible that storage injections will be reported for one or more weeks in March, as operators take advantage of mild weather to get a head start on what will prove to be a difficult endeavor. Thus, the availability of natural gas this summer will be dramatically less than last year. Consumption will be constrained by availability at levels below 2002.

Recent supply and demand balances show that fuel oil consumption has been increasing and that many energy-intensive industrial facilities have been reducing natural gas use, particularly in the ammonia

industry, as a result of high prices. During the second quarter of 2003, demand growth of about 3 Bcfd would normally ensue from the economic outlook. However, supply constraints and the 5 Bcfd of additional storage injections will severely limit demand growth. The crunch on gas supply and demand should be alleviated in part during the third quarter of 2003, as new supply sources from Kern River, Cove Point, and offshore Gulf of Mexico become available.

U.S. electricity demand is expected to grow by about 1.1% in 2003, with most of the growth coming in the beginning of the year. With normal or mild weather, third- and fourth-quarter demands are lower than those of 2002. Power generation with natural gas is expected to trail year-ago levels for the second half of 2003.

U.S. Storage

According to the DOE/EIA storage survey for the week ending March 14, working gas storage was 636 Bcf, or 1,000 Bcf below last year's level (Table 7). Last year, high levels of working gas in storage meant that storage withdrawals continued into April. This year, injections could start in March. Working gas in storage is expected to rebound slightly in late March. Also, the monthly storage levels, which reflect a census of all storage operators, have been higher than the weekly surveys. Thus, the end-of-quarter storage level using monthly data is expected to be slightly above the weekly survey. Working gas in storage for the end of March 2003 will be 600–700 Bcf, compared with 1,500 Bcf last year.

The trend in storage injections is weather sensitive. An indicator of market tightness is calculated from the trend in storage injections, compared with year-ago and five-year averages, adjusted for changes in degree-days and nuclear generation. For recent months, a very high rate of storage withdrawals has been caused by extreme weather. Thus, the indicator suggested that the market was responding to weather rather than being tighter. If weather-adjustment parameters are used from prior years, the indicator would still be that the market is tightening by about 3 Bcfd for January and February. Other indicators such as the continuing decline in U.S. production, the very large draw down in Canadian storage, and the 7% growth rate for power generations for the past three quarters also indicate continued tightening of the North American gas market. This spring, the overall supply demand indicators will continue to indicate significant tightness, though the weather-adjusted storage will show much higher levels of net injections than last year.

U.S. Production

Continued revisions and updates to EIA data show that the rate of decline in U.S. dry gas production (Table 11) accelerated in the fourth quarter of 2002, while Texas onshore gas well production was also decreasing by about 1% (Table 12). Other production indicators, such as company reports and drilling activity, support the conclusion of declining supply. While rigs drilling for natural gas have had diminished effect on production in recent years, a hypothetical increase in supply would require an increase in reserves and producing wells, which is brought about by drilling. In 2001, it took 22,000 gas wells to increase production by about 400 billion cubic feet (Bcf). When gas well completions slipped to 16,000 in 2002, gas production fell by an apparent 700 Bcf. For 2003, gas well completions could exceed 19,000, with an average of 850 gas rigs drilling. Whether this is enough to lead to an increase in U.S. gas production is uncertain.

The natural gas rig count in March rose to 760, more than 10% above year-ago levels, but far short of the 1,058 peak reached in July 2001. Production is expected to continue on a downward trend in the first half of 2003, following meager trends in rig activity and spending. The U.S. gas-directed rig count averaged about 700 in 2002 and should average 850 for 2003. A strong pickup in U.S. drilling activity during the second half of 2003 could turn around the recent declines in supply.

00250

For 2002, production is now reported at nearly 700 million cubic feet per day (mmcfd) below year-ago levels. With the survey of major U.S. producers showing a 5–6% decline in every quarter of 2002, gas production is starting 2003 off on a downward trend.

The Rocky Mountains will increase gas production during 2003, perhaps the only major basin to do so. Rocky Mountain supply is constrained by pipeline capacity, which will be alleviated in part by the Kern River expansion in May 2003. The Bureau of Land Management has approved 39,000 coal bed methane wells for the Powder River Basin area. These wells are expected to have supply costs around $2 per mmcf, so most will be drilled. An average well adds about 300 mmcf of gas reserves. Thus, the total drilling program could add over 11 trillion cubic feet of gas reserves and up to 3 Bcfd of additional production.

The Bureau of Land Management has also been asked to approve a substantial increase in infill drilling in the Jonah field in Wyoming. This basin is providing a large share of the production increase for the Kern River expansion. Further increases in gathering and processing will be required for the expected production increase. The Jonah field is one of the largest in Wyoming. Also, the Pinedale Anticline production is increasing. Williams field service is planning to add 350 mmcfd of processing capacity at its Opal plant to handle the increase in Pinedale production.

Overall, U.S. production is expected to decrease by nearly 2% in 2003, with most of the decrease coming in the first half of the year. The major supply increases projected for 2003 include Kern River, a full year of Canyon Express, and new deepwater projects of which five will be tied into the Okeanos pipeline, the opening of Cove Point, and a rebound in drilling activity in both Canada and hopefully the United States. These events should help to turn around dismal production trends. However, there are almost no new gas plants or producing area pipelines planned for this year, though several expansions are indicated for the Rockies. Thus, all of the leading indicators for supply, spending, offshore projects, rig count, natural gas plants, and pipelines are indicating flat to negative trends for U.S. production this year.

Interfuel substitution will have an impact on gas markets this year. Fuel oil demand is running about 3 billion cubic feet per day (Bcfd) ahead of year-ago trends in December and January; part of the increase is related to economic growth and a cold winter. There are two constraints on interfuel substitution. First, the capacity to use oil in place of natural gas has diminished in recent years, from 9 Bcfd in the mid 1990s to a lesser amount in 2003. Closure of old oil-fired power plants has contributed to the reduction in interfuel substitution capability. Second, fuel oil supply is limited by the very low inventories in the United States. Recent oil supply disruptions have made fuel oil expensive. Thus, interfuel substitution will not be sufficient in and of itself to replace declining natural gas supplies.

Demand destruction has been evidenced in the first quarter, as nearly one half of the ammonia industry has been shut down. Also, methanol-, aluminum-, and ethane-based industries have experienced fuel cost issues. The ammonia sector uses up to 1.6 Bcfd of gas supply in normal times, but reduced demand to less than 1 Bcfd during previous price spikes, such as early 2001. Ammonia, methanol, and aluminum have featured in demand destruction—a painful alternative to interfuel substitution—in past episodes of high prices.

Total natural gas demand will be constrained by supply and imports. U.S. natural gas production is expected to decrease about 2% in 2003, while net imports will increase only slightly. The startup of the third train at Trinidad in spring 2003 could add another 450 million cubic feet per day to U.S. imports. However, the dire inventory situation in Western Canada will curtail increases in exports to the United States. While natural gas consumption has increased in the first quarter of 2003 because of cold weather, the prospect is for year-over-year decreases during the remainder of this year.

Long-Term Prices

Long-term natural gas prices will be driven by the marginal cost of increasing supply and the demand response to price changes. The strong demand response to high natural gas prices was clearly evident in 2001. Residential and commercial customers lowered thermostats; industrial and power generators switched to residual fuel oil, and when prices were extremely high, to distillate fuel oil; and ammonia plants, which use gas inputs, were shut down.

On the other side of the equation is the marginal supply cost, which includes the costs of both production and transportation of natural gas. The cost estimates for new gas supply include a return on investment. Some supplies, such as coalbed methane, are very low cost. However, production from this source will not be adequate to meet North America's gas demand. Further, much of new coalbed methane production will come from the Rockies and western Canada. The transportation cost from these supplies to market will be quite high. At a minimum, gas supply from the Gulf offshore must be economic. The marginal supply cost suggests prices of above $3.00 per MMBtu at Henry Hub to balance the market.

This supply cost is likely to increase. A major cause of the increased production cost is that existing fields are maturing. New fields are smaller. The smaller fields mean that it takes more drilling and exploration to increase gas production. Also, the productive capacity of smaller wells declines faster than that of large wells. Higher decline rates mean that the United States now has to replace 27% of its productive capacity each year, compared with 14% in 1990. Thus, a slowdown in drilling activity would show up quickly in diminished supply capability.

As production increases, low-cost reserves will be depleted. The depletion of these reserves will make it necessary to develop higher cost supplies. This will require higher natural gas prices. Finding rates and the initial investment cost are the major determinants of supply cost. Finding rates are expected to remain fairly stable in the forecast period because of advances in seismic and drilling technology. Also, horizontal drilling often results in a high initial rate of production from a well—a good result and one that mitigates increases in the supply cost. Inflation in day rates and other drilling costs, however, is starting to reflect high utilization rates. Thus, the overall supply cost is rising in the near term, although it is assumed that technology advancements will limit the cost increases of conventional supplies to the rate of inflation over the next decade.

Still, the cost of meeting demand will require a large increase in the scale of the gas industry. A sequence of large-scale supply projects, including exploration, development, transportation, and storage, will have to be developed. The cheapest wellhead gas may be far distant from markets, requiring substantial additional investment downstream from the wellhead. Large-scale incremental gas supplies in the future will come from LNG, the Scotian Shelf, Newfoundland, and Alaska.

LNG supplies will require Henry Hub prices of between $2.85 per MMBtu and $4.00 per MMBtu. Supplies from the Scotian Shelf (off the cost of Nova Scotia) will require wellhead prices above $3.00 per MMBtu. The supply cost for Alaskan gas is expected to equate to Henry Hub prices of between $4.00 and $5.00 per MMBtu 2010 (between $3.20 and $4.00 in 2000 dollars).

The gas price required to develop deepwater supplies is complex. Three key factors are the size of reserves found, the success rate of exploration, and the cost of exploration. The PanCanadian Panuke field originally had a low probability of success. Changing assessment of the potential size of the field and the exploration cost first raised the prospect of going ahead and then further change, delayed it.

Also, there are economies of scale. The Maritimes and Northeast (M&N) pipeline currently has a capacity of 0.5 Bcf/day. There are proposals to expand M&N for supplies from Pan Canadian's Panuke production to 1 Bcf/day in 2006. It is anticipated that this expansion will lower the current transportation tariff to the U.S. from approximately $1.20 per MMBtu to $1.00 per MMBtu. Ultimately, the pipeline capacity could expand to 2 Bcf/day, with a tariff of $.75 per MMBtu.

LNG is the third source of imports that will help to set the long-run price of gas in the United States. New LNG projects can be developed at $2.85-4.00 per million Btu delivered to pipeline in the United States. The lower end of the price band reflects additions to the Atlantic LNG project in Trinidad and use of existing terminals, while the higher estimates reflect the costs for developing LNG at new sites more remote from the United States. (Projected growth in U.S. LNG imports would be handled by pre-existing receiving and regasification facilities, which lowers the price required to make LNG economic.)

The size and configuration of the proposed pipeline project will be important determinants of the cost of Alaskan natural gas supply. However, taxes, regulatory issues, and the application of technology will also be key factors driving the cost of Alaskan natural gas. There are 32-38 trillion cubic feet (Tcf) of recoverable gas reserves in the Prudhoe Bay area. Proposals to develop transportation services for Alaskan gas range from 4 to 6 billion cubic feet per day.

Two alternative routes for transporting natural gas from Alaska to the Lower 48 are being given the most serious consideration. The Mackenzie Delta Producers Group is advocating the so-called "over the top" or northern route. This route would go under the Beaufort Sea and through Canada's Mackenzie River Valley. The other route, the southern one, is the Alaskan Natural Gas Transportation System (ANGTS). Foothills Pipeline proposes this route.

The ANGTS project would go from the Prudhoe Bay in Alaska along the TransAlaskan Pipeline System (TAPS) and the Alaskan Highway to Gordondale, Alberta. The length of the pipeline is 1,750 miles. This pipeline system would also be able to access Mackenzie Delta's 9 Tcf of gas reserves through the proposed Dempster Lateral. The Alaskan Natural Gas Transportation System (ANGTS) has already been approved by environmental agencies, and is designed to connect to the Foothills and Northern Border pipeline facilities that were prebuilt for this project.

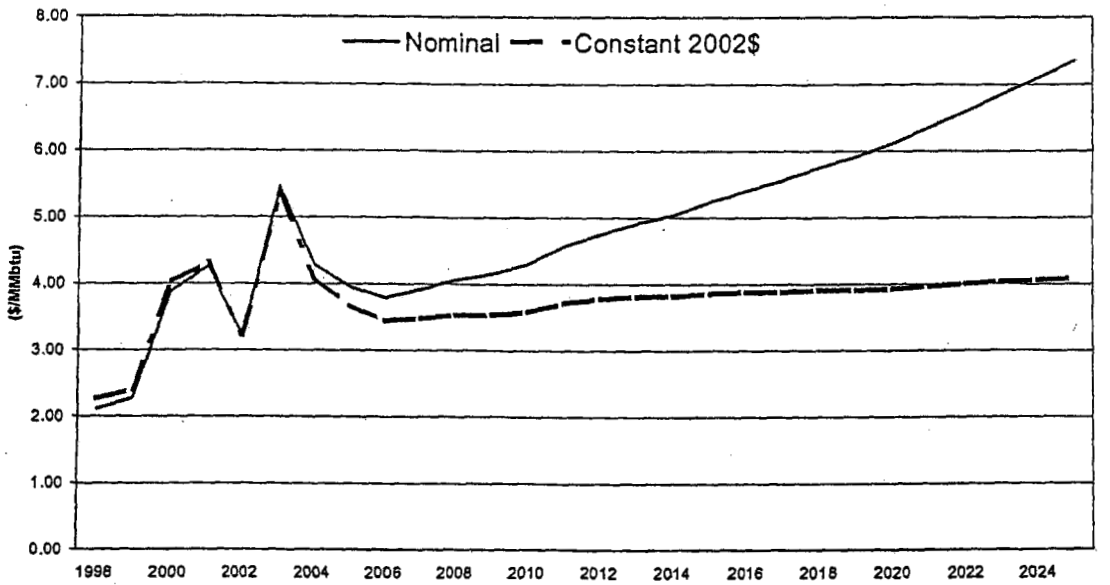
Estimated project costs for transporting natural gas from Alaska to Alberta range from $8 to $17 billion. The most recent estimates, released by the Mackenzie Delta Producers Group, were $15 billion for the northern route to $17 billion for the southern route. These cost estimates translate into estimated transportation costs ranging from $2.00 to $2.40 per MMBtu (nominal US dollars). A wellhead price of about $1.00-1.50 (in 2010 dollars) should be adequate to provide for the producers and governments. The current tariffs for Foothills and Northern Border are about $0.80 from Alberta to Chicago. Thus, a Chicago price of between $3.80 and $4.70 per MMBtu would be required by 2010. Chicago prices could range between zero and $.30 per MMBtu higher than Henry Hub prices by 2010. Thus, the Henry Hub prices that would make Alaskan gas economic range from $3.50 and $4.70 per MMBtu ($3.20 and $4.20 in 2000 dollars). At the low end of the range, Alaskan gas would be viable by 2010 and at the high end by 2015. The current forecast assumes that Alaskan gas will come on in late 2011.

The supply cost to reach a 30 Tcf gas market is thus dependent on LNG and Alaskan gas. If Alaskan gas requires a $3.80 price in Chicago, while LNG has a cost of close to $4.00 delivered to the East Coast, the equivalent Henry Hub prices would be about $3.50. At a much lower level of demand, the gas industry could be supplied from traditional sources at $2.50-$3.00. Hence, the long-term gas price reflects an inclined supply curve.

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Natural Gas Prices - Henry Hub Bidweek Price

(Dollars per mmBtu)



00254

COAL

As we wind out way out of the winter months, coal markets reflect more supply-demand balance than we have seen for many years. The significance of this development is that coal buyers can no longer indefinitely delay procurements they way they have for the past year or so, when they were saddled with enormous stockpiles created by a warm winter and cool economy. This is not to say that buyers are under immediate pressure to replenish their inventories. Indeed, power companies have emerged from the winter months in relatively good shape. They will, however, need to rebuild for the coming summer and they have several months to do this.

Our general outlook for this year calls for a relatively strong firming of prices as we move into summer, the result of previously low coal prices, an anticipated higher burn due to elevated natural gas prices, the seasonally increase in electricity demand that accompanies the summer months, and a gradually improving economy. There are, however, two major areas of uncertainty that keep us from feeling totally comfortable with this scenario, with the resulting risk to the forecast decidedly in favor of even higher prices.

The first area of uncertainty lies within the coal industry itself, in the form of very limited excess capacity. That does not create a problem if our "Base Case" scenario of gradually increasing demand actually occurs; coal capacity can be expanded in a methodical fashion to meet this slowly rising call on coal. What is worrisome, however, is if some demand-side "event" occurs that sharply and immediately generates a surge in demand for coal. Coal capacity is close to the production limits in most regions. In the Pittsburgh seam area of Northern Appalachia, CONSOL has been persistent about closing unneeded operations (Dilworth, Humphrey, Meigs #2 and Windsor have all been recently shut), but now recent difficulties at Mine 84, McElroy and Loveridge raise questions as to that region's ability to respond. Likewise, in Central Appalachia, the closure at Marrowbone and the uncertainty surrounding Horizon's mines--- coupled with the backlog of permits to be dealt with in the aftermath of the reversal of the Haden decision--- pose major obstacles to meeting any sudden increase in demand.

The second area of uncertainty lies outside the coal industry, but could have a dramatic effect on the demand picture. The recent surge in natural gas prices are causing coal buyers to draw nervous parallels with the situation that led to the fly-up in coal prices that occurred in late 2000/early 2001. If natural gas prices are sustained throughout much of this year at high levels, then many intermediate coal-fired unit that normally operate in the 30-45% capacity factor range could be called into full service. Concerns that this might occur are already in evidence with recent upward shifts in the NOx and, to a lesser degree, the SO2 emissions markets (although other factors are at play as well helping to stimulate those price increases).

In addition, the uncertainties surrounding a likely war in Iraq are substantial, but we will confine our comments to the impact such a war might have on the economy and, thus, electricity demand. Many observers believe that the anxiety created by the on-again, off-again war situation is causing great harm to the economy in the sense that both corporations and individuals are reluctant to make even short-term commitments, stunting economic growth. While this is undoubtedly true, we believe that the causes of economic stress in this country are more varied, and will likely persist in the aftermath of conflict in Iraq.

On the political front, the long-awaited Bush pronouncement on New Source Review withstood a close vote in the Senate and should give coal, particularly low sulfur coal, a major boost in the marketplace over at least the next 5 years or so. The President's decision to mention a reintroduction of Clear Skies legislation in the State of the Union address caught many observers off guard, but it remains to be seen

whether this was simply a political gesture with little clout or the prelude to a major push to obtain the most favorable terms by those who believe that there will never be a more pro-industry President-Congress combination than what we have now.

Short-Term Prices

All this leads us back to whether or not we could see a surge in coal prices this year along the lines of what we experienced two years ago. Three of the five factors that hit markets at that time are in evidence today---little excess mining capacity, problems at some large mines that could keep production response limited, and high natural gas prices. The two missing ingredients are (1) weather and (2) low coal stockpiles, although we are not completely out of the woods on those. A severe, early winter hit in 2000 that caught buyers very short on inventories and scrambling into the market to buy coal from anywhere at any price. At this point in time, we are still several weeks from coming out of a very harsh winter, but there is an end in sight. Moreover, buyers are not in a desperate situation from an inventory standpoint, but as alluded to earlier, they will need to begin replenish their stocks for the summer over the next few month, a process better begun sooner than later.

So is meeting 3 out of 5 of the past conditions sufficient to see another coal price spike in 2003? For those who argue that we will not see any major price increase, the stronger inventory position of power companies (relative to the desperate situation that existed in 2000-2001) looms large. Moreover, they argue, coal production costs are not rising significantly, natural gas prices could potentially ease in the shoulder months and into the summer, and we may even see some substantial discounting by natural gas-fired combined cycle units as they struggle to remain operating at least at some level. Finally, proponents of low prices argue, many coal suppliers---especially those in the Powder River Basin hoping to carve out major inroads into Midwestern and Eastern markets in the next few years---should be wary of jacking up prices at a time these potential customers are taking a hard look at investing in the requisite capital improvements to burn PRB coal.

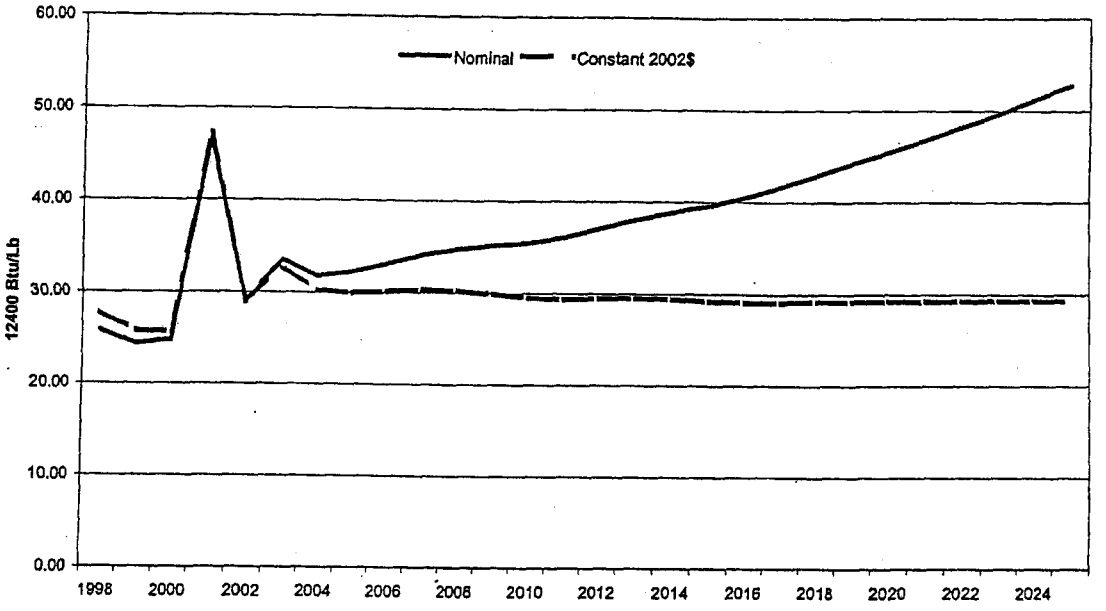
Yet the arguments that we could see higher prices are equally compelling. Producers maintain that occasional spikes in the coal spot market are now a reality in a more constrained supply situation. Moreover, suppliers note that this situation shouldn't scare off potential customers, but should rather emphasize the importance of signing contracts (possibly with an options clause to handle these kinds of situations) so as to avoid these market spikes. Certainly, with an impressive portion of coal companies now public, they are likewise being pushed by Wall Street to maximize their profit potential by exercising their market power when conditions allow.

So where to we see price moving? We expect that Central Appalachian prices could easily move up to the $35 mark (for a compliance, 12,400-12,500 BTU, CSX origin mine) and that PRB prices, after a lag, could follow with a commensurate jump. This need not necessarily happen given the economic climate, but it could also be surpassed given all the other variables in play.

A host of forces are at work influencing prices this year. As we try to sort out these elements, our expectation is that declines in Powder River Basin prices will lead to price declines in eastern coal. Several major factors should pull prices down from last year's highs: the slowing economy, the mild winter, and the end to desperation buying now that stocks have been replenished. Finally, there is the important reality that the still-high differential between current prices and production costs provides ample room for spot prices to come off without endangering producer profits. We believe the price retrenchment, however, will not follow the familiar pattern of the past, where prices have gone into a

virtual free fall after a sustained period of price elevation. Although inventories are higher, producer retrenchment has limited the amount of available coal.

Coal Prices - Central Appalachia
(Dollars per MMBtu)



Long Term Prices

Last year's increases in real coal prices will be reversed in the long-term forecast. U.S. delivered coal prices will decline in real terms over the forecast period as more pressure is brought to bear on the fuel component of the electric power industry. This pressure to provide both cheaper and less polluting fuel will force overall delivered coal prices to the electric power industry to decline in real terms so that coal can retain as much of its market share as possible.

The overall decline in delivered steam coal prices to the electric power industry will come from a number of sources. Continued efficiency improvements in the mining sector and competition with more efficient natural gas-fired generation stations will continue to promote real coal price declines. In the last ten years, the greatest drops in price came from transportation cost reductions and long-term contract expirations. The transportation cost reductions stemmed from the consolidation in the rail industry that has left four large regional rail lines that promise some, but no longer significant, price declines due to efficiency improvements. The early high-cost, long-term contracts without adjustment clauses from the late 1970s and 1980s have expired, also contributing to the delivered cost decline. With their expiration, average minemouth coal prices have fallen markedly since their peak in the mid-1980s; but the majority

of the price reductions from this source have already occurred. Coal contracts of 20 years at a fixed price no longer exist. Most contracts are for three to five years and have a market clause. Thus, contract prices are becoming more sensitive to current market conditions.

Emission allowance prices are expected to strengthen when the inventory of excess allowances from past years is depleted. This could happen as early as 2003-05 when utilities will be adding more scrubbers for sulfur removal as well as SCRs for NOx removal. Higher allowance prices mean higher costs of using coal.

00258

PETROLEUM COKE

- The strike in Venezuela started on December 2, 2002 and has significantly disrupted supplies of petroleum coke but it's effects are gradually subsiding as petroleum production is restored. Initially, it resulted in a slightly higher international call for coal as petroleum coke prices soar, but the need for replacement coal was highly dispersed. As a result, we don't expect a significant impact on coal markets these from developments. Petcoke markets are quite another thing, however, and prices for low grade, high sulfur product that reached into the mid-$20's in early 2003 will subside slowly.

- Petroleum coke supply is expected to increase with the new heavy oil projects in Venezuela with over 500,000 barrels per day of coking capacity. Also, new cokers are going into refineries in the US that use heavy oil from Mexico and Venezuela. North and South America provide over two thirds of the worlds petroleum coke supply of 60 million tons. World supply is expected to increase to 70 million tons as the new coking projects are added. The installation of significantly greater coking capacity in refineries in the 2001-2004 period will provide a huge boost to petroleum coke availability that will tip the balance in favor of supply over demand.

- Petroleum coke is used as a blend with steam coal by many utilities, but comprises only a small percentage of utility fuel consumption. Coal plants with scrubbers, with the new fluidized bed technology or with gasification can use petroleum coke. Increasing coke production -resulting from increasing residual fuel conversion and falling delivered prices- is making this product attractive to some utilities. Generally, petroleum coke prices have to be priced very competitively on a delivered basis to attract utilities.

- Petroleum coke prices have a ceiling value placed by steam coal but have no floor value. As refiners produce more petcoke, their marketing strategies may evolve from viewing petcoke as a byproduct to be discarded and more to a product that can be priced competitively in a growing market.

- When residual fuel is converted to petroleum coke, the sulfur and metals in the residual fuel are concentrated in the petroleum coke. As long as transportation costs do not remove the current price advantage that coke has over coal, high-sulfur coke can be burned economically with coal, particularly in plants already equipped with scrubbers, although coke's fuel properties are somewhat different from those of coal.

- Green coke is the form of coke used as fuel. Less than 10 percent of the fuel-quality green coke produced domestically is burned as fuel domestically, and this amount used for utility fuel represents only 5 percent of total petroleum coke demand. Petroleum coke is generally blended with coal in pulverized coal plants or gasification units.

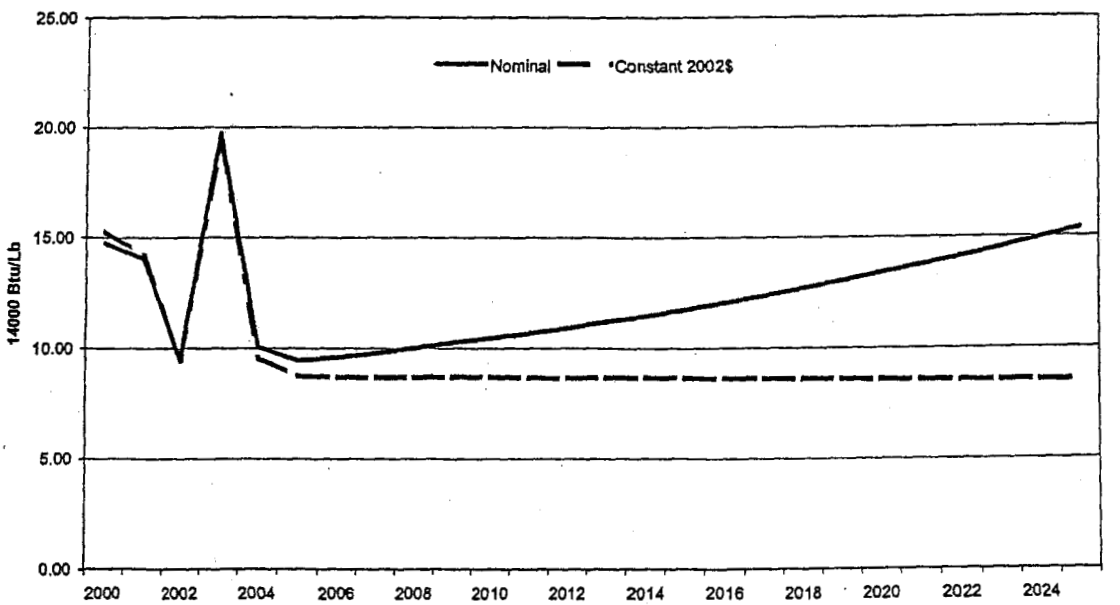
- The price of coke continues to decrease despite volatility in coal, oil and natural gas prices. The average delivered cost of petroleum coke to utilities in 1999 was 65.4 cents per million Btu and declined to 58.5 cents in 2000. The average delivered price of coal was 120 cents per million Btu in 2000, down from 121.6 cents in 1999. Petroleum coke prices are especially competitive with coal prices in Florida since the state is near the large coke-producing refineries on the Gulf Coast, and more distant from coal producing regions.

- Tampa Electric Company completed test burns and began using petroleum coke in up to a 20-percent blend with coal in its Big Bend Units 3 and 4. In 1998, the utility used a total of 163

thousand tons of petroleum coke but this reached 211 thousand tons in 2000 after declining to 30 thousand tons in 1999.

- Seminole Electric Cooperative received approval to burn coke blends of up to 30 percent in its generating station and began using some petroleum coke in 1997. However, no usage was reported in 2000. In 1999, the utility took receipt of 204 thousand tons of petroleum coke similar to the level in 1998.
- Florida Power Corporation was exploring the possibility of burning small blends of coke (5 percent) in its Crystal River Units 1 and 2. Florida Power felt that, even at that low blend percentage, it could save more than $1 million a year; however, the company ran into permitting problems over concerns that the coke is high in sulfur content and the Crystal River units do not have scrubbers. The utility has not received any petroleum coke since 1995.
- Jacksonville Electric Authority has varied its consumption of petroleum coke from 873 thousand tons in 1998 and 630 thousand tons in 1997 to 342 thousand tons in 1999 and 444 thousand tons in 2000.

Petroleum Coke - Gulf Coast FOB
(Dollars per Ton)



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DATA DEFINITIONS

Background: *Discussion of Location, Contracts, Delivery Routes, and Embedded Costs in the measurement of Fuel Prices as Prepared by Global Insight.*

Note on Taxes: *Since the Superfund tax of 9.7 cents per barrel expired as of December 31, 1995, the spot price forecasts do not include any special taxes as well.*

PETROLEUM

All petroleum product spot price history is from Platts. Platts defines the fuel specifications unless otherwise noted.

Distillate:

- ***This definition applies to tables 1-2:*** The Gulf Coast annual average price is calculated from the monthly average of spot cargoes transacted. Cargo assessments assume reasonably prompt arrival, typically 5-15 days away. Volumes are at least one vessel with 150,000 barrels of product, except where vessel size restrictions are in effect.

  Specifications: 0.2% sulfur (at New York Harbor; up to 0.5% sulfur outside New York), 40 cetane, 34° API gravity, 130° F minimum flash point. These are the specifications for "normal" New York distillate; low sulfur distillate is 0.05% sulfur and 42 cetane, essentially equivalent to on-highway diesel. Since prices are generally quoted in cents per gallon, these prices were multiplied by 0.42 to arrive at a price in dollars per barrel. The standard DOE/EIA conversion factor of 5.825 mmBtu per barrel of distillate was used to calculate the price in dollars per mmBtu.

  The Tampa spot price is based upon assessments of the terminal price at this location. The annual average price is an arithmetic average of the monthly average prices.

Residual Fuel:

- ***This definition applies to tables 5-6:*** Annual average price calculated from the monthly average of spot cargoes for the Gulf Coast. Cargoes can originate anywhere from Corpus Christi, Texas to the Mississippi. Platt's prices reflect cargoes lifting within 7 to 14 days or for New York Harbor, cargoes arriving within 5 to 15 days. Volumes are at least one vessel with 150,000 barrels of product, except where vessel size restrictions are in effect. Historical data for Gulf Coast cargoes includes 0.7%, 1%, 2.2%, and 3.5% sulfur. Historical data for the 0.7% sulfur residual fuel oil has been discontinued by Platt's. Analysis of this data shows that the Gulf Coast 1% sulfur price averages about $2 per barrel less than the New York Harbor price, reflecting a normal transportation premium. Also, analysis of the delivered cost of residual fuel oil to Florida utilities shows that they essentially pay the Gulf Coast spot price. The standard DOE/EIA conversion factor of 6.287 mmBtu per barrel of residual fuel is used to calculate the price in dollars per mmBtu. The specifications for 1.0% residual fuel are gravity 10.5 API, viscosity 225 ssf, maximum sulfur 1.0 %.

PETROLEUM COKE

- ***This definition applies to table 7:*** The petroleum coke price is obtained from JD Energy, Coal Monthly for Gulf Coast FOB with an energy content of 14000 Btu per pound. Also, the *Cost and*

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Quality of Fuels for Electric Utility Plants publication of the DOE/EIA is referenced where prices are reported for individual plants.

NATURAL GAS PRICES

Henry Hub Prices:

- ***This definition applies to tables 3-4:*** Global Insight uses the *Inside FERC Gas Market Report* (IFGMR) for spot natural gas prices. Spot prices are reported in dollars per million Btu. Bidweek index prices representing 30-day transactions are used for the monthly price. Annual prices are averages of the monthly prices. Spot price forecasts are prepared for specific locations for which several are in the Gulf Coast. The spot prices reported for the Gulf Coast region include the Henry Hub cash index, the average delivered to pipeline price for Louisiana and the average price for the entire Gulf Coast including Texas and Louisiana. The index value is calculated by IFGMR staff from information provided by participants in the spot market.

Florida Gas Transmission Zone 2:

This definition applies to tables 3-4: Global Insight uses the Inside FERC Gas Market Report for bidweek prices and Gas Daily for daily cash prices. Both the Bidweek and the average monthly cash prices are provided. Florida Gas Transmission zone 2prices reflect market conditions in Mississippi, Alabama and the Mobile Bay region.

COAL PRICES

This definition applies to table 7: Coal prices are reported in dollars per ton and in dollars per million Btu.

Purchase Locations:
The specific coal grades provided in the fuel price analysis reflect purchases at the minemouth by production basins: Northern Appalachia, Central Appalachia, Illinois Basin and the Powder River Basin. The center of Northern Appalachian coal production is the Pittsburgh seam south of Pittsburgh, PA in the Monongahela Valley. The Central Appalachian production basin is centered around the Big Sandy River with southern West Virginia to the northeast and eastern Kentucky to the southwest. The Illinois basin includes the states of Illinois and Indiana and the western portion of Kentucky. The Powder River Basin is located in the northeast corner of Wyoming and Southeastern Montana.

Type of Contracts:
Coal is purchased for delivery to coal-fired power plants under either a spot or contract agreement. Spot purchases can be for scheduled deliveries up to a year in length. Contract purchases last longer than one year, generally anywhere from three to five years in length. Current contracts have price adjustment clauses included that will allow for a periodic re-negotiation of the contract price based upon the changing market price. Some older coal delivery contracts that were instituted in the late 1970's and early 1980's are still in existence. These older contracts last upwards of twenty years with no clause for price adjustment. As a rule, these contracts will be significantly above the spot market price or new contract price.

Delivery Routes:
Rail lines to Florida include CSX and Norfolk Southern. CSX and Norfolk Southern serve the Northern and Central Appalachian basins and the Illinois basin.

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For rail delivery from Northern Appalachia, the coal will most likely originate from mines with access to CSX and move to Baltimore. Central Appalachian coal is likely to move on Norfolk Southern to Norfolk and then to other destinations. The coal in either producing region could also originate from mines served by the other railroad with a transfer, but this would incur an added transshipment cost.

Either Burlington Northern Santa Fe or Union Pacific must first transport coal originating from the Powder River Basin. A third railroad, Dakota, Minnesota, & Eastern will soon gain access to the Powder River basin with an eastern terminus on the Mississippi River. The coal shipments would then be transferred to CSX lines for delivery. The logistical problems of rail shipment of bulk commodities across the Mississippi River and into South Atlantic would make the cost of such transportation relatively expensive.

IMPLICIT PRICE DEFLATOR

- ***This definition applies to real dollar values:*** The implicit price deflator is the chained price index for the U.S. gross domestic product. The base year is set to 2002, i.e. the deflator in 2002 = 1.000. The deflator is used to transform nominal price forecasts into forecasts stated in constant, or real, 2002 dollars.

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TABLE 1: DISTILLATE FUEL PRICES - MONTHLY SHORT-TERM FORECAST

Spot Prices, #2 Fuel Oil, Cents per Gallon

	Posted Price at Tampa, FL	Spot Price at Gulf Coast
Jan-99	35.23	31.47
Feb-99	32.77	28.79
Mar-99	40.24	36.61
Apr-99	47.39	41.11
May-99	45.78	40.17
Jun-99	44.03	41.77
Jul-99	51.14	48.53
Aug-99	56.69	53.69
Sep-99	62.56	58.61
Oct-99	60.88	56.79
Nov-99	66.56	62.46
Dec-99	68.58	64.80
Jan-00	77.56	72.33
Feb-00	85.99	75.51
Mar-00	84.95	72.82
Apr-00	78.05	69.05
May-00	81.92	73.24
Jun-00	81.27	76.32
Jul-00	82.14	76.75
Aug-00	91.18	87.02
Sep-00	102.74	97.14
Oct-00	99.14	94.19
Nov-00	101.65	96.73
Dec-00	93.74	82.56
Jan-01	104.48	84.48
Feb-01	88.58	76.78
Mar-01	75.30	69.40
Apr-01	80.14	73.35
May-01	83.21	75.44
Jun-01	80.71	74.45
Jul-01	72.00	68.29
Aug-01	75.17	72.02
Sep-01	76.48	70.35
Oct-01	64.87	60.56
Nov-01	57.10	52.68
Dec-01	53.63	50.26
Jan-02	54.89	51.08
Feb-02	55.54	51.90
Mar-02	65.01	61.36
Apr-02	68.30	64.67
May-02	69.51	64.40
Jun-02	66.11	62.51
Jul-02	69.48	65.89
Aug-02	72.03	68.53
Sep-02	79.95	76.15
Oct-02	81.95	75.95
Nov-02	76.12	70.61
Dec-02	83.37	79.83

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DISTILLATE FUEL PRICES: MONTHLY SHORT-TERM FORECAST (CONTINUED)
Spot Prices, #2 Fuel Oil, Cents per Gallon
Forecast Starts March 2003

Jan-03	91.46	88.02
Feb-03	115.21	105.65
Forecast		
Mar-03	114.30	105.82
Apr-03	100.29	93.08
May-03	80.88	75.44
Jun-03	69.30	64.91
Jul-03	69.53	65.12
Aug-03	71.58	66.98
Sep-03	72.00	67.36
Oct-03	73.21	68.46
Nov-03	71.66	67.05
Dec-03	73.55	68.78
Jan-04	72.35	67.68
Feb-04	66.24	62.13
Mar-04	61.70	58.00
Apr-04	60.85	57.23
May-04	63.62	59.75
Jun-04	62.67	58.88
Jul-04	63.51	59.64
Aug-04	64.56	60.60
Sep-04	70.19	65.72
Oct-04	74.73	69.85
Nov-04	73.32	68.57
Dec-04	73.00	68.28
Jan-05	68.34	64.04
Feb-05	66.21	62.10
Mar-05	65.13	61.12
Apr-05	68.14	63.86
May-05	66.88	62.70
Jun-05	66.09	61.99
Jul-05	66.68	62.53
Aug-05	68.97	64.61
Sep-05	72.56	67.87
Oct-05	76.44	71.40
Nov-05	74.81	69.92
Dec-05	75.22	70.29
Jan-06	72.67	67.98
Feb-06	70.79	66.26
Mar-06	69.56	65.14
Apr-06	72.35	67.68
May-06	70.74	66.22
Jun-06	69.81	65.37
Jul-06	70.43	65.93
Aug-06	72.82	68.10
Sep-06	76.54	71.49
Oct-06	80.58	75.17
Nov-06	78.81	73.55
Dec-06	79.17	73.88

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TABLE 2: DISTILLATE FUEL PRICES - ANNUAL LONG-TERM FORECAST

Spot Price #2 Fuel Oil, Cents per Gallon
Forecast Starts 2003

	NOMINAL		CONSTANT 2002 DOLLARS	
	Posted Price at Tampa, FL	Spot Price at Gulf Coast	Posted Price at Tampa, FL	Spot Price at Gulf Coast
1995	50.68	47.48	57.21	53.60
1996	63.75	58.98	70.59	65.31
1997	58.57	54.10	63.62	58.76
1998	42.17	38.19	45.25	40.97
1999	50.99	47.07	53.93	49.79
2000	88.36	81.14	91.54	84.06
2001	75.97	69.01	76.88	69.83
2002	70.19	66.07	70.19	66.07
2003	83.58	78.06	81.61	76.22
2004	67.23	63.03	63.97	59.97
2005	69.62	65.20	64.64	60.54
2006	73.66	68.90	66.90	62.55
2007	76.40	71.58	67.86	63.59
2008	78.48	73.59	68.24	63.99
2009	80.37	75.44	68.40	64.19
2010	82.73	77.71	68.88	64.69
2011	85.33	80.16	69.37	65.20
2012	88.44	83.18	70.24	66.07
2013	93.29	87.83	72.32	68.07
2014	97.63	91.99	73.79	69.51
2015	102.30	96.43	75.33	71.01
2016	106.99	100.96	76.75	72.40
2017	111.33	105.12	77.69	73.35
2018	115.73	109.37	78.51	74.18
2019	120.59	114.00	79.49	75.16
2020	125.32	118.61	80.34	76.01
2021	130.02	123.15	81.06	76.75
2022	135.21	128.15	81.90	77.60
2023	140.63	133.38	82.78	78.49
2024	146.65	139.19	83.85	79.57
2025	152.13	144.49	84.47	80.22

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TABLE 3: NATURAL GAS PRICES - MONTHLY SHORT-TERM FORECAST

Henry Hub and FGT Mobile Bay Zone 2, Nominal Dollars per Million Btu

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-98	2.27	2.28	
Feb-98	2.04	2.01	2.17
Mar-98	2.26	2.25	2.19
Apr-98	2.33	2.29	2.38
May-98	2.27	2.25	2.09
Jun-98	2.03	2.01	2.06
Jul-98	2.36	2.36	2.06
Aug-98	1.93	1.92	1.75
Sep-98	1.63	1.61	1.91
Oct-98	2.07	2.03	1.79
Nov-98	2.00	1.99	2.02
Dec-98	2.12	2.10	1.64
Jan-99	1.80	1.79	1.80
Feb-99	1.81	1.78	1.72
Mar-99	1.64	1.62	1.75
Apr-99	1.88	1.89	2.12
May-99	2.35	2.35	2.20
Jun-99	2.23	2.23	2.24
Jul-99	2.28	2.27	2.23
Aug-99	2.62	2.62	2.73
Sep-99	2.90	2.90	2.47
Oct-99	2.55	2.54	2.67
Nov-99	3.06	3.03	2.30
Dec-99	2.14	2.14	2.31
Jan-00	2.36	2.35	2.36
Feb-00	2.61	2.63	2.61
Mar-00	2.61	2.63	2.74
Apr-00	2.88	2.90	2.98
May-00	3.08	3.08	3.55
Jun-00	4.37	4.41	4.21
Jul-00	4.36	4.38	3.88
Aug-00	3.83	3.83	4.32
Sep-00	4.62	4.62	4.96
Oct-00	5.29	5.29	4.92
Nov-00	4.50	4.51	5.39
Dec-00	6.02	6.03	8.70

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Table 3. NATURAL GAS PRICES: MONTHLY SHORT-TERM FORECAST (CONTINUED)
Henry Hub and FGT Mobile Bay Zone 2, Nominal Dollars per Million Btu
Forecast Starts 2003

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-01	9.91	9.94	8.00
Feb-01	6.22	6.27	5.37
Mar-01	5.03	5.05	5.01
Apr-01	5.35	5.34	5.08
May-01	4.87	4.86	3.90
Jun-01	3.73	3.74	3.42
Jul-01	3.16	3.21	2.99
Aug-01	3.19	3.18	2.87
Sep-01	2.34	2.35	2.11
Oct-01	1.86	1.86	2.40
Nov-01	3.16	3.13	2.27
Dec-01	2.24	2.26	2.31
Jan-02	2.61	2.61	2.19
Feb-02	2.03	2.06	2.23
Mar-02	2.39	2.41	2.96
Apr-02	3.41	3.44	3.42
May-02	3.36	3.40	3.55
Jun-02	3.37	3.42	3.29
Jul-02	3.26	3.30	3.07
Aug-02	2.95	3.01	3.14
Sep-02	3.27	3.30	3.58
Oct-02	3.72	3.72	4.13
Nov-02	4.13	4.21	3.95
Dec-02	4.13	4.20	4.52
Jan-03	4.96	4.94	6.30
Feb-03	5.66	5.68	7.71
Mar-03	9.11	9.01	6.24
Forecast			
Apr-03	5.86	5.89	5.92
May-03	5.56	5.59	5.35
Jun-03	5.04	5.07	5.27
Jul-03	5.43	5.46	5.40
Aug-03	5.41	5.44	5.05
Sep-03	4.72	4.73	4.63
Oct-03	4.50	4.50	4.59
Nov-03	4.70	4.71	4.64
Dec-03	4.61	4.63	4.70

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Table 3. NATURAL GAS PRICES: MONTHLY SHORT-TERM FORECAST (CONTINUED)
Henry Hub and FGT Mobile Bay Zone 2, Nominal Dollars per Million Btu

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-04	4.76	4.76	4.56
Feb-04	4.57	4.58	4.46
Mar-04	4.54	4.55	4.27
Apr-04	4.22	4.22	4.07
May-04	4.13	4.12	4.00
Jun-04	4.10	4.10	3.96
Jul-04	4.04	4.06	3.96
Aug-04	4.08	4.08	4.00
Sep-04	4.14	4.14	4.04
Oct-04	4.16	4.15	4.12
Nov-04	4.29	4.28	4.20
Dec-04	4.32	4.32	4.13
Jan-05	4.15	4.15	4.10
Feb-05	4.22	4.22	4.07
Mar-05	4.10	4.10	3.82
Apr-05	3.74	3.74	3.64
May-05	3.72	3.71	3.69
Jun-05	3.84	3.84	3.76
Jul-05	3.88	3.89	3.79
Aug-05	3.90	3.91	3.85
Sep-05	3.98	3.98	3.90
Oct-05	4.01	4.00	3.93
Nov-05	4.04	4.04	3.85
Dec-05	3.87	3.87	3.86
Jan-06	4.00	4.00	3.93
Feb-06	4.02	4.02	3.83
Mar-06	3.82	3.82	3.60
Apr-06	3.56	3.56	3.50
May-06	3.60	3.59	3.55
Jun-06	3.68	3.69	3.59
Jul-06	3.68	3.69	3.61
Aug-06	3.72	3.73	3.68
Sep-06	3.83	3.82	3.75
Oct-06	3.86	3.85	3.77
Nov-06	3.87	3.87	3.76
Dec-06	3.83	3.83	3.94

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TABLE 4: NATURAL GAS PRICES - ANNUAL LONG-TERM FORECAST

Henry Hub and FGT Mobile Bay Zone 2, Dollars per Million Btu
Forecast Starts 2003

Year	(Current) Henry Hub	(Current) FGT Bidweek	(Current) FGT Cash	Deflator (2002=1.0)	(2002$) Henry Hub	(2002$) FGT Bidweek	(2002$) FGT Cash
1998	2.11	2.09	2.00	0.932	2.26	2.24	2.15
1999	2.27	2.26	2.21	0.945	2.40	2.39	2.34
2000	3.88	3.89	4.22	0.965	4.02	4.03	4.37
2001	4.26	4.26	3.81	0.988	4.31	4.31	3.86
2002	3.22	3.25	3.33	1.000	3.22	3.25	3.33
Forecast							
2003	5.46	5.47	5.48	1.024	5.34	5.34	5.35
2004	4.28	4.29	4.29	1.051	4.07	4.08	4.08
2005	3.95	3.96	3.96	1.077	3.67	3.68	3.68
2006	3.79	3.80	3.81	1.101	3.44	3.45	3.46
2007	3.91	3.92	3.91	1.126	3.47	3.48	3.48
2008	4.06	4.07	4.07	1.150	3.53	3.54	3.53
2009	4.15	4.16	4.17	1.175	3.54	3.54	3.54
2010	4.30	4.31	4.31	1.201	3.58	3.59	3.59
2011	4.56	4.57	4.57	1.230	3.71	3.72	3.71
2012	4.76	4.77	4.75	1.259	3.78	3.79	3.77
2013	4.92	4.93	4.92	1.290	3.81	3.82	3.81
2014	5.05	5.06	5.06	1.323	3.81	3.82	3.82
2015	5.24	5.25	5.26	1.358	3.86	3.87	3.87
2016	5.40	5.42	5.43	1.394	3.88	3.88	3.89
2017	5.56	5.57	5.59	1.433	3.88	3.89	3.90
2018	5.76	5.77	5.79	1.474	3.90	3.91	3.93
2019	5.93	5.94	5.97	1.517	3.91	3.91	3.93
2020	6.12	6.13	6.17	1.560	3.92	3.93	3.95
2021	6.36	6.37	6.41	1.604	3.96	3.97	4.00
2022	6.60	6.61	6.65	1.651	4.00	4.00	4.03
2023	6.85	6.86	6.90	1.699	4.03	4.04	4.06
2024	7.09	7.11	7.15	1.749	4.06	4.06	4.09
2025	7.35	7.36	7.40	1.801	4.08	4.09	4.11

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TABLE 5: RESIDUAL FUEL PRICES - MONTHLY SHORT-TERM FORECAST

Spot Prices, #6 Fuel Oil, Nominal Dollars per Barrel, at Gulf Coast

	SULFUR CONTENT		
	0.7%	1.0%	3.0%
Jan-99	11.08	10.23	8.25
Feb-99	9.77	8.97	7.55
Mar-99	11.58	10.78	10.13
Apr-99	14.04	13.24	12.83
May-99	14.39	13.85	12.73
Jun-99	14.39	13.79	13.40
Jul-99	16.49	15.88	15.09
Aug-99	19.36	18.76	17.70
Sep-99	20.57	19.97	19.05
Oct-99	20.24	19.65	18.46
Nov-99	21.15	20.55	18.22
Dec-99	18.86	18.26	17.92
Jan-00	20.03	19.43	19.22
Feb-00	22.19	21.59	20.95
Mar-00	23.80	23.20	21.61
Apr-00	23.18	22.43	18.78
May-00	26.12	25.04	21.27
Jun-00	28.89	27.89	22.74
Jul-00	27.78	26.53	20.50
Aug-00	28.89	27.71	20.28
Sep-00	32.49	31.49	23.60
Oct-00	32.47	31.47	23.02
Nov-00	33.45	30.64	20.45
Dec-00	31.18	27.88	16.24
Jan-01	30.09	28.09	18.79
Feb-01	26.86	25.35	20.68
Mar-01	25.09	24.31	18.59
Apr-01	25.11	24.11	14.90
May-01	24.69	23.74	16.77
Jun-01	22.96	21.96	17.72
Jul-01	21.46	20.63	17.36
Aug-01	21.38	20.34	17.54
Sep-01	23.16	22.19	19.79
Oct-01	19.34	18.39	15.36
Nov-01	16.83	15.96	13.59
Dec-01	17.78	16.73	14.74
Jan-02	16.40	15.42	14.82
Feb-02	16.44	15.45	15.24
Mar-02	20.42	19.37	19.20
Apr-02	23.46	22.54	21.93
May-02	24.03	23.04	21.94
Jun-02	24.49	23.50	21.38
Jul-02	23.25	22.25	21.86
Aug-02	25.24	24.27	22.80
Sep-02	26.45	25.45	24.81
Oct-02	28.57	27.58	23.19
Nov-02	24.92	23.77	18.76
Dec-02	27.28	26.20	22.41

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Table 5. RESIDUAL FUEL PRICES: MONTHLY SHORT-TERM FORECAST (CONTINUED)
Spot Prices, #6 Fuel Oil, Nominal Dollars per Barrel, at Gulf Coast
Forecast Starts March 2003

	SULFUR CONTENT		
	0.7%	1.0%	3.0%
Jan-03	32.51	30.96	29.73
Feb-03	37.14	34.68	27.76
Forecast			
Mar-03	38.64	35.01	30.26
Apr-03	34.75	31.51	31.96
May-03	25.64	23.27	25.65
Jun-03	22.19	20.15	22.00
Jul-03	22.78	20.72	22.36
Aug-03	21.27	19.37	22.00
Sep-03	21.73	19.81	22.18
Oct-03	23.63	21.57	24.17
Nov-03	22.33	20.41	23.55
Dec-03	22.72	20.78	22.56
Jan-04	27.56	25.26	21.48
Feb-04	23.98	21.99	18.62
Mar-04	22.72	20.86	17.53
Apr-04	23.10	21.24	17.57
May-04	24.43	22.49	18.93
Jun-04	24.35	22.44	18.65
Jul-04	25.01	23.08	18.97
Aug-04	22.94	21.19	18.39
Sep-04	25.08	23.20	19.93
Oct-04	26.94	24.95	21.55
Nov-04	25.67	23.80	21.22
Dec-04	25.87	24.02	20.21
Jan-05	23.63	21.96	18.74
Feb-05	21.71	20.19	17.16
Mar-05	21.68	20.19	17.03
Apr-05	23.33	21.76	18.07
May-05	23.19	21.66	18.30
Jun-05	23.17	21.67	18.08
Jul-05	23.70	22.19	18.31
Aug-05	22.09	20.70	18.05
Sep-05	23.39	21.95	18.94
Oct-05	24.86	23.36	20.27
Nov-05	23.62	22.22	19.90
Dec-05	24.02	22.62	19.12
Jan-06	22.61	21.32	18.28
Feb-06	20.86	19.70	16.81
Mar-06	20.80	19.66	16.66
Apr-06	22.25	21.06	17.57
May-06	22.03	20.87	17.73
Jun-06	21.97	20.84	17.49
Jul-06	22.46	21.33	17.70
Aug-06	20.91	19.89	17.43
Sep-06	22.12	21.06	18.27
Oct-06	23.48	22.39	19.53
Nov-06	22.28	21.27	19.16
Dec-06	22.63	21.63	18.39

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TABLE 6: RESIDUAL FUEL PRICES - ANNUAL LONG-TERM FORECAST

Spot Price #6 Fuel Oil at Gulf Coast, Dollars per Barrel, at Gulf Coast
Forecast starts 2003

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	NOMINAL			CONSTANT 2002 DOLLARS		
	0.7%	1.0%	3.0%	0.7%	1.0%	3.0%
1995	15.18	14.69	13.77	17.13	16.58	15.54
1996	18.04	17.47	15.58	19.98	19.35	17.25
1997	16.59	16.15	14.41	18.02	17.54	15.65
1998	12.85	12.14	9.69	13.79	13.02	10.40
1999	15.99	15.33	14.28	16.92	16.21	15.10
2000	27.54	26.27	20.72	28.53	27.22	21.47
2001	22.90	21.82	17.15	23.17	22.08	17.36
2002	23.41	22.40	20.69	23.41	22.40	20.69
2003	27.11	24.85	25.35	26.47	24.27	24.75
2004	24.81	22.88	19.42	23.60	21.77	18.48
2005	23.20	21.71	18.50	21.54	20.15	17.17
2006	22.03	20.92	17.92	20.00	18.99	16.27
2007	21.78	20.81	17.88	19.34	18.49	15.88
2008	22.39	21.40	18.39	19.47	18.61	15.99
2009	22.96	21.94	18.85	19.53	18.67	16.04
2010	23.63	22.59	19.41	19.67	18.80	16.16
2011	24.38	23.31	20.05	19.83	18.96	16.31
2012	25.31	24.19	20.83	20.10	19.22	16.55
2013	26.73	25.56	22.03	20.72	19.81	17.07
2014	28.01	26.78	23.10	21.17	20.24	17.46
2015	29.38	28.08	24.25	21.63	20.68	17.86
2016	30.77	29.42	25.42	22.07	21.10	18.23
2017	32.05	30.64	26.51	22.36	21.38	18.50
2018	33.36	31.89	27.61	22.62	21.63	18.73
2019	34.78	33.26	28.82	22.93	21.93	19.00
2020	36.20	34.62	30.02	23.20	22.18	19.24
2021	37.59	35.95	31.18	23.43	22.40	19.43
2022	39.12	37.41	32.45	23.69	22.65	19.65
2023	40.72	38.94	33.77	23.97	22.92	19.88
2024	42.50	40.64	35.25	24.30	23.23	20.15
2025	44.12	42.19	36.60	24.50	23.43	20.32

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TABLE 7: COAL PRICES - ANNUAL LONG-TERM FORECAST – FOB CSX

Nominal Dollars per Ton
Forecast Starts 2003

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	22.80	18.25	25.77	25.16	
1999	22.35	17.44	24.30	23.86	
2000	22.19	16.83	24.70	24.30	14.75
2001	32.57	24.63	46.71	40.88	14.04
2002	27.41	21.51	28.96	30.64	9.45
2003	24.41	20.45	33.52	29.13	19.72
2004	24.98	20.54	31.75	29.16	10.06
2005	25.54	18.65	32.24	28.39	9.43
2006	26.05	18.71	33.16	27.91	9.58
2007	26.56	19.21	34.10	27.64	9.77
2008	26.97	19.97	34.74	28.09	9.99
2009	27.25	20.88	35.14	29.19	10.24
2010	27.06	21.89	35.44	29.99	10.44
2011	27.40	22.76	36.10	30.19	10.66
2012	27.95	23.24	37.10	30.20	10.90
2013	28.60	23.68	38.09	30.30	11.19
2014	29.27	24.10	38.92	30.45	11.45
2015	30.00	24.58	39.61	30.71	11.73
2016	30.75	25.05	40.53	30.95	12.03
2017	31.56	25.56	41.73	31.25	12.35
2018	32.42	26.11	42.99	31.55	12.69
2019	33.30	26.67	44.26	31.82	13.03
2020	34.21	27.23	45.55	32.08	13.38
2021	35.14	27.80	46.88	32.43	13.74
2022	36.12	28.41	48.29	32.82	14.12
2023	37.11	29.02	49.72	33.20	14.52
2024	38.15	29.66	51.21	33.59	14.93
2025	39.24	30.33	52.78	34.03	15.35

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COAL PRICES - ANNUAL LONG-TERM FORECAST – FOB CSX (CONTINUED)

2002 Dollars per Ton
Forecast Starts 2003

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb
1998	24.46	19.58	27.65	27.00	
1999	23.65	18.45	25.71	25.25	
2000	22.99	17.44	25.60	25.18	15.28
2001	32.97	24.92	47.28	41.37	14.21
2002	27.41	21.51	28.96	30.64	9.45
2003	23.84	19.98	32.73	28.45	19.26
2004	23.77	19.55	30.21	27.75	9.57
2005	23.71	17.31	29.93	26.36	8.76
2006	23.66	16.99	30.11	25.35	8.70
2007	23.59	17.06	30.29	24.55	8.68
2008	23.45	17.37	30.21	24.43	8.69
2009	23.19	17.77	29.91	24.84	8.71
2010	22.54	18.23	29.51	24.97	8.69
2011	22.28	18.50	29.35	24.54	8.67
2012	22.20	18.46	29.46	23.99	8.65
2013	22.17	18.36	29.52	23.49	8.67
2014	22.13	18.22	29.42	23.02	8.66
2015	22.09	18.10	29.17	22.61	8.64
2016	22.06	17.97	29.07	22.20	8.63
2017	22.02	17.84	29.12	21.81	8.62
2018	21.99	17.71	29.17	21.40	8.61
2019	21.95	17.58	29.18	20.98	8.59
2020	21.93	17.46	29.20	20.56	8.58
2021	21.90	17.33	29.23	20.22	8.56
2022	21.88	17.21	29.25	19.88	8.55
2023	21.85	17.08	29.26	19.54	8.54
2024	21.81	16.96	29.28	19.21	8.54
2025	21.79	16.84	29.30	18.89	8.53

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TABLE 8: COAL PRICES - ANNUAL LONG-TERM FORECAST – FLORIDA DELIVERED

Nominal Dollars per Ton
Forecast Starts 2003

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb
2000	42.37	37.01	38.88	39.28
2001	52.96	45.02	61.04	56.01
2002	47.45	41.54	43.04	45.51
2003	44.86	40.91	47.89	44.31
2004	45.61	41.17	46.25	44.47
2005	46.35	39.46	46.86	43.84
2006	47.07	39.74	47.93	43.51
2007	47.77	40.43	49.01	43.39
2008	48.43	41.44	49.82	44.03
2009	49.02	42.65	50.44	45.35
2010	49.13	43.95	50.94	46.37
2011	49.77	45.13	51.82	46.79
2012	50.65	45.94	53.05	47.06
2013	51.66	46.74	54.29	47.42
2014	52.70	47.53	55.38	47.84
2015	53.77	48.35	56.32	48.36
2016	54.88	49.18	57.48	48.86
2017	56.07	50.08	58.96	49.45
2018	57.38	51.07	60.53	50.07
2019	58.72	52.08	62.12	50.69
2020	60.09	53.12	63.74	51.29
2021	61.54	54.21	65.44	52.03
2022	63.09	55.38	67.24	52.84
2023	64.66	56.57	69.07	53.65
2024	66.29	57.80	70.98	54.48
2025	68.01	59.09	72.99	55.38

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COAL PRICES - ANNUAL LONG-TERM FORECAST – FLORIDA DELIVERED (CONTINUED)

2002 Dollars per Ton
Forecast Starts 2003

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb
2000	43.90	38.35	40.29	40.70
2001	53.61	45.56	61.78	56.69
2002	47.45	41.54	43.04	45.51
2003	43.81	39.95	46.77	43.27
2004	43.40	39.17	44.00	42.32
2005	43.03	36.64	43.51	40.71
2006	42.75	36.09	43.53	39.52
2007	42.43	35.90	43.53	38.53
2008	42.12	36.03	43.32	38.28
2009	41.72	36.30	42.93	38.60
2010	40.91	36.60	42.42	38.61
2011	40.47	36.69	42.13	38.04
2012	40.23	36.49	42.14	37.38
2013	40.05	36.24	42.09	36.76
2014	39.83	35.92	41.86	36.16
2015	39.60	35.60	41.47	35.61
2016	39.37	35.28	41.24	35.05
2017	39.13	34.95	41.14	34.51
2018	38.93	34.65	41.07	33.97
2019	38.71	34.33	40.95	33.41
2020	38.52	34.05	40.86	32.88
2021	38.37	33.80	40.80	32.44
2022	38.21	33.54	40.72	32.01
2023	38.06	33.29	40.65	31.58
2024	37.90	33.05	40.59	31.15
2025	37.76	32.81	40.53	30.75

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Q. Please provide all documents related to Seminole's best estimates or projections of future SO2, NOx, or CO2 emission allowance prices.

A. Please see attached documents, at the pages Bates numbered 00278-00316, which are responsive to the request.

Seminole Electric Cooperative
SO2 Allowance Sales Summary

Date	Buyer	Sold	$/Unit	Total
12/20/2001	Mirant Americans Energy Marketing	2,500	$171	$427,500
12/20/2001	Edison Mission Marketing & Trading	2,500	$171	$427,500
7/25/2003	DTE Coal Services	5,000	$176	$880,000
12/29/2003	PSEG Energy Resources & Trade LLC	6,000	$215	$1,290,000
5/17/2004	Morgan Stanley Capital Group	10,000	$322	$3,220,000
11/30/2004	America Electric (Ohio Power Company)	3,500	$690	$2,415,000
2/15/2005	America Electric (Ohio Power Company)	5,000	$630	$3,150,000
1/26/2006	JP Morgan	3,000	$1,540	$4,620,000
		37,500		$16,430,000

EVALUATION OF NOx CONTROL STRATEGIES FOR SEMINOLE UNITS 1 & 2 UNDER THE CLEAR SKIES ACT OF 2003

FINAL REPORT

J. Marchetti
E. Cichanowicz
M. Hein
Consultants to Seminole Electric Cooperative

February 3, 2004

I. INTRODUCTION

The purpose of this project is to identify the costs of NOx control strategies for Seminole 1 & 2 under the Clear Skies Act of 2003 (CSA). We made some modifications to the CSA allowance allocation procedures based upon Senate hearings and discussions.[1] The focus of this analysis is to evaluate various combinations of combustion, post-combustion and/or allowance purchases to the meet the reduction targets under CSA. This information or outputs from this analysis will allow Seminole to compare various technology deployment schedules and costs; thereby, identify an optimal NOx control strategy for Seminole 1 & 2. The *Emission-Economic Modeling System (EEMS),* which is the same model that was used in the NRECA analysis, was used to evaluate the different deployment/ compliance strategies. In addition, the analysis evaluates any further mercury removal resulting from the installation of Selective Catalytic Reduction (SCR) technology in combination with Seminole's existing FGD systems. All monetary values are expressed in 2003 dollars.

As part of this analysis, we identified those compliance simulations, in which excess allowances would exist, to offset the NOx emissions of a planned 600 MW coal-unit at the Seminole site. This planned 600 MW unit (Seminole 3) is projected to enter commercial operation in 2012 and emit 1,700 tons of NOx per year. The annual NOx emissions are based upon an assumed NOx emission rate of 0.07 lbs/mmbtu and an annual capacity factor of 100 percent.

II. CLEAR SKIES ACT

The CSA calls for almost 70 percent reductions in SO2, NOx and mercury (Hg) emissions from 2000 levels, as shown in Table 1. These reductions are to take place over two phases, Phase I for NOx begins in 2008 and 2010 for both SO2 and Hg. Phase II of CSA commences in 2018 for all gases. The reduction targets for each phase are national emission caps, which by their existence allow for the trading of emission allowances that are allocated to each affected generating unit. For the purpose of this analysis, it was assumed that the CSA will be adopted as proposed.

TABLE 1
CLEAR SKIES ACT: TARGETS AND TIMETABLES

	2000 Emissions	Phase I Caps	Phase II Caps	Percent Reduction
SO2	11.2 million tons	4.5 million tons in 2010	3 million tons in 2018	73%
NOx	5.1 million tons	2.1 million tons in 2008	1.7 million tons in 2018	67%
Hg	48 tons	26 tons in 2010	15 tons in 2018	68%

[1] The adjustments to CSA allowance allocation procedures included the elimination of auction account for each gas and those annual allowances were added into the annual allocation; thereby, increasing an affected unit's annual allocation. The second adjustment increased the Phase I mercury cap from 26 tons to 36 tons.

All fossil generating units greater than 25 MW, including gas turbine and combined-cycle units, as well as co-generators selling one-third of their potential electrical output are classified as affected units and will be required to meet the reduction targets and timetables of CSA. All affected units that would be on-line by December 31, 2004 would receive an SO2, NOx and Hg allocation. In addition to a unit's annual allocation, CSA allows banked Title IV SO2 (thru 2009) and NOx SIP Call (thru 2007) allowances to be carried forward and used for compliance. It should be noted, that no NOx SIP Call allowances are applicable for Florida.

The NOx allowances are allocated between an East and West zone with no trading between zones. Of particular note, the allowance allocations for East zone indicate a much more stringent reduction target, in comparison to the West zone. Also, the allocation of Hg allowances, which only applies to coal units, involves the use of coal adjustment factors to reflect the types of coal combusted.[2] These coal adjustment factors are applied to a unit's baseline heat input; thereby, modifying the baseline heat input and awarding more allowances to lignite and sub-bituminous coal-fired units in comparison to bituminous coal-fired units.

III. CONTROL TECHNOLOGY OPTIONS AND CSA ASSUMPTIONS

Control Technology Options

Five technologies were evaluated to determine the least cost NOx compliance strategy. These are: (a) Combustion Tuning/Optimization (Combustion Modifications); (b) Conventional SCR; (c) Compact SCR; (e) Selective Non-Catalytic Reduction; and, (f) NOxStar. It should be noted that combustion modifications were not considered in combination with conventional SCR. These technologies are overviewed in this section and more detailed information on capital and O&M costs and performance assumptions are described in the Appendix A.

Combustion Tuning/Optimization

Both units will adopt improvements to the combustion tuning and firing systems to reduce NOx from approximately 0.44 to 0.30 lbs/mmbtu. These modifications will focus on improving the distribution of both fuel and air, to improve NOx control capability. Also, the over-fire air ports will be modified to improve penetration of the overfire combustion air into the furnace. Regarding the burner, the inner "barrel" will be replaced to improve coal distribution. Also, hardware will be retrofit to the pulverizers to eliminate coal "roping" as it leaves the pulverizer, allowing for a uniform distribution of fuel to be delivered across the burners. Finally, a CFD model of the wind-box will be conducted to determine the airflow distribution, and identify means to improve the distribution. The capital cost for these combustion modifications is $15/kW and has a

[2] The CSA coal adjustment factors are: 3.0 for lignite; 1.25 for sub-bituminous; and, 1.0 for bituminous or other fuel.

NOx removal efficiency of 32 percent from current NOx emission rates at Seminole 1 & 2.

Conventional SCR

In the context of this study, conventional SCR is defined as the use of a 3-4 layer catalytic reactor, with a catalyst volume that provides a space velocity of 1800-2500 1/h. This embodiment of SCR is broadly adopted in the U.S. to meet the NOx SIP Call. The capital and operating costs for both Seminole coal-fired units were developed by Sargent & Lundy. The capital costs for SCR range between $117 and $122/kW, with NOx removal efficiencies between 78 and 84 percent.

Compact SCR

Both Seminole units present a unique opportunity to deploy a single-layer reactor for SCR, deriving a modest reduction depending on the catalyst replacement frequency. This concept has not been applied commercially; however we believe there is little technical risk as long as a detailed and extensive coal flow modeling study can be conducted. The compact SCR concept requires retrofit of a compressed reactor and catalyst layer, requiring abrupt changes to flue gas flow within a confined space. Under these process conditions, the usual rules of flue gas handling and duct design cannot be observed. As a consequence, flue gas velocity mal-distribution will be induced, if countermeasures are not taken. The purpose of cold flow modeling (or, alternatively, computational fluid dynamic modeling, CFD) is to define the extent of flue gas mal-distribution, and determine the preliminary design of turning vanes and other flue gas velocity rectification equipment. The results of cold flow or CFD modeling will provide a quick and low cost screening analysis to estimate process conditions entering the reactor, and thus more accurately predict NOx removal. The capital costs for Compact SCR is $55/kW, and has a NOx removal efficiency of 50 percent.

Selective Non-Catalytic Reduction (SNCR)

The feasibility of SNCR for large coal-fired boilers had been dismissed for most of the 1990s. This was due to concerns for the inability to mix injected urea into flue gas within the necessary temperature window to achieve sufficient NOx removal. However, several demonstration projects conducted in recent years (Himes, 2003) suggest SNCR can be applied to derive modest NOx reductions on large coal-fired boilers. The most significant technical risk for Seminole is the generation of excessive residual NH3, which could compromise the ability to produce wallboard-quality byproduct gypsum. Regardless, SNCR can attain modest levels of NOx reduction on both of Seminole's coal-fired units. The capital costs for SNCR is $10/kW, and has a NOx removal efficiency of 25 percent.

NOxStar

The NOxStar process is evolving from small-scale pilot tests to a commercial demonstration at TVA's Kingston Station. The process is similar to SNCR, but employs the injection of hydrocarbons with urea to expand the temperature window over which the N-H fragments from urea decomposition react with NOx. Despite the uncertainties in the process, the capital cost and operating requirements are modest, for a process that could derive up to 40% NOx removal. Further, TVA is commercially applying the process at Colbert, thus one additional commercial experience case will be available in the next few years. The capital costs for NOxStar is $40/kW.

CSA NOx and Hg Allowance Allocations

CSA NOx and Hg allowance allocations for each of Seminole's affected units are displayed in Tables 2 & 3 in Section IV.

CSA NOx Allowance Prices

The NOx allowance prices used in the compliance simulations were derived from a series of modeling runs of CSA done by Charles River Associates (CRA). One CRA simulation used a SCR capital cost of $80/kW, while the second CRA simulation used a SCR capital cost of $160/kW. From these two simulations the Project Team derived a time series of NOx allowance prices which assumed an SCR capital cost of $120/kW. Listed below are the NOx allowance prices (in $/ton) used in these simulations:

2008 - $2,026
2010 - $1,215
2012 - $1,326
2015 - $1,428
2018 - $1,755
2020 - $1,443

The allowance price spikes in 2008 and 2018 indicate that utilities are deferring SCR installations until Phase II (2018) of CSA.

Seminole Generation Forecasts, Heat Rates and NOx & Hg Emission Rates

Seminole provided the Project Team 2003 – 2020 *net* generation forecasts for Seminole, Payne Creek and the five planned GTs. In addition, the Project Team evenly divided Seminole's total generation values between units 1 & 2. The Project Team used the following heat rates for each of the affected plants: Seminole – 10,000 Btu/kWh; Payne Creek – 7,675 Btu/kWh; and, Planned GTs – 10,921 Btu/kWh.

The Base Case NOx and Hg emission rates used for Seminole 1 & 2 were 0.44 lb/mmbtu and 1.1 lb/TBtu, respectively. The Base Case NOx emission rates employed for Payne Creek and the Planned GTs were 0.04 lb/mmbtu (12 ppm) and 0.08 lb/mmbtu (25 ppm), respectively.

IV. BASE CASE EMISSIONS AND CSA REDUCTION TARGETS

NOx Emissions

Table 2 illustrates Seminole's annual NOx emissions for selected years between 2008 and 2020. As shown in Table 2, NOx emissions peak in 2008 and then begin to decline and level off as system-wide generation, primarily at both Seminole 1 & 2, decreases annually through 2014 and then stabilizes through 2020. Consequently, under the CSA regulatory regime Seminole would face its greatest Phase I NOx removal requirement (13,493 tons) during the first compliance year (2008), as shown in Table 2. With a constant Phase I allowance allocation and decreasing annual NOx emissions, Seminole's yearly removal requirement decreases annually through most of Phase I. However, beginning in 2018 (Phase II) Seminole's removal requirement will increase to 13,782 tons, and remain between 13,600 and 13,900 tons through 2020.

TABLE 2
NOx EMISSIONS AND CSA ALLOWANCES
(in tons)

NOx EMISSIONS	**2008**	**2013**	**2018**	**2020**
SEMINOLE (FL) 1	10,685	10,067	9,860	9,889
SEMINOLE (FL) 2	10,685	10,067	9,860	9,889
PAYNE CREEK 1-2	467	356	256	255
5 PLANNED GT	151	125	125	125
NOx ALLOCATIONS	**2008**	**2013**	**2018**	**2020**
SEMINOLE (FL) 1	3,646	3,646	2,712	2,712
SEMINOLE (FL) 2	3,595	3,595	2,674	2,674
PAYNE CREEK 1-2	1,255	1,255	933	933
5 PLANNED GT	0	0	0	0
NEEDED REMOVAL	**2008**	**2013**	**2018**	**2020**
SEMINOLE (FL) 1	7,039	6,421	7,148	7,177
SEMINOLE (FL) 2	7,091	6,473	7,186	7,215
PAYNE CREEK 1-2	-788	-899	-677	-679
5 PLANNED GT	151	125	125	125
Yearly Removal Requirement	13,493	12,120	13,782	13,838

Note: Payne Creek would have more allowances allocated than annual emissions resulting in excess allowances.

Mercury Emissions

Mercury emissions follow the same trend as NOx emissions, peaking during the first compliance year (2010) then declining and stabilizing through 2020, as shown in Table 3. Due to your extremely low Hg emission rate (1.1 lb/TBtu), Seminole will be allocated more allowances than it will emit resulting in an annual negative removal requirement under each phase of CSA. This negative removal requirement indicates that Seminole is well below the reduction targets of CSA without having to deploy mercury control technologies.

TABLE 3
Hg EMISSIONS AND CSA ALLOWANCES
(in pounds)

Hg EMISSIONS	**2010**	**2013**	**2018**	**2020**
SEMINOLE (FL) 1	51.8	50.3	49.3	49.4
SEMINOLE (FL) 2	51.8	50.3	49.3	49.4
Hg ALLOWANCES	**2010**	**2013**	**2018**	**2020**
SEMINOLE (FL) 1	149.6	149.6	62.3	62.3
SEMINOLE (FL) 2	147.5	147.5	61.5	61.5
NEEDED REMOVAL	**2010**	**2013**	**2018**	**2020**
SEMINOLE (FL) 1	-97.8	-99.3	-13.0	-12.9
SEMINOLE (FL) 2	-95.7	-97.2	-12.2	-12.0
Yearly Removal Requirement	-193.5	-196.5	-25.2	-24.9

Of particular note, between 2010 and 2017 (Phase I of CSA) Seminole will be able to bank 1,570 mercury allowances (pounds), which could be used to offset mercury emissions from Seminole Unit 3.

V. COMPLIANCE SIMULATIONS

Emission-Economic Modeling System was used to determine the optimal timing of technology investment and allowance purchases for each case. Both the Payne CC and planned five GTs were part of these NOx simulations. The Project Team evaluated nine cases (simulations) and they were as follows:

- **Case 0: SCR** – This case calls for the installation of an SCR on the Seminole Unit 1 in 2007, and a second SCR to be installed on Unit 2 in 2008. In addition, eighty (80) percent of all "excess" NOx allowances,

resulting from over-control due to the two SCRs, would be sold on the national market. *No combustion modifications would be installed on either unit* in this case and the SCR emission rate for this simulation is 0.07 lbs/mmbtu.

- **Case 1: Early SCR and Combustion Modifications** – This simulation installs SCR on Unit 1 in 2007 and combustion modifications are installed on Unit 2 coupled with allowance purchases to comply with CSA. The SCR emission rate for this simulation is 0.07 lbs/mmbtu and the combustion modification emission rate is 0.30 lbs/mmbtu.

- **Case 2: Early SCR/Combustion Modifications/NOxStar** – This simulation installs SCR on Unit 1 in 2007 and deploys combustion modifications and NOxStar on Unit 2 coupled with allowance purchases to comply with CSA. The SCR emission rate for this simulation is 0.07 lbs/mmbtu and the emission rate for the combination of combustion modifications and NOxStar is 0.18 lbs/mmbtu.

- **Case 3: Early SCR/Combustion Modifications/SNCR** - This simulation installs SCR on Unit 1 in 2007 and deploys combustion modifications and SNCR on Unit 2 coupled with allowance purchases to comply with CSA. The SCR emission rate for this simulation is 0.07 lbs/mmbtu and the emission rate for the combination of combustion modifications and SNCR is 0.22 lbs/mmbtu.

- **Case 4: Early SCR/Combustion Modifications/Compact SCR** – This simulation installs SCR on Unit 1 in 2007 and deploys combustion modifications and a Compact SCR on Unit 2 coupled with allowance purchases to comply with CSA. The SCR emission rate for this simulation is 0.07 lbs/mmbtu and the emission rate for the combination of combustion modifications and Compact SCR is 0.15 lbs/mmbtu.

- **Case 5: SCR/Combustion Modifications/NOxStar** – This simulation mirrors the technology deployment schedule of Case 2; however, the SCR installed on Unit 1 would achieve an emission rate of 0.10 lbs/mmbtu.

- **Case 6: Combustion Modifications and SNCR** – This simulation installs combustion modifications and SNCR on both units, coupled with NOx allowance purchases to comply with CSA The emission rate for the combination of combustion modifications and SNCR is 0.22 lbs/mmbtu.

- **Case 7: Combustion Modifications Only** – This simulation installs only combustion modifications on both units, coupled with NOx allowance purchases to comply with CSA The combustion modifications emission rate is 0.30 lbs/mmbtu.

- **Case 8: No Technology** – This simulation installs no NOx control technology and relies on allowance purchases to comply with CSA

VI. FINDINGS

Overview of Compliance Costs

The Project Team initially evaluated the least cost compliance solution (NOx control strategy) for each of the nine cases discussed in Section IV. The least cost compliance is defined as the most inexpensive way of meeting the reduction objectives of a regulatory regime using control technology and/or allowance purchases. A very important element of these simulations is the allowance price forecast, which was discussed in Section III. These price forecasts are based upon a series of assumptions about the long term compliance and availability of NOx allowances under CSA. Given the potential volatility that could occur surrounding future allowance prices and availability, any significant increase or decrease in prices could alter compliance decisions and make on more or less dependent on allowances for compliance. An overview of the findings for each of the nine cases are displayed in Table 4, which breaks down the total annualized compliance costs into technology and allowance purchases/sales for the years 2008 to 2020.

TABLE 4
TOTAL ANNUALIZED COMPLIANCE COST: 2008 – 2020
(in 2003 $)

Cases	Technology Costs	Allowance Purchases/Sales(-)	Total Costs
0	346,175,360	-67,658,227	278,517,133
1	190,468,680	18,983,416	209,452,096
2	190,468,680	18,983,416	209,452,096
3	200,665,995	7,480,795	208,146,790
4	190,468,680	18,983,416	209,452,096
5	184,843,040	32,490,746	217,333,786
6	102,003,680	50,500,520	152,504,200
7	34,762,000	122,539,615	157,301,615
8	0	248,608,032	248,608,032

Notes: 1. Annualized compliance cost is composed of annualized capital costs, annual O&M and annual allowance purchases or sales.
2. Eighty percent of all available allowances are sold in the year they are generated.

Case 0: Case 0 has a total annualized costs of $278.5 million, which is the most expensive of the all the technology deployment scenarios, even though Seminole would sell almost $68 million in allowances between 2008 and 2020 and would not have to rely on the allowance market for compliance. The major factor contributing to this significant

cost is operating two SCRs (Unit 1 in 2007 and Unit 2 in 2007) simultaneously over a 13 year period.

Under Case 0, Seminole's system-wide NOx emissions are reduced 82 percent from Base Case levels to an average annual emission level of 3,645 tons. This reduction translates into a system-wide emission rate of 0.07 lbs/mmbtu, which will create between 2008 and 2020 an average of 3,479 excess allowances per year. Some of these excess allowances could be used to offset the NOx emissions (1,700 tons) at Seminole 3.

Case 1: Case 1, as shown in Table 4, has a total annualized compliance cost of $209.4 million. Specifically, Case 1 installs an SCR on Unit 1 in 2007 and combustion modifications on Unit 2 in 2008 and has to purchase almost $19 million in allowances

Under Case 1, Seminole's system-wide NOx emissions are reduced 57 percent from Base Case levels to an average annual level of 8,920 tons. This reduction translates into a system-wide emission rate of 0.16 lbs/mmbtu. To meet the CSA reduction targets from 2008 to 2020, Seminole would be required to purchase, on average, 927 NOx allowances per year.

Case 2: The least cost compliance solution for Case 2 would be to install the SCR on Unit 1 (2007) and combustion modifications on Unit 2 in 2008, and purchase NOx allowances between 2008 and 2020. Under the current allowance price forecast (Section III) it is cheaper to purchase allowances annually than pay the annualized costs for NOx Star ($6.4 million). The total compliance costs would be identical to Case 1 ($209.4 million). With no installation of NOxStar, NOx emissions will be reduced to the same level as Case 1 (average annual level of 8,920 tons per year and a system-wide emission rate of 0.16 lbs/mmbtu). Like Case 1, Seminole would be required to purchase about 927 allowances per year between 2008 and 2020. However, if NOxStar were installed on Unit 2 in 2012 approximately 1,724 excess allowances would be generated per year between 2012 and 2020. These excess allowances could be used to offset NOx emissions from Seminole 3.

Case 3: Case 3 has estimated total compliance costs of $208.1 million, as shown in Table 4. In Case 3 an SCR is installed on Unit 1 in 2007 and combustion modifications and a SNCR on Unit 2 in 2008 and 2017, respectively. This deployment schedule allows Seminole to reduce its dependency on allowance purchases for compliance; whereby, allowance costs represent only 3.6 percent of this case's total compliance costs.

Under Case 3, Seminole's system-wide NOx emissions are reduced 59.4 percent from Base Case levels to an average annual level of 8,368 tons. This reduction translates into a system-wide emission rate of 0.15 lbs/mmbtu. To meet the CSA reduction targets from 2008 to 2020, Seminole would be required to purchase, on average, 145 NOx allowances per year.

Case 4: Similar to Case 2, the least cost solution for this case would be to install the SCR on Unit 1 (2007) and combustion modifications on Unit 2 in 2008, and purchase NOx allowances between 2008 and 2020. Like Case 2, it is cheaper to purchase allowances annually than pay the annualized costs for a Compact SCR ($7.0 million). The total compliance costs would be identical to Cases 1 & 2 ($209.4 million). With no installation of the Compact SCR, NOx emissions will be reduced to the same level as both Cases 1 & 2 (average annual level of 8,920 tons per year and a system-wide emission rate of 0.16 lbs/mmbtu). Like Cases 1 & 2, Seminole would be required to purchase about 927 allowances per year between 2008 and 2020. However, if the Compact SCR were installed on Unit 2 in 2012 approximately 2,402 excess allowances would be generated per year. Some of these excess allowances could be used to offset NOx emissions from Seminole 3.

Case 5: In this case, the SCR emission rate is 0.10 lbs/mmbtu, compared to the 0.07 lbs/mmbtu in the other cases. The least cost solution for this case would be the installation of an SCR on Unit 1 in 2007 and combustion modifications on Unit 2 in 2008 and the purchase of NOx allowances between 2008 and 2020. With no NOxStar installed, the total compliance costs for this case is $217.3 million. The primary factor causing the difference in compliance costs between this case and Case 2 is attributed to the higher SCR emission rate; whereby, Seminole would be faced with increased allowance purchases.

Under Case 5, Seminole's system-wide NOx emissions are reduced 53.3 percent from Base Case levels to an average annual level of 9,608 tons. This reduction translates into a system-wide emission rate of 0.17 lbs/mmbtu. To meet the CSA reduction targets from 2008 to 2020, Seminole would be required to purchase, on average, 1,615 NOx allowances per year.

Case 6: The least cost alternative or best NOx control strategy is Case 6, which installs both combustion modifications and SNCR on both units in 2008, and has estimated total compliance costs of $152.5 million, as displayed in Table 4. However, this compliance strategy is heavily dependent on the availability and price of allowances. Approximately 33 percent or one-third or Seminole's compliance costs for this strategy are attributed to allowance purchases.

Under Case 6, Seminole's system-wide NOx emissions are reduced by almost 49 percent from Base Case levels to an average annual level of 10,562 tons. This reduction translates into a system-wide emission rate of 0.19 lbs/mmbtu. To meet the CSA reduction targets from 2008 to 2020, Seminole would be required to purchase an average 2,532 NOx allowances per year.

Case 7: Case 7, which only installs combustion modifications on both units in 2008, yielded a slightly higher total compliance cost of $157.3 million, but 78 percent of this case's compliance costs would be attributed to allowance purchases.

Under Case 7, Seminole's system-wide NOx emissions are reduced by 31.1 percent from Base Case levels to an average annual level of 14,195 tons. This reduction translates into a system-wide emission rate of 0.26 lbs/mmbtu. To meet the CSA reduction targets from 2008 to 2020, Seminole would be required to purchase an average 6,202 NOx allowances per year.

Case 8: If Seminole decided to rely 100 percent on the allowance market to comply with CSA and install no control technologies (Case 8), the total annualized costs would be $248.6 million. This is the second most expensive compliance option, as well as the compliance strategy with the most risk, because of its total reliance on allowances for compliance.

Specifically under Case 8, there would be no reductions in Seminole's annual emissions, resulting in average annual system-wide NOx emissions of 20,617 tons. These annual NOx emissions translate into a system-wide emission rate of 0.37 lbs/mmbtu. With no technological reductions to meet the CSA reduction targets, Seminole would be required to purchase an average of 12,624 allowances per year.

Mercury Co-Benefit

The deployment of SCRs in Cases 0 through 5 would create additional reductions in mercury emissions. Specifically, Base Case mercury emissions for Seminole 1 & 2, as shown in Table 3, are projected to average 100 pounds per year between 2010 and 2020. In Case 0, the SCRs installed on both Seminole units by 2008 are expected to remove an additional 11 pounds of mercury per year, which will reduce Seminole's overall mercury emissions to 89 pounds per year.

In Case 1 to 5 the SCR installed on Seminole 1 in 2007 is expected to remove almost 5.4 pounds of mercury per year between 2010 and 2020. This additional removal will reduce Seminole's overall mercury emissions to almost 95 pounds per year.

Compliance Cost Effects for Cases 2 and 4 of Installing NOxStar and Compact SCR

As mentioned earlier in this section, in both Cases 2 & 4, neither NOxStar (Case 2) or the Compact SCR (Case 4) were installed because they were both found to be to expensive, in a least cost framework in comparison to the purchase of NOx allowances. The Project Team undertook several sensitivity analyses to evaluate the compliance cost implications of installing NOxStar (Case 2) and Compact SCR (Case 4) anytime between 2008 and 2020. As pointed out at the beginning of this section not installing either technology would result in a total compliance cost of $209.4 million for each case.

Briefly for Case 2, as illustrated in Table 5, the longer Seminole waits to install NOxStar, the less expensive it becomes. This trend is a function of a very expensive technology being installed (annualized cost of $6.4 million) and operated over long periods, along with low allowance prices which can not offset the high operating costs.

For NOxStar under Case 2 to be applied earlier (before 2020) allowance prices would have to reach $2,904/ton, which is the first (or crossover) allowance price at which technology is installed.

As mentioned earlier, if NOxStar were installed in 2012, Seminole would generate between 2012 and 2020 an average of 1,724 excess NOx allowances per year. These excess allowances could be used to offset the annual NOx emissions (1,700 tons) of Seminole 3. Since none of the excess allowances would be sold, the total compliance costs of installing NOxStar in 2012 are expected to be $253.2 million.

TABLE 5
CASE 2: COMPLIANCE COST IMPLICATIONS OF INSTALLING NOxSTAR
(in 2003 $)

NOxStar Year Installed	Total Annual Cost	Value of Allowances after Installation	Net Annual Cost
NONE	209,452,096	0	209,452,096
2008	274,259,800	28,036,724	246,223,076
2009	269,880,795	25,110,247	244,770,548
2010	264,652,931	22,484,301	242,168,630
2011	258,987,167	20,426,346	238,560,820
2012	253,170,882	18,127,721	235,043,161
2013	247,263,066	15,635,799	231,627,267
2014	241,438,720	13,140,370	228,298,350
2015	235,338,744	10,358,628	224,980,116
2016	229,367,129	7,599,462	221,767,666
2017	223,318,748	4,552,332	218,766,416
2018	217,364,870	1,336,346	216,028,524
2019	215,116,770	864,200	214,252,569
2020	212,410,377	371,203	212,039,174

The same trend as Case 2 applies to Case 4, as illustrated in Table 6. The longer Seminole waits the less expensive the compliance strategy becomes. For the Compact SCR under Case 4 to be installed earlier (before 2020) allowance prices would have to reach $3,144/ton.

As mentioned earlier, if Compact SCR were installed in 2012, Seminole would generate an average of 2,402 allowances per year between 2012 and 2020. These excess allowances would be able to offset the annual NOx emissions of 1,700 tons from Seminole 3 and allow Seminole to sell approximately 562 allowances per year (or 5,058 allowances from 2012 to 2020) in the national market. The sale of these allowances after

the emission offset of Seminole 3 would create almost $7.4 million in allowance revenue, resulting in a total compliance cost of $251.2 million.

TABLE 6
CASE 4: COMPLIANCE COST IMPLICATIONS OF INSTALLING COMPACT SCR
(in 2003 $)

CSCR Year Installed	Total Annual Cost	Value of Allowances after Installation	Net Annual Cost
NONE	209,452,096	0	209,452,096
2008	282,065,280	38,842,589	243,222,691
2009	277,115,545	34,735,568	242,379,976
2010	271,301,606	31,192,400	240,109,206
2011	265,048,447	28,448,383	236,600,064
2012	258,638,662	25,440,958	233,197,705
2013	252,134,046	22,214,179	229,919,867
2014	245,708,060	18,972,129	226,735,931
2015	238,999,239	15,435,961	223,563,278
2016	232,423,069	11,897,193	220,525,875
2017	225,764,303	8,020,819	217,743,485
2018	219,204,055	3,909,655	215,294,399
2019	216,343,975	2,493,870	213,850,105
2020	213,020,927	1,149,288	211,871,640

Summary of Findings

The various subsections of Section VI present the results of a series of case simulations that attempt to identify the most cost-effective NOx control strategy for Seminole 1 & 2. Of all the information that is presented, we would like to point out three important findings:

- The least cost NOx strategy for Seminole 1 & 2 is Case 6, which installs both combustion modifications and SNCRs on both units in 2008 and relies on the purchase of an average 2,532 NOx allowances per year. The 2008 to 2020 compliance costs for this case is $152.5 million.
- The least cost NOx strategy in which Seminole does not have to purchase allowances for compliance (or otherwise has no allowance risk) is a modified Case 3, in which an SCR is installed on Unit 1 in 2007 and combustion modifications and SNCR are installed on Unit 2 in 2008. The 2008 to 2020 compliance costs for this case is $210.5 million. (These costs are not reflected in Table 4).

- The least cost NOx strategy that generates enough excess NOx allowances to offset the NOx emissions of Seminole 3 is a modified Case 4, in which an SCR is installed on Unit 1 in 2007 and combustion modifications (2008) and Compact SCR (2012) are installed on Unit 2. The 2008 to 2020 compliance costs for this case is $251.2 million. Under this case approximately 1,840 allowances would be held back each year to offset annual NOx emissions at Seminole 3 and for other internal uses, while the remaining allowances (approximately 562 allowances per year) would be sold. The sale of these allowances would generate $7.4 million between 2012 and 2020, which is reflected in the above mentioned compliance costs. (These costs are not reflected in Table 6).

APPENDIX A

NOx CONTROL ASSUMPTIONS

This section summarizes the assumptions supporting the NOx control technology assumptions.

COMBUSTION TUNING AND OPTIMIZATION

Both units will adopt improvements to the combustion tuning and firing systems to reduce NOx from approximately 0.44 to 0.30 lbs/MBtu. These modifications will focus on improving the distribution of both fuel and air, to improve NOx control capability. Also, the overfire air ports will be modified to improve penetration of the overfire combustion air into the furnace. Regarding the burner, the inner "barrel" will be replaced to improve coal distribution. Also, hardware will be retrofit to the pulverizers to eliminate coal "roping" as it leaves the pulverizer, promoting a uniform coal distribution across the burners. Finally, a CFD model of the windbox will be conducted to determine the airflow distribution, and identify means to improve the distribution.

The capital cost for these improvements is assumed to be $15/kW, or $10.7 million. The fixed O&M costs are assumed to be $160,000 annually, which is 1.5 percent of the total capital costs.

CONVENTIONAL SCR

SCR costs are derived from the report prepared by Sargent and Lundy (S&L Report SL-5664, November, 2003). Reported capital costs of $122/kW (Option 1A) to $117/kW (Option B) are assumed to be comprehensive, and thus include all balance-of-plant factors (BOP) and AFDC. Fixed operating costs are projected, which appear to be about 0.40% of SCR process capital (consistent with other estimates I have reviewed). Operating costs are based on replacement catalyst, reagent, and auxiliary power beyond that required for baseline plant operation. The replacement catalyst strategy defined by (a) supplement of initial catalyst inventory after 17,000 operating hours, and (b) replacement of catalyst layers at intervals of approximately 17,000 hours.

Operating costs are based on the S&L analysis, which assumes annual deployment of NOx control technology are projected to be $350,000 per year for fixed O&M and variable O&M from 0.72 to 0.74 mills/kWh.

COMPACT SCR

Both Seminole units present the opportunity to deploy a compact, one-layer SCR reactor. This option is allowed by the extended height between the economizer outlet and air heater inlet. This space allows for one extended layer of catalyst, and depth both preceding and following the layer for flue gas expansion, and routing to the air heater.

Given the relatively small inventory of catalyst, operating lifetime is assumed to be 12,000 hours. Catalyst removed from the compact reactor will still possess useful activity, and it can be used (perhaps with regeneration) as replacement catalyst for the conventional SCR unit. Operating costs are based on providing for replacement catalyst, reagent consumption, and auxiliary power requirements.

The capital cost for the compact SCR reactor at Seminole is unknown. However, the process equipment required is reduced by more than half, and the possibility to "modularize" construction and provide for in-shop assembly of major components suggests installation costs will be greatly reduced. Balance-of-plant upgrades, in particular fan modifications, will be reduced. Accordingly, we assumed a capital cost of $55/kW along with a fixed O&M cost of $200,000 per year and variable O&M cost of 0.55 mills/kWh.

SNCR

SNCR cost and information and performance estimates are derived form the recent summary by Hines (2003). Assumptions for capital and operating cost and performance are derived from several recent commercial demonstrations, the most relevant a 720 MW twin tangential-fired furnace. SNCR performance using a single level of injectors was determined from baseline levels of 0.22 lbs/MBtu. The results show NOx reductions of (a) 14% at 2 ppm residual NH3, and (b) 25% at 5 ppm residual NH3 are measured.

We assumed that a next-generation version of SNCR will be available to meet the CSA. This will include (a) multi-layer nozzles, which although increasing complexity will improve the ability to control reagent injection, and (b) "smart" reagent control, with reagent injection bias determined from NOx and flue gas temperature data. These features – not yet demonstrated but possibly available commercially by 2005 – are analysis assumed to provide for 25% NOx reduction, with 1-2 ppm residual NH3.

Capital costs for this system are assumed to be $10/kW.

Fixed O&M cost is assumed to be 1.5% of capital charge, incurred annually. Variable operating cost is derived from (a) urea reagent consumption, at a molar injection ratio of 0.8, and (b) auxiliary power for the compressed air-driven injectors, selected to be 0.20% of plant output. Fixed O&M costs are projected to $108,000 per year and variable O&M are expected to be 0.37 mills/kWh.

NOxStar

NOxStar cost and process information is obtained from the summary by Hesselman (2003), a review of NOx control technology in Power Engineering (Schimmoller, 2003) and discussions with staff at Fossil Energy Research Corporation, whom conducted the demonstration tests at TVA's Kingston station (Muzio, 2003).

Data provided by the process developers for two test furnaces and full-scale data from Kingston cannot be directly extrapolated to other plants. Specifically, it is reported that in the demonstration at TVA's Kingston plant, NOx reduction of 68% was achieved, but in combination with furnace air staging. NOxStar reduction alone can be inferred with two assumptions: (a) the uncontrolled NOx rate for this unit is 0.7 lbs/MBtu, and (b) furnace staging derived 35% NOx reduction. Considering that furnace staging provided 35% NOx reduction implies the NOxStar process actually treated boiler exit flue gas with 0.45 lbs/MBtu NOx, meeting a target of 0.22 lbs/MBtu. These assumptions suggest the process reduction provided by NOxStar is 50%.

The NOx removal data is further adjusted for two reasons:

Initial NOx Rate The tendency of SNCR to exhibit a higher NOx removal on units with higher inlet NOx is well-documented. The similarity of NOxStar process chemistry to SNCR is such that I believe the same trend holds for this process. The reported reduction from levels estimated as 0.45 lb/MBtu is adjusted to account by 10% (e.g. from 50 to 45%) for the lower boiler outlet NOx rate of 0.30 lbs/MBtu.

Residual NH3 NOxStar publications report residual NH3, but these measurements are conducted at the air heater exit, in contrast to the usual location of the air heater inlet. Accordingly, it is likely that the 2-4 ppm residual NH3 reported by NOxStar is more like 4-8 ppm entering the air heater. The significance of this difference is the potential for deposition within the air heater deposition of sulfates and bisulfates of ammonia, and absorption by ash of ammonia compounds. Given the importance of maintaining negligible residual NH3 entering the Seminole FGD process, we assumed the mole ratio of reagent (as depicted in Figure 5 of Hesseleman, 2003) is lowered from the apparent value of 2.0 to 1.25. The impact of this reduction in NSR is equivalent to 0.10 lbs/MBtu, which is another 10% compromise in NOx control. Consequently, a net value of 35% is assumed.

For the above reasons, the long-term, commercially achievable NOx reductions provided by the NOxStar process for Seminole conditions is anticipated to be 35%, from boiler NOx exit values of 0.30 lbs/MBtu. The analysis will be based on the maximum anticipated NOx removal of 40%, allowing for further process evolution in the next 3 years.

Capital costs will be assumed to be $40/kW, based on the estimate prepared by NOxStar staff for Seminole ($33/kW), and allowing for an additional $7/kW for urea receiving/storage facilities, and a natural gas pipeline.

Similar to SNCR, fixed operating costs are assumed to be 1.5% of capital, incurred annually. Variable operating costs for NOxStar will be derived based on a (1) molar ratio of urea to NOx of 1.25, and (2) a methane (e.g. natural gas) consumption rate equal to the moles of NH compounds, or 50% of the urea molar requirement (Muzio, 2003). For the specific conditions of this analysis, the consumption of natural gas should not exceed 250 scfm, at full load Auxiliary power consumption is assumed to be slightly higher than for SNCR (0.25% of capacity), due to the need to inject and aggressively mix hydrocarbon reagent. Fixed O&M cost is projected at $250,000 per year with variable O&M expected to be 0.66 mills/kWh.

Mercury Co-benefits

The discussion be summarizes our observations regarding the increase in mercury (Hg) removal possible attributable to the use of SCR NOx control for Seminole Electric Units 1 and 2.

The Hg measurements conducted for Seminole Electric by RMB Consulting and reported on May 27, 2003 (Martin, 2003) cite Hg removal by the existing control equipment, and Hg speciation, based on two series of field tests. These field trials addressed the use of a 70/30 blend of "baseline" bituminous coal and petroleum coke (Trial A), and 100% of "baseline" bituminous coal (Trial B). The data showed Hg removal of (a) 83% for the 70/30 firing blend (based on two measurement points), and (b) 83% for the 100% bituminous firing (based on three measurement points). The speciation data (as measured at the FGD inlet) showed that oxidized Hg represented 75 and 59 % of the total Hg inventory for Trial A and Trial B, respectively.

Measurements at the stack suggested that about 95% of the oxidized Hg was removed by the wet FGD process, which is operated to produce commercial grade gypsum. This high Hg removal is consistent with observations that FGD process equipment with low sulfite content offer high removal (e.g. the Hg "re-emission" of oxidized Hg as elemental appears correlated with high sulfite chemistry conditions).

The relatively high fraction of Hg oxidized (59-75%) and the success in removing almost all oxidized Hg suggests a further increase in oxidized Hg by SCR will enable higher Hg removal by the FGD process.

The composition of coal and petroleum coke fired was reviewed with respect the Hg oxidation and potential influence of SCR. Most notably, the "baseline" coal samples feature relatively high sulfur (3%) and chloride content (usually >1,200 ppm). The use of petroleum coke introduces a fuel with higher sulfur (6%) but relatively low chloride content (100 ppm). Accordingly, the use of even up to a 30% blend may not materially

change the oxidation state, as the blended fuel chloride content will in most cases remain above 1,000 ppm.

The most recently published SCR-induced Hg oxidation data suggests that an average increase by 35 percentage points was observed for a wide range of coals (Chu, 2003). Given the high chloride in the Seminole coal (even with 30% blending of pet coke) an increase of Hg removal from 83% to 90-95% is believed to be feasible.

Our recommendation is that we use 93% in the calculations of Hg mass removal rate with SCR in combination with the existing FGD system. This removal represents an improvement of 10 percentage points over the current removal under Seminole's existing congifuration. Although higher Hg removal has been observed in ICR and other field data, the uncertainty of the data and the variability of Hg in coal prevent using these higher removal efficiencies.

Table A-1
Summary of NOx Control Costs

Technology	Boiler NOx Rate (lbs/MBtu)	Design Outlet (lbs/MBtu)	Capital ($/kW)	Capital ($M)	Fixed O&M ($000/yr)	Variable O&M (mills/kWh)	NOx Removal (% or rate)
SCR Option 1B	0.44	0.10	117.4	83.9	350	0.72	78
SCR Option 1A	0.44	0.07	122	87.0	350	0.74	84
Combustion Tuning/Opt	0.44	0.30	15	10.7	160	0	to 0.30 lbs/MBtu
Compact SCR	0.30	0.15	55	39.3	200	0.55	50
SNCR	0.30	0.22	10	7.1	108	0.37	25
NOxStar	0.30	0.18	40	28.5	250	0.66	40

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Citation	Publication
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Chu, 2003	Chu, P. et. al. "Power Plant Evaluation of the Effect of SCR Technology on Mercury", Proceedings of the 2003 Mega-Symposium, May, 2003, Washington, DC.
Martin, 2003	Letter from RMB Consulting to Mike Roddy, May 27, 2003

Case Summaries

Case #	Unit 1	Unit 2	NOx Allowances perYear
0	**SCR** (0 .07 lb/mmBtu)	**SCR** (0.07 lb/mmBtu)	3479 (sale)
1	SCR (0.07 lb/mmBtu)	**Comb Mods** (0.3 lb/mmBtu)	927 (purchase)
2	SCR (0.07 lb/mmBtu)	Comb Mods + **NOxStar** (0.18 lb/mmBtu)	1724 (sale)
3	SCR (0.07 lb/mmBtu)	Comb Mods + **SNCR** (0.22 lb/mmBtu)	738 (sale)
4	SCR (0.07 lb/mmBtu)	Comb Mods + **CSCR** (0.15 lb/mmBtu)	2402 (sale)
5	SCR **(0.1 lb/mmBtu)**	Comb Mods + **NOxStar** (0.18 lb/mmBtu)	934 (sale)
6	Comb Mods + **SNCR** (0.22 lb/mmBtu)	Comb Mods + **SNCR** (0.22 lb/mmBtu)	2532 (purchase)
7	**Comb Mods** (0.3 lb/mmBtu)	**Comb Mods** (0.3 lb/mmBtu)	6206 (purchase)
8	**Allowance Purchases Only**	**Allowance Purchases Only**	12624 (purchase)

NOx REDUCTION TECHNOLOGIES

SCR – Selective Catalytic Reduction

SNCR – Selective Non-Catalytic Reduction

CSCR – Compact SCR, a single catalyst layer installed in the existing ductwork

NOxStar – an ammonia injection process similar to SNCR

Comb Mods - Combustion Modifications/Optimization

TABLE 2

NOx EMISSIONS AND CSA ALLOWANCES (in tons)

NOx EMISSIONS	2008	2013	2018	2020
SEMINOLE (FL) 1	10,685	10,067	9,860	9,889
SEMINOLE (FL) 2	10,685	10,067	9,860	9,889
PAYNE CREEK 1-2	467	356	256	255
5 PLANNED GT	151	125	125	125

NOx ALLOWANCES	2008	2013	2018	2020
SEMINOLE (FL) 1	3,646	3,646	2,712	2,712
SEMINOLE (FL) 2	3,595	3,595	2,674	2,674
PAYNE CREEK 1-2	1,255	1,255	933	933
5 PLANNED GT	0	0	0	0

NEEDED REMOVAL	2008	2013	2018	2020
SEMINOLE (FL) 1	7,039	6,421	7,148	7,177
SEMINOLE (FL) 2	7,091	6,473	7,186	7,215
PAYNE CREEK 1-2	-788	-899	-677	-679
5 PLANNED GT	151	125	125	125
Yearly Removal Requirement	13,493	12,120	13,782	13,838

Note: Payne Creek would have more allowances allocated than annual emissions resulting in excess allowances.

TABLE 5

CASE 2: COMPLIANCE COST IMPLICATIONS OF INSTALLING NOxSTAR (in 2003 $)

NoxStar Year Installed	Total Annual Cost	Value of Allowances after Installation	Net Annual Cost
NONE	209,452,096	0	209,452,096
2008	274,259,800	28,036,724	246,223,076
2009	269,880,795	25,110,247	244,770,548
2010	264,652,931	22,484,301	242,168,630
2011	258,987,167	20,426,346	238,560,820
2012	253,170,882	18,127,721	235,043,161
2013	247,263,066	15,635,799	231,627,267
2014	241,438,720	13,140,370	228,298,350
2015	235,338,744	10,358,628	224,980,116
2016	229,367,129	7,599,462	221,767,666
2017	223,318,748	4,552,332	218,766,416
2018	217,364,870	1,336,346	216,028,524
2019	215,116,770	864,200	214,252,569
2020	212,410,377	371,203	212,039,174

TABLE 6

CASE 4: COMPLIANCE COST IMPLICATIONS OF INSTALLING COMPACT SCR (in 2003 $)

CSCR Year Installed	Total Annual Cost	Value of Allowances after Installation	Net Annual Cost
NONE	209,452,096	0	209,452,096
2008	282,065,280	38,842,589	243,222,691
2009	277,115,545	34,735,568	242,379,976
2010	271,301,606	31,192,400	240,109,206
2011	265,048,447	28,448,383	236,600,064
2012	258,638,662	25,440,958	233,197,705
2013	252,134,046	22,214,179	229,919,867
2014	245,708,060	18,972,129	226,735,931
2015	238,999,239	15,435,961	223,563,278
2016	232,423,069	11,897,193	220,525,875
2017	225,764,303	8,020,819	217,743,485
2018	219,204,055	3,909,655	215,294,399
2019	216,343,975	2,493,870	213,850,105
2020	213,020,927	1,149,288	211,871,640

TABLE 1
CLEAR SKIES ACT: TARGETS AND TIMETABLES

Pollutant	2000 Emissions	Phase I Caps (2010)	Phase II Caps (2018)	Percent Reduction
SO2	11.2 million tons	4.5 million tons	3 million tons	73%
NOx	5.1 million tons	2.1 million tons (in 2008)	1.7 million tons	67%
Hg	48 tons	26 tons	15 tons	68%

TABLE 3

Hg EMISSIONS AND CSA ALLOWANCES (in pounds)

Hg EMISSIONS	2010	2013	2018	2020
SEMINOLE (FL) 1	51.8	50.3	49.3	49.4
SEMINOLE (FL) 2	51.8	50.3	49.3	49.4

Hg ALLOWANCES	2010	2013	2018	2020
SEMINOLE (FL) 1	149.6	149.6	62.3	62.3
SEMINOLE (FL) 2	147.5	147.5	61.5	61.5

NEEDED REMOVAL	2010	2013	2018	2020
SEMINOLE (FL) 1	-97.8	-99.3	-13.0	-12.9
SEMINOLE (FL) 2	-95.7	-97.2	-12.2	-12.0
Yearly Removal Requirement	-193.5	-196.5	-25.2	-24.9

"TOTAL ANNUALIZED COMPLIANCE COSTS" INCLUDE THE FOLLOWING:

- **Annualized Capital Costs**
- **Fixed Charge Rate – 0.11**
- **Fixed O&M**
- **Variable O&M**
- **Annual Allowance Purchases or Sales**

NOx Allowance Price Predictions

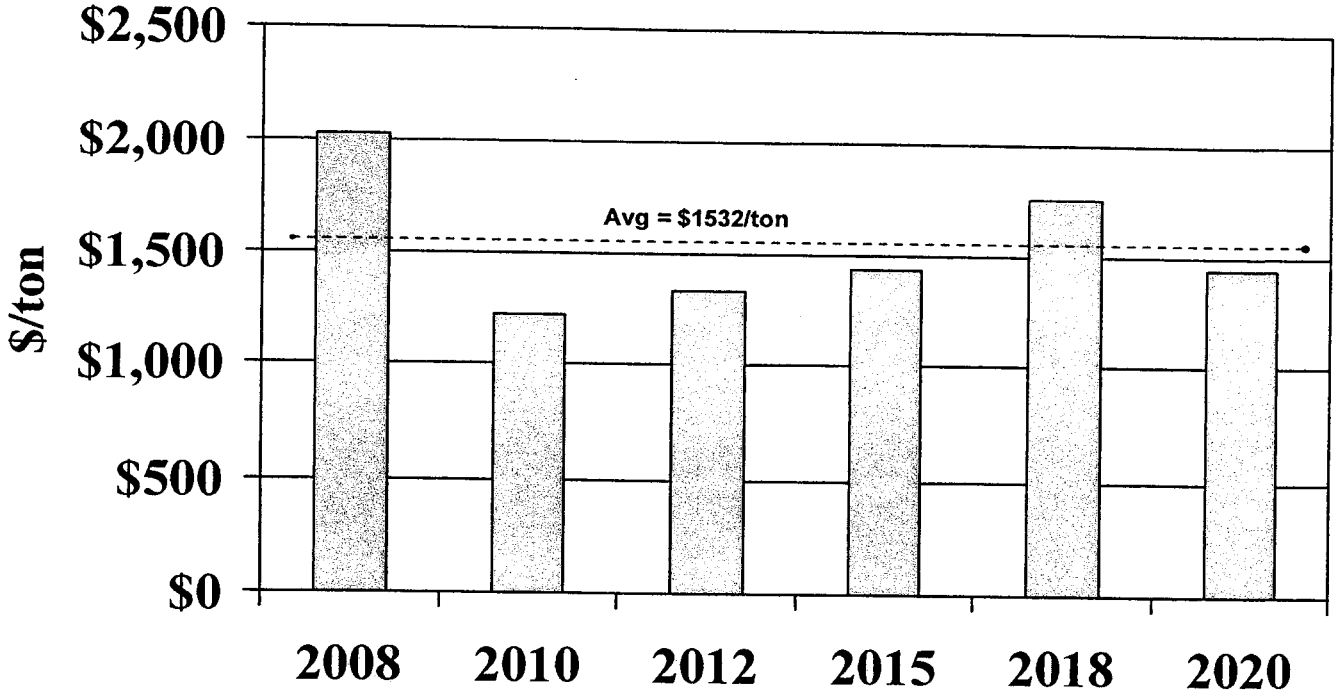


TABLE 4

TOTAL ANNUALIZED COMPLIANCE COST: 2008 – 2020, (in 2003 $)

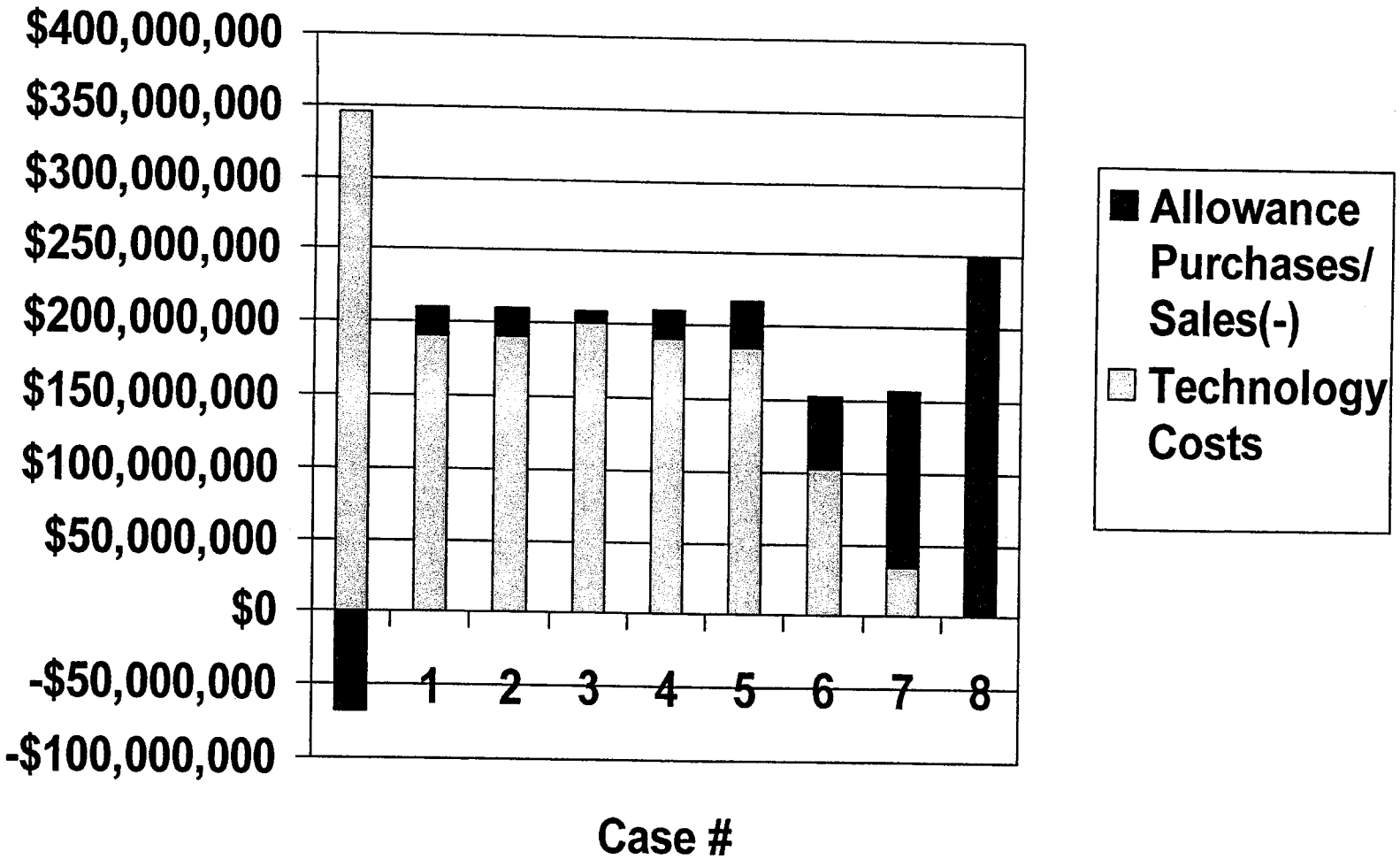
Cases	Technology Costs	Allowance Purchases/Sales(-)	Total Costs
0	346,175,360	-67,658,227	278,517,133
1	190,468,680	18,983,416	209,452,096
2	190,468,680	18,983,416	209,452,096
3	200,665,995	7,480,795	208,146,790
4	190,468,680	18,983,416	209,452,096
5	184,843,040	32,490,746	217,333,786
6	102,003,680	50,500,520	152,504,200
7	34,762,000	122,539,615	157,301,615
8	0	248,608,032	248,608,032

Notes:

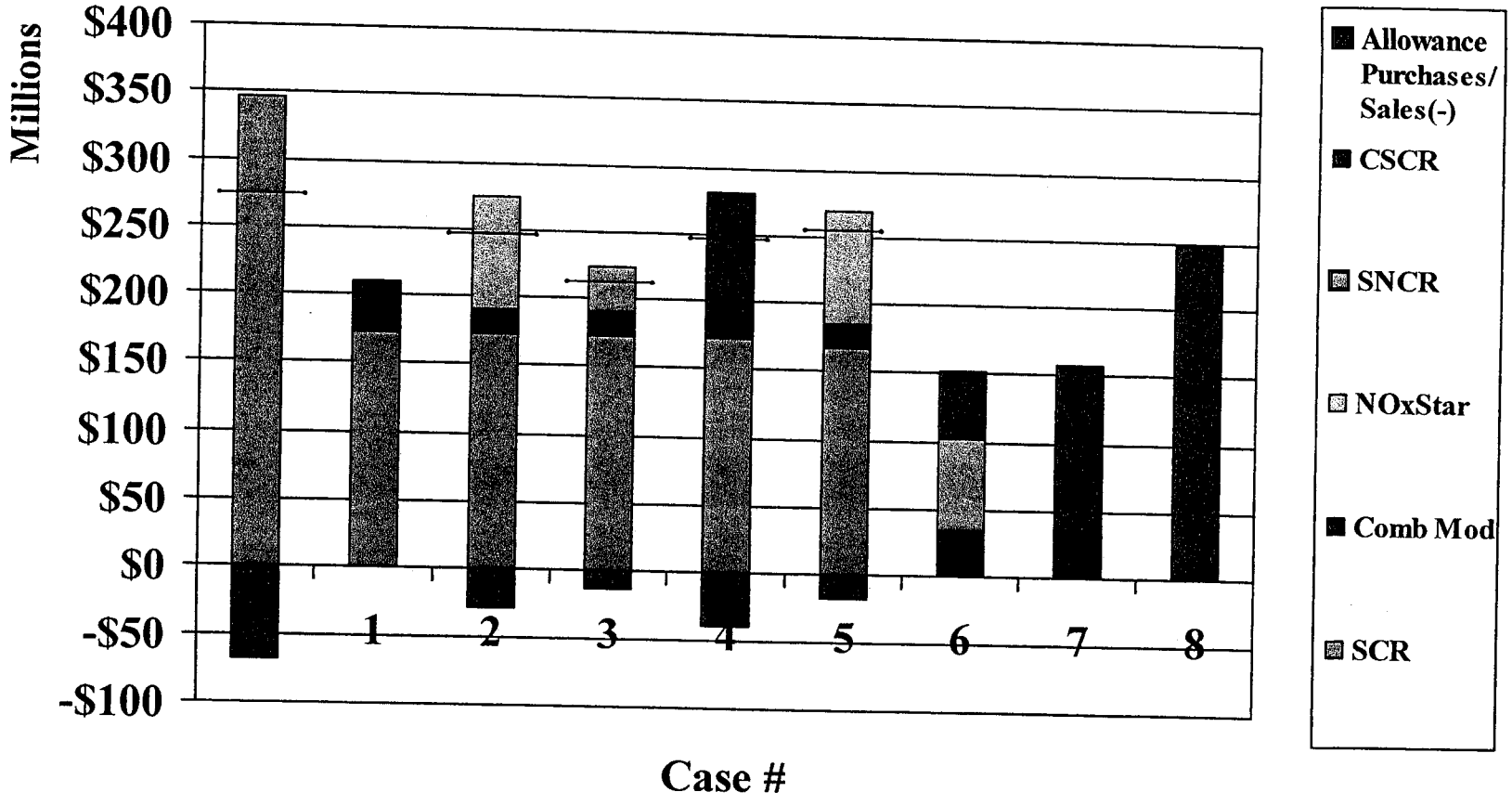
1. Annualized compliance cost is composed of annualized capital costs, annual O&M and annual allowance purchases or sales

2. Eighty percent of all available allowances are sold in the year they are generated.

Total Compliance Costs Thru 2020



Total Compliance Costs - 2008 Thru 2020



Total Compliance Costs - 2008 Thru 2020
Least-Cost Options

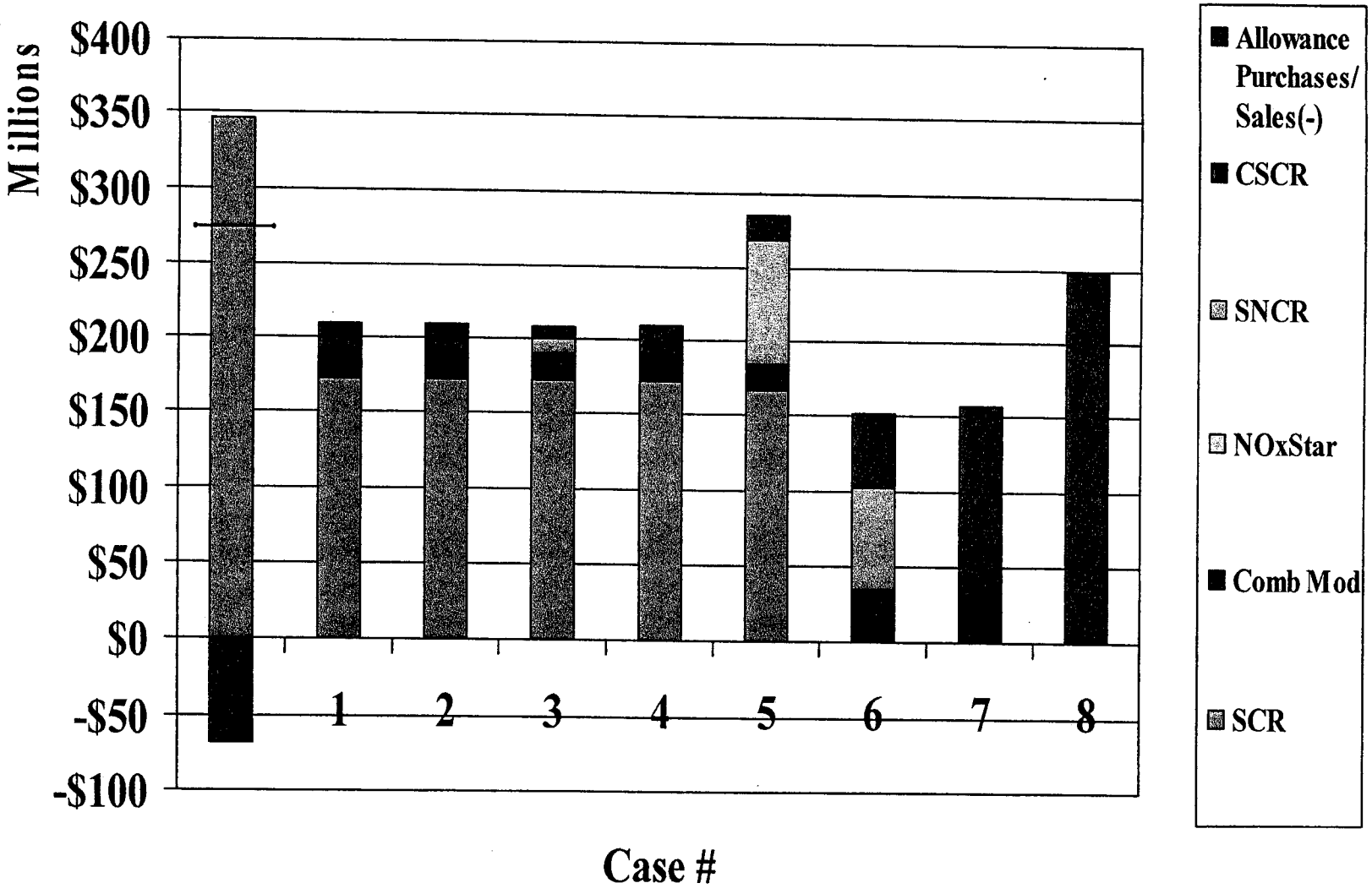


TABLE A-1
SUMMARY OF NOx CONTROL ASSUMPTIONS

Technology	Boiler NOx Rate (lbs/MBtu)	Design Outlet (lbs/MBtu)	Capital ($/kW)	Capital ($M)	Fixed O&M ($000/ yr)	Variable O&M (mills/kWh)	NOx Removal (%)
SCR Option 1B	0.44	0.10	117.4	83.9	350	0.72	78
SCR Option 1A	0.44	0.07	122	87.0	350	0.74	84
Combustion Tuning/Opt	0.44	0.30	15	10.7	160	0	to 0.30 lbs/MBtu
Compact SCR	0.30	0.15	55	39.3	200	0.55	50
SNCR	0.30	0.22	10	7.1	108	0.37	25
NOxStar	0.30	0.18	40	28.5	250	0.66	40

COMBUSTION
MODIFICATIONS/OPTIMIZATION

Fuel Balancing

- Reliable pipe-to-pipe fuel measurement & adjustment capability
- Pulverizer & Burner modifications to reduce "coal roping"

Air Balancing

- Computer modeling of air ductwork to improve air distribution to burners
- Modifications to burner sleeve dampers (hoods), air registers and over-fire air ports to restore reliable operation

PROPOSED EPRI STUDY

Phase I – SECI Information Analysis, $14,000

- *Station site visit*
- *CEMS data collection/analysis*
- *Conceptual compliance strategy development*

Phase II – Mill & Boiler Performance Assessment, $60,000

- *Develop & conduct baseline testing of the Unit and its Mills*

Phase III – Computational Fluid Dynamic Modeling, $25,000

- *Modeling of the ductwork from the FD fans, up to and including boiler windboxes. Ultimate goal to improve airflow balance in the windbox.*

Phase IV – Economic and Performance of NOx Control Technologies, $38,000

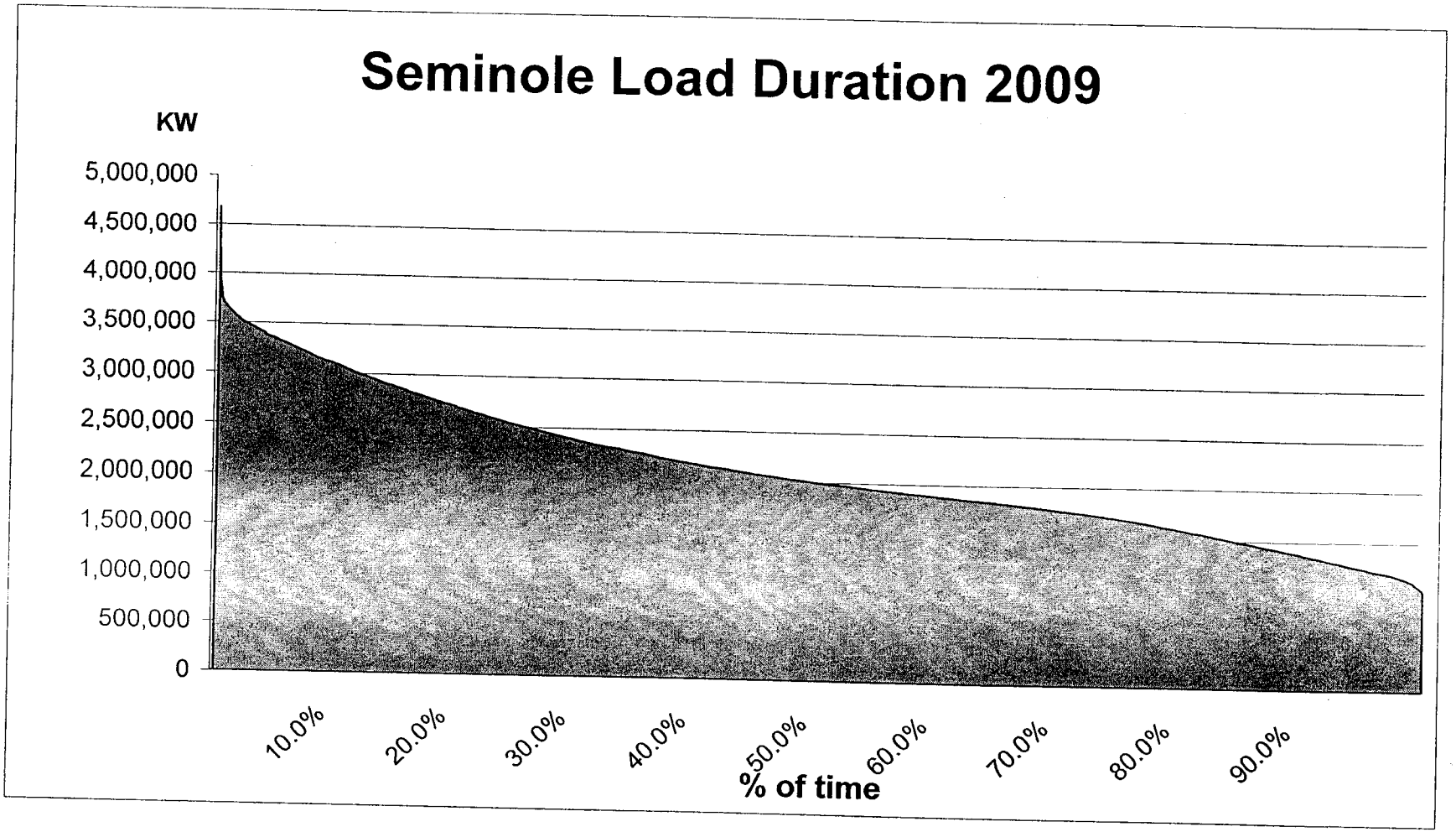
PROPOSED EPRI STUDY

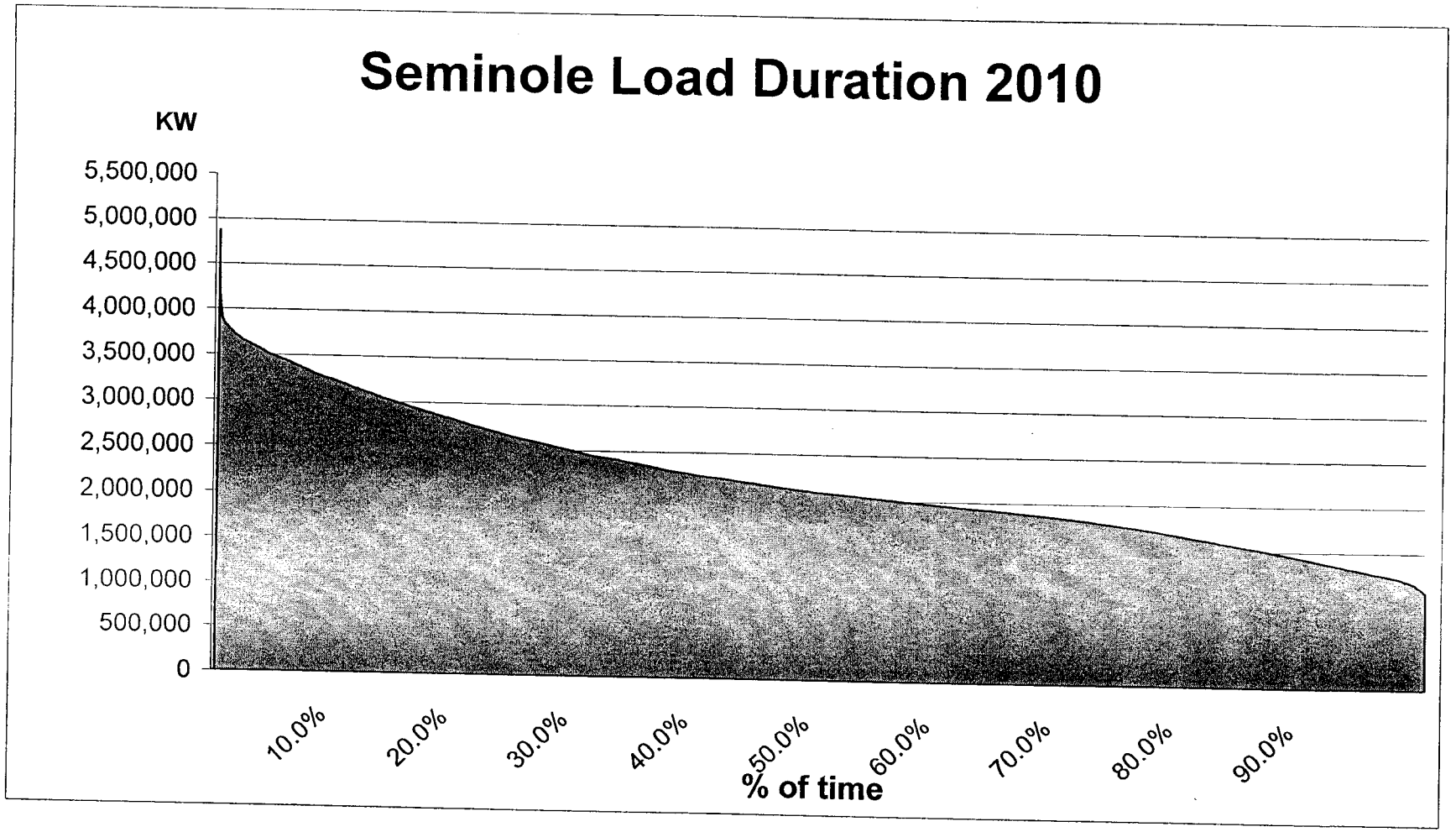
- **Phase I** – SECI Information Analysis, $14,000
- **Phase II** – Mill & Boiler Performance Assessment, $60,000
- **Phase III** – Computational Fluid Dynamic Modeling, $25,000
- **Phase IV** – Economic and Performance of NOx Control Technologies, $38,000
- **Phase V** – Results Presentation, $10,000
- **Phase VI** – Bid Specification Support, $25,000

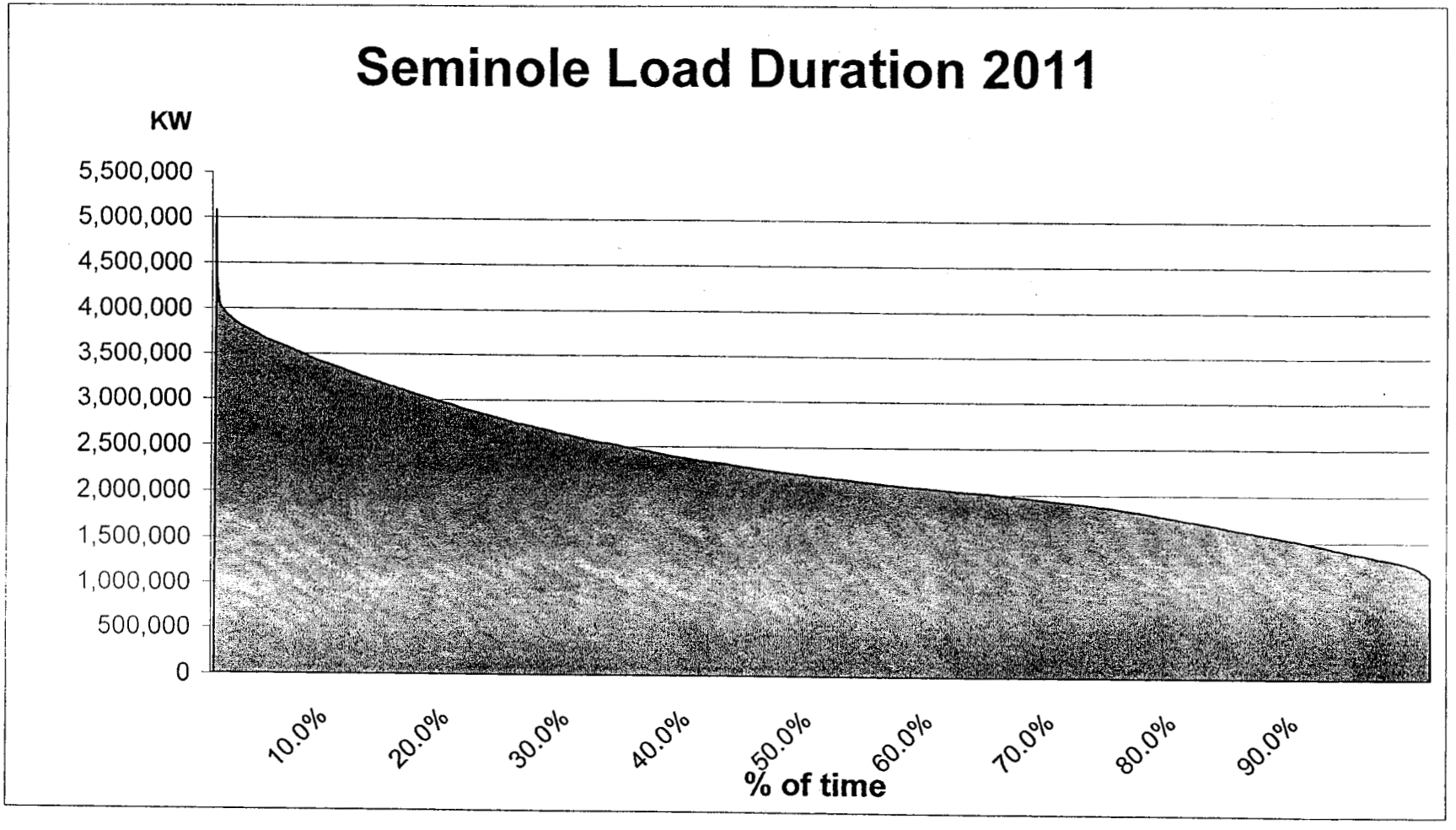
Total = $172,000

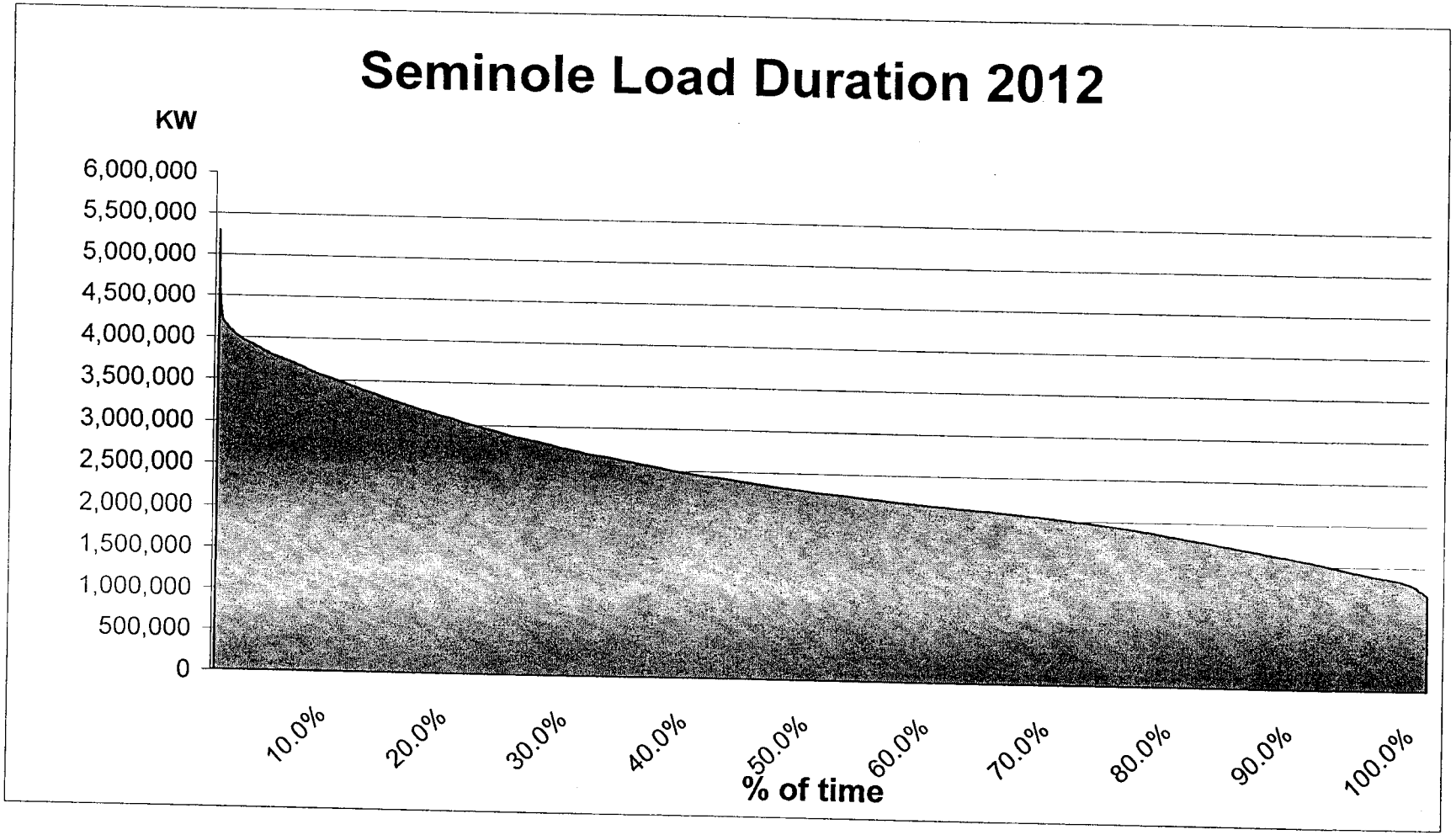
Q. Please provide the load duration curves that were used to arrive at the rough estimate of Seminole's optimal system generation mix.

A. Please see attached documents, at the pages Bates numbered 00317-00320, which reflect load duration curves for forecast year 2009, 2010, 2011 and 2012.


Seminole Load Duration 2009
KW
5,000,000
4,500,000
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
10.0%
20.0%
30.0%
40.0%
50.0%
60.0%
70.0%
80.0%
90.0%
% of time


Seminole Load Duration 2010
KW
5,500,000
5,000,000
4,500,000
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
10.0%
20.0%
30.0%
40.0%
50.0%
60.0%
70.0%
80.0%
90.0%
% of time


Seminole Load Duration 2011
KW
5,500,000
5,000,000
4,500,000
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
10.0%
20.0%
30.0%
40.0%
50.0%
60.0%
70.0%
80.0%
90.0%
% of time


Seminole Load Duration 2012
KW
6,000,000
5,500,000
5,000,000
4,500,000
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
10.0%
20.0%
30.0%
40.0%
50.0%
60.0%
70.0%
80.0%
90.0%
100.0%
% of time

Q. Please provide the bus bar cost and assumptions used to evaluate the amount of base load generation need in 2012.

A. In answering this question, Seminole has assumed it relates to the "rough estimate" analysis in question 6. In advance of Seminole's April 2004 Base Load RFP, Seminole's planning staff used the techniques described in Mr. Mahaffey's testimony to arrive at a rough estimate of the amount of base load capacity needed in the 2009-2012 time frame. The following attachments, at the pages Bates numbered 00321-00325, demonstrate the analysis used to develop the rough estimate of the optimum amount of base load generation (and other types of generation) needed in the 2009-2012 time frame.

Attachment 1 – Generic unit bus bar cost detail
Attachment 2 – Capacity factor breakpoint
Attachment 3 – Approximation of optimum resource mix

Resource Mix Optimization
2003 Base Case
Cost of Generic Capacity

BASE

Year	Capacity Costs $/kw month	Fixed O & M $/kw month	Fuel Transportation $/kw month	Total Fixed Costs $/kw month	Var O & M $/kwh
2003	$11.87	$2.50	$0.00	$14.37	$0.75
2010	$13.65	$2.84	$0.00	$16.49	$0.85
2011	$13.92	$2.89	$0.00	$16.81	$0.87
2012	$14.22	$2.94	$0.00	$17.16	$0.88
2013	$14.50	$2.99	$0.00	$17.49	$0.90
2014	$14.80	$3.05	$0.00	$17.85	$0.91
2015	$15.08	$3.10	$0.00	$18.18	$0.93
2020	$16.61	$3.38	$0.00	$19.99	$1.01

INPUTS:	**Heat Rate**	**9300**	**btu/kwh**
	Petcoke Burn	**30**	**Percent**

INTERMEDIATE

Year	Capacity Costs $/kw month	Fixed O & M $/kw month	Fuel Transportation $/kw month	Total Fixed Costs $/kw month	Var O & M $/kwh
2003	$4.98	$0.75	$2.04	$7.77	$0.55
2010	$5.73	$0.85	$2.16	$8.74	$0.62
2011	$5.85	$0.87	$2.16	$8.87	$0.63
2012	$5.97	$0.88	$2.16	$9.01	$0.65
2013	$6.09	$0.90	$2.16	$9.14	$0.66
2014	$6.21	$0.91	$2.16	$9.28	$0.67
2015	$6.33	$0.93	$2.16	$9.42	$0.68
2020	$6.98	$1.01	$2.16	$10.15	$0.74

INPUTS:	**Heat Rate**	**7000**	**btu/kwh**
	Oil Burn	**0**	**Percent**

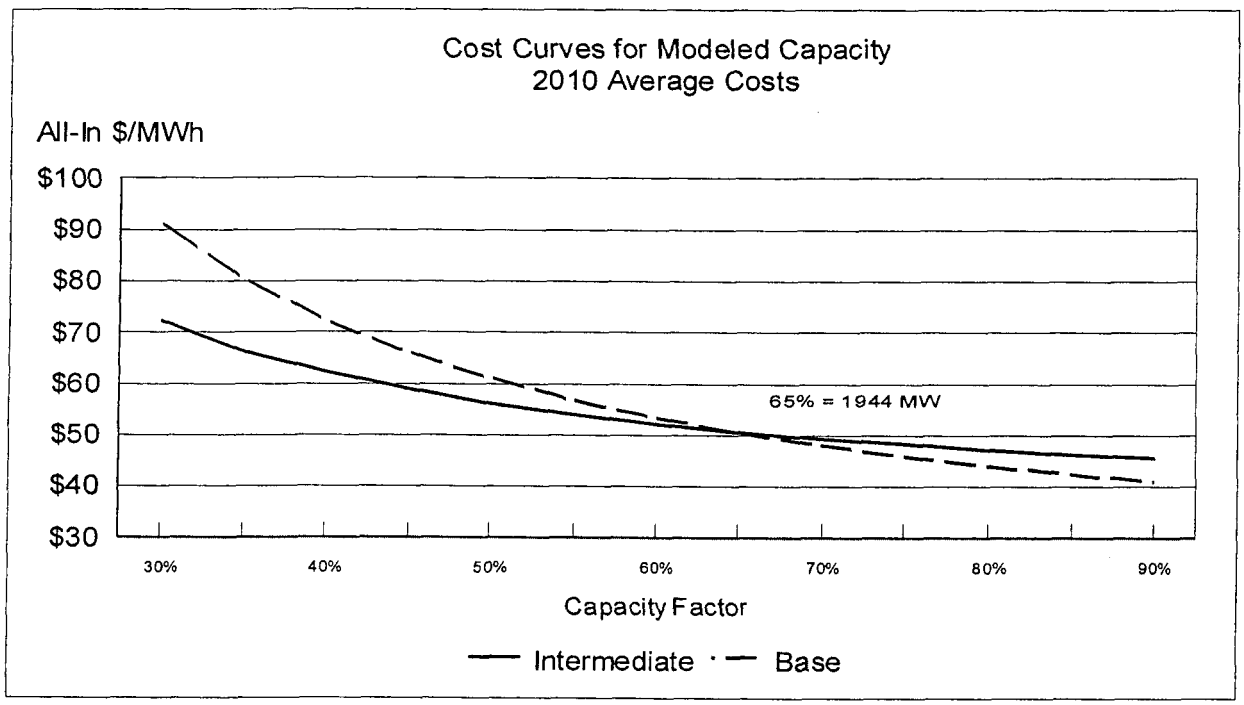
Notes: Capacity costs shown are 1st year costs.

Coal $/mmbtu	Petcoke $/mmbtu	Fuel Costs $/kwh	Total Variable Costs $/kwh
$1.71	$0.99	$13.87	$14.62
$1.86	$1.05	$15.01	$15.87
$1.88	$1.07	$15.20	$16.07
$1.90	$1.08	$15.38	$16.26
$1.92	$1.11	$15.60	$16.50
$1.94	$1.13	$15.80	$16.72
$1.97	$1.15	$16.01	$16.94
$2.08	$1.28	$17.13	$18.14

Nat'l Gas $/mmbtu	#2 Oil $/mmbtu	Fuel Costs $/kwh	Total Variable Costs $/kwh
$4.50	$5.02	$31.50	$32.05
$4.53	$5.97	$31.71	$32.33
$4.79	$6.15	$33.53	$34.16
$4.99	$6.38	$34.93	$35.58
$5.15	$6.73	$36.05	$36.71
$5.28	$7.04	$36.96	$37.63
$5.48	$7.38	$38.36	$39.04
$6.37	$9.04	$44.59	$45.33

Resource Mix Optimization
2003 Base Case
2010 Annual Production Costs for 150 MW

Capacity Factor	MWH	Base Capacity				Intermediate Capacity				
		Fixed Costs ($ x 1000)	Variable Costs ($ x 1000)	Total Costs ($ x 1000)	All-in Costs ($/MWh)	Fixed Costs ($ x 1000)	Variable Costs ($/MWh)	Total Costs ($ x 1000)	All-in Costs ($/MWh)	Difference ($/MWh)
30%	394,200	$29,682	$6,254	$35,936	$91.16	$15,726	$12,746	$28,472	$72.23	($18.93)
35%	459,900	$29,682	$7,297	$36,979	$80.41	$15,726	$14,870	$30,596	$66.53	($13.88)
40%	525,600	$29,682	$8,339	$38,021	$72.34	$15,726	$16,995	$32,721	$62.25	($10.08)
45%	591,300	$29,682	$9,381	$39,063	$66.06	$15,726	$19,119	$34,845	$58.93	($7.13)
50%	657,000	$29,682	$10,424	$40,106	$61.04	$15,726	$21,243	$36,969	$56.27	($4.77)
55%	722,700	$29,682	$11,466	$41,148	$56.94	$15,726	$23,368	$39,094	$54.09	($2.84)
60%	788,400	$29,682	$12,508	$42,190	$53.51	$15,726	$25,492	$41,218	$52.28	($1.23)
65%	854,100	$29,682	$13,551	$43,233	$50.62	$15,726	$27,616	$43,342	$50.75	$0.13
70%	919,800	$29,682	$14,593	$44,275	$48.14	$15,726	$29,741	$45,467	$49.43	$1.30
75%	985,500	$29,682	$15,635	$45,317	$45.98	$15,726	$31,865	$47,591	$48.29	$2.31
80%	1,051,200	$29,682	$16,678	$46,360	$44.10	$15,726	$33,989	$49,715	$47.29	$3.19
85%	1,116,900	$29,682	$17,720	$47,402	$42.44	$15,726	$36,114	$51,840	$46.41	$3.97
90%	1,182,600	$29,682	$18,762	$48,444	$40.96	$15,726	$38,238	$53,964	$45.63	$4.67



2003 Base Cas
Resource Mix for Capacity Planning (
(In MW)

Year	Maximum Demand	PR	Commitment	Committed Resources	Total Capacity Need	Base Need	Committed Resources
2010	4984	1220	3764	2732	1321	1879	1305
2011	5200	1284	3916	2732	1484	1965	1305
2012	5420	1348	4072	2677	1706	2050	1250
2013	5637	1407	4230	2677	2188	2137	1250
2014	5865	0	5865	2227	4518	2228	1250
2015	6101	0	6101	2227	4789	2324	1250
2016	6343	0	6343	2227	5067	2422	1250
2017	6592	0	6592	2227	5354	2523	1250
2018	6848	0	6848	2227	5648	2628	1250
2019	7112	0	7112	2227	5952	2737	1250
2020	7383	0	7383	2227	6263	2849	1250
2021	7663	0	7663	2227	6585	2967	1250
2022	7951	0	7951	2227	6917	3086	1250
2023	8248	0	8248	2227	7258	3208	1250
2024	8556	0	8556	2227	7612	3313	1250
2025	8876	0	8876	2227	7980	3471	1250
2026	9209	0	9209	2227	8363	3608	1250
2027	9553	0	9553	2227	8759	3751	1250
2028	9911	0	9911	2227	9171	3874	1250
2029	10282	0	10282	2227	9597	4054	1250
2030	10670	0	10670	2227	10044	4216	1250

Notes: Total capacity need includes reserve capacity.
HPS capacity is not included in this data.

e
Based on Optimization)

Net Base Need	Intermediate Need	Committed Resources	Net Inter Need	Peaking Need	Committed Resources	Net Peaking Need
574	1170	1022	148	1004	415	589
660	1217	1022	195	1034	415	619
800	1267	1022	245	1066	415	651
887	1318	1022	296	1410	415	995
978	1371	572	799	3146	415	2731
1074	1425	572	853	3267	415	2852
1172	1481	572	909	3391	415	2976
1273	1538	572	966	3520	415	3105
1378	1601	572	1029	3646	415	3231
1487	1665	572	1093	3777	415	3362
1599	1729	572	1157	3912	415	3497
1717	1795	572	1223	4050	415	3635
1836	1866	572	1294	4192	415	3777
1958	1938	572	1366	4339	415	3924
2063	2026	572	1454	4500	415	4085
2221	2081	572	1509	4655	415	4240
2358	2167	572	1595	4815	415	4400
2501	2253	572	1681	4982	415	4567
2624	2358	572	1786	5166	415	4751
2804	2432	572	1860	5338	415	4923
2966	2522	572	1950	5533	415	5118

Q. According to Mr. Mahaffey, at Seminole's March 2005 meeting of the Board of trustees, Seminole's decided to proceed with the planning, permitting, and construction of SGS Unit 3 as a 750 supercritical pulverized coal unit, for commercial operation in May 2012. He stated that this was based on a technology study performed by Burns & McDonnell. He also stated that R. W. Beck had been commissioned to develop the analytical tools necessary for Seminole to perform detailed risk analyses of power supply alternatives. Provide the risk analyses that Seminole performed in the following areas:

a. Possibility of Construction cost overruns for SGS Unit 3, a 750 MW supercritical coal plant.
b. Unexpected O&M costs due to SGS unit 3 burning a 70% bituminous coal and 30% petroleum coke mixture.
c. The probability that SGS Unit 3 will have to convert to burning 100% bituminous coal.
d. **That there was an 80% probability that the coal-based scenario would yield lower cost to Seminole than a gas-based scenario.**

A. The risk analyses conducted by Seminole using the risk assessment tools developed by R.W. Beck addressed only items (a) and (d).

Item (a) - The probability distribution function (PDF) employed to address cost overruns for SGS Unit 3 (item a) is shown under tab D of Appendix K to the Need Study. This PDF was based on an underlying assumption that the Burns and McDonnell project cost contingency of 10% was divided into two portions. The first 5% of the contingency margin was assumed to be a reasonable expectation for project costs and therefore for the purposes of the risk assessment represented the base unit costs. The remaining 5% of the 10% contingency margin was assumed to be the uncertainty margin which could go either way (i.e., plus or minus 5%). However, in Seminole's economic case supporting SGS Unit 3, the entire 10% contingency margin for both coal and gas units was included in unit costs.

Item (d) – A graphical depiction of the 80% probability of a favorable economic result for the coal alternative versus the gas alternative is shown under Section 1.3 (page 1-5) of Appendix K to the Need Study.

CERTIFICATE OF SERVICE
Docket Nos. 060220-EC

I HEREBY CERTIFY that a true and correct copy of Seminole Electric Cooperative Inc.'s Response to Staff's First Request for Production of Documents (Nos. 1-8) has been furnished by hand delivery this 2nd day of May, 2006, to the following:

Martha Carter Brown, Esq.
Legal Division
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

By: _____
Charles A. Guyton

TALLAHASSEE/55043.2

SQUIRE SANDERS | LEGAL COUNSEL WORLDWIDE

Including
STEEL HECTOR & DAVIS LLP

215 South Monroe Street, Suite 601
Tallahassee, Florida 32301-1804

Office: +1.850.222.2300
Fax: +1.850 222.8410

Direct: +1.850.222.3423
CGuyton@ssd.com

May 2, 2006

VIA HAND DELIVERY

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 060220-EC

Dear Ms. Bayó:

Enclosed for filing please find an original and seven (7) copies of Seminole Electric Cooperative's Notice of Serving Responses to Staff's First Set of Interrogatories (Nos. 1-36) and First Request for Production of Documents (Nos. 1-8)

If there are any questions regarding this transmittal, please contact me at (850) 222-2300.

Sincerely,

SQUIRE, SANDERS & DEMPSEY L.L.P.

Charles A. Guyton

CAG/gcm
Enclosure
cc: Martha Carter Brown, Esq.

TALLAHASSEE/55064.1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Seminole Generating Station Unit 3 electrical power plant in Putnam County, by Seminole Electric Cooperative, Inc.	)))))	**Docket No. 060220-EC** **Date: May 2, 2006**

SEMINOLE ELECTRIC COOPERATIVE INC.'S NOTICE OF SERVING RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-36) AND FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-8)

Seminole Electric Cooperative, Inc. ("Seminole") hereby gives notice of serving its responses to Staff's First Set of Interrogatories (Nos. 1-36) and First Request for Production of Documents (Nos. 1-8) to Martha Carter Brown, counsel for Staff, on May 2, 2006.

Respectfully submitted,

Squire, Sanders & Dempsey LLP
Attorneys for Seminole Electric Cooperative, Inc.
215 S. Monroe St., Suite 601
Tallahassee, FL 32301

By: _____
Charles A. Guyton
Fla. Bar No. 0398039

CERTIFICATE OF SERVICE
Docket No. 060220-EC

I HEREBY CERTIFY that a true and correct copy of Seminole Electric Cooperative's Notice of Serving Responses to Staff's First Set of Interrogatories (Nos. 1-36) and First Request for Production of Documents (Nos. 1-8) has been furnished by hand delivery this 2nd day of May, 2006, to the following:

Martha Carter Brown, Esq.
Legal Division
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

By: _____
Charles A. Guyton

TALLAHASSEE/55040.1

CCA Note: For Copy of Complete Filing, See DN 02090-06.pmf

060220-EC

SEMINOLE ELECTRIC COOPERATIVE, INC.

Petition to Determine Need for

Electric Power Plant

March 2006

Need Study

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060220-EC Exhibit No. 3
Company/ SEC
Witness: Need Study + Appendices (SEC-1)
Date: 06-07-06

DOCUMENT NUMBER-DATE
02090 MAR 10 06
FPSC-COMMISSION CLERK

CCA Note: For Copy of Complete Filing, See DN 02091-06.rmf

060220-EC

SEMINOLE ELECTRIC COOPERATIVE, INC.

Petition to Determine Need for

Electric Power Plant

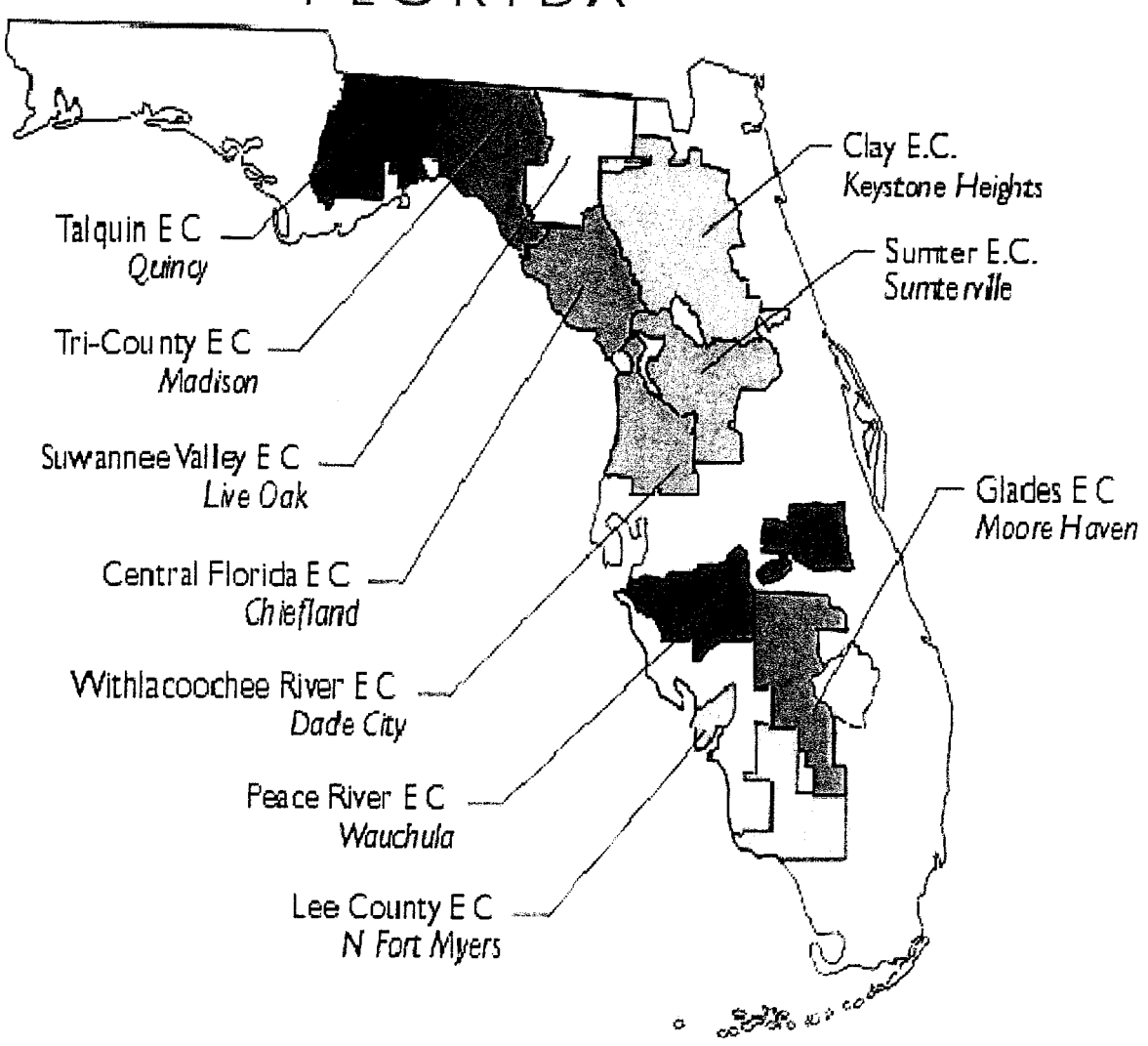
March 2006

Appendices

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

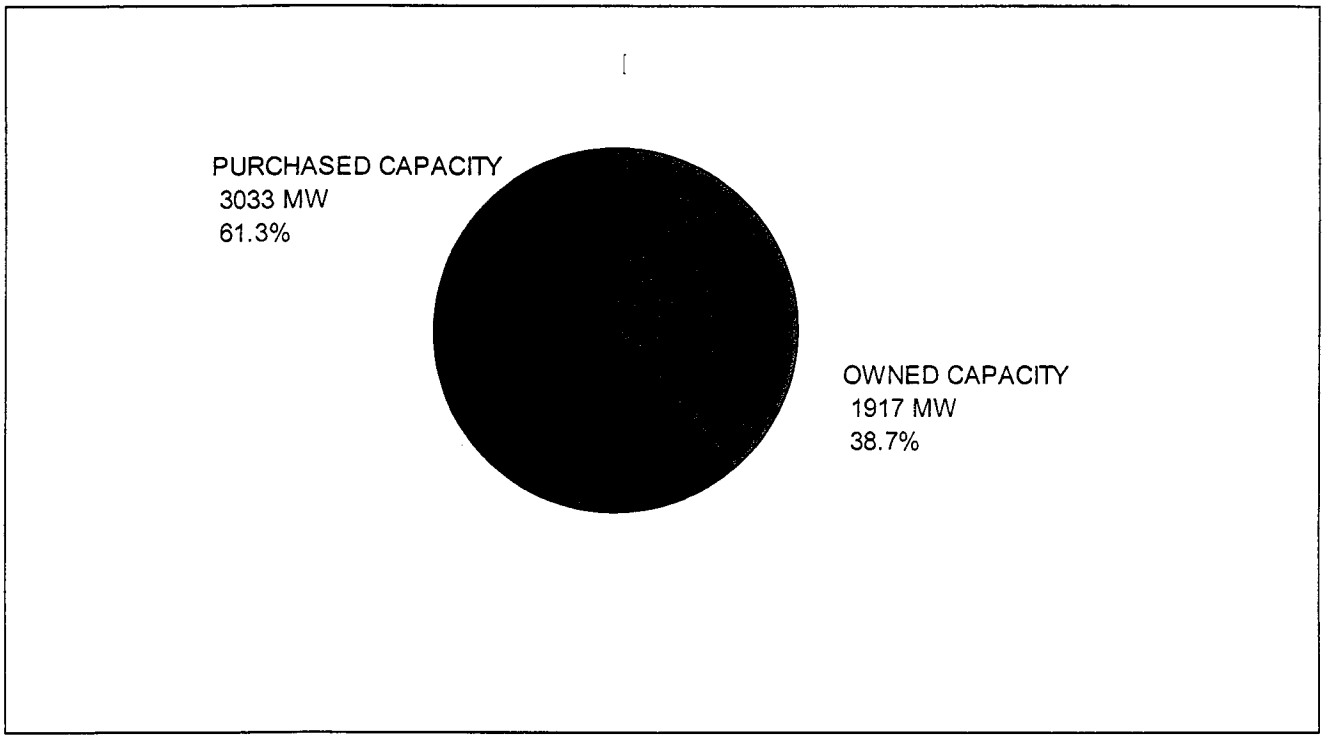
DOCUMENT NUMBER-DATE
02091 MAR 10 06
FPSC-COMMISSION CLERK

Seminole's Member Distribution Cooperatives



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 4
Company/ SEC
Witness: Timothy S. Woodbury (TSW-1)
Date: 06-07-06

SEMINOLE'S 2006 CAPACITY RESOURCES



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060221-EC Exhibit No. 5
Company/ SEC
Witness: Timothy S. Woodbury (TSW-2)
Date: 06-07-06

SEMINOLE'S POWER PURCHASE CONTRACTS WITH RENEWABLE RESOURCES

Supplier	*County*	*Fuel*	*MW Capacity*	*Begin Date*	*End Date*
Bio-Energy Partners	Broward	Landfill Gas	7	01/01/05	12/31/09
DG Telogia Power, LLC	Liberty	Biomass	12	06/01/04	12/31/19
Lee County, Florida	Lee	Solid Waste	35 - 55	12/01/99	07/30/20

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060220-EI Exhibit No. 6
Company/ SEC
Witness: Timothy S. Woodbury (TSW-3)
Date: 06/07/06

SEMINOLE'S POWER PURCHASE CONTRACTS

Supplier	Service	Fuel	MW Capacity	Begin Date	End Date
Progress Energy Florida	Partial Requirements	System	1,105*	02/01/84	12/31/13***
Progress Energy Florida	Intermediate	System	150	01/01/99	12/31/13
Progress Energy Florida	Intermediate	System	150	06/01/06	12/31/13
Progress Energy Florida	Intermediate	System	150	12/01/06	12/31/13
Progress Energy Florida	Full Requirements	System	150+**	01/01/10	07/30/20
Hardee Power Partners Limited[a]	Firm Capacity & Energy	Gas/Oil	356	01/01/93	12/31/12
Calpine Construction Finance Company, L.P.[b]	Firm Capacity & Energy	Gas/Oil	360	06/01/04	05/31/12
Oleander Power Project, Limited Partnership [c]	Firm Capacity & Energy	Gas/Oil	546	12/01/02	12/31/09
Oleander Power Project, Limited Partnership [d]	Firm Capacity & Energy	Gas/Oil	364 with option for total of 546	01/01/10	12/31/15
Reliant Energy Florida, LLC [e]	Firm Capacity & Energy	Gas/Oil	364	12/01/01	12/31/06
Reliant Energy Florida, LLC [e]	Firm Capacity and Energy	Gas/Oil	364	12/01/08	05/31/14
The City of Gainesville	Full Requirements	System	17*	10/22/73	12/31/12***

* Capacity is variable over time. Amount shown represent estimated 2006 maximum monthly peak demand purchase.
** Capacity is variable over time. Amount shown represents estimated 2010 maximum monthly peak demand purchase.
*** End Date for this contract represents end of initial term. Contract continues unless terminated by either party with certain notice.
[a] Subsidiary of Invenergy, LLC.
[b] Subsidiary of Calpine Corporation.
[c] Subsidiary of Southern Power Company.
[d] Executed February 17, 2006
[e] Subsidiary of Reliant Energy, Inc.

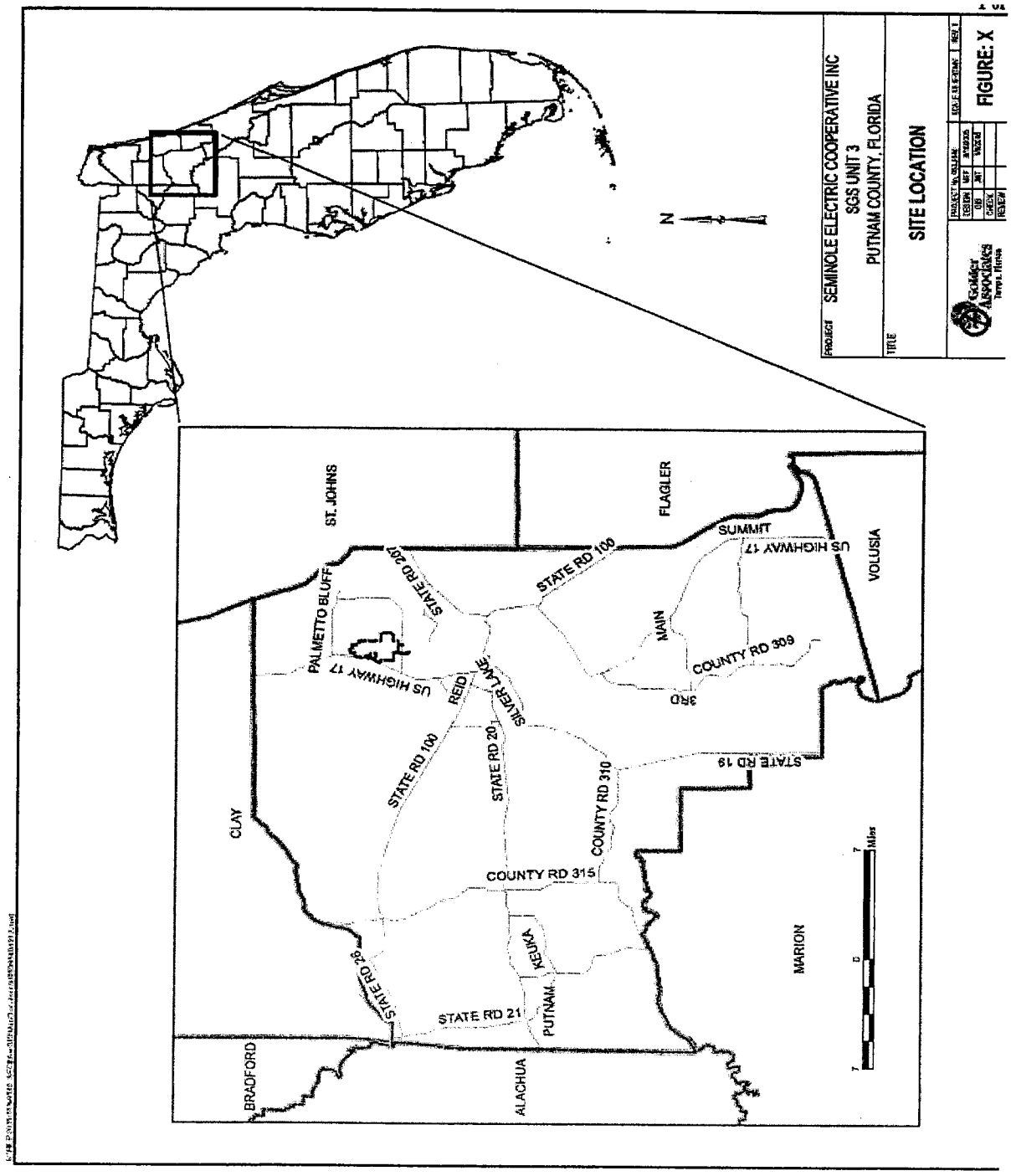
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 7
Company/ SEC
Witness: Timothy S. Woodbury (TSW-4)
Date: 06/07/06

SEMINOLE INTERCONNECTIONS

Utility Interconnection	Voltage (kV)	Location
FPL	230	Rice
FPL	230	Rice
FPL	230	SGS
FPL	230	SGS
FPL/Lee	230	Lee #2 Sub
FPL	230	Charlotte
TECO	230	Hardee Sub
Hardee Power Partners Limited	230	Hardee Sub
PEF	230	Vandolah
JEA	230	Firestone Tie Point
City of Ocala	230	Ocala #2 Tie Point
PEF	230	Martin West Tie Point
PEF	230	Silver Springs Tie Point
PEF	230	Silver Springs
PEF	230	Dearmin Tie Point

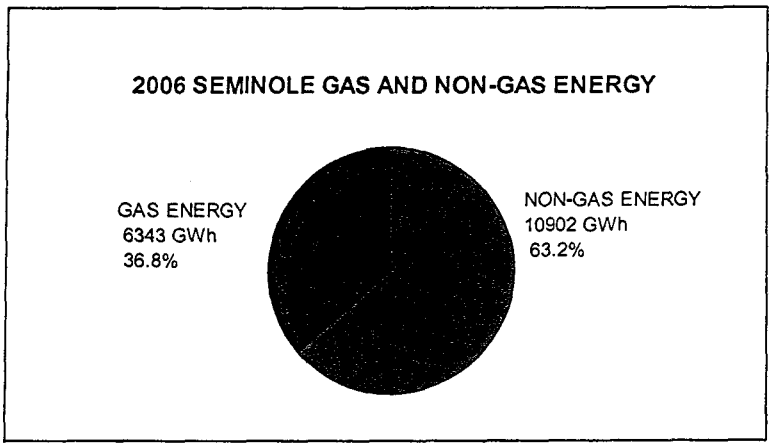
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 8
Company/ SEC
Witness: Timothy S. Woodbury (TSW-5
Date: 6-07-06

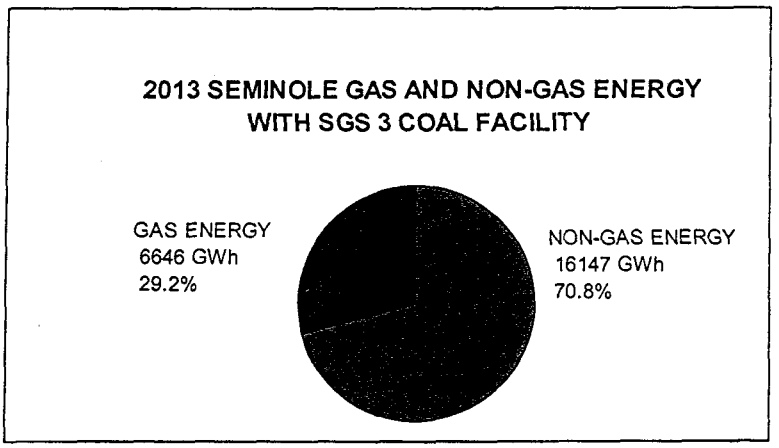
Site Location Map – Putnam County

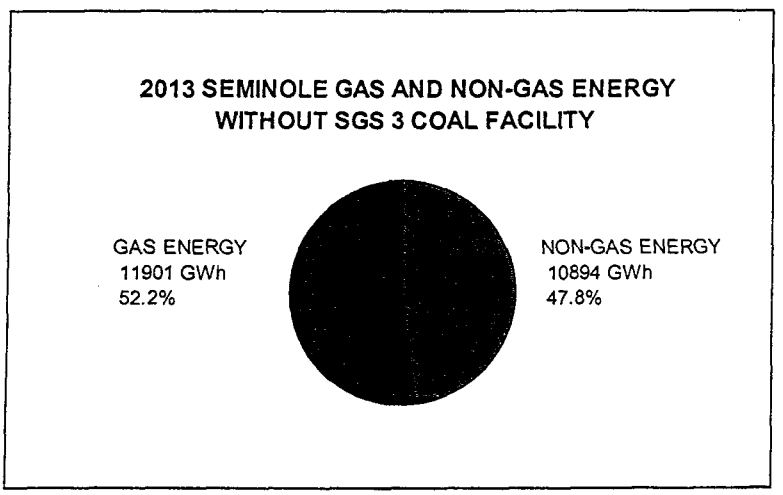


FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 10
Company/ SEC
Witness: Mike Opalinski (MPO-1)
Date: 06-07-06

SEMINOLE'S RELIANCE UPON NATURAL GAS GENERATION

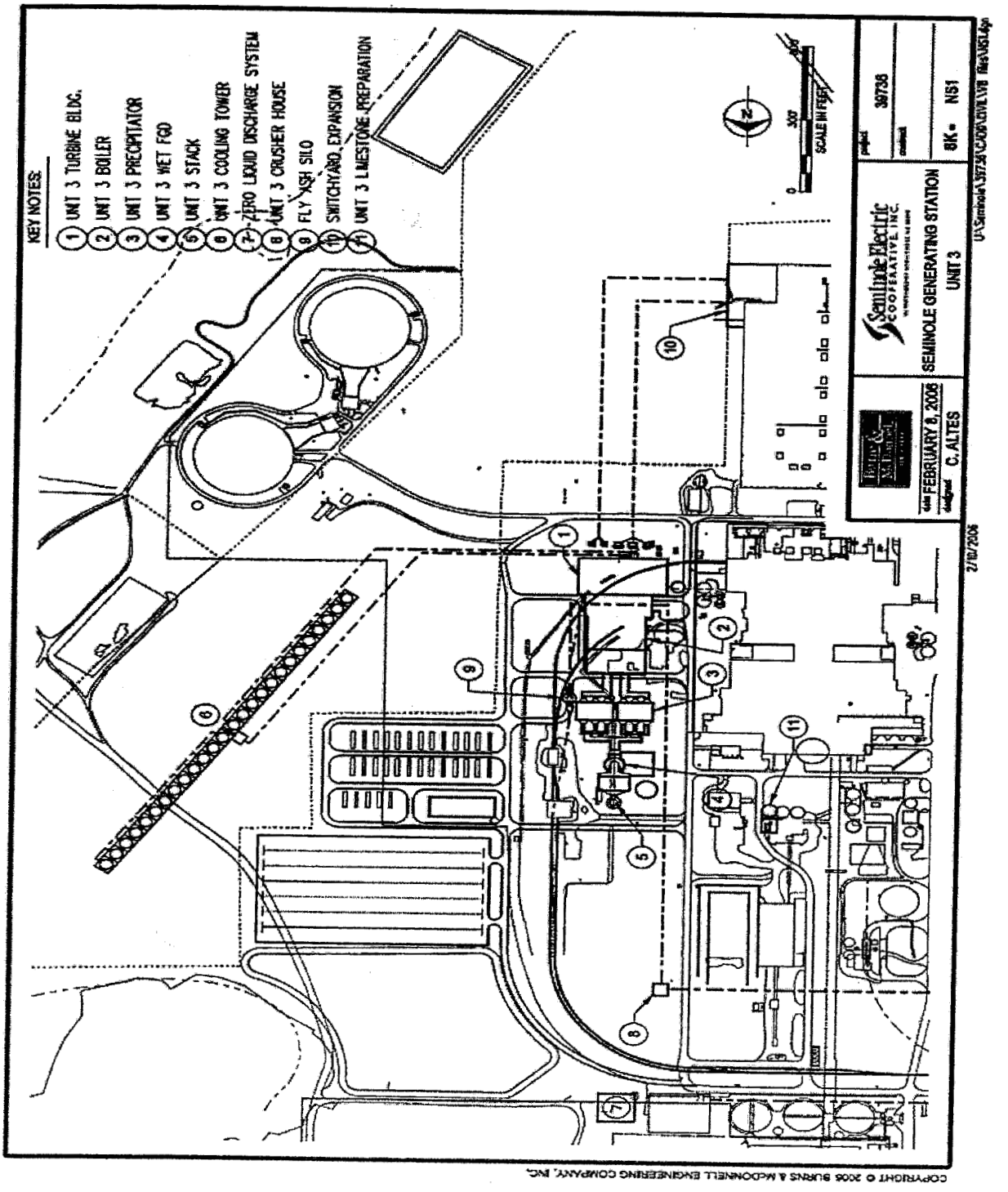






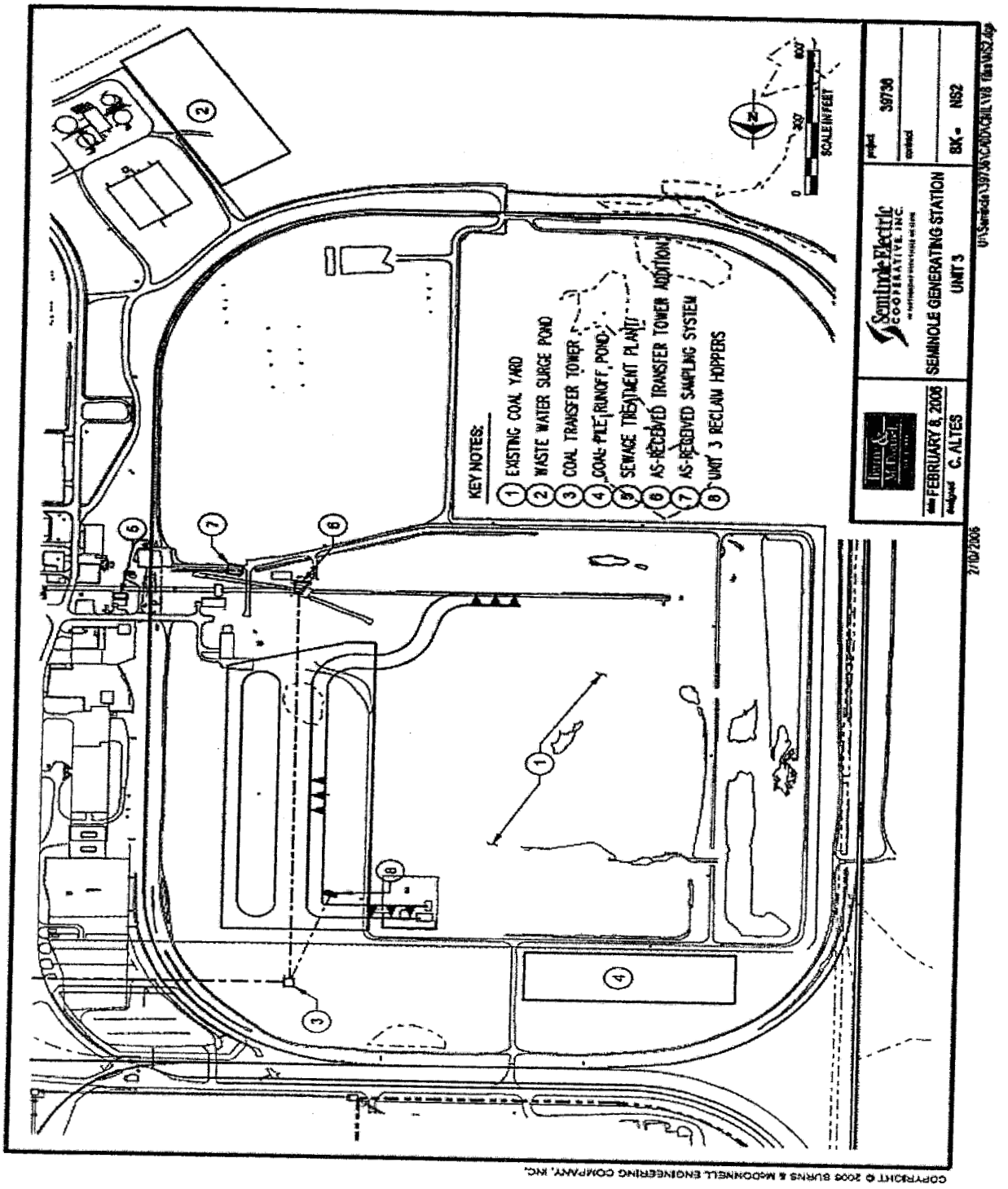
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 9
Company/ SEC
Witness: Timothy S. Woodbury (TSW-6
Date: 6-07-06

Site Arrangement With SGS Unit 3



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 11
Company/ SEC
Witness: Mike Opalinski (MPO-2)
Date: 06-07-06

Site Arrangement With SGS Unit 3



SGS UNIT 3 PROJECT
CAPITAL COST COMPONENTS

Cost Description	Cost Estimates ($)
Permitting and Licensing	1,724,860
Engineering	37,001,193
Operator Training	500,000
Preoperational Testing, Start-up & Calibration	12,056,800
Legal	1,425,000
Site Surveys/Studies	535,000
Performance Testing	2,103,200
Civil	49,426,836
Structural	87,411,231
Electrical & Construction Procurement	93,993,081
Control Procurement	8,737,946
Mechanical Procurement	647,319,207
Spare Parts	10,500,000
Initial Fills	480,000
Construction Testing	1,968,282
Power Breakers	4,850,000
Interest During Construction	182,373,299
Plant Equipment, Furnishings & Furniture	430,000
Site Security	1,728,000
Sales Tax	1,400,000
Building Risk Insurance	5,640,000
Temporary Utilities	1,349,461
Seminole Labor, Overhead & Travel	15,589,746
Escalation	233,434,974
Project Bonds	5,000,000
Startup Testing	33,134,544
Value of Test Energy	(33,134,544)
Financing Costs	5,350,000
Initial Coal Inventory	17,442,850
Estimated Total Cost	1,429,770,966

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 12
Company/ SEC
Witness: Mike Opalinski (MPO-3)
Date: 06-07-06

Summary of Richard Klover's Experience

Mr. Klover is the Project Manager for SGS Unit 3. He has a broad background in project development, detailed design, procurement, construction, startup and project management of coal fired power plants.

Mr. Klover recently was involved in the preparation of the EPC proposal for the 650 MW coal fired power plant at the Nebraska City Power Station for Omaha Public Power District in Nebraska City, NE. The project consisted of a subcritical pulverized coal boiler, SCR, dry scrubber and baghouse burning PRB coal.

Mr. Klover was involved in the development and permitting for the 275 MW coal fired power plant at the Southwest Power Station for City Utilities of Springfield, Mo. He also served as Proposal Manager on the EPC proposal for a 90 MW coal fired power plant for Corn Belt Energy Generation Cooperative.

Mr. Klover served as Project Manager on the Qitaihe Power Plant Project, a 2 x 350 MW coal-fired unit for Heilongjiang Electric Power Company in China. He was responsible for the detailed design of the steam turbine island for the project, coordination with the owner at design liaison meetings and involved in the procurement of Chinese equipment and materials.

Mr. Klover has been involved with several large coal fired projects. Mr. Klover served as project mechanical engineer on the Powder River Basin coal conversion project at the Associated Electric Cooperative; 2 x 600 MW New Madrid Power Plant. He was responsible for the preparation of the ash handling, coal handling, cyclone boiler modifications and construction contracts.

For the Old Dominion/Virginia Power Clover Project, a 2 x 440 MW pulverized coal power plant in Virginia, Mr. Klover served as the Mechanical Engineer during design and then as an on-site Start-up Engineer for the owner, responsible for the startup of all plant equipment and systems, including the boiler, turbine, water treatment, baghouse, and wet scrubber.

Additional coal-fired project experience includes:

Client	Services Performed
Minnkota Power Cooperative and Minnesota Power	Feasibility Study.
NIPSCO	ID Fan Replacement Study.
PSI Energy	Boiler improvements.
Kansas City Power & Light Company	Feasibility Study.
Crawfordsville Electric Light & Power	Coal Yard Runoff System.
Wisconsin Power & Light	Technology Assessment Study.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 13
Company/ SEC
Witness: Richard Klover (RAK-1)
Date: 06-07-06

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
TXU Power	Oak Grove Units 1 & 2	860 MW 860 MW	Lignite	TBD	TBD	2010/2011	Condition Assessment, Conceptual Engineering, Owner's Engineer, EPC Specifications, EPC Negotiations, Contract Administration, Construction Management
City Water Light & Power, Springfield, IL	Dallman Unit 4	220MW	Coal	TBD	TBD	2011	Owner's Engineer, EPC specifications negotiations
Seminole Electric Coop., Inc. Palatka, FL	Seminole Generating Station Unit 3	750 MW	Coal 70/30 Blend Bit/Pet	TBD	TBD	May 2012	Life Cycle Assessment, Feasibility Study, Preliminary Engineering, Permitting Support, Detailed Design, Construction Management Startup/Commissioning
Kansas City Power & Light Kansas City, MO	Hawthorn 5	500 MW	Coal PRB	B&W	Existing GE 2520 P/1000F	Full load operation, June 22, 2001	Engineer and permitting for replacement of boiler and air pollution control equipment after major boiler explosion.
Western Farmers Electric Corp. Hugo, OK	Hugo 2	750MW	Coal PRB	TBD	TBD	2010	Owner;s Engineer, Project Definition, Siting Study, Dev. Support, Conc. Design, Detailed Cost Estimate, Permitting/Env. Feasibility EPC spec and negotiations, Contract Administration, Construction Management

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060920-EC Exhibit No. 14
Company/ SEC
Witness: Richard Klover (RAK-2
Date: 06-07-06

Exhibit RAK-2
Page 1 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
MidAmerican Energy	Council Bluffs Unit 4	790 MW	Coal	Hitachi	Hitachi	2007	Owner's engineer, interface engineering, CM
Peabody Energy	Thoroughbred Unit 1 Unit 2	750 MW 750 MW	Coal Coal	Alstom	Alstom	TBD	Owner's Engineer
Kansas City Power & Light	Iatan Unit 2	750MW	Coal PRB	TBD	TBD	2010	Engineer for design of new coal-fired plant, permitting support, project definition
City of Public Service San Antonio, TX	JK Spruce 2	600MW	Coal	TBD	TBD	2009	Owner's Engineer, Conceptual design study, impact on existing units, EPC Contract, EPC Negotiation, EPC Contract Administration
Tanjung Bin Power Sdn Bhd. Johore, Malaysia	Tanjung Bin Units 1, 2, 3	3 x 700 MW	Coal	IHI	Toshiba 166 bars/538°C	2007/2008	Independent Engineer, Technical assessment, monthly site visits and progress reports to project financers.
Otter Tail Power (Big Stone II Partners)	Big Stone Unit II Big Stone City, SD	600 MW	Coal	TBD	TBD	2008/2009	Technology assessment, project cost estimate and economics, project development services, project scheduling, conceptual engineering, permitting, assist in joint ownership contracting

Exhibit RAK-2
Page 2 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
Tractebel – Mississippi, USA	Red Hills 1	500 MW	Lignite	2 – CFB, Stein (Alstom)	Toshiba 2400P/1000F	2001	Permitting, technical assistance, turnkey bid documents, evaluation, contract negotiation, design review, const. Monitoring.
Peabody Energy	Prairie State Energy Campus	2 x 750MW	Coal	TBD	TBD	TBD	Owner's Engineer, Development engineering support, Support Boiler and Turbine Procurement, Support Owner w/Contract Negotiations
Dominion Energy	Upshur County	450 MW	Coal	CFB	TBD	2005	Engineer for feasibility study, permitting support, EPC spec, cost estimate, bid evaluation, Owner's Engineer.
Louisville Gas & Electric Co. Louisville, KY	Trimble Unit 2	750 MW	Coal	TBD	TBD	TBD	Engineering for feasibility study, cost estimates, and conceptual design. Also preparatory BACT analysis for permitting efforts.
Reliant	Seward Project	500 MW	Waste Coal	2-CFB Alstom	Alstom 2400P/1000F	2004	Engineer for EPC Spec, cost estimate, bid evaluation, Owner's Engineer.
Sunflower Electric Power Corporation Hays, KS	Holcomb Unit 2	400 MW	PRB Coal	PC Unit Vendor TBD	TBD	TBD	Dev. Support, Fatal Flaw Review, Env./Air Permitting Unit 1 impact study

Exhibit RAK-2
Page 3 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
Mid-American Power, LLC Green Bay, WI	Stoneman II	250 MW	PRB Coal	PC Unit Vendor	TBD	2006	Owner engineering, Permit support.
Wisconsin Public Service Corporation	TBD	500 MW	PRB Coal	TBD	TBD	2007	Full Permitting Technical, feasibility, and capital cost study.
Rapids Power, LLC (Minnesota Power)	Rapids Power Unit 1	250 MW	Coal, Wood	CFB	TBD	2006	Conceptual design, detailed cost estimate.
City of Springfield, IL	New Generation	220 MW	Bit.	TBD	TBD	2010	Siting Study, Dev. Support, Conc. Design, Detailed Cost Estimate Permitting/Env. Feasibility
Nations Energy, Mexico	Sabinas 1	180	Coal	Lurgi	Siemens	2001	Owner's Engineer.
General Electric, China	Qitaihe 1 Qitaihe 2	350 350	Coal Coal	N/A N/A	General Electric TC/2F33 2400P/1000F	2000 2001	Detailed design of turbine island, equipment spec, procurement assistance.
Old Dominion Electric Cooperative - Richmond, VA	Clover 1 Clover 2	424 424	Coal Coal	CE Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1995 1996	Turnkey spec., bid, contract negotiation, design compliance review, construction monitoring.
South Carolina Electric & Gas – Columbia, SC	Unit 1	350	Coal	CE Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1995	Evaluation of turnkey bids, negotiation of final turnkey contract.

Exhibit RAK-2
Page 4 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
San Antonio Public Service - San Antonio, TX	JK Spruce 1	500	Coal	CE Balanced Draft	Westinghouse TC/4F30 2400P/1000F	1994	Evaluation of turnkey bids, negotiation of final turnkey contract.
Deseret G&T Cooperative - Sandy, UT	Bonanza 1	400	Coal	Foster Wheeler Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1986	Feasibility study, site selection, environmental analysis, water supply analysis, system planning, detailed design, field services, start-up.
Plains Electric G&T Cooperative-Albuquerque, NM	Escalante 1	233	Coal	CE Balanced Draft	General Electric TC/2F26 1800P/1000F	1985	Feasibility study, financing assistance, site selection, environmental analysis & testing, fuel study, system planning, water supply analysis, design, field services, start-up and testing, preparation of operating manuals.
Western Farmers Electric Cooperative - Anadarko, OK	Hugo 1	400	Coal	B&W Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1982	Feasibility study, financing assistance, site selection, environmental analysis, water supply and wastewater evaluations, fuel study and acquisition, design, field

Exhibit RAK-2
Page 5 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
							services, start-up and testing, preparation of operating manuals.
Sikeston Board of Municipal Utilities - Sikeston, MO	Sikeston 1	235	Coal	B&W Balanced Draft	General Electric TC/2F26 1800P/1000F	1981	Financing assistance, water supply analysis, design, field services, start-up.
Gainesville Regional Utilities – Gainesville, FL	Deerhaven 2	236	Coal	Riley Balanced Draft	Westinghouse TC/2F26 1800P/1000F	1981	Official statements, environmental analysis, fuel study and acquisition, water supply pilot plant study, design, field services, start-up.
Associated Electric Cooperative- Springfield, MO	Thomas Hill 3	670	Coal	B&W Balanced Draft	Westinghouse TC/4F33 2400P/1000F	1981	Feasibility study, fuel study, environmental analysis, environmental testing, design, field services, start-up and testing, preparation of operating manuals.
Basin Electric Power Cooperative- Bismarck ND	Laramie River 1 Laramie River 2 Laramie River 3	570 570 570	Coal Coal Coal	B&W Balanced Draft	General Electric TC/4F30 2400P/1000F	1980 1981 1982	Fuel study, site selection, regional siting study, water supply analysis, environmental analysis, environmental testing, feasibility study, Wyoming

Exhibit RAK-2
Page 6 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
							Industrial Siting Council application, testimony before state agency hearings, design, field services, start-up and testing, preparation of operating manuals.
Southern Illinois Power Cooperative - Marion, IL	Marion 4	173	Coal	B&W Cyclone	General Electric TC/2F23 1800P/1000F	1978	Feasibility study, financing assistance, environmental analysis, environmental testing, fuel study, system planning, water supply analysis, design, field services, electrical testing, start-up and testing.
Springfield Water Light & Power - Springfield, IL	VY Dallman 3		Coal	CE Balanced Draft	General Electric TC/2F23 2400P/1000F	1978	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, water supply analysis, design, field services, start-up and testing.
Arizona Electric Power Cooperative - Benson, AZ	Apache 1 Apache 2	195 195	Coal Coal	Riley Balanced Draft	General Electric TC/2F23 2400P/1000F	1978 1979	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, system planning, water supply analysis, design, field services, start-up and testing,

Exhibit RAK-2
Page 7 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
							preparation of operating manuals.
South Mississippi Electric Power Association – Hattiesburg, MS	RD Morrow 1 RD Morrow 2	204 204	Coal Coal	Riley Balanced Draft	General Electric TC/2F23 2400P/1000F	1977 1978	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, water supply analysis, design, field services, start-up and testing.
Austin Electric Utility Department - Austin, TX	Decker Creek 2	400	Gas	B&W Balanced Draft	Westinghouse TC/2F35 2400P/1000F	1977	Feasibility study, fuel study, environmental analysis, design, field services.
Springfield City Utilities – Springfield, MO	Southwest 1	195	Coal	Riley Balanced Draft	Westinghouse TC/2F25 2400P/1000F	1976	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, water supply analysis, design, field services, start-up and testing.
Henderson Municipal Power & Light – Henderson, KY	Station Two 1 Station Two 2	175 175	Coal Coal	Riley Balanced Draft	General Electric Westinghouse TC/2F23 1800P/1000F	1973 1974	Feasibility study, financing assistance, site selection, environmental analysis, environmental testing, fuel study, water supply analysis, design, field services, start-up and testing.

Exhibit RAK-2
Page 8 of 9

Summary of Burns & McDonnell Steam Electric Power Station Experience

Client Name & Location	Unit Name	MW	Fuel	Boiler	Turbine	Operation Date	Scope of Services
Associated Electric Cooperative- Springfield, MO	New Madrid 1 New Madrid 2	600 600	Coal Coal	B&W Cyclone	ABB TC/4F33 2400P/1000F	1972 1977	Initial planning, bond package assistance, site selection, env. studies, detailed design, procurement, resident const., start-up and testing, prep.of operating manuals.
Associated Electric Cooperative- Springfield, MO	Thomas Hill 2	275	Coal	B&W Cyclone	General Electric TC/2F30 2400P/1000F	1969	Initial planning, detailed design, procurement, resident construction, start-up and testing, preparation of operating manuals.
Singapore Public Utility Board, Singapore (ABM)	Tuas 1-8	8 x 600	Oil	IHI	Hitachi 2400P/1000F	1998	Feasibility studies.
Singapore Public Utilities Board, Singapore (ABM)	Pulau Seraya 7 Pulau Seraya 8 Pulau Seraya 9	250 250 250	Oil Oil Oil	Babcock-Hitachi	Parsons 2400P/1000F	1996	Evaluation of boiler and turbine tenders.

ABM indicates projects performed by UK registered joint venture company, Atkins • Burns & McDonnell.

Exhibit RAK-2
Page 9 of 9

Seminole Generating Station
650 MW Solid Fuel Fired Unit
Feasibility Study

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Seminole Electric Cooperative, Inc.

August 2004
Project 36571

Burns & McDonnell
SINCE 1898

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 15
Company/ SEC
Witness: Richard Klover (RAK-3)
Date: 06-07-06

Burns & McDonnell
SINCE 1898

August 13, 2004

Mr. John Hurley
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

Project No. 36571
650 MW Solid Fuel Fired Unit Feasibility Study

Mr. Hurley:

Burns & McDonnell is pleased to submit our 650 MW Solid Fuel Fired Unit Feasibility Study to Seminole Electric Cooperative, Inc. (SECI). The study evaluates the economics of a 600 MW (net) pulverized coal unit at the Seminole Generating Station (SGS) in Palatka, Florida. The purpose of the study is to provide a preliminary evaluation of a solid fuel fired generating resource at SGS to evaluate against other offers that SECI may receive in response to the power supply request for proposals issued by SECI.

The attached report summarizes the findings of the feasibility study and provides our recommendations regarding the most economical, long-term baseload energy resource for SECI. If you have any questions regarding the report, please contact me at 816-822-3274 or Jeff Greig at 816-822-3392.

It is a pleasure to be of service to SECI in this matter.

Sincerely,

Richard A. Klover

Richard Klover
Project Manager

Jeff Greig
General Manager

ENGINEERS • ARCHITECTS • CONSULTANTS
9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690
http://www.burnsmcd.com

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1.0 EXECUTIVE SUMMARY

1.1 SCOPE OF WORK

The purpose of this study was to evaluate the economics of a 600 MW net pulverized coal unit, Unit 3, for Seminole Electric Cooperative, Inc. (SECI) at the Seminole Generating Station (SGS). The study addresses site requirements, water supply requirements, capital cost, operating and maintenance costs, performance, schedule and bus bar cost for a new unit.

Additional assessment studies were completed to evaluate subcritical versus supercritical steam cycle technologies, natural draft versus mechanical draft cooling towers, and to address the engineering, environmental, and commercial issues associated with integrated gasification combined cycle (IGCC) technology. Each of these additional studies is described below and is included as an attachment to the report.

1.1.1 Subcritical vs. Supercritical Assessment

An evaluation of subcritical versus supercritical steam cycle technologies was completed and is included as Attachment A. The subcritical steam cycle was based on 7 feedwater heaters and steam turbine throttle conditions of 2,520 psig at 1,050 F and a reheat steam temperature of 1,050 F. The supercritical steam cycle was based on 8 feedwater heaters and steam turbine throttle conditions of 3,600 psig at 1,050 F and a reheat steam temperature of 1,050 F.

1.1.2 Cooling Tower Assessment

A preliminary economic evaluation was conducted to determine the impact of cooling tower technology on the capital and operating costs for the 600 MW net unit. The evaluation compared natural draft and mechanical draft cooling tower technologies. The results of the evaluation indicate the mechanical draft cooling tower has a differential net present value of $11.7M lower than a natural draft cooling tower. However, the cost estimates for the new unit are based on a natural draft tower. This assessment is included as Attachment B of this study.

1.1.3 Integrated Gasification Combined Cycle Assessment

Integrated Gasification Combined Cycle (IGCC) technology was evaluated due to the potential link between the relatively stable costs of solid fuels and the efficient operation of combined cycle gas turbines. An evaluation of a 600 MW net IGCC plant is included as Attachment C.

IGCC is a developing technology that has not performed reliably in commercial operation in the past, and whose capital cost basis is not well established at the present time. Therefore, it is recommended this technology not be considered for new generation at this time. There is planned development of gasification for coal in the near future, however it will be at least 4 -5 years before additional operational experience and information will be available on the cost and reliability of the technology.

1.2 ECONOMIC ANALYSIS SUMMARY

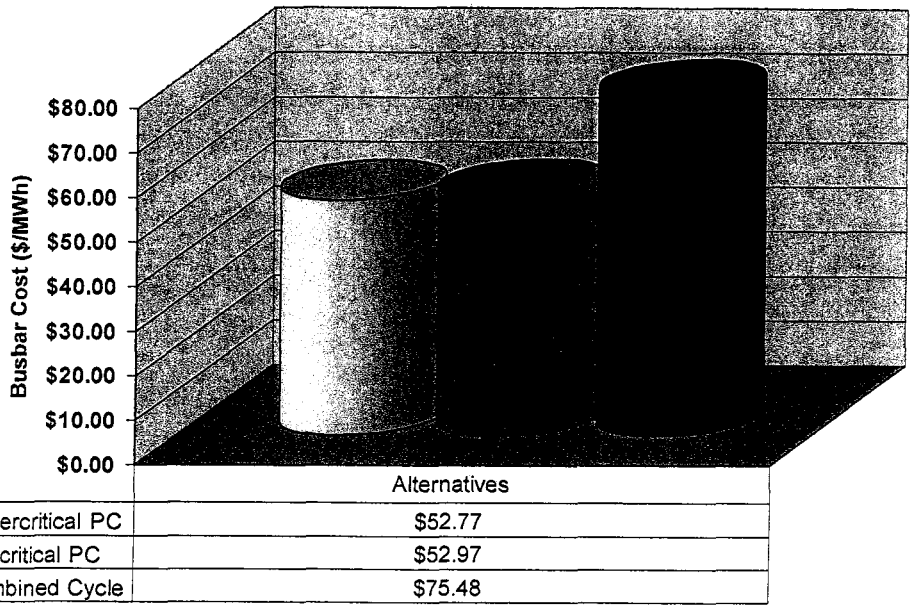
Burns & McDonnell prepared pro forma economic analyses of the following three alternatives:

- Construction of a new brownfield 600 MW net subcritical solid fuel fired generating unit
- Construction of a new brownfield 600 MW net supercritical solid fuel fired generating unit
- Construction of a new greenfield 500 MW net gas fired combined cycle unit

A 20-year economic analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs for each alternative. A 500 MW greenfield combined cycle alternative was included to provide a relative comparison of the expected project economics of a gas-fired unit. The features and scope of the 600 MW net solid fuel fired units included in the cost estimate are provided in more detail in Section 3 of this study.

Economic pro forma analyses were used to determine the 20-year levelized busbar cost of power generated from each alternative. Figure 1-1 presents a graph of the resulting levelized busbar power costs for the three alternatives considered, in 2012 dollars. The levelized busbar costs of the supercritical and subcritical units ($52.77 and $52.97/MWh, respectively) are significantly lower than that of the greenfield, conventional combined cycle alternative ($75.48/MWh).

Figure 1-1
20-Year Levelized Busbar Costs (2012$)



	Alternatives
Supercritical PC	$52.77
Subcritical PC	$52.97
Combined Cycle	$75.48

1.3 SCHEDULE

A preliminary schedule was prepared for the design and construction of the 600 MW net solid fuel fired unit and is included in Section 3. For planning purposes, the key milestone dates working backward from a June,2012 commercial operation date for the new 600 MW net solid fuel fired unit would be as follows:

- Commercial Operation — June 2012
- Initial Synchronization — November 2011
- Substation Backfeed — December 2010
- Start Construction — September 2008
- Full Notice to Proceed — November 2007
- Award Turbine Contract — November 2007
- Award Boiler Contract — November 2007
- Permits Issued — November 2007
- File SCA and EA with FDEP and RUS — Mar 2006
- Begin preparation of SCA, PSD, and EA Documents — April 2005
- Start Preliminary Design to Support Permitting — April 2005

1.4 CONCLUSIONS AND RECOMMENDATIONS

Based upon economic criteria in Section 6, the construction of a new 600 MW net supercritical or subcritical unit is considered to be the most economical alternative to provide long-term baseload capacity and energy for SECI. The overall economics of a gas-fired combined cycle unit are not as favorable as those of the subcritical or supercritical solid fuel-fired units when operating at high capacity factors due to the higher fuel costs associated with natural gas.

1.5 FUTURE PLANNING CONSIDERATIONS

This study provides information for SECI to evaluate the alternatives identified in this study against SECI's request for proposals for additional capacity. Some additional steps for SECI consideration include the following:

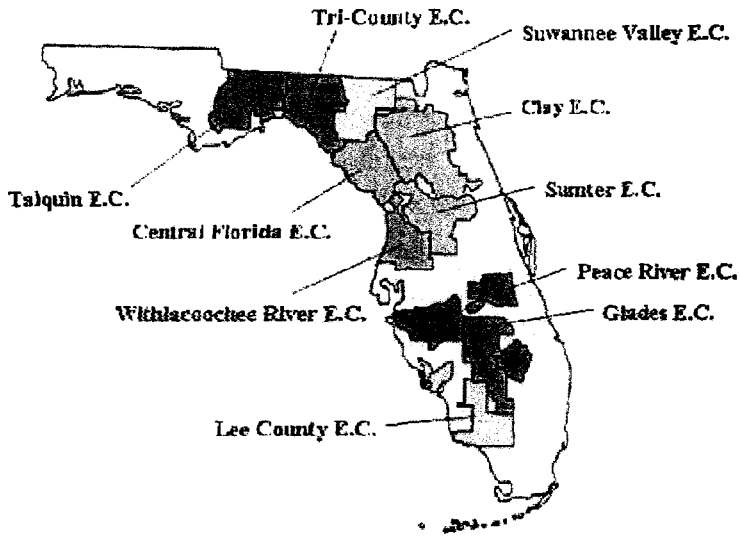
- The schedule reflects the need for preliminary engineering to start in 2005 in order to support preparation of permits. The process of selecting an engineer should be started.
- If the potential for additional power off-take participation exists, increasing the capacity of the new unit should be evaluated due to the economies of scale with larger units.
- It may be necessary to purchase additional property in order to support landfill requirements for the life of the unit.

2.0 INTRODUCTION

2.1 BACKGROUND

SECI has identified the need for additional baseload capacity by the 2012 timeframe. One option for meeting this need is the construction of an additional unit, Unit 3, at SGS. SECI seeks a generation resource with fuel price stability in order to secure long-term, low-cost generation for its member cooperatives. As a generation and transmission cooperative, SECI provides wholesale electric service to its ten member electric distribution cooperatives from a mix of firm resources. These resources include owned generation and purchased capacity, including two solid fuel fired units at SGS, a gas-fired combined cycle facility at Payne Creek, and an ownership interest in Progress Energy Florida's nuclear unit. The member electric distribution cooperatives are located throughout Florida, serving over 775,000 customers in 46 different counties. Figure 2-1 shows the SECI member system.

Figure 2-1
SECI Member System



2.2 SCOPE OF WORK

Seminole Electric Cooperative, Inc. retained Burns & McDonnell (B&McD) to evaluate the feasibility of developing and installing a new solid fuel generation resource adjacent to its present Seminole Generating Station. This additional solid fuel fired unit is designated and referred to in this study as SGS Unit 3. This study includes the following scope of work:

- Preparation of a preliminary site arrangement drawing for a new 600 MW net pulverized coal unit located on the SGS plant site.
- Preparation of a project scope description for the 600 MW net solid fuel fired unit.
- Preparation of capital and operating cost estimates for the new unit.
- Estimate of the plant output and heat rate.
- Preparation of preliminary plant water balance including the impact of the new unit.
- Preparation of a preliminary Level 1 schedule.
- Preparation of a preliminary assessment of the anticipated BACT/MACT requirements for the new unit.
- Preparation of a preliminary assessment of the existing infrastructure to support the new 600 MW net solid fuel fired unit.
- Development of a pro forma with an estimated bus-bar cost.
- Preparation of a preliminary assessment of subcritical and supercritical steam cycle technologies.
- Preparation of a preliminary assessment of mechanical draft versus natural draft cooling tower.
- Preparation of a preliminary evaluation of an IGCC plant.

The new unit is based on a 600 MW net solid fuel fired power plant. The boiler and emissions controls equipment for the new unit would be designed to operate with a blend of 70% eastern bituminous coal and 30% petcoke fuel. The operating and maintenance cost estimates for the economic pro forma were also based on a 70/30 blend of coal and petcoke.

Life cycle economic analysis of the new unit was conducted, resulting in a levelized bus-bar delivered cost of energy. In addition, a cost sensitivity analysis was performed.

2.3 OBJECTIVE

The purpose of the study is to provide a preliminary evaluation of a solid fuel generation resource at SGS to evaluate against the SECI request for capacity proposals.

3.0 DESCRIPTION OF PLANT

3.1 OVERVIEW

The description of the unit evaluated in this study is a 600 MW net pulverized coal (PC) fired steam generator (boiler) with a single reheat steam turbine on a brownfield site. The proposed location is adjacent to two existing subcritical 600 MW PC units at SGS.

The unit will be designed to operate on a 70/30 blend of bituminous coal and petcoke. An existing rail spur will be used to supply coal to the new unit via unit trains. Existing plant equipment and systems will be used for coal unloading and stockout.

The PC-fired steam generator will utilize balanced-draft combustion with reheat. Additional features will include selective catalytic reduction (SCR) for NO_x reduction, carbon injection for mercury control, an electrostatic precipitator (ESP) for particulate collection, a wet flue gas desulphurization system (FGD) for sulfur dioxide (SO_2) reduction and a wet ESP for sulfuric acid (H_2SO_4) reduction. Steam generated by the steam generator will be supplied to the steam turbine to complete the power generation cycle. Treated cooling water for the water-cooled surface condenser will be provided from the circulating water system that includes a natural draft cooling tower and circulating water pumps. Raw water for the cooling system will be supplied from the St. Johns River utilizing new pumps installed in the existing river water pump structure.

Electrical output from the new unit will be stepped up to 230 kV and interconnected into the existing transmission system through the existing 230 kV switchyard.

3.1.1 Schedule

A preliminary schedule was prepared for the design and construction of the 600 MW net solid fuel fired unit and is included at the end of Section 3. The schedule includes time for

- Permit preparation/engineering support, permit submittal and regulatory review.
- Equipment and construction package preparation and bid evaluation/award.
- Facility design.
- Equipment fabrication and delivery.
- Construction, startup and testing.

A project permit preparation and regulatory review time of 30 months was included in the schedule. Construction time is estimated to require 45 months for the 600 MW net unit. A construction schedule of 24 months was assumed for the 500 MW combined cycle alternative. The schedule includes the construction period required for upgrades to the existing switchyard. If new transmission lines are deemed necessary, the total time required for permitting and construction of the new unit would increase significantly.

The project execution method identified in the schedule is based on a multiple contract approach with an owner's engineer completing the engineering, SECI completing procurement, and multiple construction contracts. The schedule assumes that SECI would not commit to financial liabilities relative to the release of the major equipment and construction contracts until the critical construction permits are received.

3.1.2 Operating and Control Philosophy

The unit is expected to be operated at base load. The project is configured to normally operate at maximum continuous rating output. The proposed unit is capable of load following with overnight/weekend/holiday load reductions (steam generator at 50-percent load).

All routine start-up and shutdown operations will be from a central control room via a distributed control system (DCS). The SGS Unit 3 control room will be located in the existing control room. Facility automation will be designed to insure secure and safe operation of all plant equipment. Maintenance support will be supplied by on-site staff as required for routine maintenance activities. Maintenance support for major shutdowns is expected to be contracted.

The level of equipment redundancy included in the cost estimates for the unit is based on discussions with SECI and represents accepted industry standards for similar utility grade units.

The unit is not configured to generate electricity while isolated from the utility grid or to have "black-start" capability in the base cost estimate.

3.1.3 Pulverized Coal Boiler Technology

Conventional pulverized coal technology is a reliable energy producer around the world and is characterized by the operating pressure of the cycle, subcritical or supercritical. Subcritical and supercritical technology refers to the state of the water that is used in the steam generation process. The

critical point of water is 3,208.2 psia and 705 °F. At this critical point, there is no difference in the density of water and steam. The majority of the steam generators built in the United States utilize subcritical technology. These units utilize a steam drum and internal separators to separate the steam from the water. In the steam generator, high pressure steam is generated for throttle steam to the steam turbine. In this study, both subcritical and supercritical PC boilers were evaluated. Attachment A of this report provides a more detailed explanation and comparison of the two boiler technologies considered.

3.1.4 Site Layout

The plant will be oriented with the axis of the steam generator perpendicular to the steam turbine axis. The ESP and wet FGD will be located symmetrically about the boiler axis and extend to the north. The stack will be located north of the wet FGD. The remaining permitted landfill expansion area and the associated stormwater runoff pond will be located to the east of the new unit. For a graphic interpretation of the site layout, refer to the site arrangement Drawings SK-YGA1 and SK-YGA2 located at the end of this section.

3.1.4.1 Main Structures

The primary structures include the turbine building, which will house the steam turbine-generator and auxiliaries, and steam cycle equipment. The main control room will be located in the existing control room. Auxiliary buildings will be provided as required for the functions of the power generating facilities. Auxiliary buildings will be constructed, wherever possible, utilizing a pre-engineered building system. The main structures will be the turbine, steam generator, wet FGD, ESP, wet ESP, fly ash silo, natural draft cooling tower and chimney. A new water treatment building and warehouse will be included. The steam generator, ESP, wet FGD, and wet ESP will be outdoors. The existing administration offices will support the needs of the new unit.

3.1.4.2 Equipment Location

The new unit will be laid out to facilitate access to equipment and systems for maintenance and operations. The steam turbine-generator will be located indoors and will be interconnected with the existing turbine hall. The condensate pumps, boiler feedwater pumps, feedwater heaters, deaerator, condensate polisher, closed cooling water pumps and heat exchangers, generator surge protection cabinet, DCS equipment, switchgear, motor control centers, 480-volt load centers, and DC power system equipment will be located in the turbine building. The steam generator will be located outdoors.

3.1.5 Fuel and Reagents

Primary fuel for the PC steam generator will be a blend of bituminous coal and petcoke. The boiler and air pollution control equipment would be selected to be capable of meeting the required thermal performance and emissions firing the fuels indicated in Attachment E. This fuel analysis represents a 70/30 blend of bituminous coal and petcoke, resulting in a sulfur content of approximately 4.25%.

The fuel oil system will be used to supply start-up fuel for the new steam generator. A new 150,000 gallon fuel oil storage tank will be provided for the new unit.

Limestone can be delivered to the new unit by truck to the site utilizing the existing limestone handling systems.

Anhydrous ammonia will be delivered by truck to the site. It will be diluted with air and be injected at the economizer outlet, upstream of the SCR catalyst to reduce NOx emissions.

Activated carbon will be delivered by truck. The activated carbon will then be injected into the flue gas upstream of the ESP for mercury control.

3.1.6 Water Supply & Wastewater Treatment

A water mass balance diagram was developed for SGS reflecting the impact of Unit 3 to the existing two units and is included at the end of this section. The diagram depicts the following water supply and wastewater treatment streams.

Raw water will be supplied from the St John's River using new river water supply pumps installed in the existing river water pump structure. A new raw water supply line will be installed from the river water pump structure to the plant. Raw water will be pumped to the cooling tower basin for makeup to the circulating water system. Cycle makeup water will be provided from the existing well water system.

Service water for pump seals and miscellaneous hose stations will be supplied from the existing service water system. New service water pumps and a head tank will be provided. Potable quality water for drinking fountains, washrooms, showers, and toilet facilities will be supplied from the existing potable water system.

Surface water, collected from floor drains and containment areas around equipment, that may contain small amounts of oil, will be directed through an oil/water separator. The water discharged from the oil/water separator will be combined with other waste streams and discharged to the existing equalization basin. Collected oil from the oil/water separator will be trucked off site by a licensed waste disposal firm.

Process wastewater, except cooling tower blowdown and site runoff, will be discharged to the equalization basin and reused as makeup to the wet FGD. Wastewater from the wet FGD will be directed to the existing clarifier and filters. The clarified FGD blowdown will be used for fly ash dust suppression with the excess being directed to the brine concentrator. Condensate from the brine concentrator will be recovered as makeup to the wet FGD with the waste concentrate from the brine concentrator being evaporated in a spray dryer. Cooling tower blowdown and site runoff will be discharged to the St. Johns River through the existing discharge pipeline. Although the pipeline has sufficient capacity, further evaluation of the water discharge permit limit will need to be completed. Storm water runoff from non-process equipment areas, such as parking lots and building roofs, will be directed through an on-site storm water collection and drainage system and discharged to the St. Johns River.

3.1.7 Electrical Interconnection

Electrical output from the new unit will be stepped up to 230 kV. The turbine generator output will be connected through three single phase generator step-up transformers to the existing 230 kV switchyard. The existing folded breaker-and-a-half switchyard will be modified to add one three-breaker bay to accommodate the new unit and its startup transformers.

The unit startup power will be through two 30/40/50 MVA, 230:6.9/6.9 kV startup transformers. Auxiliary power will transfer to the steam turbine-generator through two 30/40/50 MVA 23:6.9/6.9 kV auxiliary transformers after the unit is on line.

3.1.8 Ash and Scrubber Sludge Disposal

A dry bottom ash extraction system will be used to transport the dry bottom ash to a storage silo. The bottom ash silo will be sized for three day's capacity. Bottom ash from the new unit will be sold. One fly ash silo with a storage capacity of three days will be provided. Fly ash will be trucked from the storage silo to an on-site landfill for disposal or for off site sales. Gypsum will be sold to the adjacent wallboard plant.

3.2 MAJOR EQUIPMENT AND SYSTEM DESCRIPTIONS

3.2.1 Steam Generator

The plant will include one PC steam-generating unit. The steam generator is a subcritical unit designed to supply steam to the steam turbine at 2,520 psig and 1050 °F / 1050 °F at 100-percent load when burning a 70/30 blend of coal and petcoke.

Superheat and reheat temperature will be automatically controlled by regulating attemperator spray water flow to spray water control valves with automatic block valves.

Gravimetric feeders will meter raw coal to the pulverizers. Steam generator auxiliary equipment will also include two 60% capacity, electric motor-driven primary air (pulverized coal transport) fans and two 60% capacity, steam generator forced draft (secondary combustion air) fans with an air preheater. The steam generator features low NO_x burners and fuel oil igniters. Three 50% capacity induced draft fans will be included downstream of the ESP.

3.2.2 Air Pollution Control Equipment

Flue gas exiting the steam generator passes through the following equipment and systems to reduce emission levels.

- SCR to reduce NO_x emissions.
- Activated carbon injection system for mercury control.
- ESP for particulate control.
- Wet FGD to reduce the SO_2 emissions.
- Wet ESP to reduce sulfuric acid emissions.

3.2.3 Steam Turbine-Generator

The steam generator will provide steam to a main steam turbine-generator. The steam turbine-generator converts mechanical energy of the steam turbine to electrical energy. For this project a 2,520 psig, 1050 F/ 1050 F, single-reheat, dual casing, four-flow down-exhaust, condensing steam turbine is arranged with seven stages of feedwater heaters and a surface condenser. The turbine will drive an electric generator. The steam-turbine generator unit will be designed for indoor operation.

3.2.4 Surface Condenser

The water-cooled surface condenser will be a dual, rectangular shell, two pressure, split waterbox, two pass condenser with a retention hotwell for the subcritical cycle. The condenser will be designed to maintain the steam turbine backpressure at normal maximum continuous rating of the steam turbine at summer design conditions. The condenser will accept the steam exhausted from the low pressure steam turbine. Air removal from the condenser's upper portion will be via two full capacity vacuum pumps. To dissipate the energy in the condensing steam, a circulating water system will supply cooling water from the natural draft cooling tower to the water-cooled condenser.

3.2.5 Circulating Water System

The circulating water system will be designed to operate at up to approximately 3.5 cycles of concentration to maintain proper water quality while limiting the quantity of blowdown water. Blowdown from the circulating water system will be discharged into the St. Johns River.

The cooling tower will be a concrete, natural draft type with high efficiency fill. The cooling tower will be designed to maintain the rated turbine back pressure at the design ambient conditions. Cooling water is pumped from the natural draft cooling tower to the condenser by three 50-percent capacity circulating water pumps.

3.2.6 Closed Cooling Water System

The closed cooling water system is a closed-loop system that provides and cools cooling water for various equipment. This system includes the head tank, closed cooling water pumps, and plate and frame closed cooling water heat exchangers. Two 100 percent capacity, single-speed, horizontal, motor-driven, closed-cooling water pumps will be provided. Two 100 percent capacity closed cooling water heat exchangers will be provided. This system will be designed so that the flow to any piece of equipment can be controlled either by manual valves or control valves.

3.2.7 Steam System

The steam system transports steam from the steam generator to the main steam turbine-generator and feedwater heaters. A cross-tie with the existing boilers will be provided to supply steam for start-up and shutdown operations. A steam turbine bypass system is not included.

The main steam piping transports steam from the superheater outlet of the steam generator to the inlet of the high-pressure turbine. Steam is exhausted from the high-pressure turbine and transported through the cold reheat piping to the reheater section of the steam generator where steam is reheated. The hot reheat piping transports the reheated steam to the intermediate pressure turbine.

This system also transports steam from extractions in the turbine to the high-pressure heaters, boiler feedpump steam turbine drives, low-pressure heaters, and the deaerating feedwater heater. The main steam and hot reheat systems include attemperators, where feedwater is injected as necessary to control the temperature of the steam being supplied to the steam turbine.

The steam pipelines will be provided with drains at all low points. Drain pots will be provided to collect condensate from the low points in the steam piping and return it to the main condenser. The drain pots will drain the various low points of the piping system at the maximum steam flows.

All extraction lines from the steam turbine, except those leading to the heaters in the condenser neck, will be equipped with power assisted, nonreturn valves to ensure that steam will not flow back to the turbine. These lines will also be supplied with motor-operated shutoff valves to prevent steam turbine water induction.

3.2.8 Condensate System

The condensate system delivers deaerated condensate via three, 50-percent capacity vertical can, condensate pumps. These pumps transport condensate from the condenser hotwell, through the gland steam condenser and low-pressure feedwater heaters to the boiler feed pump. A minimum flow bypass system will be provided to assure the condensate pumps operate above their minimum flow rate at all times.

3.2.9 Feedwater System

The feedwater system provides water to the high-pressure feedwater heaters and then to the steam generator's economizer inlet via two 60-percent capacity boiler feed pumps. The main boiler feed pumps are furnished with steam turbine drives. The feedwater system also provides spray water for main steam and hot reheat attemperators for steam temperature control. A minimum flow system will be provided to assure the boiler feed pumps operate above their minimum flow rate at all times. A single, 30% capacity, motor driven start-up boiler feed pump is also included.

3.2.10 Coal Handling System

The coal handling system for the SGS Unit 3 will be based on handling bituminous coal with a density of 50 pounds per cubic foot and petroleum coke with a density of 45 pounds per cubic foot. The existing rotary dumper and stockout system has adequate capacity (approximately 3,000 tons per hour) to handle the new unit. A condition assessment is advisable to determine if existing equipment can meet expected capacity levels. Existing Units 1 and 2 currently receive approximately one unit train (10,000 tons per train) per day (320 trains per year). The addition of Unit 3 will increase this requirement to approximately 1.5 unit trains per day (485 trains per year).

The current long term coal storage pile, for Unit 1 and 2, maintains 45 to 60 days of coal. Adding Unit 3 requirements to the existing coal pile will equate to a total area of approximately 23 acres (1,200,000 tons) for all three units. The existing coal storage area has adequate capacity for all three units.

The existing as-received sampling tower will be modified by removing the existing as-received sampling system, providing a new motorized flop gate at the head end of Conveyor CB-2, providing a new belt feeder to transfer coal to a new reversible yard conveyor and a new enclosed structure attached to the existing tower. The new reversible yard conveyor will be provided with a new trencher type stacker / reclaimer (similar to the existing machine) and will be capable of stacking out 3,000 tph and reclaiming at 1,700 tph of bituminous coal or petroleum coke.

The new reversible yard conveyor will be approximately 1,500 feet long and will provide approximately 3 days of active reclaimable storage for all three units. The head end of the reversible yard conveyor will be located in the new structure, adjacent to the existing tower and will be provided with a diverter gate to direct coal to either existing Conveyor CB-7A or CB-7B.

The existing as-fired sampling tower will be modified by removing the existing as-fired sampling system and providing new motorized flop gates at the head end of Conveyors CB-8A and CB-8B. The new gates will direct coal to new Unit 3 feed conveyors to transfer coal from the as-fired tower to a new tower adjacent to Unit 3. The Unit 3 tower will be provided with a surge bin and variable speed belt feeders (2) which discharge to dual tripper conveyors. The tripper conveyors will be provided with dual pant leg traveling trippers complete with cable reels and floor seal system.

Replacement of the existing as-received and as-fired sampling systems will be accomplished by installing sweep arm primary samplers on the respective belt conveyors and modular self-contained secondary sampling systems, located at grade, immediately underneath the primary sampler(s).

Dust control for the new coal handling system will be a dry baghouse type collection system and will be provided to limit particulate emissions complying with all local, state and federal regulations. The baghouse collector will be provided with a walk-in clean air plenum, centrifugal fan, ductwork and dust return system. The existing dust collection systems will be upgraded as required to maintain current emission regulations.

3.2.11 Water and Wastewater Treatment Systems

The water and wastewater treatment systems will provide high purity water for use as makeup to the boiler and to maintain the high purity requirements of the condensate system. Wastewater treatment will allow the facility to operate in a zero discharge mode from all plant services other than cooling tower blowdown and site runoff. The water and wastewater treatment systems shall consist of the following subsystems:

- Cycle makeup treatment system
- Sampling and analysis system
- Condensate polishing system
- Brine Concentrator/spray dryer system

3.2.11.1 Cycle Makeup Treatment System

The cost estimate is based on providing a single two-pass reverse osmosis (RO) system with a design product flow of 150 gpm. The effluent from the second pass RO will be polished using an electrodionization (EDI) system. The EDI system will use electricity to maintain fully regenerated ion exchange resin within the EDI cells. The use of an EDI for polishing of the two-pass RO system will eliminate the need for acid and caustic regenerant storage and handling. Reject from the RO and EDI systems will be recovered in the existing equalization basin and recovered as makeup to the wet scrubbers.

3.2.11.2 Sampling and Analysis System

The sampling and analysis system will consist of three major components: a sample rack, a water quality panel, and a sample chiller. Samples from the plant shall be routed to the centrally located sampling and

analysis system for continuous analyses, monitoring, data logging, and trending analysis and recording.

Analyzers will be shared by different sample points where continuous analysis of parameters is not critical (i.e. sodium and silica). System will include a conditioning panel utilizing condensate for primary cooling and cooling water or chilled water for secondary cooling to condition the samples to the necessary temperature. The wet section of the panel will contain the analyzers and sensors. The dry section of the panel will contain the monitors.

3.2.11.3 Condensate Polishing System

The condensate system will be provided with full flow (4 x 35 % capacity) deep bed polishers with external regeneration. The condensate polishing system will treat the water from the discharge of the condensate pumps. All of the condensate will flow from the condensate system through the condensate polisher exchangers. The condensate polisher vessels will consist of a mixture of cation and anion resins. The effluent of the condensate polishing system will be returned to the condensate system upstream of the gland steam condenser.

3.2.11.4 Brine Concentrator/Spray Dryer System

The scrubber blowdown from all units will be treated in the existing clarifier and filters for reduction of suspended solids. The filtered blowdown will be directed to two, 50% capacity, brine concentrators. Each brine concentrator will have a treatment capacity of 300 gpm. The solids in the brine concentrator makeup will be concentrated in a waste stream which will be about 10 percent of the brine concentrator inlet flow rate. This concentrate stream will be sent to a single spray dryer for final disposal. The water content of the brine concentrator waste will be evaporated and the resulting dry solids will be sent to a landfill. The remaining 90 percent of the brine concentrator influent will be evaporated and condensed with the condensate being recovered as makeup to the wet scrubbers.

3.2.12 Electrical Generation & Distribution

The electrical systems supply the power produced by the plant to the transmission system and supply the power required for operation of all plant equipment. The systems include all metering and protective relaying required for operation of the plant electrical systems.

The turbine generator output will be connected through single phase generator step-up transformers and power circuit breakers to the existing 230 kV switchyard. The generator step-up transformers will be three, single phase transformers. The unit start-up source will be provided through the addition of 230 kV

breakers in the switchyard and via overhead cable taps to the high side terminals of two start-up transformers. Each start-up transformer will be a 50% rated three winding transformer.

The high side terminals of the two unit auxiliary transformers will tap into the isolated phase bus between the generator and the step-up transformers. Each unit auxiliary transformer will be three winding and 50% rated.

The secondary of each of the unit auxiliary and start-up transformers will each have two 6.9 kV windings that are connected by non-segregated bus duct to 6.9 kV switchgear buses.

3.2.13 Auxiliary Power Supply

This system receives power from the unit auxiliary transformers and startup transformers and steps it down to 6.9 kV and connects to 6.9 kV switchgear buses. The 6.9 kV switchgear buses distribute power throughout the plant with step down transformers to distribute to the various voltage levels to all of the systems requiring AC electrical power for their operation. Startup and initial commissioning will be accomplished by feeding power from the switchyard, through the startup transformers. After the generator is on-line, station power will transfer from the startup transformers to the unit auxiliary transformers that are tapped off the generator via isolated phase bus.

3.2.14 Control Systems

The control system will be a physically and functionally distributed microprocessor based, on-line distributed control system (DCS). The main DCS interface for Unit 3 will be located in the existing control room. The DCS will be used for supervisory control and monitoring of all major plant systems. In addition, programmable logic controllers (PLCs) will be provided for auxiliary systems such as coal handling, ash handling, water treatment, sootblowers, etc.

The boiler, turbine and auxiliary controls will be provided under various equipment contracts. In general, where equipment is furnished as a "package", the auxiliary control system will be included in that package. However, since the turbine, boiler and heat cycle are operated as a unit in response to load demand, the associated coordinated load, combustion and burner management controls will be provided under the Distributed Control System (DCS) package. In addition, the DCS will serve as the primary Human Machine Interface (HMI) for plant wide remote controls and monitoring, except where local control is mandated. The auxiliary systems, usually PLC based, are each to be designed using project

standard requirements for control philosophy and electrical design.

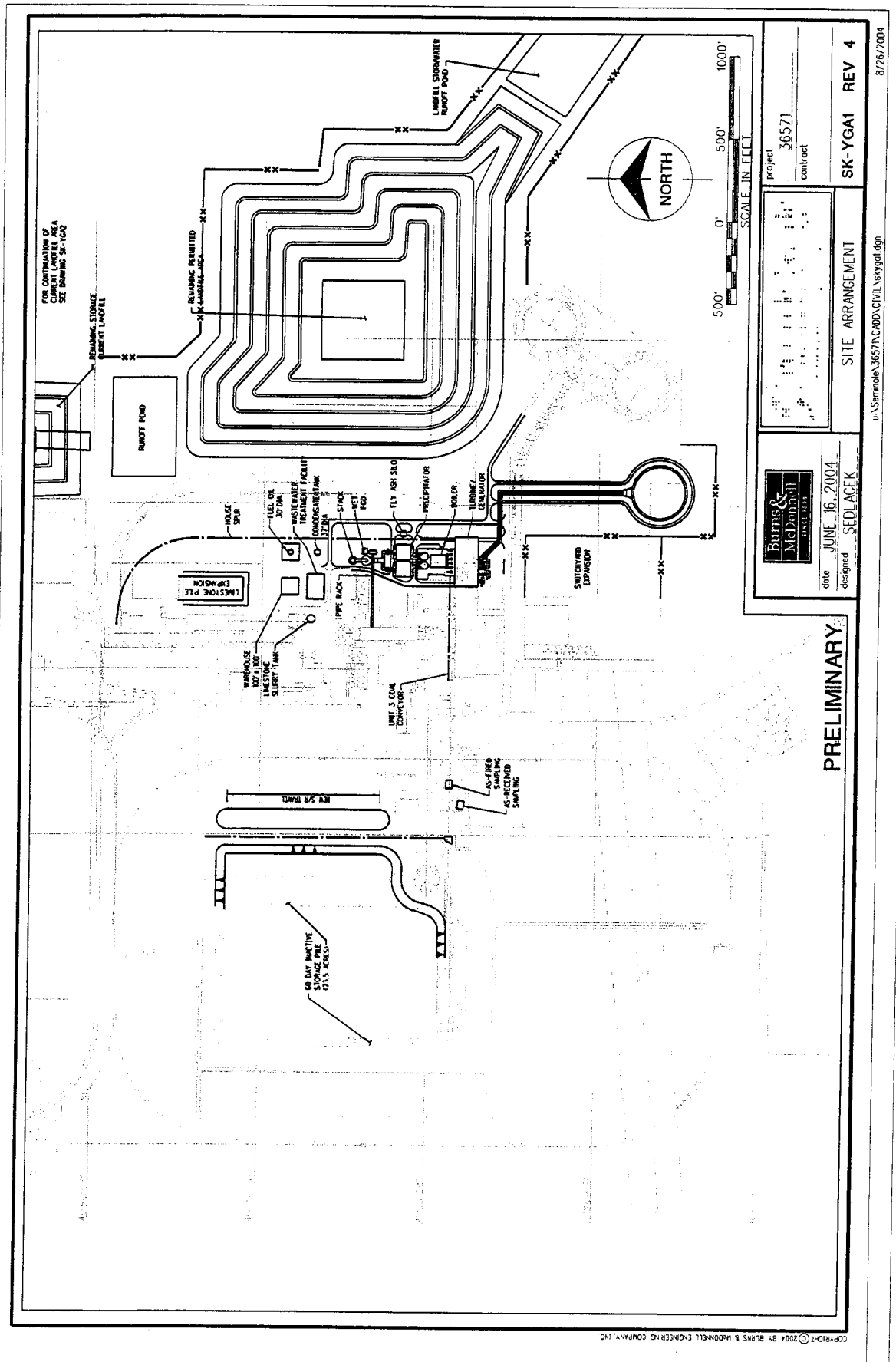
3.2.15 DCS and Related Systems

All information from DCS controllers and I/O is passed to the operator through operator server/client personal computers operating on a dedicated Ethernet Local Area Network (LAN), the DCS Information Network. Servers, located in a Computer Room or Control Equipment Room, will provide the gateway from the LAN to the proprietary DCS Data Highway. The servers and clients will be powered in two groups from two separate sources of power. The servers may be operated in a redundant mode if throughput allows operator updates once per second.

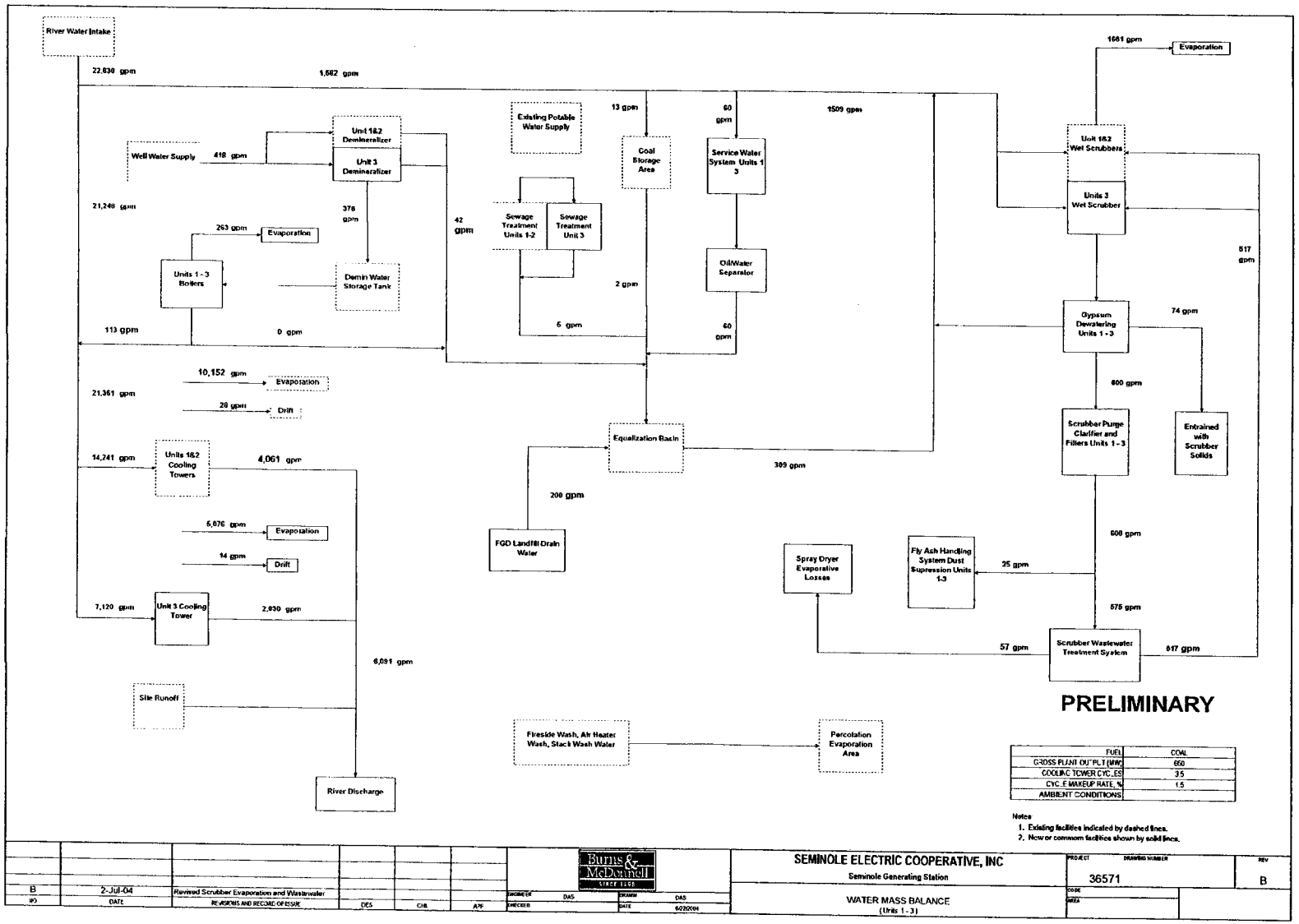
A plant historian will be provided to allow several months of data to be stored from and retrieved by the DCS. It shall also allow for the archive and retrieval of data through the use of CD R/W drive or streaming tape. The historian will supply data to all operator servers and client workstations. The DCS will allow the seamless retrieval of short-term and long-term data into the same DCS operator trends. The historian will be redundant for data backup or will be provided with short- term history storage to backup data for at least several days in event the historian is down.

3.2.16 Continuous Emissions Monitoring System (CEMS)

One CEMS downstream of the SCR/ESP/wet FGD/wet ESP and a data acquisition system is included. The final flue gas outlet CEMS will consist of sampling devices with sample tubing to the emissions rack mounted near the base of the stack in an enclosure. The system will include a cylinder rack for calibration gases. The CEMS monitors stack emissions with hardware and reporting package software will meet the requirements of 40 CFR 60 and 40 CFR 75 as determined by the permit requirements. The CEMS is designed to communicate with the plant DCS system to provide automatic report production compatible with permit requirements.


PRELIMINARY
SITE ARRANGEMENT
SK-YGA1 REV 4
project 36571
contract
date JUNE 16, 2004
designed SEDLACEK
Burns & McDonnell
8/26/2004
u:\Seminole\36571\CADD\CIVIL\skygal.dgn
NORTH
SCALE IN FEET
0'
500'
1000'
LANDFILL STORMWATER RUNOFF POND
REMAINING PERMITTED LANDFILL AREA
REMAINING STORAGE CURRENT LANDFILL
FOR CONTINUATION OF CURRENT LANDFILL AREA SEE DRAWING SK-YGA2
RUNOFF POND
HOUSE SPUR
FLEX OIL 30' DIA.
WASTEWATER TREATMENT FACILITY
CONDENSATE TANK 32' DIA
STACK
WET FGD
FLY ASH SILO
PRECIPITATOR
BOILER
TURBINE / GENERATOR
LIMESTONE PILE EXPANSION
PIPE RACK
WAREHOUSE 100' x 100'
LIMESTONE SLURRY TANK
UNIT 3 COAL CONVEYOR
SWITCHYARD EXPANSION
AS-FIRED SAMPLING
AS-RECEIVED SAMPLING
NEW S/E TRACK
60 DAY INACTIVE STORAGE PILE (23.5 ACRES)
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LANDFILL EXPANSION AREA
LANDFILL STORMWATER RUNOFF POND
RUNOFF POND
RELOCATED DRAINAGE CURRENTLY ON LANDFILL
PRELIMINARY
NORTH
Burns & McDonnell
date JUNE 25, 2004
designed GANDER
LANDFILL EXPANSION
project 36571
contract
SK-YGA2 REV 2
8/30/2004
u:\Seminole\36571\CADD\CIVIL\skygo2.dgn
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Notes
1. Existing facilities indicated by dashed lines.
2. New or common facilities shown by solid lines.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DES	CHK	APP
B	2-Jul-04	Revised Scrubber Evaporation and Wastewater			

Burns & McDonnell SINCE 1898

ENGINEER DAS CHECKED DRAWN DAS DATE 6/29/2004

SEMINOLE ELECTRIC COOPERATIVE, INC
Seminole Generating Station

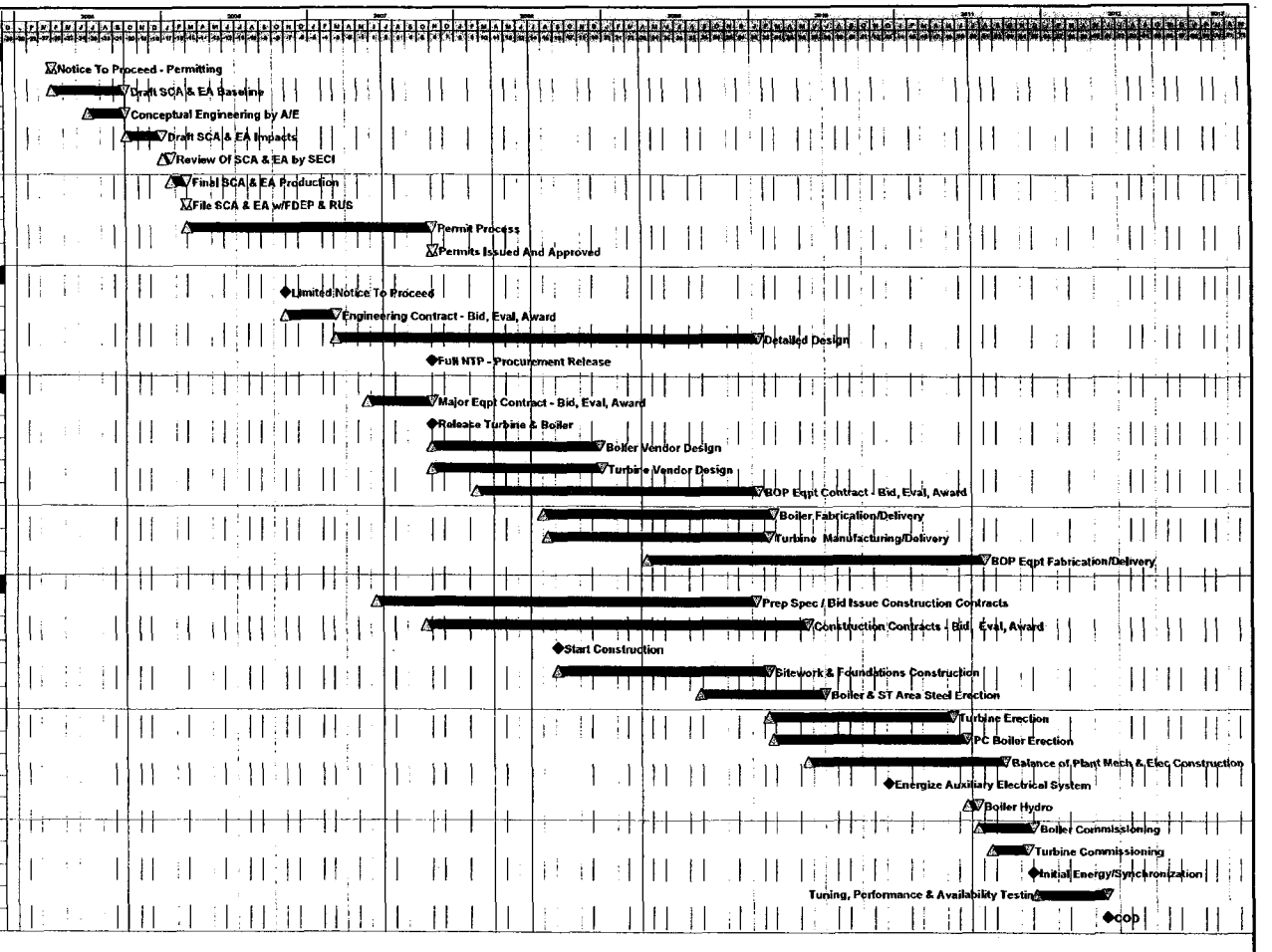
WATER MASS BALANCE
(Units 1 - 3)

PROJECT 36571 DRAWING NUMBER REV B

CODE AREA

Exhibit RAK-3
28 of 89

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
Permitting				
C61311	Notice To Proceed - Permitting	1	01APR05*	01APR05
C61312	Draft SCA & EA Baseline	131	01APR05	30SEP05
C61313	Conceptual Engineering by A/E	66	01JUL05	30SEP05
C61314	Draft SCA & EA Impacts	65	03OCT05	30DEC05
C61315	Review Of SCA & EA by SECI	15	02JAN06	20JAN06
C61316	Final SCA & EA Production	27	23JAN06	28FEB06
C61317	File SCA & EA w/FDEP & RUS	1	01MAR06	01MAR06
C61318	Permit Process	436	01MAR06	31OCT07
C61319	Permits Issued And Approved	1	01NOV07	01NOV07
Engineering				
C61012	Limited Notice To Proceed	0	01NOV06*	
C61172	Engineering Contract - Bid, Eval, Award	90	01NOV06	06MAR07
C61210	Detailed Design	750	07MAR07	19JAN10
C61010	Full NTP - Procurement Release	0	01NOV07	
Procurement				
C61182	Major Eqpt Contract - Bid, Eval, Award	117	22MAY07	31OCT07
C61020	Release Turbine & Boiler	0	01NOV07	
C61170	Boiler Vendor Design	297	01NOV07	19DEC08
C61180	Turbine Vendor Design	300	01NOV07	24DEC08
C61183	BOP Eqpt Contract - Bid, Eval, Award	500	20FEB08	19JAN10
C61050	Boiler Fabrication/Delivery	410	31JUL08	24FEB10
C61040	Turbine Manufacturing/Delivery	394	11AUG08	11FEB10
C61052	BOP Eqpt Fabrication/Delivery	600	15APR09	02AUG11
Construction & Startup				
C61185	Prep Spec / Bid Issue Construction Contracts	675	14JUN07	13JAN10
C61030	Construction Contracts - Bid, Eval, Award	675	18OCT07	19MAY10
C61060	Start Construction	0	05SEP08	
C61220	Sitework & Foundations Construction	375	05SEP08	11FEB10
C61070	Boiler & ST Area Steel Erection	220	27AUG09	30JUN10
C61080	Turbine Erection	326	12FEB10	13MAY11
C61150	PC Boiler Erection	343	25FEB10	20JUN11
C61230	Balance of Plant Mech & Elec Construction	350	20MAY10	21SEP11
C61090	Energize Auxiliary Electrical System	0		03DEC10
C61110	Boiler Hydro	19	21JUN11	15JUL11
C61120	Boiler Commissioning	98	18JUL11	30NOV11
C61100	Turbine Commissioning	65	19AUG11	17NOV11
C61130	Initial Energy/Synchronization	0		30NOV11
C61160	Tuning, Performance & Availability Testing	127	08DEC11	01JUN12
C61140	COD	0		01JUN12



Start Date 01SEP04
Finish Date 01JUN12
Data Date 01SEP04
Run Date 02SEP04 16:16

Early Bar
Progress Bar
Critical Activity

SM12

Sheet 1 of 1

Seminole Electric Cooperative, Inc.
Seminole Generating Station
Unit 3
600 MW Net Pulverized Coal Plant

© Primavera Systems, Inc.

Burns & McDonnell
SINCE 1898

4.0 PERFORMANCE AND EMISSIONS

4.1 PERFORMANCE

Estimated performance was developed for 600 MW net subcritical and supercritical PC units at SGS. The estimates summarized in this section are based on in-house data and information from similar projects. A performance summary is shown in Table 4-1.

Table 4-1: 600 MW (net) Performance

Boiler Type	Pulverized Coal Subcritical 1,050 F/1,050 F	Pulverized Coal Supercritical 1,050 F/1,050 F
Net Plant Output (kW)	600,000	600,000
STG Heat Rate (Btu/kW-hr)	7,430	7,172
STG Gross Output (kW)	648,649	652,174
Boiler Efficiency (%)	87.1	87.1
Auxiliary Power (kW)	48,649	52,174
Auxiliary Power (%)	7.5%	8.0%
Net Plant Heat Rate (Btu/kW-hr)	9,220	8,949

4.1.1 Start-up and Load Following

Cold start-up times for a PC boiler are commonly in the 5-6 hour range. Supercritical boilers are capable of reaching maximum load 15% to 20% faster than subcritical units because supercritical boilers do not have thick wall components like a steam drum. However, supercritical units are typically base loaded units due to the economic advantage of the steam cycle efficiency.

4.2 EMISSIONS

A preliminary assessment of the anticipated Best Available Control Technology (BACT) was performed and the anticipated emissions requirements for a new 600 MW net PC unit at SGS were developed. The BACT levels estimated for this study are not absolute. BACT emission levels change with time, unit type, and fuel type. The emission rates represent Burns & McDonnell's best estimated BACT levels taking into account technology limitations and current expected guaranteed performance levels.

4.2.1 Emissions Control Technologies

The control technologies required for either a subcritical or supercritical unit is based on firing a blend consisting of 70% bituminous coal and 30% pet coke. The fuel analysis for the blended fuel is shown in Appendix E. As a result, the emissions control equipment required to accommodate the blended fuel is as follows:

- SCR for NO_x control.
- Activated Carbon Injection System for mercury (Hg) control.
- ESP for particulate (PM) control.
- FGD for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.

4.2.1.1 Selective Catalytic Reduction System

The SCR system uses anhydrous ammonia, which is injected into the flue gas at the economizer exit and a catalyst that reduces NO_x to molecular nitrogen and water. Ammonia slip would be below 2 ppm. Sonic horns are used for removal of fly ash from the catalyst during operation.

The anhydrous ammonia is pumped from the storage tank as a liquid to the ammonia vaporization and injection equipment. The liquid ammonia is vaporized by an electric heater and fed to the dilution equipment. The ammonia is mixed with air and injected into the flue gas ductwork upstream of the catalyst.

4.2.1.2 Activated Carbon Injection System

The reagent injection system injects activated carbon into the flue gas upstream of the ESP for mercury control. The mercury present in the flue gas absorbs the activated carbon and is collected in the ESP downstream. Fly ash collected in the ESP downstream will not be saleable due to the injection of carbon.

The carbon injection system consists of a pneumatic loading system, storage silos, hoppers, blowers, transport piping, and control system. The injection equipment would likely be skid mounted. There is a high probability for the need of additional air compressors to convey the carbon to the injection point and provide the flow and pressure to get the carbon into the flue gas stream and properly mixed.

4.2.1.3 Electrostatic Precipitator

An ESP will be provided to reduce particulate emissions. The ESP will generate a high voltage electrical field that will give the particulate matter an electric charge (positive or negative). The charged particles will then be collected on a collection plate. A rapper or hammer system will be utilized to vibrate the particles off of the collection plates and into the hoppers for disposal.

4.2.1.4 Wet FGD

In the wet FGD process, a slurry of finely ground limestone ($CaCO_3$) in water is recirculated through an absorber tower to provide turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas and results in the absorption of SO_2 into the slurry liquid. The gas/liquid contact also results in removal of a significant amount of the residual fly ash. Chemical reactions between the limestone and the absorbed SO_2 take place within the absorber and in the absorber sump, resulting in the formation of solid particles of calcium sulfite ($CaSO_3$). Some of the oxygen in the flue gas participates in the reactions, resulting in the formation of particles of calcium sulfate ($CaSO_4$) as well. A forced oxidation system will be utilized to inject air into the absorber sump to promote the formation of calcium sulfate and minimize the formation of calcium sulfite solids. The resultant slurry is recycled and processed in the dewatering system.

4.2.1.5 Wet ESP

The utilization of a high sulfur fuel along with a wet FGD requires a wet ESP to decrease the concentration of sulfuric acid aerosol (acid mist) particles entering the stack. The wet ESP would be located at the top of the absorber tower in a vertical flow configuration to minimize layout space requirements. The wet ESP will introduce an electric field that will remove the acid mist from the flue gas onto collecting plates. A washing system will be provided to remove the particulate matter deposited on the collecting plates. The liquid will be collected and either diverted to the wet FGD system, recycled, or disposed of.

4.2.2 Expected Pollutant Limits

Based on the control technologies described above, the preliminary BACT emission limits for the subcritical and supercritical units being evaluated are as follows:

Table 4-2: Preliminary BACT Emission Limits

Pollutant	Emission Limit
NO_x	0.07 lb/MMBtu
SO_2	0.18 lb/MMBtu
PM	0.015 lb/MMBtu
Hg	6 x 10^-6 lb/MW-hr
CO	0.15 lb/MMBtu
H_2SO_4	0.005 lb/MMBtu

The PM emission rate of 0.015 lb/MMBtu is filterable particulate matter only. A PM_{10} emission limit including filterables and condensibles has not been guaranteed by vendors on the condensable portion. Further, the mercury emission limit specified is based on recent test data and does not represent a typical vendor guarantee. In addition, the CO limit is based on the expected byproducts from the combustion process in the boiler and is not a controlled pollutant.

4.2.3 Emission Allowances

This study does not account for the purchasing of emission allowances that may be required for compliance.

5.0 COST ESTIMATES

5.1 CAPITAL COST ESTIMATES

The cost estimates summarized in this section represent screening-level cost estimates used in evaluating the installation of a 600 MW net PC unit adjacent to the existing units at SGS. Equipment costs are based on recent vendor quotes for similar equipment and in-house data. Construction commodities and indirect costs are based on Burns & McDonnell's experience. Burns & McDonnell did not solicit bids from equipment manufacturers or contractors for equipment or construction services.

The capital cost estimates for 600 MW net subcritical and supercritical PC units are included in Table 5-1.

TABLE 5-1: COST ESTIMATES (2010$)

Description	600 MW PC Subcritical	600 MW PC Supercritical
PROCUREMENT		
Mechanical Procurement		
Steam Turbine - Generator	$ 38,973,000	$ 41,359,000
Boiler Island/APC Equipment	$ 145,386,000	$ 146,594,000
Surface Condenser & Air Removal Equipment	$ 4,892,000	$ 4,608,000
Boiler Feed Pumps	$ 1,457,000	$ 1,861,000
Condensate Pumps/Circulating Water Pumps	$ 1,796,000	$ 1,796,000
Miscellaneous Mechanical Equipment	$ 27,370,000	$ 31,091,000
Electrical & Control Procurement		
GSU, Auxiliary Transformers	$ 5,280,000	$ 5,280,000
Medium Voltage Metal-Clad Switchgear	$ 5,320,000	$ 5,320,000
480 V Switchgear & Transformers	$ 1,108,000	$ 1,108,000
Miscellaneous Electrical Equipment	$ 2,379,000	$ 2,379,000
Control Procurement	$ 2,931,000	$ 2,931,000
Water Treatment Procurement	$ 16,960,000	$ 16,960,000
Structural Procurement	$ 7,382,000	$ 7,382,000
CONSTRUCTION		
Major Equipment Erection		
Steam Turbine - Generator Erection	$ 6,193,000	$ 5,428,000
Boiler Island/APC Equipment Erection	$ 141,499,000	$ 143,896,000
Furnish & Erect Packages		
Cooling Tower	$ 20,000,000	$ 18,560,000
Material Handling Systems	$ 20,272,000	$ 20,272,000
Chimney	$ 12,500,000	$ 12,500,000
Civil / Structural Construction	$ 58,619,000	$ 58,638,000
Mechanical Construction	$ 76,999,000	$ 83,653,000
Electrical Construction	$ 54,010,000	$ 54,010,000
PROJECT INDIRECTS		
Construction Management	$ 12,625,000	$ 12,625,000
Preoperational Testing, Startup, & Calibration	$ 11,933,000	$ 11,933,000
Miscellaneous Construction Indirects	$ 7,569,000	$ 7,569,000
Project Management & Engineering	$ 39,256,000	$ 39,256,000
Project Bonds	$ 7,834,000	$ 7,834,000
Escalation	$ 115,365,000	$ 116,673,000
Project Development	$ 3,000,000	$ 3,000,000
Owner Operations Personnel	$ 2,856,000	$ 2,856,000
Substation / Transmission Upgrades	$ 2,400,000	$ 2,400,000
Land	$ -	$ -
Permitting & License Fees	$ 2,643,000	$ 2,643,000
Initial Fuel Inventory	$ 12,096,000	$ 11,850,000
Miscellaneous Owner Costs	$ 11,485,000	$ 11,578,000
Sales Tax & Duties	$ 1,196,000	$ 1,345,000
Owner Contingency	$ 88,158,000	$ 89,719,000
TOTAL PROJECT COST	**$ 969,742,000**	**$ 986,906,000**

5.1.1 Capital Cost Estimate Assumptions

The cost basis for the subcritical and supercritical solid fuel fired options is defined in Table 5-2. More specifically, the following are the major assumptions and exclusions upon which the facility cost estimates are based:

- Project will be executed under a multiple contract method. This contracting method assumes an engineer for plant design, procurement by SECI, and construction performed by multiple contractors.
- Cost estimate is based on a non-union labor force for the Palatka, Florida area, 40-hour work week, single shift with some overtime.
- Rail access is nearby and suitable for receipt of heavy equipment.
- Cost estimate includes escalation to support commercial operation in June 1, 2012. Escalation at the rate of 2.5% to the midpoint of construction in 2010 is included in the estimate.
- No piles have been included. All foundations are assumed to be spread footings or matt foundations.
- Rock, existing structures, underground utilities, or other obstructions will not be encountered in the area of the plant.
- Hazardous substances will not be encountered in the area of the plant.
- No aesthetic landscaping or structures are included.
- Off-site road, bridge, or other improvements are not included.
- Transmission system costs are not included.

Table 5-2: 600 MW (net) Subcritical Plant Cost Basis/Assumptions

General:	
Water Supply:	
Cooling Tower Make-up:	
Source:	River water will be used for makeup to the cooling tower.
Supply:	Cooling tower makeup water will be supplied from new pumps installed in the existing intake structure. New supply piping will included.
Storage:	None.
Cycle Make-up:	Existing well water system will feed the water treatment system.
Service Water:	New service water pumps and head tank will be included to supply service water to the new unit.
Potable Water:	Potable water will be supplied from existing system.
Wastewater Disposal:	
Process Wastewater:	Plant wastewater except cooling tower blowdown and site runoff (does not include landfill and coal pile runoff) will be discharged to the equalization basin and reusued or evaporated in brine concentrators. Cooling tower blowdown and site runoff will be discharged to the St. Johns River.
Contaminated Wastewater:	Drains from areas around equipment that could be contaminated with oil will be directed through an oil/water separator and discharged to the existing equalization basin.
Sanitary Wastewater:	Sanitary waste will be treated in a new package sewage treatment plant and effluent will be discharged to the equalization basin.
Stormwater Discharge:	Stormwater (except for coal pile and landfill runoff) will be collected in a storm drainage system and discharged to St. Johns River.
Start-up Fuel:	Start-up fuel for the project will be fuel oil. A new fuel oil storage tank will be included to provide adequate capacity for the new unit. New fuel oil pumps will be required for the new unit.
Solid Fuel:	
Types:	Plant will be designed to operate with a 70/30 blend of eastern bituminous coal and petcoke.
Delivery:	Solid fuel will be delivered to the plant by rail only. Trains are anticipated to be up to 100 car unit trains.
Dead Storage:	Solid fuel will be stored in uncovered outdoor piles. Total storage for all three units of 60 days will be provided.
Live Storage:	New unit outdoor active pile shall have approximately 24 hours of full load operation.
Boiler Storage:	Boilerbuilding silo storage shall have a minimum of 24 hours of full load operation.
Blending:	70% coal and 30% petcoke blend.
Sorbent Supply (Scrubber):	
Source:	Current limestone supplier or as required.
Size:	Limestone size shall be a maximum of 3".
Delivery:	The existing truck unloading system has adequate capacity for the new unit.
Storage:	15 days of covered storage and 40 to 60 days of total storage. Sizing of sorbent storage will be based upon design fuel.
Fly Ash & Scrubber Sludge Disposal:	
Disposal:	Fly ash will be disposed of in the on-site landfill. Gypsum will be sold to the adjacent wallboard plant. Landfill capacity (including expansion requirements) will be based on 25-30 year production assuming a 70/30 blend of coal and pet coke. Landfill costs will include a composite liner with leachate collection system installed on both the current landfill area and the expansion area. Cover material thickness will be 3 feet.
Day Storage:	One fly ash silo with minimum of 3 days of fly ash storage will be provided. Silo will be sized for the fuel with highest ash production rate.
Transportation:	Fly ash will be transported to the landfill via trucks.
Bottom Ash Disposal:	
Ash Disposal:	Bottom ash will be sold.
Ash Storage:	Bottom ash will be collected and stored in a silo sized for 3 days of bottom ash storage.
Ash Transportation:	Bottom ash will be extracted using a dry ash handling system and phenumatically conveyed to a silo. The bottom ash will then be trucked off for off-site sale.
Ammonia:	
Types:	Anhydrous Ammonia
Delivery:	Truck with self contained unloading pump
Storage:	15 day storage tank capacity
Construction Utilities:	
Water Supply:	Water supply for construction will be from the existing plant make-up water system (well water pumps).
Construction Power:	Power supply for construction will be from the existing plant via a power line and temporary transformer.
Equipment Delivery:	Major equipment will be delivered to the site via rail. Other equipment will be received via rail or truck, whichever is more economical.

Civil:	
Disposal of Spoils:	Spoils will be disposed of on site. No hazardous materials are anticipated to be found in the soils.
Soil Conditions / Stability:	Existing soils are assumed to be stable in and around the area of the new unit and suitable for use as laydown without any further preparation. Soils are assumed to be adequate for structural fill. No overexcavation and recompaction is included.
Subsurface Rock:	Removal of subsurface rock is not included.
Cut & Fill:	Site will be developed as a balanced site requiring minimal off-site fill and minimal disposal of spoils. Assumed minimal site slopes across the width and off-site fill will be available from within 10 miles of the site.
Dewatering:	Some dewatering of the main power plant structures is anticipated. This will be confirmed with preliminary geotechnical studies.
Construction Stormwater Control:	Silt fences will be required for construction erosion control. No other special erosion control is included.
Roads:	Existing main plant roads will be used. Minor roads and maintenance areas associated with the new unit will have an asphalt finish.
Parking:	Parking areas will be surfaced with asphalt concrete.
Rail Scale:	Existing weight measurement system will be used.
Coal Pile Run-off:	New coal storage areas will not be required. Coal pile run-off will be directed to the existing equalization basin.
Site Security:	Assume existing fencing and gates are adequate except where landfill expansion requires modification to existing fence and where fencing is required around new facilities such as the cooling tower.
Landscaping:	Minimal landscaping is included. Disturbed areas will be seeded for erosion control.
Structural:	
Soil Bearing Capacity:	Soils are assumed to be suitable for bearing capacities greater than 2500 psf. Therefore, spread footings and matt foundations are anticipated for all structures under this scope of work.
Piling:	No piling is anticipated.
Groundwater:	Some dewatering costs will be included.
Boiler Enclosure:	Boiler will not be enclosed.
Steam Turbine Enclosure:	Steam turbine will be enclosed. The steam turbine hall will interface with the existing steam trubine hall.
Administration Facilities:	No additional administration space will be required.
Control Facilities:	Existing control room will be utilized for new operator stations.
Warehouse/Storage Facilities:	An additional 100 ft. x 100 ft. warehouse will be included.
Water Treatment Building:	Additional building space will be included for water treatment equipment.
Maintenance Shop:	No additional maintenance shop area will be included.
Yard Maintenance Building	No additional yard maintenance facilities will be included.
Electrical Enclosures	Several buildings of various sizes located to reduce wiring runs.
Stack:	Stack to be provided with manlift for access.
Height	675' tall.
Velocity	A maximum of 60 feet per second.
Diameter	Exit diameter of 24'.
Liner Material	Clad C-276
Mechanical:	
Boiler:	Drum type, balanced draft, natural circulation, pulverized coal boiler with steam turbine throttle conditions of 2520 psig and 1050F and with reheat at 1050 F designed for 100% of VWO output on the steam turbine.
Steam Turbine Generator:	Nominally 600MW, 3,600 rpm, down-exhaust, reheat, tandem compound, four flow type designed to normally operate at maximum output (turbine or generator limited) at a 0.9 PF.
Feedwater Heaters:	Seven stages of feedwater heating.
Steam Turbine Bypass:	Not included as the unit is intended to be base loaded.
Auxiliary Boiler:	Will use an auxiliary steam system for new unit start-up.
Heat Rejection:	
Condenser:	Split waterbox, wet surface condenser with 316SS tubes.
Cooling Tower/Cooling Pond:	Utilize a concrete, natural draft cooling tower without fire protection.
Fans:	
FD Fans:	2x60% motor driven, constant speed, centrifugal, with inlet guide vanes.
ID Fans:	3x50% motor driven, constant speed, centrifugal with inlet guide vanes.
PA Fans:	2x60% motor driven, constant speed, centrifugal with inlet dampers
Air Heaters:	2x50%
Pumps:	
Boiler Feed Pumps:	2x60% steam turbine driven, constant speed, barrel pumps
Start-up boiler feed pump:	1x30% motor driven start-up pump.
Condensate Pumps:	3x50% constant speed motor driven pumps
Circulating Water Pumps	3x50% motor driven constant speed, standard construction

Water Treatment:	
Steam Cycle Make-up:	Additional 150 gpm of demineralizer capacity will be provided.
Cooling Tower Make-up:	Chemical feed for pH adjustment, corrosion/scale control, and blowdown treatment as required.
Cooling Tower Sidestream:	Not included.
Service Water Make-up:	Service water will be supplied from existing system.
Condensate Polishing	4x35% capacity deep bed polisher vessels with external regeneration.
Wastewater Treatment:	
Scrubber Purge Water	Brine concentrators (2) with spray dryer provided to treat scrubber purge water from Units 1 - 3. Solid waste hauled to the on-site landfill.
Compressed Air Supply:	3x50% capacity rotary screw air compressors with desiccant type air dryers
Fire Protection:	Fire protection system per NFPA. The fire water loop will be extended around the new unit. New diesel driven, motor driven, and motor driven jockey pumps will be included for the new unit.
Water Storage:	
Condensate Storage:	Additional 300,000 gallons of storage capacity is included.
Raw Water Storage:	Use existing well water and river water system. However, a new 15,000 gallon surge tank and pumps will be added to the well water system.
Demineralized Water Storage:	Combined with condensate storage.
Potable Water Storage	Potable water will be supplied from existing system.
Auxiliary Cooling:	
Type:	Closed Cooling Water System
Exchangers:	Plate & Frame with 316SS plates
Coal Handling:	
Unloading:	Existing rotary car dumper will be used.
Check Weighing:	Belt scale on existing conveyor will be used.
Stockpiling:	As recommended by Burns & McDonnell.
Dead Storage Reclaim:	Dozer w/ hoppers as this is not the normal fuel reclaim method. Only used in emergencysituations. Existing dozers will be used in conjunction with new trencher.
Live Storage Reclaim:	New trencher stacker / reclaimer and existing trencher stacker / reclaimer.
Reclaim redundancy:	Use existing and new trencher.
Crushers:	Use existing crushers.
Reclaim Sizing:	Fill 24 hour usable volume.
Pulverizers:	One redundant coal silo / pulverizer unit based upon design fuel blend. Worst case fuel may utilize the redundant unit without any further redundancy.
Limestone Handling	
Unloading:	Use existing truck unloading system.
Storage:	Short term and long term storage will be indoor/outdoor storage piles using existing mobile equipment with existing reclaim equipment. Storage will be expanded to maintain 45-60 days of limestone storage.
Delivery to Scrubber:	Reclaimed and delivered to 1x100% limestone bins (12 hour storage) via 1x100% limestone conveyor.
Preparation:	Crushed limestone will be prepared in existing 2x100% ball mills. One new limestone slurry storage tanks will be added for the new unit.
Fly Ash Handling	
Removal from ESP	Pressurized pneumatic conveying systems including 2x50% trains with 3x50% blowers to the ash silo. Conveying system will be sized to remove 24 hours of ash in an 8 hour shift.
Ash Load-out:	Ash truck loadout systems will be provided below the silo via gravity or pneumatic conveying. Ash loadout will include 2x100% ash conditioning systems (pug mills). Fly ash transport to the on-site landfill will be by truck. Alternate dry loadout capability via truck will be provided to support ash sales.
Bottom Ash Handling	
Removal from Boiler	Dry extraction bottom ash removal system.
Ash Load-out:	Trucked from Silo.
Scrubber Sludge Handling:	
Hydroclones	Radial hydroclone assembly with a minimum of 2 spare cyclones.
Vacuum Filter	Two 100% capacity belt filters sized for all 3 units.
Pug Mills	Not required
Ash Storage:	Included with fly ash handling.
Sludge Storage	Not included.
Sludge Disposal	Gypsum conveyed to wall board plant on site.
Scrubber	
Type:	Wet FGD - Forced Oxidized
Size:	1x100% module for the 600 MW unit.
Turndown capability:	5:1 as a minimum.
Redundancy:	A spare recycle pump or organic acid feed system shall be provided.
Accessories:	

ESP	
Redundancy	None
Type:	Ridgid frame
SCA:	(To be determined)
Activated Carbon Injection	An activated carbon injection system will be provided for mercury control.
Maximum Injection Rate	20 lbs/mmACF
Wet ESP	
Type	Vertical flow located above absorber module.
Number of fields	A minimum of 2 fields.
SCA:	(To be determined)
SCR	
Catalyst type	Honeycomb
Space Velocity	(To be determined)
SCR Bypass	There will be a SCR bypass for fuel oil starting.
Economizer Bypass	There will be an economizer bypass on the water side to maintain temperature at low loads.
Emissions Control:	
Emissions Control:	
NOx:	SCR guaranteed for 0.07 lb/MMBtu of exhaust NOx.
Ammonia Slip:	3 ppmvd @ 3% O2
CO:	Combustion controls to 0.15 lb/MMBtu.
SOx:	Wet scrubber to accomplish 0.18 lb/MMBtu. Equipment guaranteed for 98% removal of the inlet SO_2 concentration.
PM10:	Electrostatic precipitator to accomplish emissions of 0.015 lb/MMBtu (filterable only).
Mercury:	Carbon injection system to reduce mercury emissions to 6×10^{-6} lb/MW-hr (Approximately 0.6 lb/Tbtu heat input).
Sulfuric Acid Mist:	Wet ESP guaranteed for 0.005 lb/mmBtu.
General Notes - Not Scope Items	
Coal Handling:	Covered conveyors with dust collection at transfers and wet suppression at stockout.
Stack Height:	"Good Engineering Practice" - per US Code Title 42, Ch 85,Sub 1, Part A, Section 7423 - approx. 2.5 times the height of the tallest adjacent structure (boiler). Assumed 675 feet for estiamte.
Electrical	
Generator Step-up Transformer:	Three, single phase step-up transformers to provide ability to use the existing spare transformer. Transformers will be rated at OA/FA/FOA.
Black Start Capability:	Not Included.
Emergency Generator:	Included for essential power only.
Emergency Power:	2 hour DC system with a UPS for supply to the control system and critical instrumentation.
Start-up / Back-up Power:	Start-up of unit will be accomplished using 2X 50% three winding start up transformers.
Auxiliary Power Supply:	Two 50% three winding auxiliary transformers connected to the bus between the generator and the GSU. Transfer from start up power to unit auxiliary power after the bus is synchronized to the generator.
Plant Control System:	Distributed control system with remote located I/O panels.
Plant Communications:	
External and Office to Office	Tie into existing infrastructure.
Internal around plant	Gaitronics communication system throughout the plant.
Switchyard Communications	Not included.
Transmission / Interconnection:	
Switchyard:	Included.
Transmission:	Not included.
Interconnection to Existing Transmission:	Included.
Construction:	
General Liability Insurance:	Included
Builder's Risk Insurance:	Not Included
Performance Bonds:	Included
Performance/Stack Testing:	Included
Commissioning / Start-up:	Included
Operator Training:	Included
Permits:	Building permits and construction permits will be included. Air, NPDES, and other plant discharge permits will not be included.
Construction Schedule	It is assumed that the construction schedule will be adequate to allow the project to be completed with minimal overtime. Construction schedule will be estimated as a 5x8 with some overtime.

Miscellaneous:	
Permanent Plant Operating Spare Parts:	Allowance will be included.
Maintenance Tools & Equipment.	Allowance will be included.
Fuel, Lime, and Ash Transportation Equipment:	Allowances will be included to cover the cost of any permanent on-site mobile equipment purchased for fuel, ash, or limestone transportation.

Items Excluded from the Scope:
1. Legal Costs.
2. Costs for Owner's operations personnel (during construction and commissioning/start-up).
3. Fuel, limestone, and ash transportation equipment or rental costs for equipment required to transport such materials to or from the site. Allowances will be included for on-site equipment.
4. Land Costs.
5. Sound abatement above normal supply.
6. Aesthetic landscaping other than erosion control.
7. Emergency diesel generator (black start capability).
8. Waste water treatment or disposal other than discharge to a location on site.

5.1.2 Limitations, Qualifications and Estimate Risk Assessment

The estimates and projections prepared by Burns & McDonnell relating to construction costs and schedules are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by Burns & McDonnell.

Due to the capital intensive nature of solid fuel generation projects resources and length of construction period, there is capital cost risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact several US boiler manufacturers are currently under financial duress, and the skilled workforce that constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives, which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

5.1.3 Black Start Alternate Pricing

Although not included in the capital cost estimates being evaluated in the pro forma analyses, SECI requested a screening level cost for providing black start capability for the new unit. The cost associated with providing black start capability is estimated at $14,000,000. This price represents an installed cost for the black start emergency diesel generator sets including exhaust gas ducting and stacks, switchgear, transformers, radiator coolers, instrumentation, testing and commissioning.

The estimated load required by the diesel generator sets is approximately 20 MW. This auxiliary load estimate is based on starting a single primary air fan, forced draft fan, induced draft fan, circulating water pump, and condensate pump. In addition, the vacuum pumps, closed cooling water pump, auxiliary cooling water pump and various other smaller auxiliary systems were considered in the start-up power consumption estimate.

5.2 OPERATIONS & MAINTENANCE (O&M) COST ESTIMATES

A summary of the calculated variable and fixed O&M costs for the subcritical and supercritical solid fuel fired alternatives are included in Tables 5-3 and Table 5-4. These costs were estimated based on the assumptions discussed in this section.

Table 5-3: O&M Cost Estimate
Seminole Generating Station Unit 3
1 x 600 MW Subcritical

Operating Assumptions						
Basis Year for Cost Estimate						2004
Capacity Factor						85.0%
Load Factor						100.0%
Net Unit Output, kW						600,000
Number of Units						1
Net Output, kW						600,000
Net Annual Output, MWh						4,467,600
Net Steam Turbine Heat Rate						7,430
Net Plant Heat Rate, Btu/kWh						9,220
Fuel Consumption, MMBtu/hr						5,532
Annual Fuel Consumption, MMBtu						41,191,272
Boiler Technology						Pulverized Coal
Type of NOx Control						SCR
Type of SO2 Control						Wet
Type of Particulate Control						ESP
Type of H2SO4 Control						Wet ESP
Type of Mercury Control						Carbon Injection
Type of Heat Rejection						Cooling Tower
Cooling Tower Materials of Construction						Concrete
Make-up Water Softening Required						Yes
Zero Discharge Facility						Yes
Type of Sidestream Treatment						None
Fixed O&M						
Labor		46 people @	$ 70,448			***$ 3,240,610***
Office & Admin						***$ 75,000***
G&A (Home Office / Support)						**By Seminole**
Other Fixed O&M						***$ 1,350,000***
Employee Expenses/Training						
Contract Labor						
Environmental Expenses						
Safety Expenses						
Buildings, Grounds, and Painting						
Other Supplies & Expenses						
Communication						
Control Room/Lab Expenses						
Annual Steam Turbine Inspections						***$ 100,000***
Annual Boiler Inspections						***$ 80,000***
Annual APC Inspections						***$ 100,000***
Start-up power demand charge	$ -	per kW-Mo	15,000	KW		$ -
Water supply demand charge	$ -	per acre-ft	0	acre-ft		$ -
Water discharge demand charge	$ -	per acre-ft	0	acre-ft		$ -
Standby Power Energy Costs	$ -	per kW-hr	3,942,000	KW-hr		$ -
Standby Power Service Fee	$ -	per Month	12	Mo		$ -
Property Taxes						**In Proforma**
Insurance						**In Proforma**
Total Fixed O&M Annual Cost						***$ 4,945,610***
Major Maintenance Costs (Capitalized)						
Steam Turbine / Generator Overhaul	7446	Op Hours/yr	$ 50.00	$/hour		***$ 372,300***
Steam Generator Major Replacements (Boiler $10MM@10yrs & Burners @ 20 yrs & Walls)			968,052	$/yr		***$ 968,100***
Baghouse Bag Replacement	-	$/Replacement	5	years		$ -
SCR Catalyst Replacement	$3,153,759	Catalyst Cost	3	yrs life		***$ 1,051,300***
Water Treatment System Replacements			4,843	$/yr		***$ 4,800***
Total Annual Major Maintenance Costs						***$ 2,396,500***

Non-Fuel Variable O&M					
Water Consumption					
Raw Water	3455	MMGal/yr @	$0.00 /kGal	$	-
Raw Water Make-up Treatment	3455	MMGal/yr @	$0.14 /kGal	$	488,300
Potable Water	1	MMGal/yr @	$1.00 /kGal	$	1,500
Water Discharge	907	MMGal/yr @	$0.00 /kGal	$	-
Cooling Tower Treatment Chemicals	3181	MMGal/yr @	$0.05 /kGal	$	174,900
Demin Water Treatment	56	MMGal/yr @	$0.04 /kGal	$	2,500
Boiler Treatment Chemicals	2893	MMGal/yr @	$0.0158 /kGal	$	45,600
Maintenance & Consumables (lube oil, nitrogen, hydrogen, etc.)					
SCR System General Maintenance					
General Maintenance			$67,082 $/yr	$	67,100
Scrubber System General Maintenance					
Absorber, Dewatering & Accessories			$126,114 $/yr	$	126,100
Limestone Preparation			$367,064 $/yr	$	367,100
Water Treatment System General Maintenance			$63,878 $/yr	$	63,900
Cooling Tower System General Maintenance			$200,000 $/yr	$	200,000
Brine Concentrator and Spray Dryer System O&M			$2,349,000 $/yr	$	2,349,000
Other Variable O&M				$	5,383,800
Electronics, Controls, BOP Electrical					
Steam Generators					
BOP					
Misc. Maintenance Expenses					
Consumables					
Emissions Controls					
Lime Consumption	NA	tpy @	$107.89 /ton	$	-
Limestone Consumption	245,789	tpy @	$8.66 /ton	$	2,128,500
SCR Ammonia (Anhydrous)	1,601	tpy @	$250.00 /ton	$	400,300
Gypsum (Sales) / Disposal	423,509	tpy @	-$10.80 /ton		(4,573,900)
Ash (Sales) / Disposal (Wet Scrubber)	107,282	tpy @	$4.00 /ton		429,100
Ash (Sales) / Disposal (Dry Scrubber)	NA	tpy @	$4.00 /ton		-
Bottom Ash (Sales) / Disposal	26,820	tpy @	-$6.50 /ton		(174,300)
Carbon Injection	4,762	tpy @	$1,040.00 /ton		4,952,200
Total Non-Fuel Variable O&M Annual Cost				$	12,431,700
Total Fixed and Variable O&M Annual Cost				$	19,773,810
Total Fixed O&M Annual Cost, $/kW-yr					8.24
Total Emission Allowance Costs, $/yr				$	-
Total Major Maintenance (Capitalized Costs), $/MWh				$	0.54
Total Non-Fuel Variable O&M Annual Cost, $/MWh				$	2.78
Total O&M Cost, $/MWHr					4.43

Notes:

1. O&M costs do not include the following:
   - Taxes
   - Insurance
   - Firm fuel supply costs
   - Wheeling costs
   - Fuel
   - Backup or standby power
   - Initial spares, pre-op costs (computers, software, office equipment, etc.), or O&M mobilization fees
2. Assumes limestone / lime are 90% CaCO3 and limestone has 10% moisture.
3. Assumes SO2 removal of 98% for wet.
4. Assumes 0.2 lb/MMBtu of boiler NOx production and .04 lb/MMBtu NOx out of stack.
5. Assumes Ash and gypsum contains 5% moisture.
6. Carbon injection assumes control to meet proposed MACT.
7. SCR replacements assumes that catalyst is regenerated and not disposed of.
8. The above costs and heat rate information assume the unit is operating at 100% load.
9. Staffing costs assume non-union operator wage rates and assume 5% overtime.

Table 5-4: O&M Cost Estimate
Seminole Generating Station Unit 3
1 x 600 MW Supercritical

Operating Assumptions						
Basis Year for Cost Estimate						2004
Capacity Factor						85.0%
Load Factor						100.0%
Net Unit Output, kW						600,000
Number of Units						1
Net Output, kW						600,000
Net Annual Output, MWh						4,467,600
Net Steam Turbine Heat Rate						7,172
Net Plant Heat Rate, Btu/kWh						8,949
Fuel Consumption, MMBtu/hr						5,369
Annual Fuel Consumption, MMBtu						39,980,552
Boiler Technology						Pulverized Coal
Type of NOx Control						SCR
Type of SO2 Control						Wet
Type of Particulate Control						ESP
Type of H2SO4 Control						Wet ESP
Type of Mercury Control						Carbon Injection
Type of Heat Rejection						Cooling Tower
Cooling Tower Materials of Construction						Concrete
Make-up Water Softening Required						Yes
Zero Discharge Facility						Yes
Type of Sidestream Treatment						None
Fixed O&M						
Labor		46 people @	$ 70,448			***$ 3,240,610***
Office & Admin						***$ 75,000***
G&A (Home Office / Support)						**By Seminole**
Other Fixed O&M						***$ 1,350,000***
Employee Expenses/Training						
Contract Labor						
Environmental Expenses						
Safety Expenses						
Buildings, Grounds, and Painting						
Other Supplies & Expenses						
Communication						
Control Room/Lab Expenses						
Annual Steam Turbine Inspections						***$ 100,000***
Annual Boiler Inspections						***$ 80,000***
Annual APC Inspections						***$ 100,000***
Start-up power demand charge	$ -	per kW-Mo	15,000	KW		$ -
Water supply demand charge	$ -	per acre-ft	0	acre-ft		$ -
Water discharge demand charge	$ -	per acre-ft	0	acre-ft		$ -
Standby Power Energy Costs	$ -	per kW-hr	3,942,000	KW-hr		$ -
Standby Power Service Fee	$ -	per Month	12	Mo		$ -
Property Taxes						**In Proforma**
Insurance						**In Proforma**
Total Fixed O&M Annual Cost						***$ 4,945,610***
Major Maintenance Costs (Capitalized)						
Steam Turbine / Generator Overhaul	7446	Op Hours/yr	$ 50.00	$/hour		***$ 372,300***
Steam Generator Major Replacements (Boiler $10MM@10yrs & Burners @ 20 yrs & Walls)			968,052	$/yr		***$ 968,100***
Baghouse Bag Replacement	-	$/Replacement	5	years		$ -
SCR Catalyst Replacement	$3,153,759	Catalyst Cost	3	yrs life		***$ 1,051,300***
Water Treatment System Replacements			4,843	$/yr		***$ 4,800***
Total Annual Major Maintenance Costs						***$ 2,396,500***

Non-Fuel Variable O&M					
Water Consumption					
Raw Water	3455	MMGal/yr @	$0.00 /kGal	$	-
Raw Water Make-up Treatment	3455	MMGal/yr @	$0.14 /kGal	$	488,300
Potable Water	1	MMGal/yr @	$1.00 /kGal	$	1,500
Water Discharge	907	MMGal/yr @	$0.00 /kGal	$	-
Cooling Tower Treatment Chemicals	3181	MMGal/yr @	$0.05 /kGal	$	174,900
Demin Water Treatment	56	MMGal/yr @	$0.04 /kGal	$	2,500
Boiler Treatment Chemicals	2793	MMGal/yr @	$0.0158 /kGal	$	44,100
Maintenance & Consumables (lube oil, nitrogen, hydrogen, etc.)					
SCR System General Maintenance					
General Maintenance			$67,082 $/yr	$	67,100
Scrubber System General Maintenance					
Absorber, Dewatering & Accessories			$126,114 $/yr	$	126,100
Limestone Preparation			$367,064 $/yr	$	367,100
Water Treatment System General Maintenance			$63,878 $/yr	$	63,900
Cooling Tower System General Maintenance			$200,000 $/yr	$	200,000
Brine Concentrator and Spray Dryer System O&M			$2,349,000 $/yr	$	2,349,000
Other Variable O&M				$	5,383,800
Electronics, Controls, BOP Electrical					
Steam Generators					
BOP					
Misc. Maintenance Expenses					
Consumables					
Emissions Controls					
Lime Consumption	NA	tpy @	$107.89 /ton	$	-
Limestone Consumption	238,564	tpy @	$8.66 /ton	$	2,066,000
SCR Ammonia (Anhydrous)	1,601	tpy @	$250.00 /ton	$	400,300
Gypsum (Sales) / Disposal	411,062	tpy @	-$10.80 /ton		(4,439,500)
Ash (Sales) / Disposal (Wet Scrubber)	104,128	tpy @	$4.00 /ton		416,500
Ash (Sales) / Disposal (Dry Scrubber)	NA	tpy @	$4.00 /ton		-
Bottom Ash (Sales) / Disposal	26,031	tpy @	-$6.50 /ton		(169,200)
Carbon Injection	4,762	tpy @	$1,040.00 /ton		4,952,200
Total Non-Fuel Variable O&M Annual Cost				$	12,494,600
Total Fixed and Variable O&M Annual Cost				$	19,836,710
Total Fixed O&M Annual Cost, $/kW-yr					8.24
Total Emission Allowance Costs, $/yr				$	-
Total Major Maintenance (Capitalized Costs), $/MWh				$	0.54
Total Non-Fuel Variable O&M Annual Cost, $/MWh				$	2.80
Total O&M Cost, $/MWHr					4.44

Notes:

1. O&M costs do not include the following:
   - Taxes
   - Insurance
   - Firm fuel supply costs
   - Wheeling costs
   - Fuel
   - Backup or standby power
   - Initial spares, pre-op costs (computers, software, office equipment, etc.), or O&M mobilization fees
2. Assumes limestone / lime are 90% CaCO3 and limestone has 10% moisture.
3. Assumes SO2 removal of 98% for wet.
4. Assumes 0.2 lb/MMBtu of boiler NOx production and .04 lb/MMBtu NOx out of stack.
5. Assumes Ash and gypsum contains 5% moisture.
6. Carbon injection assumes control to meet proposed MACT.
7. SCR replacements assumes that catalyst is regenerated and not disposed of.
8. The above costs and heat rate information assume the unit is operating at 100% load.
9. Staffing costs assume non-union operator wage rates and assume 5% overtime.

5.2.1 Staffing

In addition to the existing operations staff, the Unit 3 operations staff will consist of two control room operators, two support system operators, and one roving operator on the day shift. During all other shifts, the tasks of the support system operators will be shared by the two control room operators. There will also be an additional fuel/ash operator on all shifts. The control room operators for each shift will be thoroughly trained in all aspects of plant controls and will be fully qualified to operate all plant systems.

Unit 3 will share operational staff with the existing units. The existing shift supervisor will direct shift operations, make assignments, and perform required administrative duties for the new unit. The shift supervisor will also serve as a second operator during emergencies and provide periodic relief for the primary control room operator. The existing plant staffing will be expanded by 46 employees to accommodate the new unit. By sharing staff, all units will benefit from added flexibility and will be able to operate with fewer on-site staff per unit. The additional staff required for the new unit was included as part of the fixed O&M cost and is summarized in Table 5-5.

Table 5-5: Additional Staffing Plan

Seminole Generating Station Unit 3: 600 MW Pulverized Coal, Brownfield

	Employees	Salary	OT %	OT	Bonus	Additions	Payroll Cost
Plant Manager	0	$ 100,000	5.00%	$7,500	$ 10,000	$ 36,125	$ 153,625
Administrative Assistant	1	$ 45,000	0.00%	$0	$ 4,500	$ 15,750	$ 65,250
Fuel/Ash Analysis Technician	0	$ 55,000	0.00%	$0	$ 5,500	$ 19,250	$ 79,750
Trainer	1	$ 60,000	0.00%	$0	$ 6,000	$ 21,000	$ 87,000
Technical Document Control Clerk	1	$ 40,000	0.00%	$0	$ 4,000	$ 14,000	$ 58,000
IS Analyst/Network Administrator	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Quality Assurance Specialist	0	$ 60,000	0.00%	$0	$ 6,000	$ 21,000	$ 87,000
Safety & Health Engineer	0	$ 60,000	0.00%	$0	$ 6,000	$ 21,000	$ 87,000
Plant Engineer	1	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Environmental Engineer	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Technical Services Manager	0	$ 85,000	0.00%	$0	$ 8,500	$ 29,750	$ 123,250
Maintenance/Technicians							
Maintenance Superintendent	0	$ 85,000	0.00%	$0	$ 8,500	$ 29,750	$ 123,250
Maintenance Planner	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
CMMS Specialist	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
I&C/E Supervisor	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Lead I&C/E Technician	1	$ 55,000	5.00%	$4,125	$ 5,500	$ 19,869	$ 84,494
I&C/E Technician (days)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
I&C/E Technician (shift)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
I&C/E Technician (Night)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
I&C/E Technician (Weekends)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
I&C/E Technician (Vacation)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Helper (days)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Helper (shift)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Helper (Night)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Mechanical Supervisor	0	$ 70,000	0.00%	$0	$ 7,000	$ 24,500	$ 101,500
Lead Mechanic	1	$ 55,000	5.00%	$4,125	$ 5,500	$ 19,869	$ 84,494
Mechanic (days)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Mechanic (shift)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Mechanic (nights)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Mechanic (Weekends)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Mechanic (Vacation)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Helper (days)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Helper (shift)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Helper (Night)	1	$ 30,000	10.00%	$4,500	$ 3,000	$ 11,175	$ 48,675
Operators							
Operations Superintendent	0	$ 85,000	0.00%	$0	$ 8,500	$ 29,750	$ 123,250
Senior Operations Specialist	0	$ 75,000	0.00%	$0	$ 7,500	$ 26,250	$ 108,750
Shift Supervisor	0	$ 60,000	5.00%	$4,500	$ 6,000	$ 21,675	$ 92,175
Control Room Operator (Day)	4	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Control Room Operator (Shift)	2	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Control Room Operator (Night)	2	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Control Room Operator (Weekends)	2	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Control Room Operator (Vacation)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Roving Operator (Day)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Roving Operator (Shift)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Roving Operator (Night)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Roving Operator (Weekends)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Limestone Operator (Days)	0	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Fuel Yard Lead Operator	0	$ 55,000	10.00%	$8,250	$ 5,500	$ 20,488	$ 89,238
Fuel Yard Operator (Days)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Fuel Yard Operator (Shift)	1	$ 45,000	10.00%	$6,750	$ 4,500	$ 16,763	$ 73,013
Fuel Yard Operator (Night)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Fuel Yard Operator (Weekends)	1	$ 47,250	10.00%	$7,088	$ 4,725	$ 17,601	$ 76,663
Ash Disposal Operator (Day)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Ash Disposal Operator (Shift)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Ash Disposal Operator (Night)	1	$ 42,000	10.00%	$6,300	$ 4,200	$ 15,645	$ 68,145
Ash Disposal Operator (Auxiliary)	1	$ 42,000	10.00%	$6,300	$ 4,200	$ 15,645	$ 68,145
Ash / Fuel Yard Operator (Vacation)	1	$ 40,000	10.00%	$6,000	$ 4,000	$ 14,900	$ 64,900
Water Treatment Tech/Chemist (Day)	0	$ 50,000	20.00%	$15,000	$ 5,000	$ 19,750	$ 89,750
Water Treatment Tech/Chemist (Shift)	0	$ 50,000	20.00%	$15,000	$ 5,000	$ 19,750	$ 89,750
Water Treatment Tech/Chemist (Night)	0	$ 52,500	20.00%	$15,750	$ 5,250	$ 20,738	$ 94,238
Water Treatment Tech/Chemist (Auxiliary)	0	$ 52,500	20.00%	$15,750	$ 5,250	$ 20,738	$ 94,238
Water Treatment Tech/Chemist (Vacation)	0	$ 48,000	10.00%	$7,200	$ 4,800	$ 17,880	$ 77,880

TOTAL UNIT 3 EMPLOYEES:	46.0	Additions:	35% Percentage of base hourly wage
			15% Percentage of overtime hourly wage
		Overtime Pay:	150% Multiple of base hourly wage
TOTAL PAYROLL:	$ 3,240,610	Bonus:	10% Percentage of base salary cost

5.2.2 O&M Cost Estimate Assumptions

The following costs were assumed in estimating the non-fuel variable O&M Costs:

- Ash Disposal, $4.00/ton
- Limestone, $8.66/ton
- Anhydrous Ammonia, $250/ton
- Activated Carbon, $1,040/ton
- Gypsum Sales, $10.80/ton
- Bottom Ash Sales, $6.50/ton
- Property taxes, insurance, and interest during construction are included in the proforma analysis.
- Costs associated with emission allowances are not included in the O&M cost estimates.

6.0 ECONOMIC ANALYSIS

6.1 OBJECTIVE

Pro forma financial analyses were prepared to compare the 600 MW net subcritical pulverized coal alternative to the supercritical pulverized coal and gas-fired combined cycle alternatives. The economic analyses were based on the estimated capital costs, performance, fuel costs, and operating costs for the alternatives. The two solid fuel-fired alternatives were benchmarked to a combined cycle alternative for economic comparison. The economic results are summarized in the following sections.

6.2 SOLID FUEL ASSUMPTIONS & COST ESTIMATES

The following estimates and economic assumptions were utilized in the pro forma financial analyses for the solid fuel-fired units.

- Capital Costs including Owner Costs and Contingency — Table 5-1

- Heat Rate and Performance Estimates — Table 4-1

- Delivered Solid Fuel Cost Assumption (see section 6.2.1):

Assumes 70%/30% coal/petcoke blend	2012: $2.06 ($/MMBtu)
	2013: $2.09 ($/MMBtu)
	2014: $2.17 ($/MMBtu)
	2%/yr Escalation after 2014

- Operating Assumptions:

Planned Dispatch	8,016 hours per year
	(one month planned outage)
Overall Capacity Factor	85.0%

- Financing Assumptions:

Interest Rate	6%
Term	30 years
Debt/Equity Percentage	100%/0%
Return on Equity	N/A

Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	45 months

- O&M Cost Assumptions:

Fixed O&M Costs	Tables 5-3 and 5-4
Insurance	0.16% of Replacement Cost per year
Property Taxes	2% of Net Book Value per year
Variable O&M Costs	Tables 5-3 and 5-4
Transmission Costs	Not Included – Busbar Cost Evaluation
Lime/Limestone Costs	Included in Variable O&M
Emissions Allowances	Not Included

- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Delivered Solid Fuel Inflation	2.0% per annum (after 2014)
Discount Rate	6%
Effective Tax Rate	0%
Book Depreciation (Straight Line)	30 years

6.2.1 Solid Fuel Supply Availability

Fuel supply for the existing units and proposed third unit consists of a 70%/30% blend of Illinois Basin (West Kentucky) coal and petcoke. Coal prices from the Illinois Basin (ILB) region and petcoke from refineries are impacted by many factors. The following sections provide information regarding historical solid fuel availability and pricing and future issues that may impact coal and petcoke pricing.

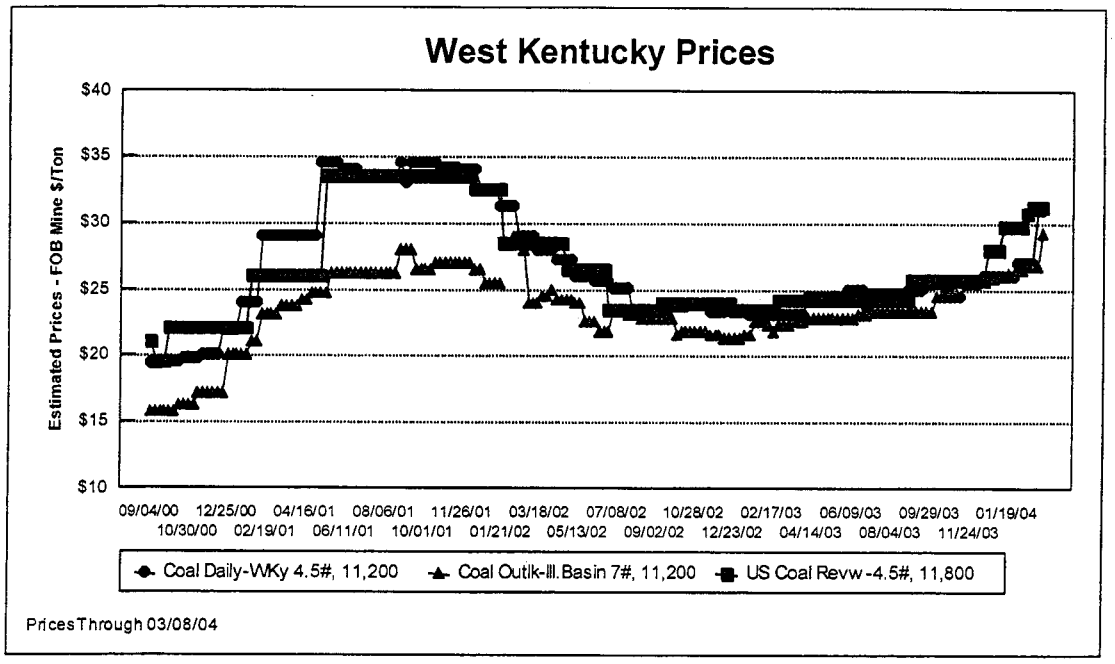
6.2.1.1 Illinois Basin Coal

The ILB coal region is comprised of bituminous coal production principally from mines in western Kentucky, Indiana, and Illinois. The coal is wide ranging in quality, generally ranging from 10,000 – 12,800 BTU, and from about 0.5 % - 5.0 % sulfur. The ILB is the fourth largest coal producing region in the U.S., accounting for about 89 million tons of coal production in 2003. The coal is shipped to markets within the U.S. by rail, or rail-to-water, with some local deliveries by truck. As with some of the other coal regions in the Eastern U.S., two major railroads, the NS and CSX, originate a great deal of the ILB shipments, but there are many regional (short-line) railroads that deliver these coals.

The high prices and strong demand during 2001 allowed Illinois Basin production to rebound from 93 million tons in 2000 to 95 million tons in 2001; however, the high prices of 2001 also allowed other regions to expand in coal production. A mild 2001/02 winter, a new generation of gas plants, and a poor economy drove coal demand down and stockpiles up, which resulted in a drop in Illinois Basin production to 92 million tons in 2002. Prices dropped accordingly. The Basin's production dropped further to 89 million tons in 2003; however, production is expected to increase to 93 million tons for 2004. Longwall problems at ExxonMobil's Monterey and Murray's Galatia mines caused most of this decline. These mines have now resumed normal production.

Prices for Illinois Basin coals have also been variable, depending upon prices from other coal supply regions, gas prices, etc., ranging from a low of $15.00 per ton in late 2000 to as high as $35.00 per ton in 2001. Current prices, again coming back up, are around $30.00 per ton, as shown in Figure 6-1. Since the beginning of 2004 prices for Illinois Basin coal have increased, reflecting the supply shortage situation in the Eastern U.S. and internationally. Every available ton of Illinois Basin low sulfur coal is now moving into various markets to satisfy the lack of supply and high demand.

Figure 6-1



Key issues and market drivers for ILB:

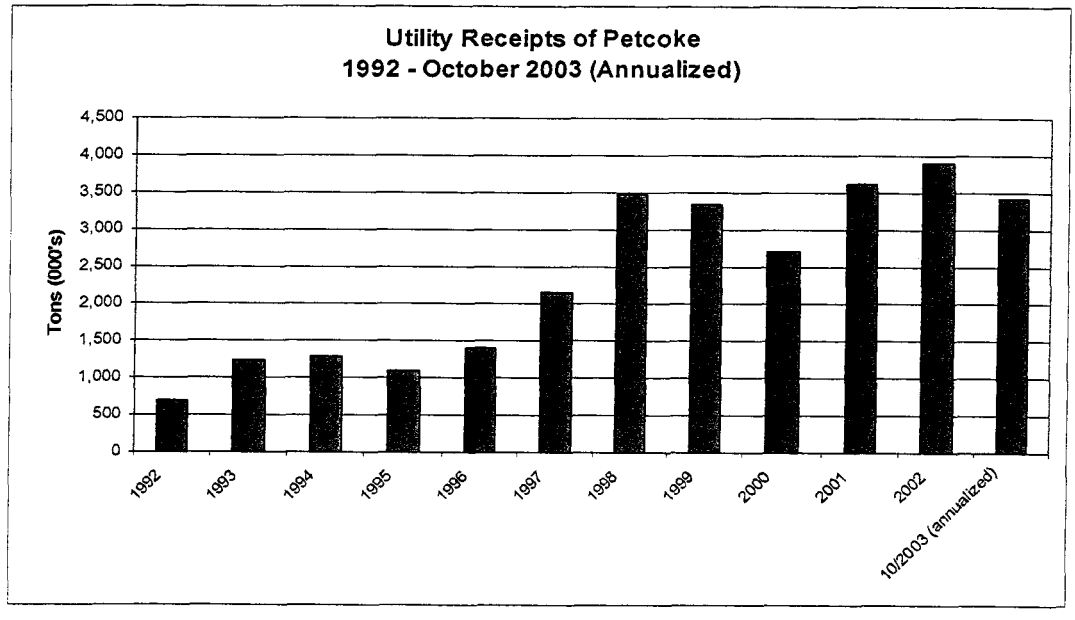
- Tremendous coal reserves exist and significant expansion is possible in the ILB
- The large mines are controlled by a few major producers (Peabody, Alliance, Freeman, Consol, etc.), but there are also a number of smaller mines in the region
- Most mines have either CSX or NS rail service, but not both
- Some mines have access to waterways, but at additional transportation cost to the docks
- Production has declined in recent years

6.2.1.2 Petroleum Coke

Petroleum coke has increasingly become an important swing fuel or fuel-blend candidate for a number of utilities in the U.S. Petcoke is a by-product of the oil refining process. There are various grades of petcoke production, with different sulfur, BTU and HGI contents. The fuel has a lot of value in the marketplace because it is a high BTU product (generally around 14,000 BTU), but its value is limited because it also contains very high sulfur content, ranging from 3% to 6%. Grindability is variable from

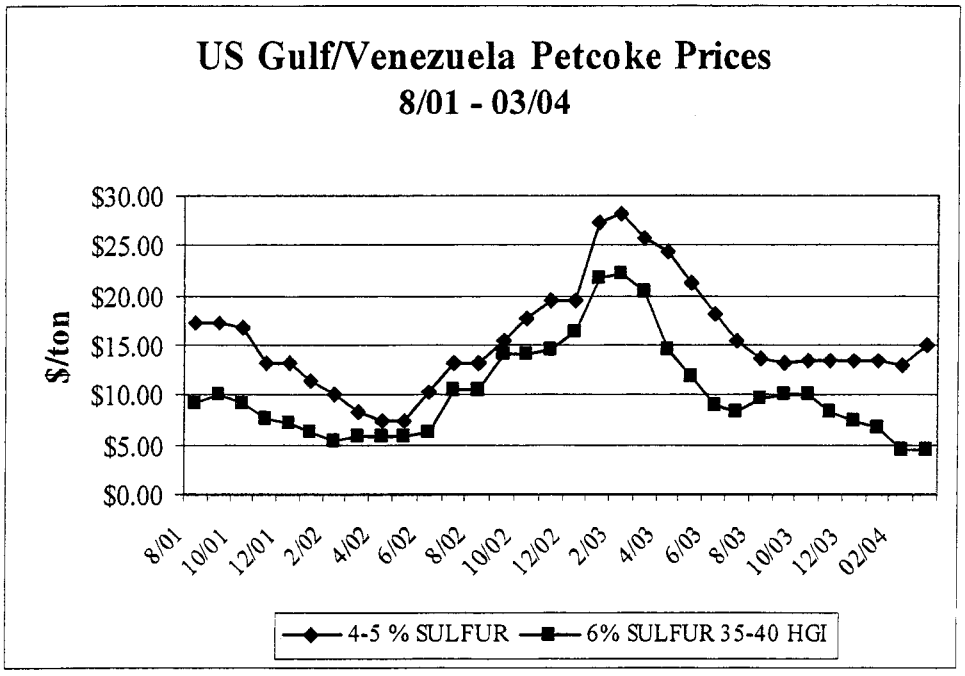
very soft to very hard (35 – 70 HGI is typical). Figure 6-2 shows the increasing deliveries of petcoke to utility plants since 1992.

Figure 6-2



The price of petcoke depends upon a number of factors and prices for other fuels, such as coal. Since petcoke is a waste-product of the oil refining process, it can literally be given away at any price and refiners will sell for low prices rather than paying storage and environmental cleanup charges. Therefore, refineries are generally inclined to dump the petcoke to keep it moving. Likewise, because of the negative impacts of burning this fuel, its upward price is capped by coal and gas prices. However, the price of petcoke generally tends to follow coal prices. Figure 6-3 shows the variation present in petcoke pricing over a 2 ½ year time period.

Figure 6-3



Prices for petcoke dropped from early 2003 as a result of higher ocean freight rates which triggered a drop in demand from consumers relying on spot ocean freight rates. Some consumers have or will switch to alternatives such as high sulfur U.S. coal.

Key issues and market drivers for petcoke:

- Principal supplies are available in the U.S. and Venezuela
- Availability is variable since production is dependent upon refineries' processing of crude oils; i.e. petcoke production is directly related to and dependent upon oil refining
- Prices are highly variable depending upon supply, demand and quality, typically ranging from $6.00 - $30.00 per ton; prices are normally closer to the low end of this range
- New production capacity is coming online in the U.S., Venezuela and the Caribbean region
- Transportation issues and costs may be significant depending upon the location of the refineries (e.g. Houston/US Gulf, Chicago, Venezuela, etc.)

6.3 COMBINED CYCLE BENCHMARK ASSUMPTIONS & COST ESTIMATES

The following estimates and economic assumptions were utilized in the gas-fired combined cycle pro forma economic analysis.

• Capital Costs including Owner Costs and Contingency	$369,600,000
• Heat Rate Performance Assumptions	6,775 Btu/kWh (HHV)
• Delivered Natural Gas Cost Assumption	2004: $5.50 ($/MMBtu) 2.5% Escalation after 2004
• Operating Assumptions:	
Planned Dispatch	8,016 hours per year
Overall Capacity Factor	85.0%
• Financing Assumptions:	
Interest Rate	6%
Term	30 years
Debt/Equity Percentage	100%/0%
Return on Equity	N/A
Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	24 months
• O&M Cost Assumptions:	
Fixed O&M Costs	$2,724,000
Insurance	0.16% of Replacement Cost per year
Property Taxes	2% of Net Book Value per year
Variable O&M Costs	$3.25 ($/MWh)
Transmission Costs	Not Included – Busbar Cost Evaluation
Emissions Allowances	Not Included

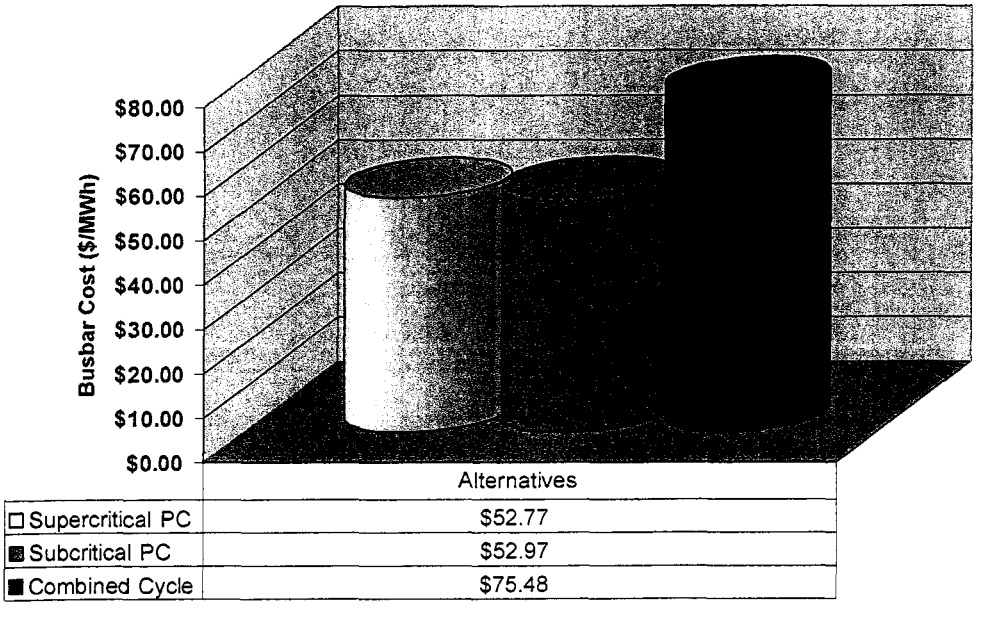
- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Delivered Natural Gas Fuel Inflation	2.5% per annum (after 2004)
Discount Rate	6%
Effective Tax Rate	0%
Book Depreciation (Straight Line)	30 years

6.4 ECONOMIC ANALYSIS RESULTS

The economic pro forma analyses were used to determine the 20-year levelized busbar cost of power for each alternative. Figure 6-4 presents a graph of the resulting 20-year levelized busbar power costs for the benchmark and both project alternatives. Figure 6-4 was developed by preparing a project pro forma for the benchmark and both alternatives under consideration. The busbar cost represents the energy cost in 2012$. The 20-year levelized busbar power costs for the supercritical PC unit, subcritical PC unit, and combined cycle benchmark unit are $52.77, $52.97, and $75.48 respectively.

Figure 6-4
20-Year Levelized Busbar Costs (2012$)



6.5 ECONOMIC CONCLUSIONS

Both the supercritical and subcritical PC units provide a low 20-year levelized busbar cost when compared to the gas-fired combined cycle plant. Combined cycle technology has a much higher fuel cost, but is much less capital cost intensive. For this reason, coal-fired technology is preferred to combined cycle technology for facilities with high capacity factors. Both of the coal-fired options are preferred to a combined cycle plant for baseload dispatch.

6.6 SENSITIVITY ANALYSIS RESULTS

Sensitivity analyses were prepared for the project alternatives under the following cases:

- Capital Cost (plus or minus 10%)
- Interest Rate (plus or minus one (1) percentage point)
- Capacity Factor (plus or minus 5%)
- Delivered Fuel Cost (plus or minus 10%)
- O&M Costs (plus or minus 10%)

The results of the sensitivity analyses are presented in tornado diagrams in Figures 6-5, 6-6, and 6-7. A tornado diagram illustrates the range of results for each sensitivity case and its impact on the levelized power cost, and ranks the results from greatest impact to least impact. The sensitivity analysis indicates that the interest rate, followed closely by fuel cost and capital cost, is the most significant factor affecting the economics of a solid fuel-fired unit. Since the pro forma analyses assume the project alternatives are to be financed with 100 percent debt, changes in the interest rate will have the greatest affect on the economics of the plant.

Figure 6-5

600 MW Pulverized Coal Supercritical Unit
Sensitivity Analysis - Tornado Diagram

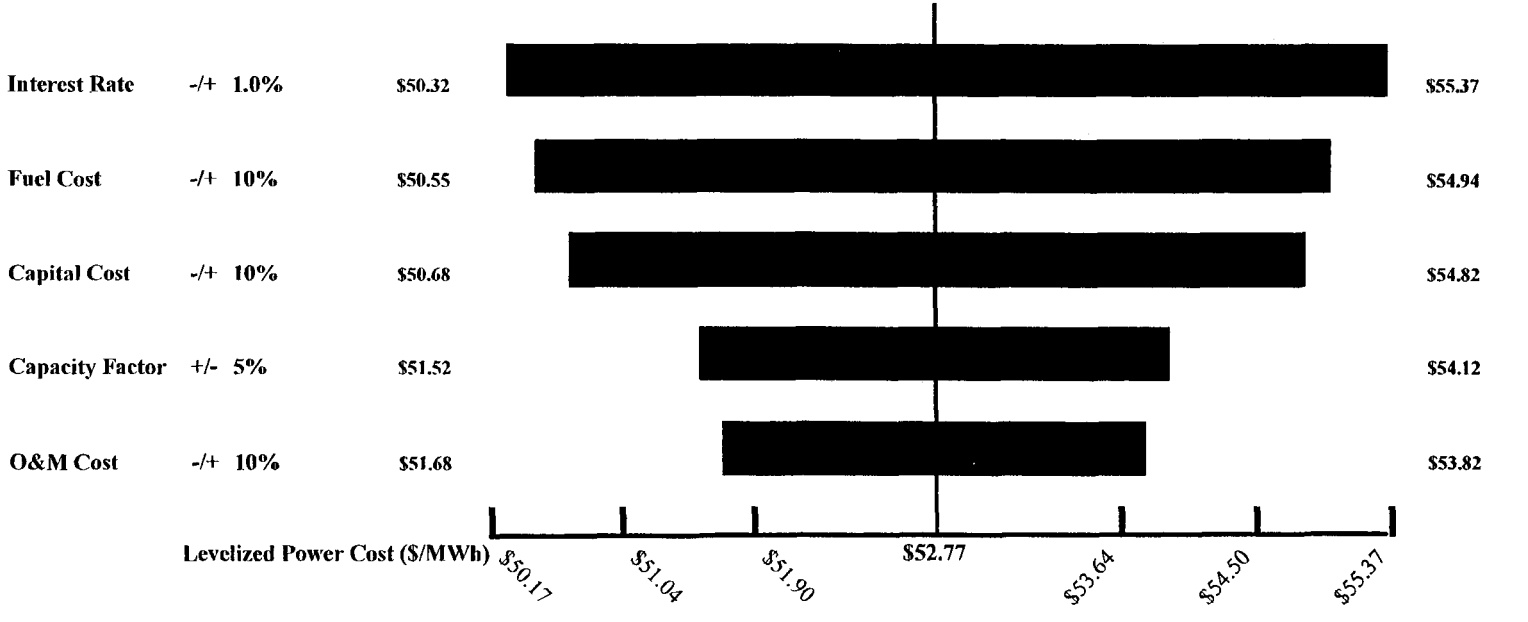


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Figure 6-6

600 MW Pulverized Coal Subcritical Unit
Sensitivity Analysis - Tornado Diagram

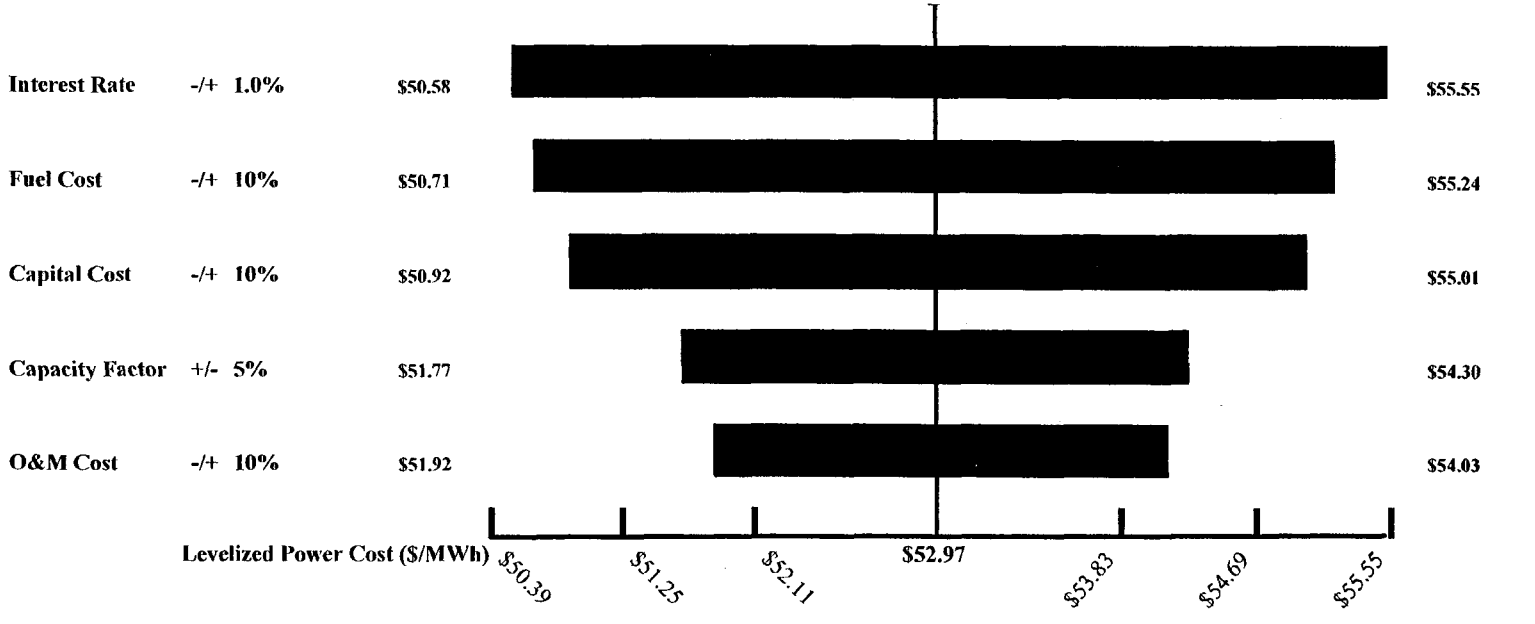


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Figure 6-7

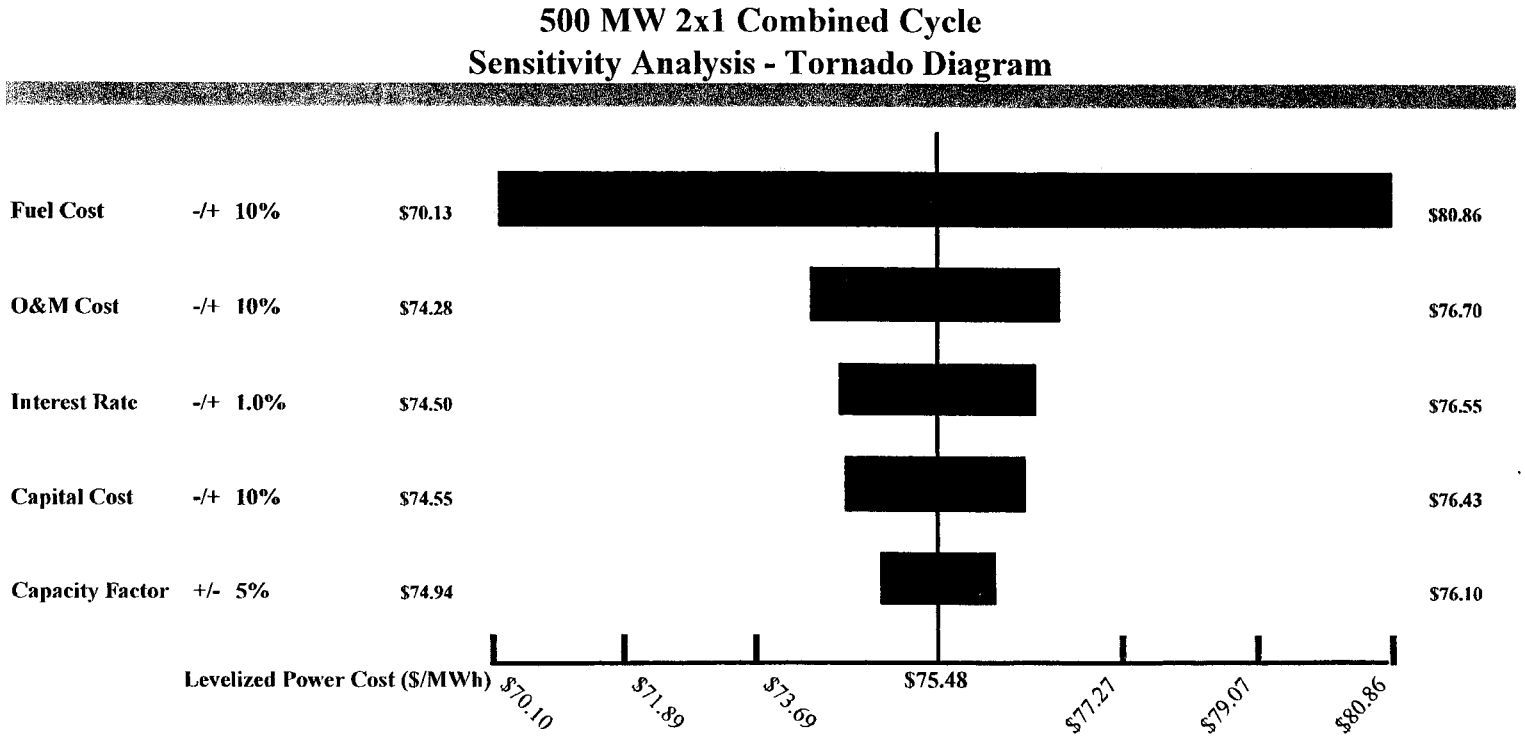


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7.0 CONCLUSIONS AND RECOMMENDATIONS

7.1 CONCLUSIONS

Both the supercritical and subcritical pulverized coal units provide a low 20-year levelized busbar cost when compared to the gas-fired combined cycle plant. Combined cycle technology has a much higher fuel cost, but is much less capital cost intensive. For this reason, solid fuel fired technology is preferred to combined cycle technology for facilities with high capacity factors. Both of the solid fuel fired alternatives are preferred to a combined cycle plant for baseload dispatch.

The supercritical unit has a slightly lower levelized bus bar cost of $52.77/MWh versus the subcritical unit bus bar cost of $52.97/MWh. Some of the considerations when selecting either a supercritical or subcritical steam cycle include:

- Operator familiarity with subcritical technology at the SGS plant.
- Lower emissions due to the higher efficiencies of the supercritical technology.
- Permitting may face fewer hurdles with a supercritical cycle versus a subcritical cycle.

The results of the cooling tower assessment indicate the mechanical draft cooling tower has a differential net present value of $11.7M lower than a natural draft cooling tower. However, the capital cost estimates include the cost of a natural draft cooling tower.

IGCC is a developing technology that has not performed reliably in commercial operation in the past. Therefore, it is recommended this technology not be considered for new generation at this time. There is planned development of gasification for coal in the near future, however it will be at least 4 -5 years before additional operational experience and information will be available on the cost and reliability of the technology.

7.2 FUTURE PLANNING CONSIDERATIONS

This study provides information for SECI to evaluate the alternatives identified in this study against SECI's request for proposals for additional capacity. Some additional steps for SECI consideration include the following:

- The schedule reflects the need for preliminary engineering to start in 2005 in order to support preparation of permits. The process of selecting an engineer should be started.
- If the potential for additional power off take participation exists, increasing the capacity of the new unit should be evaluated due to the economies of scale with larger units.
- It may be necessary to purchase additional property in order to support landfill requirements for the life of the unit.

7.3 STATEMENT OF LIMITATIONS

In preparation of this Feasibility Study, Burns & McDonnell has made certain assumptions regarding future market conditions for construction and operation of solid fuel generation resources. While we believe the use of these assumptions is reasonable for the purposes of this Study, Burns & McDonnell makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in this Study may vary.

8.0 ATTACHMENTS

8.1 ATTACHMENT DESCRIPTIONS

These attachments support the body of the document and provide additional technical detail where necessary. Section 8 includes the following attachments:

- Attachment A – Subcritical vs. Supercritical Assessment: This attachment includes a summary of an evaluation regarding subcritical and supercritical technology.

- Attachment B – Cooling Tower Assessment: This attachment is an evaluation of a natural draft cooling tower versus a mechanical draft tower for the new unit.

- Attachment C – IGCC Assessment: This attachment provides an assessment of the Integrated Gasification Combined Cycle technology.

- Attachment D – Water Analysis: Includes water analyses for the river water and the well water supply. This information was provided by SECI.

- Attachment E – Coal Analysis: Includes analyses of the bituminous coal and petcoke fuels being proposed for the SGS Unit 3 addition. This information was provided by SECI.

Attachment A – Subcritical vs Supercritical Assessment

ATTACHMENT A - SUBCRITICAL VS. SUPERCRITICAL ASSESSMENT

1.0 GENERAL

Rankine cycle steam power plants employ three main technologies for generation. These technologies are characterized by the steam cycle operating pressure: subcritical (<3200 psia) and supercritical (3200 psia to 5000 psia). The primary advantages of supercritical cycles are, improved plant efficiency due to elevated operating pressures, lower emissions, and lower fuel costs as compared to subcritical designs. However, supercritical technology requires more initial capital and has more operating complexities.

The vast majority of utility coal fired generating units in the United States utilize subcritical technology. The U.S. market includes supercritical boilers; however, most of the units were installed between 1950 and 1980. The poor maintenance history of early supercritical units combined with the lack of coal-fired unit additions hindered the development of supercritical technology within the U.S. after 1980. However, many countries beyond the U.S. continued to develop and install supercritical technology. Continued use outside the U.S. is a result of the high fuel costs overseas and has led to the development and installation of several ultra supercritical units. To date, the U.S. has no ultra supercritical units. As a result, ultra supercritical units remain an unproven technology in the U.S. Therefore, this report focuses only on the comparison of subcritical and supercritical units.

1.1 SUBCRITICAL

1.1.1 General Description of Subcritical Units

Subcritical power plants utilize pressures below the critical point of water (3206 psia) where there is a distinct difference in the state of the liquid when it is boiling. The majority of the steam generators built in the United States utilize subcritical technology with steam turbine throttle pressures up to about 2520 psig. Burning fuel in the furnace generates high pressure steam in the tubes of the boiler through convection and radiation energy transfer. This steam exits the tubes with excess water such that a two phase fluid exists. The steam separates from the water in a steam drum with internal separators and then is superheated utilizing superheater tubes.

Typical historical design steam conditions for subcritical units are 2400 psig and 1000°F at the steam turbine main steam inlet and 1000°F steam at the reheat steam inlet. Normally, these units were provided

with the capability to increase steam pressure to 2520 psig at the overpressure operating condition with the steam turbine inlet throttle valves wide open (VWO). Recent subcritical units, however, have main steam design conditions of 2520 psig at the steam turbine inlet with VWO to afford some of the efficiency improvements during normal operation that previously only overpressure operation could provide. In addition, improvements in steam cycle materials of construction have resulted in the ability to increase main steam and reheat steam temperatures to 1050°F, providing additional cycle efficiency improvements with minimal impact on project costs. The increase in main steam pressure and main steam and reheat steam temperatures results in a net heat rate improvement of approximately 2 percent over heat rates of plants operated at historical design steam conditions.

Another change to recent units is the elimination of the turbine control stage. Most of the newer units are proposed to be base-loaded with existing units or with gas turbine plants providing the load following. The benefit of an internal turbine control stage is higher operating efficiencies at reduced load. This benefit comes with a penalty to efficiency at base load. Since new base load units are not expected to operate at part-load for significant amount of time, the most economical configuration is with external throttle control valves in lieu of the internal control stage. This configuration results in a reduction in steam turbine costs and an improvement in base-load efficiency.

1.1.2 Operating Considerations

Start-up time for a subcritical pulverized coal boiler from a cold start (after a 36 hour shutdown) is a minimum of 5 hours. Historically, start-up time has been longer than the 5 hour minimum due to condensate water quality issues. Typical ramp rates are between 3-5 percent per minute for 50-100 percent loads and 3 percent for loads below 50 percent. Generally, the faster the ramp rate the larger the steam temperature control range. Thermal stresses in the steam drum limit the minimum start-up times and the maximum ramp rates.

1.1.3 Performance

Estimated annual average operational heat rates for a subcritical pulverized coal unit are between 9000 and 9600 Btu/kWh (HHV) at full load conditions. These performance estimates are based on a new and clean steam turbine operating with steam conditions of 2520psig/1050°F/1050°F and with the boiler burning a bituminous/petcoke mixture for fuel.

1.2 SUPERCRITICAL

1.2.1 General Description of Supercritical Units

Supercritical units typically operate at 3500 to 3700 psig with main steam and reheat steam temperatures of 1000°F or greater. Recent supercritical units under design in the U.S. utilize main steam temperatures between 1050°F and 1075°F and reheat steam temperatures between 1050°F and 1100°F.

Supercritical units are very similar to the subcritical units described earlier. The major difference is that the boiler operates in the supercritical region where water converts directly to steam without a two phase fluid existing. As a result of this, the supercritical boiler uses a once-through system which excludes a steam drum. Since there is no steam drum to allow the removal and blowdown of impurities in the system, all impurities carried by the steam go into the steam turbine. For this reason, the condensate system typically incorporates a full-flow condensate polisher to maintain high water quality.

Supercritical boiler designs use either spiral or vertical tube arrangements. Both designs attempt to minimize areas in the corners of the boiler where flow through the tubes is starved, which can result in elevated tube wall temperatures and premature failure. The spiral tube design has more than 30 years of experience. The primary disadvantages to the spiral tube arrangement are the complexity in supporting the tubes and the additional tube-to-tube buttwelds which results in increased construction costs. The spiral tube design also imparts additional friction drop in the system requiring larger boiler feedwater pumps. The vertical tube design (Benson technology) has less operating history, but is gaining interest due to the reduced pressure drop and simpler configuration. Siemens owns the Benson technology and licenses it to various boiler manufacturers.

1.2.2 Operating Considerations

In the past, most of the supercritical units built in the U.S. were designed for base-load operation; however, with construction of several base-load nuclear plants, many were required to load-follow. Cyclic operation of the early supercritical units caused excessive valve wear (boiler valves located within the evaporation or fluid transition zone), turbine thermal stresses and solid particle erosion (SPE) of the steam turbine blades. In addition to these issues, the complex starting sequence of supercritical boilers caused tubes to frequently overheat and fail. These problems resulted in lower availability and higher maintenance costs as compared to subcritical units.

Numerous supercritical units installed in Europe and Asia since the start of the 1980s allowed the technology to mature and resolved many problems with the earlier designs. The development of high strength materials at elevated temperatures helps to minimize the thermal stresses that caused problems in the early units. Variable pressure operation of all the circuits within the boiler eliminates the need for boiler valves in the fluid transition zone of the boiler. The development of distributed control systems (DCS) helps make the complex starting sequence much easier to control. The newer units also use a steam/water separator during startup to minimize solid particle carryover, which erodes the steam turbine blades. These changes corrected many of the early problems with supercritical units and availability of modern supercritical units now closely matches that of similar subcritical units. Only a minor maintenance increase is now required for supercritical units due to thicker tube and pipe walls.

Most operating experience in the U.S. is with the single reheat subcritical drum units. Seminole Electric Cooperative's existing units are subcritical. Therefore, installing a supercritical unit at that site would add a different technology with different operating aspects, adding complexity to the site. However, the additional complexity can be resolved through additional operator training.

The start-up time of a modern supercritical unit from a cold start (after a 36 hour shutdown) is 2 to 3 hours which is limited by thermal stresses in the boiler. Ramp rates are faster than a comparable subcritical unit at 5-7 percent per minute for 50-100 percent load and 5 percent per minute for loads under 50 percent.

1.2.3 Performance

Estimated annual average operational heat rates for a supercritical pulverized coal unit are between 8700 and 9400 Btu/kWh (HHV) at full load conditions. These performance estimates are based on a new and clean steam turbine operating with steam conditions of 3645 psig/1050°F/1050°F and with the boiler burning a bituminous/petcoke mixture for fuel.

1.3 ECONOMICS

The capital cost of a supercritical plant is approximately 1.5-percent more than an equivalent subcritical plant. Fixed operating costs for the supercritical unit are slightly higher than for a subcritical unit even though the plants require the same operating personnel because insurance costs are expected to increase with the supercritical units higher capital cost.

Non-fuel variable operating and maintenance cost is typically lower for a supercritical unit. Maintenance costs are essentially the same for either option, but the supercritical unit offers the advantage of reduced operating inputs (water, fuel, etc), emissions inputs (lime, limestone, ammonia, etc.), and waste (ash, scrubber sludge, and waste water) production due to the higher efficiencies. Further, with lower waste production rates the supercritical unit offers the benefit of reduced disposal costs. However, since SGS can sell the majority of their solid wastes, specifically bottom ash and gypsum, the subcritical unit provides the lower non-fuel variable operating and maintenance cost.

Available emissions control technologies are the same for either subcritical or supercritical units. As such, the emissions reduction capability for the two technologies is identical. However, since a supercritical unit is more efficient, it will consume less fuel. Therefore, it will generate less boiler emissions, and with the same emissions controls, will result in less emissions.

Attachment B – Cooling Tower Assessment

ATTACHMENT B - COOLING TOWER ASSESSMENT

1.0 GENERAL

Burns & McDonnell completed an economic evaluation of the differences between a mechanical draft cooling tower and a natural draft cooling tower to determine the impact of tower technology on the capital and operating costs for a 600 MW net subcritical unit at the Seminole Generating Station. To evaluate the cooling tower technologies, the net present value (NPV) was determined of the capital and operating cost differences over the life cycle of the plant and the levelized busbar cost difference between the cooling tower technologies. Further discussion of the assumptions, the estimates, and the results of the evaluation are provided below.

1.1 ASSUMPTIONS

The assumptions used in developing this cost comparison are detailed in the following sections.

1.1.1 Project Configuration

The project configuration was assumed to be as follows:

- Pulverized coal
- Bituminous/Pet Coke (70/30 Blend)
- 600 MW net plant output
- Subcritical steam conditions of 2520 psig/1050°F/1050°F
- Commercial operation date of 2012
- 100% load factor
- 85% unit capacity factor
- Steam turbine driven boiler feed pumps
- Wet limestone flue gas desulfurization (wet FGD) with forced oxidation for SO_2 control and to make gypsum
- Selective catalytic reduction for NO_x control
- Electrostatic precipitator (ESP) for particulate control
- Activated Carbon Injection for Hg control
- Wet ESP for Sulfuric Acid Mist Control
- Fly ash disposal in onsite landfill
- All gypsum and bottom ash produced is sold

1.1.2 Economic and Cost Factors

Annual economic and cost factors assumed for this evaluation are listed below.

- Evaluation term of 30 years.
- After tax discount rate of 6-percent.
- Interest during construction of 6-percent.
- Fuel Escalation of 2-percent.
- Chemical inputs (water treatment, emissions, etc) escalation of 2.5-percent.
- Material cost escalation of 2.5-percent.
- Labor cost for daily operations escalation of 2.5-percent.
- Average operator annual, all-inclusive labor cost of $75,000 ($2004).
- Property tax of 2-percent of net book value.
- Insurance rate of 0.16-percent of capital.
- Sales tax exempt.

1.1.3 Cooling Tower Design Basis

The design conditions for the two cooling towers are defined in Table 1.1.

Table 1.1 Cooling Tower Design Parameters

Parameter	Mechanical Draft Tower	Natural Draft Tower
Inlet Wet Bulb Temperature, °F	81 (note 1)	79
Range, °F	21	21
Approach, °F	11	13
Circulating Water Flow, GPM	300,000	300,000

Notes:
1. Inlet wet bulb temperature for mechanical draft cooling tower includes a 2°F recirculation allowance.

1.1.4 Plant Performance

The impact of cooling tower technology on steam turbine performance is considered minimal. However, the mechanical draft cooling tower auxiliary loads do require additional boiler and steam turbine output. A mechanical draft cooling tower designed to the parameters outlined in Table 1.1 would require 18 cells in back to back arrangement with 175 horsepower fans based on manufacturer's quotes. The resulting impact of the additional auxiliary loads is an increase in net plant heat rate of approximately 34 Btu/kWh for the mechanical draft cooling tower alternative.

1.2 CAPITAL COSTS

The differential capital cost estimate for the two cooling tower alternatives is based on vendor supplied cost data and a cost estimate for a similar sized subcritical unit from Burns & McDonnell's database as a basis. Cost adjustments reflect the differences in scope and operating requirements between the cooling tower alternatives. A summary of the capital cost comparison is included in Table 1.2.

Table 1.2 Capital Cost Comparison (2012$)

Item	Mechanical Draft Tower	Natural Draft Tower
Cooling Tower (F&E)	Base	$11,610,000
Balance of Plant	Base	($1,100,000)
Escalation	Base	$530,000
Contingency (10%)	Base	$1,050,000
Interest During Construction	Base	$1,500,000
Total Differential Cost	**Base**	**$13,590,000**

The cost difference between the alternatives is primarily in the cooling tower furnish and erection price. Other cost differences for balance of plant equipment in the table are due to the reduction in boiler heat input/steam flow with the natural draft cooling tower. The savings in auxiliary power by using a natural draft cooling tower results in less output required from the steam turbine and therefore less heat input to the boiler. Further, the natural draft cooling tower requires no fan wiring or motor control centers for additional savings.

1.3 OPERATING COSTS

As a result of the higher plant heat rate, the mechanical draft cooling tower alternative represents greater annual fuel consumption costs.

Fixed operating costs for the natural draft cooling tower are slightly higher than for a mechanical draft cooling tower even though the plants require the same operating personnel. Insurance costs are expected to increase with the natural draft tower due to its higher capital cost.

Non-fuel variable operating and maintenance however, is lower for the natural draft cooling tower. Maintenance costs are essentially the same for either alternative, but the natural draft cooling tower offers the advantage of reduced operating inputs (water, fuel, etc), emissions inputs (lime, limestone, ammonia, etc.), and waste production (ash, scrubber sludge, and waste water) due to the slightly higher efficiency. Further, the natural draft cooling tower offers the benefit of reduced ash and water disposal costs. Table 1.3 provides a summary of the operating inputs for the two cooling tower alternatives.

Table 1.3 Operating Cost Differentials (2012$)

Fuel Costs	Mechanical Draft Tower	Natural Draft Tower
Annual Fuel Consumption, MMBtu	Base	(150,000)
Annual Fuel Cost	Base	($260,000)
Differential Annual Fuel Cost:	**Base**	**($260,000)**
Differential Annual Fuel Costs, $/MWh	**Base**	**<$0.01**
Fixed Operating Costs		
Differential Annual Operator Cost	Base	$0
Differential Annual Maintenance Costs		
Fill Replacement	Base	$0
Fan & Motor Repairs	Base	($40,000)
Relative Property Tax Cost	Base	$166,000
Relative Insurance Cost	Base	$22,000
Differential Annual Fixed Operating Costs:	**Base**	**$148,000**
Differential Fixed Operating Costs, $/kW-yr:	**Base**	**<$0.01**
Variable Operating Costs		
Limestone Consumption	Base	($8,000)
Ammonia Consumption	Base	($1,000)
Activated Carbon	Base	($6,000)
Ash Disposal	Base	($3,000)
Gypsum Sales	Base	$13,000
Bottom Ash Waste Disposal	Base	$1,000
Water Consumption	Base	$0
Differential Annual Variable Operating Cost:	**Base**	**($4,000)**
Differential Variable Operating Cost, $/MWh:	**Base**	**($0.001)**

This feasibility study details the costs for fuel, limestone, ammonia, activated carbon, ash disposal, gypsum sales, bottom ash waste disposal, and water consumption used to determine total costs in Table 1.3. The feasibility study also contains the insurance rates and property tax rates. Both insurance and property tax costs use the capital cost difference between the alternatives as a basis. SECI provided the

annual maintenance costs for the natural draft cooling tower. For this analysis, fill requirements including maintenance and replacement are essentially equal for the tower alternatives. However, the mechanical draft tower does require additional maintenance due to fan and motor repair and replacement.

1.4 EVALUATION RESULTS

The net present value of capital and operating costs for the mechanical draft cooling tower is $11.7 million less than the natural draft cooling tower. The busbar cost comparison shows that the mechanical draft cooling tower has a $0.19 per megawatt hour lower levelized electrical production cost. The electrical production cost includes fuel costs, operating and maintenance costs and initial capital investment cost for each of the alternatives. In summary, the fuel and operations savings associated with the natural draft cooling tower do not provide enough benefit to justify the much greater initial capital cost of the natural draft cooling tower.

Attachment C – Integrated Gasification Combined Cycle Assessment

ATTACHMENT C - INTEGRATED GASIFICATION COMBINED CYCLE

1.0 GENERAL DESCRIPTION

Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value syngas from coal or solid waste, to be fired in a conventional combined cycle plant. The gasification process in itself is a proven technology utilized extensively for production of chemical products such as ammonia for use in fertilizer. Utilizing coal as a solid feedstock in a gasifier is currently under development for projects jointly funded by the Department of Energy (DOE) at several power plant facilities throughout the United States. The gasification process represents a link between solid fossil fuels such as coal and existing gas turbine technology. The IGCC process is shown in Figure 1 below.

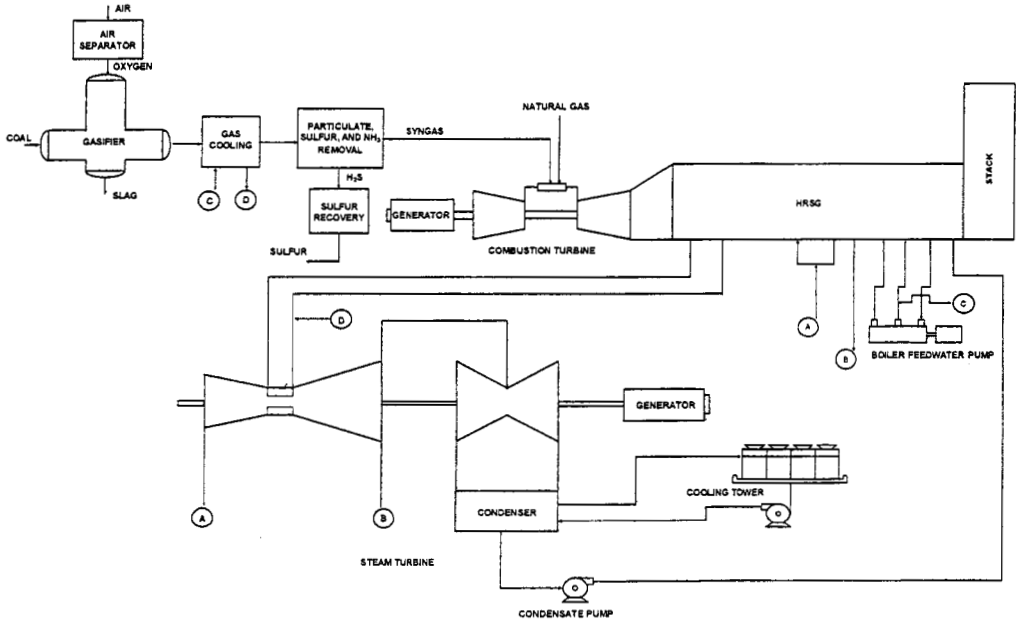


Figure 1 – IGCC Process Diagram

A 600 MW net IGCC plant would typically be composed of two coal gasifiers, a coal handling system, an air separation unit, a gas conditioning system to remove sulfur and particulate, two gas turbines, two heat recovery steam generators with supplemental duct firing and a single steam turbine. Cooling water for the steam turbine would be based on a wet cooling tower.

Integrating proven gasifier technology with proven gas turbine combined cycle technology is a recent development, and continues to be improved at the existing DOE jointly funded power plants.

Gasifiers designed to accept coal as a solid fuel generally fall into three categories: entrained flow, fluidized bed, and moving bed.

Entrained Flow

The entrained flow gasifier reactor design converts coal into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. Chevron Texaco, Conoco Phillips (E-Gas), Prenflo, and Shell produce this gasifier design. General Electric (GE) and Chevron Texaco have recently announced plans for GE to acquire Chevron Texaco's gasification business.

Fluidized Bed

Fluidized-bed reactors are highly back-mixed and efficiently mix feed coal particles with coal particles already undergoing gasification. Fluidized bed gasifiers accept a wide range of solid fuels, but are not suitable for liquid fuels. The KRW and High Temperature Winkler designs use this technology.

Moving Bed

In moving-bed reactors, large particles of coal move slowly down through the bed while reacting with gases moving up through the bed. Moving-bed gasifiers are not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design and has been utilized both at the Dakota Gasification plant for production of SNG and the South Africa Sasol plant for production of liquid fuels. BGL is another manufacturer of the moving bed design.

The majority of the DOE test facilities utilize the entrained flow gasification design with coal as feedstock. Pulverized coal is fed in conjunction with water and oxygen from an air separation unit (ASU) into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exits at around 2400 °F and is cooled to less than 400 °F in a gas cooler, which produces additional steam for both the steam turbine and gasification process. Scrubbers then remove particulate, ammonia (NH_3), hydrogen chloride and sulfur from the raw syngas stream. The cooled syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to

accept the low calorific syngas. Exhaust heat from the gas turbine then generates steam in a heat recovery steam generator (HRSG) to power a steam turbine. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged the existing IGCC installations. The syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system typical to those utilized in chemical production gasifiers.

1.1 CURRENT STATUS

The following table identifies the DOE jointly funded test facilities constructed in the United States, with various gasification system designs.

Table 1.1 Department of Energy IGCC Test Facilities

Facility	Owner	Capacity (MW)	Commercial Operation Date	Gasifier Manufacturer	Status
Polk County	Tampa Electric	252	1996	Chevron Texaco	Operating
Wabash River	PSI Energy	262	1995	Conoco Phillips	Operating
Pinon Pine	Sierra Pacific	99	1997	KRW	Decommissioned
LGTI	Dow Chemical	160	1987	Conoco Phillips	Decommissioned
Cool Water	Texaco	125	1984	Chevron Texaco	Decommissioned

There are several IGCC projects currently in the development phase, including the 540 MW power station for Global Energy, Inc. located in Lima, OH, and Excelsior Energy's 530 MW Mesaba Energy Project located in Minnesota.

1.2 PLANT CHARACTERISTICS

1.2.1 Performance

Cold start-up times for IGCC plants have typically ranged from 40-50 hours compared to a conventional PC boiler start-up time of 4-6 hours. Hot restart procedures are in testing at several of these facilities, and Eastman Kodak has developed a proprietary process that allows a fairly rapid startup, but the startup process requires flaring the syngas produced until it is adequate quality for introduction into the gas turbine. The gasification plant requires stable operation in order to maintain syngas quality and the technology to support load following continues to be developed.

Operational heat rates for DOE test facilities range from 7,800 Btu/kWh (43.7% efficiency) for Pinion Pine to 8,910 Btu/kWh (38.3% efficiency) for Wabash River. It should be noted that the Pinion Pine project did not achieve long term continued commercial operation. The Polk County facility operated at around 8,500 Btu/kWh (40.2% efficiency), but modifications to improve gas clean-up reliability reduced efficiency and increased heat rate for the plant to approximately 9,350 Btu/kWh (36.5% efficiency).

The anticipated performance for a 600 MW (net) IGCC is highly contingent upon the level of integration of the gasification process and combined cycle, the gasifier design, and the selection of the supporting systems and equipment. Estimates have ranged from 8,600 Btu/kWh to over 9,500 Btu/kWh. This estimated performance is based on new and clean equipment. Degradation is not included.

Significant design issues have prevented coal gasification units from achieving acceptable availability levels. These design issues include fouling within the syngas cooler, design of the pressurized coal feeding system, molten slag removal from the pressurized gasifier, durability of gas clean-up equipment and solid particulate carryover resulting in erosion within the gas turbine. The complexity of the combined cycle unit in conjunction with the reliability of numerous systems, including the gasifier, O_2 generator, air separation unit and multiple scrubbers have contributed to reduced plant availability.

Unit availability at the DOE jointly funded plants has been improving due to design modifications intended to improve equipment life and reliability. Polk County was able to achieve 83% availability for 2003 and Wabash River achieved 83.7% availability for 2003. All of these coal gasification plants have experienced down-time for design modifications and replacement of equipment. Polk County and Wabash River are the only two coal IGCC plants in the United States that have achieved extended periods of commercial operation. The current generation of IGCC plants should be capable of operation with an availability of around 85 percent compared to around 90 percent for conventional steam electric plants.

1.2.2 Emissions Controls

Sulfur capture for coal gasifiers at the DOE funded power plants ranged from >95% (Polk County) to >99% (Wabash River). NO_x emissions are controlled through nitrogen injection into the gas turbine at Polk County to 0.10 lb/MMBtu (25 ppm) and through steam injection into the gas turbine at Wabash River to 0.10 lb/MMBtu (25 ppm). However, Wabash did not go through Prevention of Significant Deterioration (PSD) permitting for NO_x. Polk County was required to reopen their NO_x Best Available Control Technology (BACT) analysis 18 months after startup of the facility. As a result, Polk County is currently required to meet 15 ppm NO_x.

The raw syngas produced by the IGCC process is cleaned to remove particulate, ammonia (NH_3), sulfur and nitrogen prior to being fired in the gas turbine. Acid gas cleanup processes are very effective and have been proven by the oil and gas industries for many years with over 99.8% sulfur recovery. Removal of pollutants from the syngas stream results in lower emissions than from a conventional plant utilizing the same fuels.

Mercury can be controlled in the IGCC process as well. The gasification industry has shown excellent mercury removal capability (greater than 99%).

1.2.3 Waste Disposal

The syngas sulfur removal process can result in 99.9 percent pure sulfur, which is a saleable by-product. The gasifier converts coal ash to a low-carbon vitreous slag and fly ash. The slag has beneficial use and can be utilized as grit for abrasives, roofing materials, or as an aggregate in construction. Fly ash entrained in the syngas is recovered in the particulate removal system and is either recycled to the gasifier or combined with other solids in the water treatment system and shipped off site for reuse or to be landfilled.

1.2.4 Water Requirements

An IGCC plant uses approximately one third the cooling water for condensing steam compared to a conventional steam electric plant. However, a large cooling water supply is required for coal gasification and for the air separation unit used to produce pure oxygen and when combined with the steam condensing requirements, the amount of water is comparable to a conventional steam electric plant.

1.2.5 Project Schedule

The permitting process for a greenfield 600 MW net IGCC takes approximately 18 months. The design and construction duration is approximately 48 months. In most cases, the permitting phase and design/construction phase will partially overlap to decrease the overall implementation period; however this schedule does expose the Owner to some risk if the permit is not approved. Total implementation time for a 600 MW net IGCC including permitting, design, and construction is approximately 52 – 64 months.

1.2.6 Capital Cost Estimates

Initial capital construction cost (in 1995 dollars) for the existing coal gasification plants ranged from $1,213/kW for Polk County to $1,590/kW for Wabash River.

The DOE estimates coal-based IGCC plants in the range of $1,200-1,600/kW (2004$). These estimates vary considerably based on the amount of equipment and system redundancy included in order to achieve a desired availability, based on the level of integration required to achieve a desired efficiency, and the equipment or systems required to achieve specific emissions limits. The DOE is currently contracting for studies to evaluate cost, performance, and emissions optimizations of the next generation of IGCC facilities.

1.2.7 Operations and Maintenance

Note that there has not been a long operating history for IGCC units. Scheduled maintenance consists of an outage of approximately 3 weeks/year and 4-5 weeks every five years.

1.2.8 Long Term Development

Much of future technology development will be supported through government funding support of Clean Coal Technology within the power industry. A few large scale (550 MW and greater) IGCC power plants are currently in the preliminary project development and/or permitting stage in the United States, however, commercial operation of these plants is at least 4 to 5 years in the future.

1.3 IGCC AT SEMINOLE GENERATING STATION

A greenfield 600 MW net IGCC plant requires approximately 120 acres which includes areas for coal handling, construction laydown and parking. The Seminole Generating Station site has existing coal handling infrastructure to support an IGCC plant. The space required for the IGCC power block is

approximately 45 acres. The existing site is capable of accommodating an IGCC plant however, some of the remaining permitted landfill area to the east of the existing units may have to be utilized which would reduce the life of that landfill.

The slag from an IGCC plant could be sold similar to the bottom ash from the existing units. In addition, the sulfur byproduct could also be sold if a market exits. Therefore, the potential landfill requirements would be less than a conventional steam electric plant.

The availability and reliability of the current IGCC plants is improving but is not comparable with conventional steam electric plants. The penalty for higher availability is with more redundancy and therefore higher capital costs.

Much of future IGCC technology development will be supported through government funding of clean coal technology in the power industry. Operational flexibility for rapid start-up and load following remains to be demonstrated and may be required for an IGCC plant to compete effectively within the current U.S. power market.

Acceptance of coal within the power industry and the relative price of natural gas will also influence the future development and commercialization of IGCC in the United States. The technical barriers to commercialization still remain to be addressed through future generations of government jointly funded coal IGCC facilities. Once the development effort has been successfully completed, coal fueled IGCC technology has the potential to be a reliable clean-coal generation technology.

Attachment D – Water Analysis

Surface Water Intake D-005

Date	O&G (mg/l)	Turbidity (mg/l)	Ammonia (mg/l)	Un NH4 (mg/l)	TKN (mg/l)	NO2/NO3 (mg/l)	Cu (ug/l)	Cyanide (ug/l)	Fe (mg/l)	Hg (ug/l)	Se (ug/l)	Zn (ug/l)	Cond (umho)	Ag (ug/l)	Chlorides	Sulfate	Flouride	Bromide	Magnesium	Calcium	Sodium	Potassium	Boron
1/1/00																							
2/1/00	<5	5.8																					
3/1/00	<5	7.3	<0.02	<0.02	0.86	<0.5	<10	<5	0.25	<0.5	<10	170	846										
4/1/00	<5.0	11																					
5/1/00	<5.0	6.8																					
6/1/00	<5.0	3.1	<0.02	<0.02	1.5	<0.5	<10	<5	0.1	<0.5	<10	<10	921										
7/1/00	<5	4.9																					
8/1/00	<5.0	4.4																					
9/1/00	<5	4.1	<0.0079	<0.0079	0.63	<0.032	<1.4	6.2	0.061	<0.04	<2	14	1042										
10/1/00	<0.89	5.3																					
11/1/00	1	5.7																					
12/1/00	0.7	5.9	0.021	<0.02	1.9	<0.50	<6.0	<5.0	0.097	<0.2	<2.0	17	1384										
1/1/01	1	20																					
2/1/01	0.7	7.3																					
3/1/01	1.5	13	0.11	0.0031	1	0.185	<0.9	<5	0.17	<0.072	4.9	3.9	1282	<1.9									
4/1/01	1	8.6																					
5/1/01	1.2	8.9																					
6/1/01	1.2	6.4	<0.030	<0.012	1.3	<0.050	<0.90	<10	0.13	<0.072	<4.2	<5.9	1500		330	110	<0.20	1	24	64	150	6.6	0.4
7/1/01	2.1	5.7	0.088	0.02	93	<0.050	<0.90	<10	0.11	<0.072	<4.2	<5.9		<0.050	300	110	0.17	1.1	25	34	150	6	0.32
8/1/01	6.4	8.5																					
9/1/01	3	5.5																					
10/1/01	3.7	3.7																					
11/1/01	<0.55	3.9																					
12/1/01	3.9	3.6	0.1	0.002	1.5	0.28	<0.9	<10.0	0.49	<0.072	<4.2	<30	661										
1/1/02	3.2	5.6																					
2/13/02			0.14																				
2/1/02	0.8	4.3													170	74	<0.2		14	42	96	5.9	0.22
3/1/02	1.7	8.9	0.11	<0.020	1.4	0.41	1.8	<5.0	0.52	<0.072	<3.3	<5.9	950	<1.9									
4/1/02	0.73	8.5																					
5/1/02	1.1	9.4																					
6/1/02	<0.55	7	0.075	<0.03	1.2	0.15	<0.9	<4	0.096	0.076	<3.3	14	1269	<0.17									
7/1/02	4.6	5.4																					
7/29/02			0.04	<0.002	1.3	<0.05	1.9	<8	0.21	<0.072	<4.2	<5.9	999										
8/1/02	2.5	3.9																					
9/1/02	4	3.5																					
10/1/02	0.55	2.3																					
2-Oct	0.55	2.3	<0.05																				
10/22/02			0.086	0.0012	0.91	0.19	3	<4	0.38	0.087	<4.2	<5.9		<0.17									
10/29/02			<0.05																				
11/1/02	0.55	4.4																					
12/1/02	0.55	6.2																					
1/28/03	<2.7	4.8	0.043	0.0006	2.1	0.01	0.9	4	0.35	<0.072	<4.2	<5.9	740										
3-Feb		8.9																					
3-Mar	<2.7	6.7																					
3-Apr	0.73	8.2																					
3-May	0.73	4																					
5/13/03			0.21	<0.01	0.9	0.048	2.8	<4	0.37	<0.072	<4.2	<5.9	727										
3-Jun	0.73	6.3																					
7/1/03	0.73	12																					
8/26/03			0.13	<0.01	1.3	0.017	1.7	<4	0.34	<0.072	<4.2	<5.9	712										
3-Aug	0.73	7.9																					
9/1/03																							
10/1/03																							
11/1/03	0.73	4.2																					
3-Dec	0.73	5.3																					

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Attachment D - River Water Analysis

Rev A

North Production Well

	Calcium (mg/l)	Sodium (mg/l)	Magnesium (mg/l)	Hardness (mg/l)	Silica (mg/l)	Alkalinity (mg/l)	Chloride (mg/l)	Sulfate (mg/l)	Ortho phosphate (mg/l)
North Well	43	27	19	190	14	100	69	39	<0.05
Clear Well	40	34	7.5	130	6.3	32	97	48	<0.05

Palatka Groundwater Quality - Production Wells

	North Well	South Well	North Well	After pre-treatment
Chlorides (mg/l)	67.4	173	69	97
Sulfate (mg/l)	36.9	85	39	48
Hardness (mg/l)	194	273	190	130
Fluoride (mg/l)	0.2	0.21		
Silica (mg/l)	13.76	14.64	14	6.3
COD (mg/l)	<5.0	15.6		
Alkalinity CACO3 (mg/l)	<5.0	<5.1		
Alkalinity Bicarbonate (mg/l)	126	114		
Alkalinity total (mg/l)	126	114		
Alkalinity hydroxide (mg/l)	<5.0	<5.1		
Nitrogen (mg/l)	<0.01	<0.010		
Calcium (mg/l)	42.7	59.9	43	40
Iron (mg/l)	<45	77.1		
Manganese (mg/l)	<5	<5		
Potassium (mg/l)	1.71	2.37		
Sodium (mg/l)	27.1	71.7	27	34
Magnesium (mg/l)	18.4	28.1	19	7.5

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Attachment D - Well Water Analysis

Rev A

Attachment E – Coal Analysis

Fuel Analysis

	Eastern Bituminous	Pet Coke	Blend of 70% Eastern Bituminous, 30% Pet Coke
Proximate Analysis, Wt%			
Moisture	12.00	12.00	12.00
Volatile Matter	38.85	10.01	30.20
Fixed Carbon	46.97	80.62	57.07
Ash	10.50	1.50	7.80
Sulfur	3.50	6.00	4.25
Ultimate Analysis, Wt%			
Carbon	61.72	75.37	65.82
Hydrogen	4.79	3.12	4.29
Nitrogen	1.31	1.48	1.36
Chlorine	0.30	0.30	0.30
Oxygen	5.88	0.23	4.19
Heating Value (HHV)			
Btu/lb	12,000	13,000	12,300

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Attachment E - Fuel Analysis

REV A

Seminole Generating Station
750 MW (Net) Solid Fuel Fired Unit
Feasibility Study

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Seminole Electric Cooperative, Inc.

February 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 16
Company/ SEC
Witness: Richard Klover (RAK-4)
Date: 06-07-06

Burns & McDonnell
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SINCE 1898

February 24, 2005

Mr. Tom Wess
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

750 MW (Net) Solid Fuel Fired Unit Feasibility Study

Mr. Wess:

Burns & McDonnell is pleased to submit our 750 MW (Net) Solid Fuel Fired Unit Feasibility Study to Seminole Electric Cooperative, Inc. (SECI). The study evaluates the economics of a 750 MW (net) pulverized coal unit at the Seminole Generating Station (SGS) in Palatka, Florida and compares it to the 600 MW (net) solid fuel generation options provided previously.

The attached report summarizes the findings of the feasibility study and provides our recommendations regarding the most economical, long-term baseload energy resource for SECI. If you have any questions regarding the report, please contact me at 816-822-3274 or Jeff Greig at 816-822-3392.

It is a pleasure to be of service to SECI in this matter.

Sincerely,

Richard A. Klover

Richard Klover
Project Manager

Jeff Greig
General Manager

ENGINEERS • ARCHITECTS • CONSULTANTS
9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690
http://www.burnsmcd.com

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1.0 EXECUTIVE SUMMARY

1.1 SCOPE OF WORK

The purpose of this study is to evaluate the economics of a 750 MW (net) pulverized coal unit, Unit 3, for Seminole Electric Cooperative, Inc. (SECI) at the Seminole Generating Station (SGS). Both subcritical and supercritical technologies are evaluated. The study addresses site infrastructure, capital cost, operating and maintenance costs, performance, and busbar cost for a new unit.

The major assumptions and conceptual design basis used in generating the results for this assessment are identical to the 600 MW (Net) Solid Fuel Fired Unit Feasibility Study provided previously.

1.2 ECONOMIC ANALYSIS SUMMARY

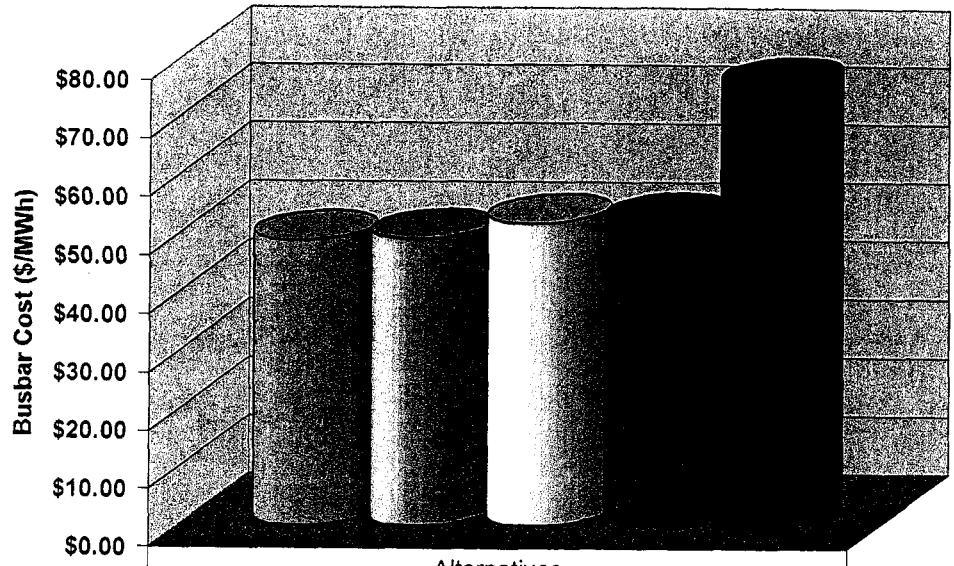
Burns & McDonnell (B&McD) prepared pro forma economic analyses of the following alternatives:

- Construction of a new, brownfield 750 MW (net) subcritical solid fuel fired generating unit
- Construction of a new, brownfield 750 MW (net) supercritical solid fuel fired generating unit

A 20-year economic analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs for each alternative. The results from the previous 600 MW (Net) Solid Fuel Fired Unit Feasibility Study are also shown for comparison purposes.

Economic pro forma analyses were used to determine the 20-year levelized busbar cost of power generated from each alternative. Figure 1-1 presents a graph of the resulting levelized busbar power costs for the two 750 MW alternatives and three previous alternatives from the 600 MW study. Results are shown in 2012 dollars. The levelized busbar costs of the 750 MW supercritical and subcritical units are $48.85 and $49.15/MWh, respectively. These costs are slightly lower than the 600 MW supercritical and subcritical alternatives ($51.84 and $52.08/MWh respectively). Additionally, the busbar costs of all the coal alternatives are significantly lower than the busbar cost for the greenfield, conventional combined cycle alternative ($75.48/MWh).

Figure 1-1: 20-Year Levelized Busbar Costs (2012$)



	Alternatives
750 MW Supercritical	$48.85
750 MW Subcritical	$49.15
600 MW Supercritical	$51.84
600 MW Subcritical	$52.08
500 MW CC	$75.48

1.3 CONCLUSIONS AND RECOMMENDATIONS

Based upon economic criteria presented in Section 6, the construction of a new 750 MW supercritical or subcritical unit has the lowest busbar cost and, therefore, is considered to be the most economical alternative to provide long-term baseload capacity and energy for SECI. The 600 MW supercritical or subcritical unit busbar costs are only slightly higher than the busbar costs for the 750 MW units. The overall economics of a gas-fired combined cycle unit are not as favorable as those of the subcritical or supercritical solid fuel-fired units when operating at high capacity factors due to the higher fuel costs associated with natural gas.

Other factors to consider when selecting between subcritical and supercritical steam cycle include the following:

- Operator familiarity with subcritical technology at the SGS plant.
- Lower emissions due to the higher efficiencies of the supercritical technology.
- Permitting may face fewer hurdles with a supercritical cycle verses a subcritical cycle.

- Corrosive coals, such as that anticipated for use at SGS Unit 3, can cause excessive wastage and circumferential cracking in the water walls and liquid phase corrosion in the superheater and reheater when burned in supercritical units with elevated steam temperatures.
- There is currently no supercritical PC operating experience with 30% pet coke blend (i.e. high sulfur fuel), regardless of steam temperature.
- There is currently no subcritical PC boiler operating experience with 30% pet coke blend (i.e. high sulfur fuel) above 1000°F/1000°F steam conditions.

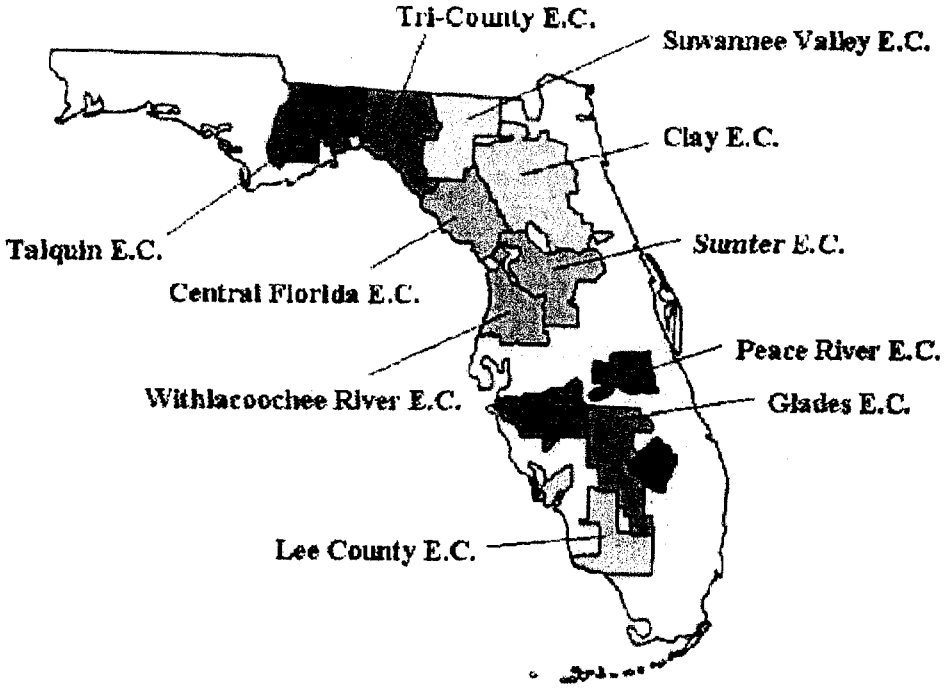
Due to the lack of experience with supercritical technology operation on high sulfur coals and the increased potential for excessive wastage, circumferential cracking, and liquid phase corrosion anticipated on a supercritical unit, B&McD recommends subcritical technology be employed for SGS Unit 3.

2.0 INTRODUCTION

2.1 BACKGROUND

SECI has identified the need for additional baseload capacity by 2012. One option for meeting this need is the construction of an additional unit, Unit 3, at SGS. SECI seeks a generation resource with fuel price stability in order to secure long-term, low-cost generation for its member cooperatives. As a generation and transmission cooperative, SECI provides wholesale electric service to its ten member electric distribution cooperatives from a mix of firm resources. These resources include owned-generation and purchased capacity. These units owned by SECI include two solid fuel fired units at SGS, a gas-fired combined cycle facility at Payne Creek, and an ownership interest in Progress Energy Florida's nuclear unit. The member electric distribution cooperatives are located throughout Florida, serving over 775,000 customers in 46 different counties. Figure 2-1 shows the SECI member system.

Figure 2-1: SECI Member System



2.2 SCOPE OF WORK

Seminole Electric Cooperative, Inc. retained Burns & McDonnell (B&McD) to evaluate the feasibility of developing and installing a new solid fuel generation resource adjacent to its present Seminole Generating Station. This additional solid fuel fired unit is designated and referred to in this study as SGS Unit 3.

The new unit is based on a 750 MW (net) solid fuel fired power plant. The boiler and emissions controls equipment for the new unit are designed to operate with a blend of 70% eastern bituminous coal and 30% petroleum coke fuel. The operating and maintenance cost estimates for the economic pro forma are also based on a 70/30 blend of coal and petroleum coke.

This study includes the following scope of work:

- Preparation of a project scope description for the 750 MW solid fuel fired unit.
- Preparation of a preliminary assessment of the existing infrastructure to support the new 750 MW solid fuel fired unit.
- Preparation of capital and operating cost estimates for the new unit.
- Estimate of the plant output and heat rate.
- Preparation of preliminary plant water balance including the impact of the new unit.
- Preparation of a preliminary assessment of the anticipated BACT/MACT requirements for the new unit.
- Development of a pro forma with an estimated busbar cost.
- Cost sensitivity analysis

2.3 OBJECTIVE

The purpose of the study is to provide a preliminary evaluation of a 750 MW solid fuel generation resource at SGS for comparison to the 600 MW solid fuel generation information provided previously and to evaluate against the SECI request for capacity proposals.

3.0 SITE INFRASTRUCTURE EVALUATION

3.1 OVERVIEW

This section is provided to determine the potential upgrades required to the existing site infrastructure due to the addition of a new 750 MW unit to the site. Impacts to the existing raw water supply, wastewater discharge, coal handling, limestone handling, and electrical interconnection are evaluated. Transmission and fuel delivery are outside the scope of this study. More detailed infrastructure studies should be performed if the preliminary economics of the project are favorable.

3.2 RAW WATER SUPPLY

A preliminary water mass balance diagram was developed for SGS reflecting the impact of Unit 3 (750 MW) to the existing two units. The water mass balance is included as Figure 3-1 at the end of this section.

Raw water is supplied from the St. John's River. Based upon preliminary information, it is expected that a new line from the intake structure to the pump structure may be required to avoid excessive pressure drop. A $300,000 allowance has been included in the capital cost estimate for the addition of this new pipe and modifications to the intake structure. Additionally a $150,000 allowance has been included for new raw water pumps and pump structure modifications.

Additional studies should be performed on the intake structure, pump structure, raw water pumps, and pipelines to more accurately establish the required upgrades.

3.3 WASTEWATER DISCHARGE

Cooling tower blowdown and site runoff is discharged to the St. Johns River through the existing discharge pipeline. Wastewater discharge booster pumps are included to increase the discharge capacity of the existing line. Storm water runoff from non-process equipment areas, such as parking lots and building roofs, is directed through an on-site storm water collection and drainage system and discharged to the St. Johns River.

Evaluation of the water discharge permit is required to determine if discharge limitations exist.

3.4 COAL HANDLING SYSTEM

Coal handling upgrades required for the addition of a new 750 MW unit are expected to be the same as that required for a new 600 MW unit. These upgrades are summarized below.

The coal handling system for the SGS Unit 3 is based on handling bituminous coal with a density of 50 pounds per cubic foot and petroleum coke with a density of 45 pounds per cubic foot. The existing rotary dumper and stockout system has adequate capacity (approximately 3,000 tons per hour) to handle the new unit. B&McD recommends that SECI perform a condition assessment of this existing equipment to determine if it can meet expected capacity levels. Existing Units 1 and 2 currently receive approximately one unit train (10,000 tons per train) per day (320 trains per year). The addition of Unit 3 increases this requirement to approximately 1.6 unit trains per day (550 trains per year).

The current long term coal storage pile, for Units 1 and 2, maintains 45 to 60 days of coal storage. Adding Unit 3 requirements to the existing coal pile equates to a total area of approximately 23.5 acres (1,225,000 tons) for all three units. The existing coal storage area has adequate capacity for all three units.

The existing as-received sampling tower is modified by removing the existing as-received sampling system, providing a new motorized flop gate at the head end of Conveyor CB-2, providing a new belt feeder to transfer coal to a new reversible yard conveyor and a new enclosed structure attached to the existing tower. The new reversible yard conveyor is provided with a new trencher type stacker / reclaimer (similar to the existing machine) and is capable of stacking out 3,000 tph and reclaiming at 1,700 tph of bituminous coal or petroleum coke.

The new reversible yard conveyor is approximately 1,500 feet long and provides approximately 3 days of active reclaimable storage for all three units. The head end of the reversible yard conveyor is located in the new structure, adjacent to the existing tower and is provided with a diverter gate to direct coal to either existing Conveyor CB-7A or CB-7B.

The existing as-fired sampling tower is modified by removing the existing as-fired sampling system and providing new motorized flop gates at the head end of Conveyors CB-8A and CB-8B. The new gates direct coal to new Unit 3 feed conveyors to transfer coal from the as-fired tower to a new tower adjacent to Unit 3. The Unit 3 tower is provided with a surge bin and two variable speed belt feeders which

discharge to dual tripper conveyors. The tripper conveyors are provided with dual pant leg traveling trippers complete with cable reels and floor seal system.

Replacement of the existing as-received and as-fired sampling systems are accomplished by installing sweep arm primary samplers on the respective belt conveyors and modular self-contained secondary sampling systems, located at grade, immediately underneath the primary sampler(s).

Dust control for the new coal handling system is a dry baghouse type collection system. The baghouse collector is provided with a walk-in clean air plenum, centrifugal fan, ductwork and dust return system. The existing dust collection systems will be upgraded as required to maintain current emission regulations.

3.5 LIMESTONE HANDLING SYSTEM

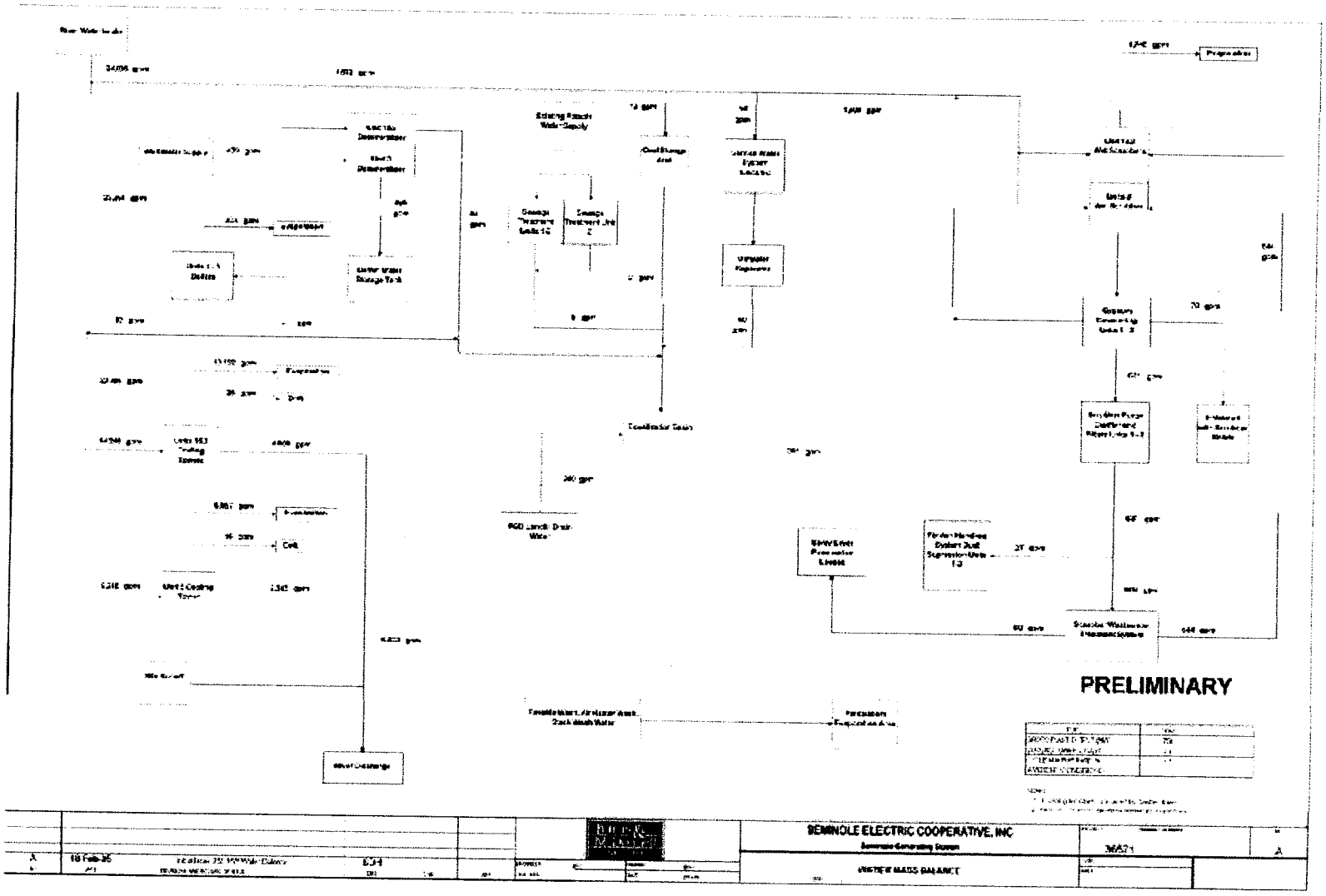
The existing limestone handling system is adequate to supply the Unit 3 limestone demand. The current outdoor limestone storage area is expanded to allow for limestone storage requirements for Unit 3. Assuming a density of 85 pounds per cubic foot, a pile height of approximately 40 feet and maintaining 45 days of storage, this new area requires approximately 2.5 acres.

3.6 ELECTRICAL INTERCONNECTION

Electrical output from the new unit will be stepped up to 230 kV. The turbine generator output will be connected through three single phase generator step-up transformers to the existing 230 kV switchyard. The existing folded breaker-and-a-half switchyard will be modified to add one three-breaker bay to accommodate the new unit and its startup transformers.

The unit startup power will be through two 30/40/50 MVA, 230:6.9/6.9 kV startup transformers. Auxiliary power will transfer to the steam turbine-generator through two 30/40/50 MVA 23:6.9/6.9 kV auxiliary transformers after the unit is on line.

Figure 3-1: Preliminary Site Water Mass Balance



4.0 PERFORMANCE AND EMISSIONS

4.1 PERFORMANCE

Estimated performance was developed for 750 MW subcritical and supercritical PC units at SGS. The estimates summarized in this section are based on in-house data and information from similar projects. A performance summary is shown in Table 4-1. Performance shown is for 100% load operation at new and clean conditions.

Table 4-1: 750 MW PC Performance

Boiler Type	Pulverized Coal Subcritical 1,050 F/ 1,050 F	Pulverized Coal Supercritical 1,050 F/ 1,050 F
Net Plant Output (kW)	750,000	750,000
STG Heat Rate (Btu/kW-hr)	7,476	7,233
STG Gross Output (kW)	810,811	815,217
Boiler Efficiency (%)	87.1	87.1
Auxiliary Power (kW)	60,811	65,217
Auxiliary Power (%)	7.5%	8.0%
Net Plant Heat Rate (Btu/kW-hr)	9,277	9,024

4.2 EMISSIONS

The results of the 600 MW preliminary Best Available Control Technology (BACT) assessment provided previously are applicable for a 750 MW unit. Those results are summarized below.

The BACT levels estimated for this study are not absolute. BACT emission levels change with time, unit type, and fuel type. The emission rates represent B&McD's best estimated BACT levels taking into account technology limitations and current expected guaranteed performance levels.

4.2.1 Emissions Control Technologies

The control technologies required for either a subcritical or supercritical unit is based on firing a blend consisting of 70% bituminous coal and 30% pet coke. As a result, the emissions control equipment required to accommodate the blended fuel is as follows:

- SCR for NO_x control.
- Activated carbon injection system for mercury (Hg) control.
- Electrostatic precipitator (ESP) for particulate (PM) control.

- Flue gas desulfurization (FGD) for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.

4.2.2 Expected Pollutant Limits

Based on the control technologies described above, the preliminary BACT emission limits for the subcritical and supercritical units being evaluated are as follows:

Table 4-2: Preliminary BACT Emission Limits

Pollutant	Emission Limit
NO_x	0.07 lb/MMBtu
SO_2	0.18 lb/MMBtu
PM	0.015 lb/MMBtu
Hg	6×10^{-6} lb/MW-hr
CO	0.15 lb/MMBtu
H_2SO_4	0.005 lb/MMBtu

The PM emission rate of 0.015 lb/MMBtu is filterable particulate matter only. A PM_{10} emission limit including filterables and condensables has not been guaranteed by vendors on the condensable portion. Further, the mercury emission limit specified is based on recent test data and does not represent a typical vendor guarantee. In addition, the CO limit is based on the expected byproducts from the combustion process in the boiler and is not a controlled pollutant.

4.2.3 Emission Allowances

Emissions allowances may be required for compliance with regulations. Costs for emissions allowances are not included for this study.

Table 5-1: Capital Cost Estimates

Description	750 MW PC Subcritical	750 MW PC Supercritical
PROCUREMENT		
Mechanical Procurement		
Steam Turbine - Generator	$ 45,257,000	$ 47,885,000
Boiler Island/APC Equipment	$ 172,900,000	$ 174,410,000
Surface Condenser & Air Removal Equipment	$ 5,979,000	$ 5,632,000
Boiler Feed Pumps	$ 1,814,000	$ 2,316,000
Condensate Pumps/Circulating Water Pumps	$ 2,175,000	$ 2,175,000
Miscellaneous Mechanical Equipment	$ 30,303,000	$ 34,486,000
Electrical & Control Procurement		
GSU, Auxiliary Transformers	$ 6,600,000	$ 6,600,000
Medium Voltage Metal-Clad Switchgear	$ 5,801,000	$ 5,801,000
480 V Switchgear & Transformers	$ 1,229,000	$ 1,229,000
Miscellaneous Electrical Equipment	$ 2,613,000	$ 2,613,000
Control Procurement	$ 2,931,000	$ 2,931,000
Water Treatment Procurement	$ 17,594,000	$ 17,594,000
Structural Procurement	$ 9,197,000	$ 9,197,000
CONSTRUCTION		
Major Equipment Erection		
Steam Turbine - Generator Erection	$ 6,548,000	$ 6,548,000
Boiler Island/APC Equipment Erection	$ 164,968,000	$ 165,994,000
Furnish & Erect Packages		
Cooling Tower	$ 23,277,000	$ 21,601,000
Material Handling Systems	$ 20,272,000	$ 20,272,000
Chimney	$ 17,500,000	$ 17,500,000
Civil / Structural Construction	$ 63,979,000	$ 63,979,000
Mechanical Construction	$ 81,120,000	$ 86,042,000
Electrical Construction	$ 58,278,000	$ 58,278,000
PROJECT INDIRECTS		
Construction Management	$ 13,467,000	$ 13,467,000
Preoperational Testing, Startup, & Calibration	$ 12,407,000	$ 12,407,000
Miscellaneous Construction Indirects	$ 7,569,000	$ 7,569,000
Project Management & Engineering	$ 41,508,000	$ 41,508,000
Project Bonds	$ 9,152,000	$ 9,152,000
Escalation	$ 130,261,000	$ 131,771,000
Project Development	$ 3,000,000	$ 3,000,000
Owner Operations Personnel	$ 2,973,000	$ 2,973,000
Substation / Transmission Upgrades	$ 2,400,000	$ 2,400,000
Land	$ -	$ -
Permitting & License Fees	$ 2,643,000	$ 2,643,000
Initial Fuel Inventory	$ 15,120,000	$ 14,812,000
Miscellaneous Owner Costs	$ 12,970,000	$ 13,056,000
Sales Tax & Duties	$ 1,270,000	$ 1,313,000
Owner Contingency	$ 99,508,000	$ 100,916,000
TOTAL PROJECT COST	**$ 1,094,584,000**	**$ 1,110,072,000**

5.1.1 Capital Cost Estimate Assumptions

The cost basis for the subcritical and supercritical solid fuel fired options is defined in Table 5-2. Additionally, the following are the major assumptions and exclusions upon which the facility cost estimates are based:

- Project is executed under a multiple contract method. This contracting method assumes an engineer for plant design, procurement by SECI, and construction performed by multiple contractors.
- Cost estimate is based on a non-union labor force for the Palatka, Florida area, 40-hour work week, single shift with some overtime.
- Cost estimate includes escalation to support commercial operation in June 1, 2012. Escalation at the rate of 2.5% to the midpoint of construction in 2010 is included in the estimate.
- Interest during construction and financing fees are not included.

Table 5-2: 750 MW Plant Cost Basis/Assumptions

General:	
Water Supply:	
Cooling Tower Make-up:	
Source:	River water is used for makeup to the cooling tower.
Supply:	Cooling tower makeup water is supplied from new pumps installed in the existing intake structure. New supply piping from the intake structure to the pump structure will be evaluated during detailed design.
Storage:	None.
Cycle Make-up:	Existing well water system will feed the water treatment system.
Service Water:	New service water pumps and head tank is included to supply service water to the new unit.
Potable Water:	Potable water is supplied from existing system.
Wastewater Disposal:	
Process Wastewater:	Plant wastewater except cooling tower blowdown and site runoff (does not include landfill and coal pile runoff) is discharged to the equalization basin and reusued or evaporated in brine concentrators. Cooling tower blowdown and site runoff is discharged to the St. Johns River.
Contaminated Wastewater:	Drains from areas around equipment that could be contaminated with oil is directed through an oil/water separator and discharged to the existing equalization basin.
Sanitary Wastewater:	Sanitary waste is treated in a new package sewage treatment plant and effluent is discharged to the equalization basin.
Stormwater Discharge:	Stormwater (except for coal pile and landfill runoff) is collected in a storm drainage system and discharged to St. Johns River.
Start-up Fuel:	Start-up fuel for the project is fuel oil. A new fuel oil storage tank is included to provide adequate capacity for the new unit. New fuel oil pumps are required for the new unit.
Solid Fuel:	
Types:	Plant is designed to operate with a 70/30 blend of eastern bituminous coal and petroleum coke.
Delivery:	Solid fuel is delivered to the plant by rail only. Trains are anticipated to be up to 100 car unit trains.
Dead Storage:	Solid fuel is stored in uncovered outdoor piles. Total storage for all three units of 60 days is provided.
Live Storage:	New unit outdoor active pile shall have approximately 24 hours of full load operation.
Boiler Storage:	Boiler building silo storage shall have a minimum of 24 hours of full load operation.
Blending:	70% coal and 30% petroleum coke blend.
Sorbent Supply (Scrubber):	
Source:	Current limestone supplier or as required.
Size:	Limestone size shall be a maximum of 3".
Delivery:	The existing truck unloading system has adequate capacity for the new unit.
Storage:	15 days of covered storage and 40 to 60 days of total storage. Sizing of sorbent storage is based upon design fuel.
Fly Ash & Scrubber Sludge Disposal:	
Disposal:	Fly ash is disposed of in the on-site landfill. Gypsum is sold to the adjacent wallboard plant. Landfill capacity (including expansion requirements) is based on 25-30 year production assuming a 70/30 blend of coal and pet coke. Landfill costs include a composite liner with leachate collection system installed on both the current landfill area and the expansion area. Cover material thickness is 3 feet.
Day Storage:	One fly ash silo with minimum of 3 days of fly ash storage is provided. Silo is sized for the fuel with highest ash production rate.
Transportation:	Fly ash is transported to the landfill via trucks.
Bottom Ash Disposal:	
Ash Disposal:	Bottom ash is sold.
Ash Storage:	Bottom ash is collected and stored in a silo sized for 3 days of bottom ash storage.
Ash Transportation:	Bottom ash is extracted using a dry ash handling system and pneumatically conveyed to a silo. The bottom ash is then trucked off for off-site sale.
Ammonia:	
Types:	Anhydrous Ammonia
Delivery:	Truck with self contained unloading pump
Storage:	15 day storage tank capacity
Construction Utilities:	
Water Supply:	Water supply for construction is from the existing plant make-up water system (well water pumps).
Construction Power:	Power supply for construction is from the existing plant via a power line and temporary transformer.
Equipment Delivery:	Major equipment is delivered to the site via rail. Other equipment is received via rail or truck, whichever is more economical.

Civil:	
Disposal of Spoils:	Spoils are disposed of on site. No hazardous materials are anticipated to be found in the soils.
Soil Conditions / Stability:	Existing soils are assumed to be stable in and around the area of the new unit and suitable for use as laydown without any further preparation. Soils are assumed to be adequate for structural fill. No overexcavation and recompaction is included.
Subsurface Rock:	Removal of subsurface rock is not included.
Cut & Fill:	Site is developed as a balanced site requiring minimal off-site fill and minimal disposal of spoils. Assumed minimal site slopes across the width and off-site fill is available from within 10 miles of the site.
Dewatering:	Some dewatering of the main power plant structures is anticipated. This will be confirmed with preliminary geotechnical studies.
Construction Stormwater Control:	Silt fences are required for construction erosion control. No other special erosion control is included.
Roads:	Existing main plant roads are used. Minor roads and maintenance areas associated with the new unit will have an asphalt finish.
Parking:	Parking areas are surfaced with asphalt concrete.
Rail Scale:	Existing weight measurement system are used.
Coal Pile Run-off:	New coal storage areas is not required. Coal pile run-off is directed to the existing equalization basin.
Site Security:	Assume existing fencing and gates are adequate except where landfill expansion requires modification to existing fence and where fencing is required around new facilities such as the cooling tower.
Landscaping:	Minimal landscaping is included. Disturbed areas are seeded for erosion control.
Structural:	
Soil Bearing Capacity:	Soils are assumed to be suitable for bearing capacities greater than 2500 psf. Therefore, spread footings and mat foundations are anticipated for all structures under this scope of work.
Piling:	Piling is not included
Groundwater:	Some dewatering costs are included.
Boiler Enclosure:	Boiler is not enclosed.
Steam Turbine Enclosure:	Steam turbine is enclosed. The steam turbine hall will interface with the existing steam turbine hall.
Administration Facilities:	No additional administration space is required.
Control Facilities:	Existing control room is utilized for new operator stations.
Warehouse/Storage Facilities:	An additional 100 ft. x 100 ft. warehouse is included.
Water Treatment Building:	Additional building space is included for water treatment equipment.
Maintenance Shop:	No additional maintenance shop area is included.
Yard Maintenance Building	No additional yard maintenance facilities are included.
Electrical Enclosures	Several buildings of various sizes located to reduce wiring runs.
Stack:	Stack is provided with manlift for access.
Height	675' tall.
Velocity	A maximum of 60 feet per second.
Diameter	Exit diameter of 24'.
Liner Material	Clad C-276
Mechanical:	
Boiler:	
Subcritical	Drum type, balanced draft, natural circulation, pulverized coal boiler with steam turbine throttle conditions of 2520 psig and 1050F and with reheat at 1050 F designed for 100% of VWO output on the steam turbine.
Supercritical	Once-through, pulverized coal boiler with steam turbine throttle conditions of 3645 psig and 1050F and with reheat at 1050 F designed for 100% of VWO output on the steam turbine.
Steam Turbine Generator:	Nominally 815 MW, 3,600 rpm, down-exhaust, reheat, tandem compound, four flow type designed to normally operate at maximum output (turbine or generator limited) at a 0.9 PF.
Feedwater Heaters:	Seven stages of feedwater heating for subcritical unit. Eight stages for supercritical unit.
Steam Turbine Bypass:	Not included as the unit is intended to be base loaded.
Auxiliary Boiler:	Will use an auxiliary steam system for new unit start-up.
Heat Rejection:	
Condenser:	Split waterbox, wet surface condenser with 316SS tubes.
Cooling Tower/Cooling Pond:	Utilize a concrete, natural draft cooling tower without fire protection.
Fans:	
FD Fans:	2x60% motor driven, constant speed, centrifugal, with inlet guide vanes.
ID Fans:	3x50% motor driven, constant speed, centrifugal with inlet guide vanes.
PA Fans:	2x60% motor driven, constant speed, centrifugal with inlet dampers
Air Heaters:	2x50%
Pumps:	
Boiler Feed Pumps:	2x60% steam turbine driven, constant speed, barrel pumps
Start-up boiler feed pump:	1x30% motor driven start-up pump.
Condensate Pumps:	3x50% constant speed motor driven pumps
Circulating Water Pumps	3x50% motor driven constant speed, standard construction

Water Treatment:	
Steam Cycle Make-up:	Additional 185 gpm of demineralizer capacity is provided.
Cooling Tower Make-up:	Chemical feed for pH adjustment, corrosion/scale control, and blowdown treatment as required.
Cooling Tower Sidestream:	Not included.
Service Water Make-up:	Service water is supplied from existing system.
Condensate Polishing	4x35% capacity deep bed polisher vessels with external regeneration.
Wastewater Treatment:	
Scrubber Purge Water	Brine concentrators (2) with spray dryer provided to treat scrubber purge water from Units 1 - 3. Solid waste hauled to the on-site landfill.
Compressed Air Supply:	3x50% capacity rotary screw air compressors with desiccant type air dryers
Fire Protection:	Fire protection system per NFPA. The fire water loop is extended around the new unit. New diesel driven, motor driven, and motor driven jockey pumps are included for the new unit.
Water Storage:	
Condensate Storage:	Additional 375,000 gallons of storage capacity is included.
Raw Water Storage:	Use existing well water and river water system. However, a new 15,000 gallon surge tank and pumps are added to the well water system.
Demineralized Water Storage:	Combined with condensate storage.
Potable Water Storage	Potable water is supplied from existing system.
Auxiliary Cooling:	
Type:	Closed Cooling Water System
Exchangers:	Plate & Frame with 316SS plates
Coal Handling:	
Unloading:	Existing rotary car dumper is used.
Check Weighing:	Belt scale on existing conveyor is used.
Stockpiling:	As recommended by Burns & McDonnell.
Dead Storage Reclaim:	Dozer w/ hoppers as this is not the normal fuel reclaim method. Only used in emergency situations. Existing dozers will be used in conjunction with new trencher.
Live Storage Reclaim:	New trencher stacker / reclaimer and existing trencher stacker / reclaimer.
Reclaim redundancy:	Use existing and new trencher.
Crushers:	Use existing crushers.
Reclaim Sizing:	Fill 24 hour usable volume.
Pulverizers:	One redundant coal silo / pulverizer unit based upon design fuel blend. Worst case fuel may utilize the redundant unit without any further redundancy.
Limestone Handling	
Unloading:	Use existing truck unloading system.
Storage:	Short term and long term storage is indoor/outdoor storage piles using existing mobile equipment with existing reclaim equipment. Storage is expanded to maintain 45-60 days of limestone storage.
Delivery to Scrubber:	Reclaimed and delivered to 1x100% limestone bins (12 hour storage) via 1x100% limestone conveyor.
Preparation:	Crushed limestone is prepared in existing 2x100% ball mills. One new limestone slurry storage tanks is added for the new unit.
Fly Ash Handling	
Removal from ESP	Pressurized pneumatic conveying systems including 2x50% trains with 3x50% blowers to the ash silo. Conveying system is sized to remove 24 hours of ash in an 8 hour shift.
Ash Load-out:	Ash truck loadout systems is provided below the silo via gravity or pneumatic conveying. Ash loadout includes 2x100% ash conditioning systems (pug mills). Fly ash transport to the on-site landfill is by truck. Alternate dry loadout capability via truck is provided to support ash sales.
Bottom Ash Handling	
Removal from Boiler	Dry extraction bottom ash removal system.
Ash Load-out:	Trucked from Silo.
Scrubber Sludge Handling:	
Hydroclones	Radial hydroclone assembly with a minimum of 2 spare cyclones.
Vacuum Filter	Two 100% capacity belt filters sized for all 3 units.
Pug Mills	Not required
Ash Storage:	Included with fly ash handling.
Sludge Storage	Not included.
Sludge Disposal	Gypsum conveyed to wall board plant on site.
Scrubber	
Type:	Wet FGD - Forced Oxidized
Size:	1x100% module
Turndown capability:	5:1 as a minimum.
Redundancy:	A spare recycle pump or organic acid feed system is provided.

ESP	
Redundancy	None
Type:	Rigid frame
SCA:	(To be determined)
Activated Carbon Injection	An activated carbon injection system is provided for mercury control.
Maximum Injection Rate	20 lbs/mmACF
Wet ESP	
Type	Vertical flow located above absorber module.
Number of fields	A minimum of 2 fields.
SCA:	(To be determined)
SCR	
Catalyst type	Honeycomb
Space Velocity	(To be determined)
SCR Bypass	There is a SCR bypass for fuel oil starting.
Economizer Bypass	There is an economizer bypass on the water side to maintain temperature at low loads.
Emissions Control:	
Emissions Control:	
NOx:	SCR guaranteed for 0.07 lb/MMBtu of exhaust NOx.
Ammonia Slip:	3 ppmvd @ 3% O2
CO:	Combustion controls to 0.15 lb/MMBtu.
SOx:	Wet scrubber to accomplish 0.18 lb/MMBtu. Equipment guaranteed for 98% removal of the inlet SO_2 concentration.
PM10:	Electrostatic precipitator to accomplish emissions of 0.015 lb/MMBtu (filterable only).
Mercury:	Carbon injection system to reduce mercury emissions to 6 x 10^{-6} lb/MW-hr (Approximately 0.6 lb/Tbtu heat input).
Sulfuric Acid Mist:	Wet ESP guaranteed for 0.005 lb/mmBtu.
General Notes - Not Scope Items	
Coal Handling:	Covered conveyors with dust collection at transfers and wet suppression at stockout.
Stack Height:	Good Engineering Practice" - per US Code Title 42, Ch 85,Sub 1, Part A, Section 7423 - approx. 2.5 times the height of the tallest adjacent structure (boiler). Assumed 675 feet for estimate.
Electrical	
Generator Step-up Transformer:	Three, single phase step-up transformers to provide ability to use the existing spare transformer. Transformers are rated at OA/FA/FOA.
Black Start Capability:	Not Included.
Emergency Generator:	Included for essential power only.
Emergency Power:	2 hour DC system with a UPS for supply to the control system and critical instrumentation.
Start-up / Back-up Power:	Start-up of unit is accomplished using 2X 50% three winding start up transformers.
Auxiliary Power Supply:	Two 50% three winding auxiliary transformers connected to the bus between the generator and the GSU. Transfer from start up power to unit auxiliary power after the bus is synchronized to the generator.
Plant Control System:	Distributed control system with remote located I/O panels.
Plant Communications:	
External and Office to Office	Tie into existing infrastructure.
Internal around plant	Gaitronics communication system throughout the plant.
Switchyard Communications	Not included.
Transmission / Interconnection:	
Switchyard:	One new 230 KV bay.
Transmission Upgrades:	Not included.
Interconnection to Existing Transmission:	Included.
Construction:	
General Liability Insurance:	Included
Builder's Risk Insurance:	Not Included
Performance Bonds:	Included
Performance/Stack Testing:	Included
Commissioning / Start-up:	Included
Operator Training:	Included
Permits:	Building permits and construction permits are included. Air, NPDES, and other plant discharge permits are not included.
Construction Schedule	It is assumed that the construction schedule is adequate to allow the project to be completed with minimal overtime. Construction schedule is estimated as a 5x8 with some overtime.

Miscellaneous:	
Permanent Plant Operating Spare Parts:	Allowance is included.
Maintenance Tools & Equipment.	Allowance is included.
Sales Tax	Estimated sales tax is included.
Other Owner's Costs	Estimated project development costs, Owner's CM, permitting costs, initial fuel inventory, building furnishings, and warehouse shelves are included.

Items Excluded from the Scope:
1. Legal Costs.
2. Fuel, limestone, and ash transportation equipment or rental costs for equipment required to transport such materials to or from the site.
3. Land Costs.
4. Sound abatement above normal supply.
5. Aesthetic landscaping other than erosion control.
6. Black start capability.
7. Waste water treatment or disposal other than discharge to a location on site.
8. Interest During Construction and financing fees.
9. Mobile Equipment.

5.1.2 Estimate Risk Assessment

Due to the capital intensive nature of solid fuel generation projects resources and length of construction period, there is capital cost risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact several US boiler manufacturers are currently under financial duress, and the skilled workforce that constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives, which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

5.2 OPERATIONS & MAINTENANCE (O&M) COST ESTIMATES

A summary of the variable and fixed O&M costs for the 750 MW subcritical and supercritical solid fuel fired alternatives are included in Tables 5-3 and Table 5-4. These costs are estimated based on the assumptions discussed in this section.

Table 5-3: O&M Cost Estimate – 750 MW Subcritical

Operating Assumptions						
Basis Year for Cost Estimate						2004
Capacity Factor						85.0%
Load Factor						100.0%
Net Unit Output, kW						750,000
Number of Units						1
Net Output, kW						750,000
Net Annual Output, MWh						5,584,500
Net Steam Turbine Heat Rate						7,430
Net Plant Heat Rate, Btu/kWh						9,220
Fuel Consumption, MMBtu/hr						6,915
Annual Fuel Consumption, MMBtu						51,489,090
Boiler Technology						Pulverized Coal
Type of NOx Control						SCR
Type of SO2 Control						Wet
Type of Particulate Control						ESP
Type of H2SO4 Control						Wet ESP
Type of Mercury Control						Carbon Injection
Type of Heat Rejection						Cooling Tower
Cooling Tower Materials of Construction						Concrete
Make-up Water Softening Required						Yes
Zero Discharge Facility						Yes
Type of Sidestream Treatment						None
Fixed O&M						
Labor		46 people @	$ 70,448			***$ 3,240,610***
Office & Admin						***$ 75,000***
G&A (Home Office / Support)						**By Seminole**
Other Fixed O&M						***$ 1,350,000***
Employee Expenses/Training						
Contract Labor						
Environmental Expenses						
Safety Expenses						
Buildings, Grounds, and Painting						
Other Supplies & Expenses						
Communication						
Control Room/Lab Expenses						
Annual Steam Turbine Inspections						***$ 100,000***
Annual Boiler Inspections						***$ 80,000***
Annual APC Inspections						***$ 100,000***
Start-up power demand charge	$ -	per kW-Mo	15,000	KW		$ -
Water supply demand charge	$ -	per acre-ft	0	acre-ft		$ -
Water discharge demand charge	$ -	per acre-ft	0	acre-ft		$ -
Standby Power Energy Costs	$ -	per kW-hr	3,942,000	KW-hr		$ -
Standby Power Service Fee	$ -	per Month	12	Mo		$ -
Property Taxes						**In Proforma**
Insurance						**In Proforma**
Total Fixed O&M Annual Cost						***$ 4,945,610***
Major Maintenance Costs (Capitalized)						
Steam Turbine / Generator Overhaul	7446	Op Hours/yr	$ 58.45	$/hour		***$ 435,241***
Steam Generator Major Replacements (Boiler $10MM@10yrs & Burners @ 20 yrs & Walls)			1,187,500	$/yr		***$ 1,187,500***
Baghouse Bag Replacement	-	$/Replacement	5	years		$ -
SCR Catalyst Replacement	$3,686,935	Catalyst Cost	3	yrs life		***$ 1,229,000***
Water Treatment System Replacements			5,429	$/yr		***$ 5,400***
Total Annual Major Maintenance Costs						***$ 2,857,141***

Table 5-3 - (Continued)

Non-Fuel Variable O&M					
Water Consumption					
Raw Water	4318	MMGal/yr @	$0.00 /kGal	$	-
Raw Water Make-up Treatment	4318	MMGal/yr @	$0.14 /kGal	$	610,400
Potable Water	1	MMGal/yr @	$1.00 /kGal	$	1,500
Water Discharge	1134	MMGal/yr @	$0.00 /kGal	$	-
Cooling Tower Treatment Chemicals	3976	MMGal/yr @	$0.05 /kGal	$	218,600
Demin Water Treatment	70	MMGal/yr @	$0.04 /kGal	$	3,100
Boiler Treatment Chemicals	4520	MMGal/yr @	$0.0126 /kGal	$	57,100
Maintenance & Consumables (lube oil, nitrogen, hydrogen, etc.)					
SCR System General Maintenance					
General Maintenance			$75,000 $/yr	$	75,000
Scrubber System General Maintenance					
Absorber, Dewatering & Accessories			$141,000 $/yr	$	141,000
Limestone Preparation			$438,803 $/yr	$	438,800
Water Treatment System General Maintenance			$75,515 $/yr	$	75,500
Cooling Tower System General Maintenance			$215,900 $/yr	$	215,900
Brine Concentrator and Spray Dryer System O&M			$2,816,250 $/yr	$	2,816,250
Other Variable O&M				$	6,508,200
Electronics, Controls, BOP Electrical					
Steam Generators					
BOP					
Misc. Maintenance Expenses					
Consumables					
Emissions Controls					
Lime Consumption	NA	tpy@	$107.89 /ton	$	-
Limestone Consumption	309,129	tpy@	$8.66 /ton	$	2,677,100
SCR Ammonia (Anhydrous)	2,002	tpy@	$250.00 /ton	$	500,400
Gypsum (Sales) / Disposal	532,647	tpy@	-$10.80 /ton		(5,752,600)
Ash (Sales) / Disposal (Wet Scrubber)	134,929	tpy @	$4.00 /ton		539,700
Ash (Sales) / Disposal (Dry Scrubber)	NA	tpy @	$4.00 /ton		-
Bottom Ash (Sales) / Disposal	33,732	tpy @	-$6.50 /ton		(219,300)
Carbon Injection	5,952	tpy@	$1,040.00 /ton		6,190,200
Total Non-Fuel Variable O&M Annual Cost				$	15,096,850
Total Fixed and Variable O&M Annual Cost				$	22,899,601
Total Fixed O&M Annual Cost, $/kW-yr					6.59
Total Emission Allowance Costs, $/yr				$	-
Total Major Maintenance (Capitalized Costs), $/MWh				$	0.51
Total Non-Fuel Variable O&M Annual Cost, $/MWh				$	2.70
Total O&M Cost, $/MWHr					4.10

Table 5-4: O&M Cost Estimate – 750 MW Supercritical

Operating Assumptions						
Basis Year for Cost Estimate						2004
Capacity Factor						85.0%
Load Factor						100.0%
Net Unit Output, kW						750,000
Number of Units						1
Net Output, kW						750,000
Net Annual Output, MWh						5,584,500
Net Steam Turbine Heat Rate						7,172
Net Plant Heat Rate, Btu/kWh						8,949
Fuel Consumption, MMBtu/hr						6,712
Annual Fuel Consumption, MMBtu						49,975,691
Boiler Technology						Pulverized Coal
Type of NOx Control						SCR
Type of SO2 Control						Wet
Type of Particulate Control						ESP
Type of H2SO4 Control						Wet ESP
Type of Mercury Control						Carbon Injection
Type of Heat Rejection						Cooling Tower
Cooling Tower Materials of Construction						Concrete
Make-up Water Softening Required						Yes
Zero Discharge Facility						Yes
Type of Sidestream Treatment						None
Fixed O&M						
Labor		46 people @	$ 70,448			***$ 3,240,610***
Office & Admin						***$ 75,000***
G&A (Home Office / Support)						**By Seminole**
Other Fixed O&M						***$ 1,350,000***
Employee Expenses/Training						
Contract Labor						
Environmental Expenses						
Safety Expenses						
Buildings, Grounds, and Painting						
Other Supplies & Expenses						
Communication						
Control Room/Lab Expenses						
Annual Steam Turbine Inspections						***$ 100,000***
Annual Boiler Inspections						***$ 80,000***
Annual APC Inspections						***$ 100,000***
Start-up power demand charge	$ -	per kW-Mo	15,000	KW		$ -
Water supply demand charge	$ -	per acre-ft	0	acre-ft		$ -
Water discharge demand charge	$ -	per acre-ft	0	acre-ft		$ -
Standby Power Energy Costs	$ -	per kW-hr	3,942,000	KW-hr		$ -
Standby Power Service Fee	$ -	per Month	12	Mo		$ -
Property Taxes						**In Proforma**
Insurance						**In Proforma**
Total Fixed O&M Annual Cost						***$ 4,945,610***
Major Maintenance Costs (Capitalized)						
Steam Turbine / Generator Overhaul	7446	Op Hours/yr	$ 58.45	$/hour		***$ 435,241***
Steam Generator Major Replacements (Boiler $10MM@10yrs & Burners @ 20 yrs & Walls)			1,187,500	$/yr		***$ 1,187,500***
Baghouse Bag Replacement	-	$/Replacement	5	years		$ -
SCR Catalyst Replacement	$3,686,935	Catalyst Cost	3	yrs life		***$ 1,229,000***
Water Treatment System Replacements			5,429	$/yr		***$ 5,400***
Total Annual Major Maintenance Costs						***$ 2,857,141***

Table 5-4 - (Continued)

Non-Fuel Variable O&M					
Water Consumption					
Raw Water	4318	MMGal/yr @	$0.00 /kGal	$	-
Raw Water Make-up Treatment	4318	MMGal/yr @	$0.14 /kGal	$	610,400
Potable Water	1	MMGal/yr @	$1.00 /kGal	$	1,500
Water Discharge	1134	MMGal/yr @	$0.00 /kGal	$	-
Cooling Tower Treatment Chemicals	3976	MMGal/yr @	$0.05 /kGal	$	218,600
Demin Water Treatment	70	MMGal/yr @	$0.04 /kGal	$	3,100
Boiler Treatment Chemicals	4363	MMGal/yr @	$0.0126 /kGal	$	55,100
Maintenance & Consumables (lube oil, nitrogen, hydrogen, etc.)					
SCR System General Maintenance					
General Maintenance			$75,000 $/yr	$	75,000
Scrubber System General Maintenance					
Absorber, Dewatering & Accessories			$141,000 $/yr	$	141,000
Limestone Preparation			$438,803 $/yr	$	438,800
Water Treatment System General Maintenance			$75,515 $/yr	$	75,500
Cooling Tower System General Maintenance			$215,900 $/yr	$	215,900
Brine Concentrator and Spray Dryer System O&M			$2,816,250 $/yr	$	2,816,250
Other Variable O&M				$	6,508,200
Electronics, Controls, BOP Electrical					
Steam Generators					
BOP					
Misc. Maintenance Expenses					
Consumables					
Emissions Controls					
Lime Consumption	NA	tpy @	$107.89 /ton	$	-
Limestone Consumption	300,705	tpy @	$8.66 /ton	$	2,604,100
SCR Ammonia (Anhydrous)	2,002	tpy @	$250.00 /ton	$	500,400
Gypsum (Sales) / Disposal	518,136	tpy @	-$10.80 /ton		(5,595,900)
Ash (Sales) / Disposal (Wet Scrubber)	131,251	tpy @	$4.00 /ton		525,000
Ash (Sales) / Disposal (Dry Scrubber)	NA	tpy @	$4.00 /ton		-
Bottom Ash (Sales) / Disposal	32,812	tpy @	-$6.50 /ton		(213,300)
Carbon Injection	5,952	tpy @	$1,040.00 /ton		6,190,200
Total Non-Fuel Variable O&M Annual Cost				$	15,169,850
Total Fixed and Variable O&M Annual Cost				$	22,972,601
Total Fixed O&M Annual Cost, $/kW-yr					6.59
Total Emission Allowance Costs, $/yr				$	-
Total Major Maintenance (Capitalized Costs), $/MWh				$	0.51
Total Non-Fuel Variable O&M Annual Cost, $/MWh				$	2.72
Total O&M Cost, $/MWHr					4.11

5.2.1 Staffing

The staffing plan for the 750 MW solid fuel generation alternative is anticipated to be identical to the staffing plan provided for the 600 MW solid fuel generation alternative. Unit 3 will share operational staff with the existing units. The existing shift supervisor will direct shift operations, make assignments, and perform required administrative duties for the new unit. The shift supervisor will also serve as a second operator during emergencies and provide periodic relief for the primary control room operator. The existing plant staffing will be expanded by 46 employees to accommodate the new unit. By sharing staff, all units will benefit from added flexibility and will be able to operate with fewer on-site staff per unit.

5.2.2 O&M Cost Estimate Assumptions

The following assumptions are used in determining the O&M costs:

- Limestone is 90% $CaCO_3$.
- SO_2 removal of 98%.
- 0.2 lb/MMBtu Boiler NO_x production and 0.07 lb/MMBtu from stack.
- Ash and gypsum contain 5% moisture.
- Activated carbon injection at 20 lb/MACF.
- SCR replacement cost assumes the catalyst is regenerated and not disposed of.
- The O&M costs assume the unit is operating at 100% load.
- Staffing costs assume non-union operator wage rates and assume 5% overtime.
- O&M costs are presented in 2004 dollars (for consistency with the previous 600 MW study).
- The following unit costs are assumed in estimating the non-fuel variable O&M costs:
    - Ash Disposal $4.00/ton
    - Limestone $8.66/ton
    - Anhydrous Ammonia $250/ton
    - Activated Carbon $1,040/ton
    - Gypsum Sales $10.80/ton
    - Bottom Ash Sales $6.50/ton

The O&M costs do not include the following:

- Property taxes and insurance (included in pro forma analysis)
- Costs associated with emission allowances
- Fuel supply costs
- Wheeling costs
- Initial spares, pre-op costs (computers, software, office equipment, etc)
- O&M mobilization fees

6.0 ECONOMIC ANALYSIS

6.1 OBJECTIVE

Pro forma financial analyses were prepared to compare the 750 MW subcritical and supercritical pulverized coal alternatives to the 600 MW subcritical and supercritical pulverized coal alternatives as well as a 500 MW gas-fired combined cycle unit. The economic analyses are based on the estimated capital costs, performance, fuel costs, and operating costs for the alternatives. The economic results are summarized in the following sections.

6.2 SOLID FUEL ASSUMPTIONS & COST ESTIMATES

The following estimates and economic assumptions are utilized in the pro forma financial analyses for the solid fuel-fired units.

- Capital Costs including Owner Costs and Contingency — Table 5-1
- Heat Rate and Performance Estimates — Table 4-1
- Delivered Solid Fuel Cost Assumption
  Assumes 70%/30% coal/petroleum coke blend — 2012: $2.06 ($/MMBtu)
  2013: $2.09 ($/MMBtu)
  2014: $2.17 ($/MMBtu)
  2%/yr escalation after 2014
- Operating Assumptions:
  Planned Dispatch — 8,016 hours per year
  (one month planned outage)
  Overall Capacity Factor — 85.0%
- Financing Assumptions:
  Interest Rate — 6%
  Term — 30 years
  Debt/Equity Percentage — 100%/0%
  Return on Equity — N/A

Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	45 months

- O&M Cost Assumptions:

Fixed O&M Costs	Tables 5-3 and 5-4
Insurance	0.16% of Replacement Cost per year
Property Taxes	2% of Net Book Value per year
Variable O&M Costs	Tables 5-3 and 5-4
Transmission Costs	Not included – busbar cost evaluation
Lime/Limestone Costs	Included in variable O&M
Emissions Allowances	Not included

- Economic Assumptions:

O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Delivered Solid Fuel Inflation	2.0% per annum (after 2014)
Discount Rate	6%
Effective Tax Rate	0%
Book Depreciation (Straight Line)	30 years

6.3 COMBINED CYCLE BENCHMARK ASSUMPTIONS & COST ESTIMATES

The following estimates and economic assumptions are utilized in the gas-fired combined cycle pro forma economic analysis.

- Capital Costs including Owner Costs and Contingency — $369,600,000

- Heat Rate Performance Assumptions — 6,775 Btu/kWh (HHV)

- Delivered Natural Gas Cost Assumption — 2004: $5.50 ($/MMBtu)
  2.5% escalation after 2004

- Operating Assumptions:

Planned Dispatch	8,016 hours per year
Overall Capacity Factor	85.0%

- Financing Assumptions:

Interest Rate	6%
Term	30 years
Debt/Equity Percentage	100%/0%
Return on Equity	N/A
Construction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Construction Financing	24 months

- O&M Cost Assumptions:

Fixed O&M Costs	$2,724,000
Insurance	0.16% of Replacement Cost per year
Property Taxes	2% of Net Book Value per year
Variable O&M Costs	$3.25 ($/MWh)
Transmission Costs	Not Included – busbar cost evaluation
Emissions Allowances	Not included

- Economic Assumptions:

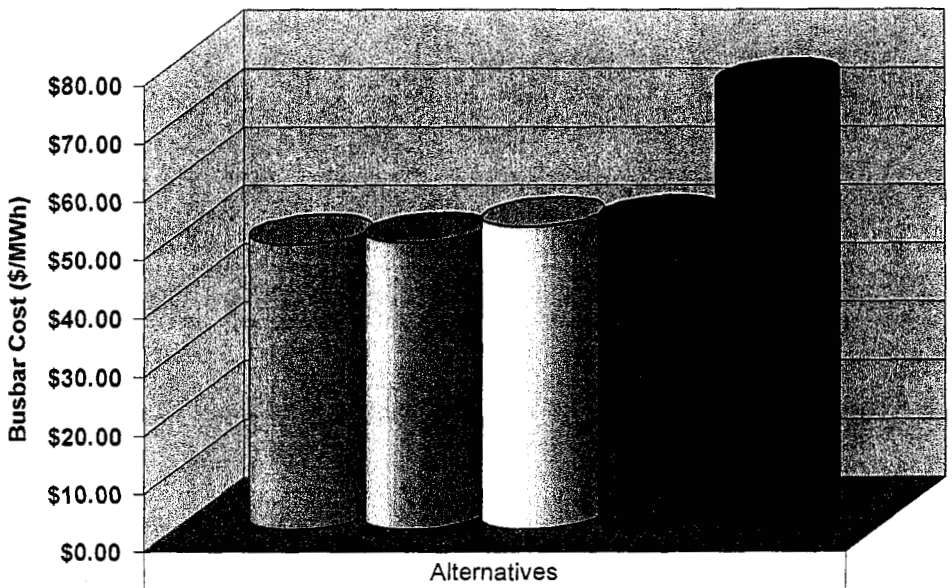
O&M Inflation	2.5% per annum
Construction Cost Inflation	2.5% per annum
Delivered Natural Gas Fuel Inflation	2.5% per annum (after 2004)
Discount Rate	6%
Effective Tax Rate	0%
Book Depreciation (Straight Line)	30 years

6.4 ECONOMIC ANALYSIS RESULTS

The economic pro forma analyses were used to determine the 20-year levelized busbar cost of power for each alternative. Figure 6-1 presents a graph of the resulting 20-year levelized busbar power costs for the benchmarks and both project alternatives. Figure 6-1 was developed by preparing a project pro forma for

the benchmarks and both alternatives under consideration. The busbar cost represents the energy cost in 2012$. The 20-year levelized busbar power costs for the 750 MW supercritical PC unit and 750 MW subcritical PC unit are $48.85/MWh and $49.15/MWh, respectively.

Figure 6-1: 20-Year Levelized Busbar Costs (2012$)



	Alternatives
750 MW Supercritical	$48.85
750 MW Subcritical	$49.15
600 MW Supercritical	$51.84
600 MW Subcritical	$52.08
500 MW CC	$75.48

6.5 ECONOMIC CONCLUSIONS

Both the 600 MW and 750 MW supercritical and subcritical PC units provide a low 20-year levelized busbar cost when compared to the gas-fired combined cycle plant. Combined cycle technology has a much higher fuel cost, but is much less capital cost intensive. For this reason, coal-fired technology is preferred to combined cycle technology for facilities with high capacity factors. Both of the coal-fired options are preferred to a combined cycle plant for baseload dispatch. Additionally, both 750 MW alternatives provide larger economies of scale than the 600 MW alternatives, as illustrated by their slightly lower levelized busbar costs.

6.6 SENSITIVITY ANALYSIS RESULTS

Sensitivity analyses were prepared for the project alternatives under the following cases:

- Capital Cost (plus or minus 10%)
- Interest Rate (plus or minus one (1) percentage point)
- Capacity Factor (plus or minus 5%)
- Delivered Fuel Cost (plus or minus 10%)
- O&M Costs (plus or minus 10%)

The results of the sensitivity analyses are presented in tornado diagrams in Figures 6-2 and 6-3. A tornado diagram illustrates the range of results for each sensitivity case and its impact on the levelized power cost, and ranks the results from greatest impact to least impact. The sensitivity analysis indicates that the interest rate, followed closely by fuel cost and capital cost, is the most significant factor affecting the economics of a solid fuel-fired unit.

Figure 6-2: Sensitivity Analysis – 750 MW Supercritical Unit

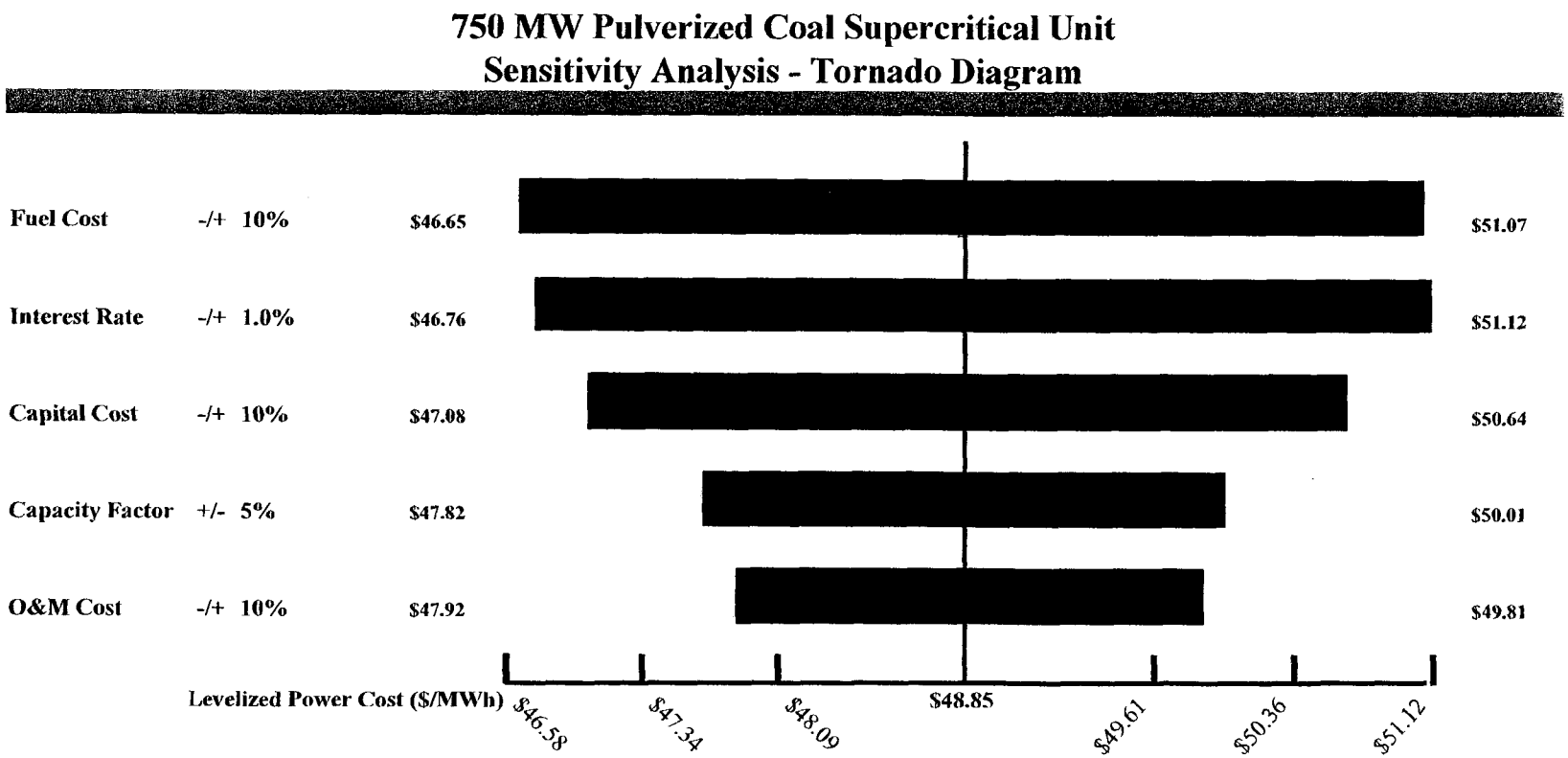


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Figure 6-3: Sensitivity Analysis – 750 MW Subcritical Unit

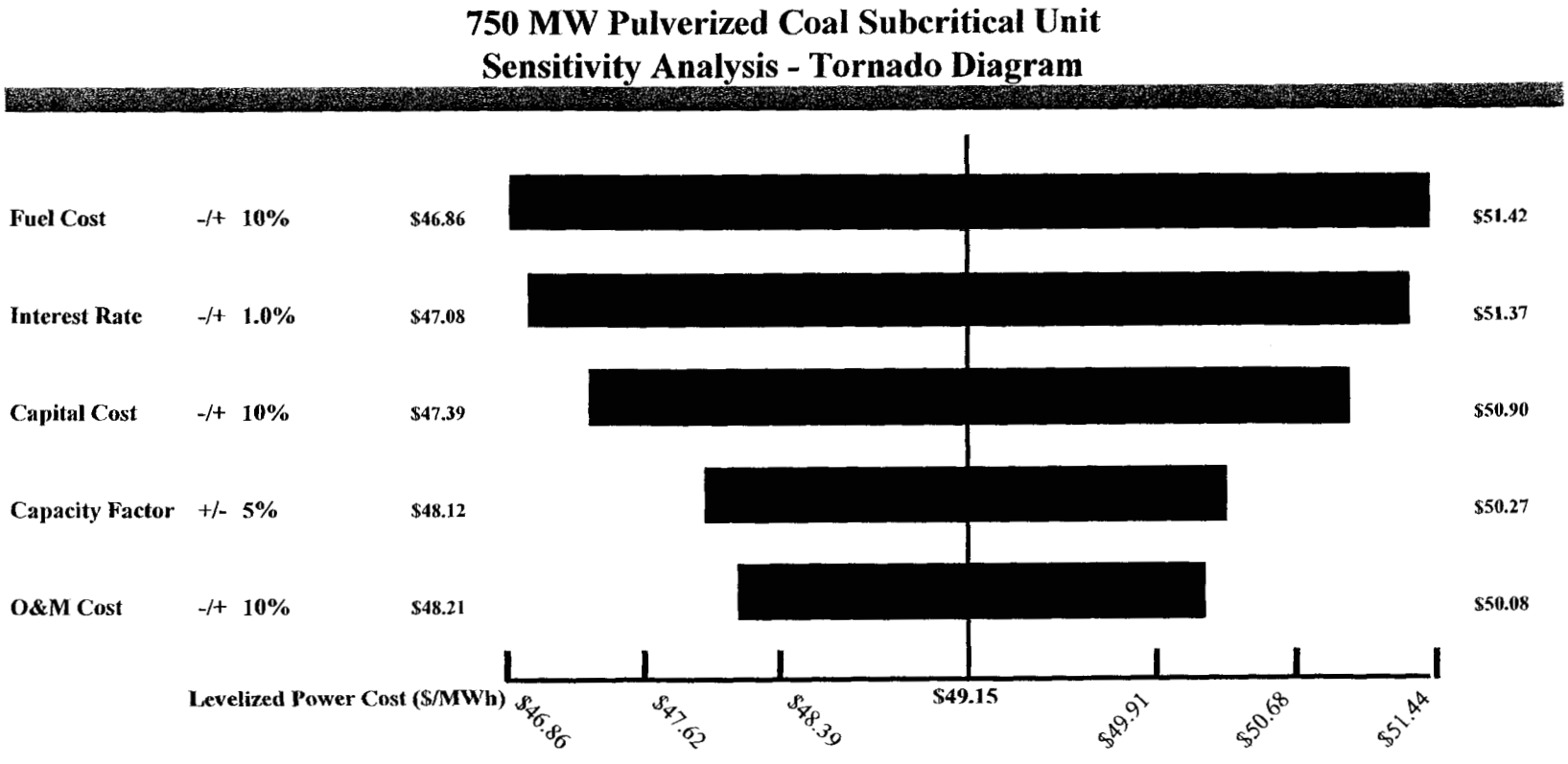


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7.0 CONCLUSIONS AND RECOMMENDATIONS

7.1 CONCLUSIONS

Both the 750 MW and 600 MW supercritical and subcritical pulverized coal units provide a lower 20-year levelized busbar cost when compared to the gas-fired combined cycle plant. Combined cycle technology has a much higher fuel cost, but is much less capital cost intensive. For this reason, solid fuel-fired technology is preferred to combined cycle technology for facilities with high capacity factors. Additionally, the solid fuel fired alternatives are preferred to a combined cycle plant for baseload dispatch.

The 750 MW supercritical unit has a slightly lower levelized busbar cost of $48.85/MWh versus the 750 MW subcritical unit busbar cost of $49.15/MWh.

Both of the 750 MW alternatives have lower levelized busbar costs than the 600 MW PC benchmark alternatives. The reason for these lower costs is the reduction in capital costs on a dollars per kilowatt ($/kW) basis for the larger 750 MW units.

Other factors to consider when selecting between subcritical and supercritical steam cycle include the following:

- Operator familiarity with subcritical technology at the SGS plant.
- Lower emissions due to the higher efficiencies of the supercritical technology.
- Permitting may face fewer hurdles with a supercritical cycle verses a subcritical cycle.
- Corrosive coals, such as that anticipated for use at SGS Unit 3, can cause excessive wastage and circumferential cracking in the water walls and liquid phase corrosion in the superheater and reheater when burned in supercritical units with elevated steam temperatures.
- There is currently no supercritical PC operating experience with 30% pet coke blend (i.e. high sulfur fuel), regardless of steam temperature.
- There is currently no subcritical PC boiler operating experience with 30% pet coke blend (i.e. high sulfur fuel) above 1000°F/1000°F steam conditions.

Due to the lack of experience with supercritical technology operation on high sulfur coals and the increased potential for excessive wastage, circumferential cracking, and liquid phase corrosion

anticipated on a supercritical unit, B&McD recommends subcritical technology be employed for SGS Unit 3.

7.2 STATEMENT OF LIMITATIONS

In preparation of this Feasibility Study, B&McD has made certain assumptions regarding future market conditions for construction and operation of solid fuel generation resources. While we believe the use of these assumptions is reasonable for the purposes of this Study, B&McD makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in this Study may vary.

Seminole Generating Station
Technology Assessment Study

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

Seminole Electric Cooperative, Inc.

March 2005
Project 38404

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 17
Company/ SEC
Witness: Richard Klover (RAK-5)

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March 9, 2005

Mr. Tom Wess
Manager of Generation Engineering
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

Project No. 38404
Technology Assessment Study

Mr. Wess:

Burns & McDonnell is pleased to submit our Technology Assessment Study to Seminole Electric Cooperative, Inc. (SECI). The purpose of the study is to provide an evaluation of supercritical pulverized coal technology, a 600 MW – 800 MW unit size assessment, and an update of the IGCC technology.

If you have any questions regarding the report, please contact me at 816-822-3274 or Jeff Greig at 816-822-3392.

It is a pleasure to be of service to SECI in this matter.

Sincerely,

Richard A. Klover

Richard Klover
Project Manager

Jeff Greig
General Manager

ENGINEERS • ARCHITECTS • CONSULTANTS
9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690
http://www.burnsmcd.com

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1.0 EXECUTIVE SUMMARY

1.1 SCOPE OF WORK

The purpose of this study was to assist Seminole Electric Cooperative, Inc. in evaluating the technical merits of supercritical pulverized coal technology, to provide a unit size assessment, and an update of the IGCC technology. The study consisted of the following assessments described below.

1.1.1 Supercritical Technology Assessment

Supercritical steam generation offers potential advantages over subcritical units. Advancements in supercritical technology make it the technology choice for some new coal-fired projects. When fuel costs are relatively high, or when reduced emissions offer a particular benefit, supercritical technology may be attractive. This assessment provides the status of the technology, examines the economics (efficiency, capital costs, and O&M costs) of supercritical steam generation and identifies the current supercritical projects in North America. Table 1.1 identifies the advantages of supercritical and subcritical steam cycles.

Table 1.1: Steam Cycle Evaluation

Criteria	Supercritical	Subcritical
Plant Efficiency	✓	
Simpler Controls		✓
Capital Cost		✓
Fuel Consumption	✓	
Fixed O&M	=	=
Variable O&M	✓	
Fuel Flexibility	=	=
Lower Design Pressure		✓
Startup Time	✓	
Ramp Rates	✓	
Emissions	✓	
Feedwater Quality Requirements		✓
Plant Availability	=	=

Supercritical steam generation in the United States experienced a troublesome operating history with the first generation of units. However, as recent data indicates that the availability of newer supercritical units both here and overseas is comparable to that of subcritical units of the same vintage. Supercritical units have significant advantages in efficiency and reduced emissions per kilowatt-hour of energy produced. They also have better plant cycling and load ramping capabilities than conventional drum type subcritical units.

1.1.2 Steam Cycle and Unit Size Assessment

The Steam Cycle and Unit Size Assessment evaluates the impact of steam parameters, turbine last stage blade length, and feedwater heater configuration on pulverized coal units. In addition, capital costs and O&M costs were developed between 600 MW and 800 MW net. Figure 1.1 shows the capital costs for both subcritical and supercritical units between 600 MW and 800 MW net.

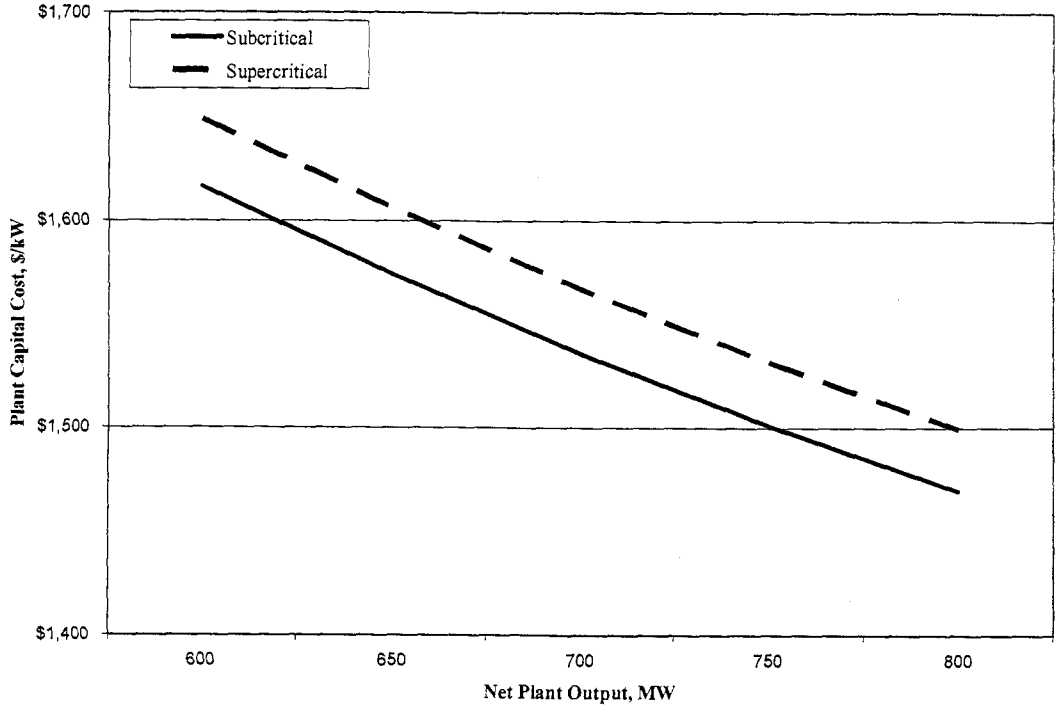


Figure 1.1: Plant Capital Cost vs. Net Plant Output

Figure 1.2 shows the differences in expected performance for both subcritical and supercritical units between 600 MW and 800 MW net. All heat rates in this report are HHV.

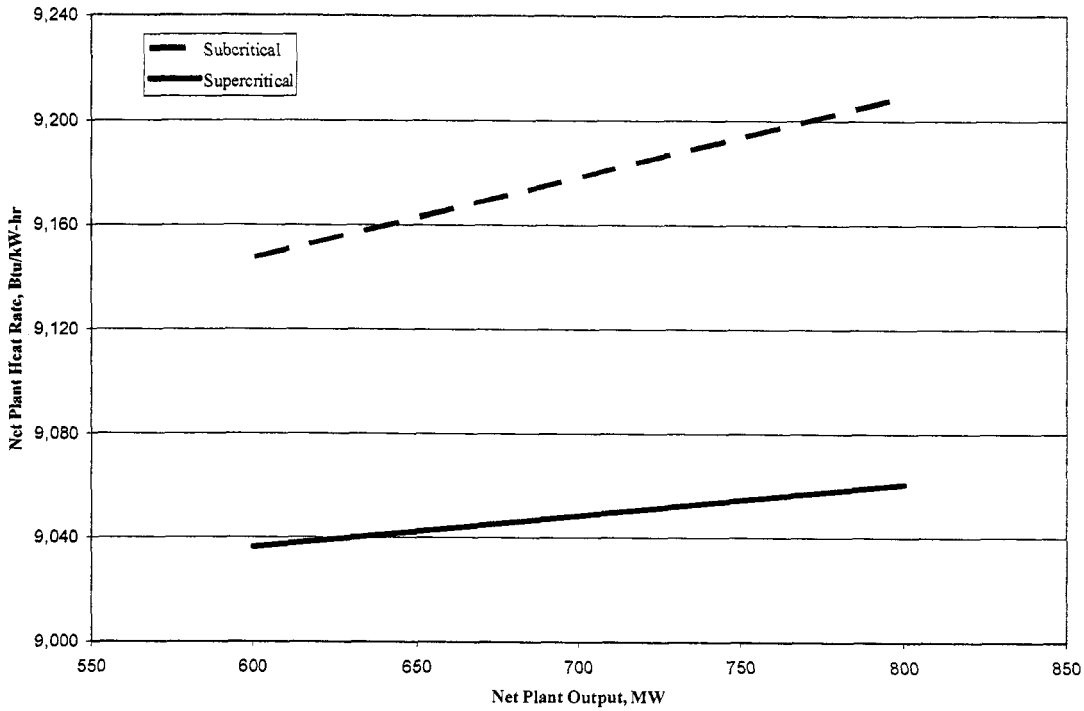


Figure 1.2: Net Plant Heat Rate vs. Net Plant Output

As the turbine output increases, the plant heat rate increases in the unit size range evaluated due to higher exhaust losses in the steam turbine. Supercritical steam cycles utilize less steam flow and therefore result in less performance degradation at the larger unit sizes. Feedwater heater configuration, turbine last stage blade lengths, and steam parameters also affect overall plant performance and are discussed in the assessment.

1.1.3 Integrated Gasification Combined Cycle Assessment

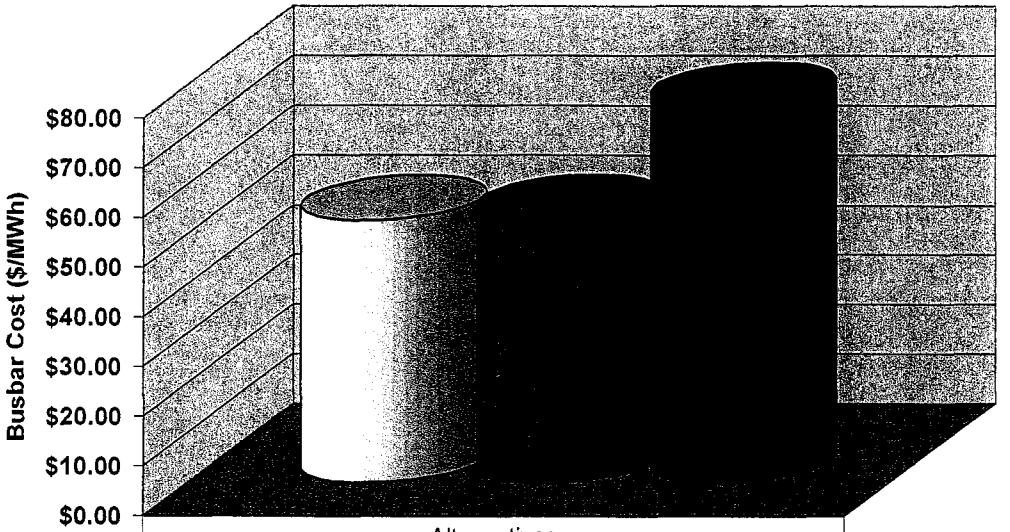
An assessment of Integrated Gasification Combined Cycle (IGCC) technology was performed due to the potential link between the relatively stable costs of solid fuels and the efficient operation of combined cycle gas turbines. This section presents current performance and economic information from the U.S. Department of Energy and General Electric, who now owns the Chevron Texaco technology. The information presented in this section is based on demonstration facilities and should be considered preliminary. There is planned development of IGCC units in the near future; however, it will be at least 4 -5 years before additional operational experience and cost information will be available.

2.0 SUPERCRITICAL ASSESSMENT

2.1 INTRODUCTION

This Supercritical Assessment is to assist Seminole Electric Cooperative, Inc. (SECI) in evaluating the technical merits of subcritical versus supercritical technology for Unit 3 at the Seminole Generating Station (SGS). The economic merits of supercritical technology were evaluated in the study "Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study" and are shown in Figure 2.1.

Figure 2.1
650 MW Solid Fuel Fired Unit
20-Year Levelized Busbar Costs (2012$)



	Alternatives
□Supercritical PC	$52.77
■Subcritical PC	$52.97
■Combined Cycle	$75.48

Rankine cycle steam power plants employ two main technologies for power generation. These technologies are characterized by the steam cycle operating pressure: subcritical (<3200 psia) and supercritical (3200 psia to 5000 psia). The primary advantages of supercritical cycles are, improved plant efficiency due to elevated operating pressures, lower emissions, and lower fuel costs as compared to subcritical cycles. However, supercritical technology has higher initial capital costs and has more operating complexities.

Supercritical units are very similar to the subcritical units. The major difference is the boiler operates in the supercritical region where water converts directly to steam without a two phase fluid existing. As a result, the supercritical boiler uses a once-through system, which does not use a steam drum. Since there is no steam drum to allow the removal and blowdown of impurities in the system, all impurities carried by the steam go into the steam turbine. For this reason, condensate systems typically incorporate a full-flow condensate polisher to maintain high water quality necessary for supercritical technology.

Supercritical boiler designs use either spiral or vertical tube arrangements. Both designs attempt to minimize areas in the corners of the boiler where flow through the tubes is typically starved, which can result in elevated tube wall temperatures and premature failure. The spiral tube design has more than 30 years of experience. The primary disadvantages of the spiral tube arrangement are the complexity in supporting the tubes and the additional tube-to-tube buttwelds, which results in increased construction costs. The spiral tube design also imparts additional friction drop in the system requiring higher head for the boiler feedwater pumps. The vertical tube design (Benson technology) has less operating history than spiral, but is gaining interest due to the reduced pressure drop and simpler construction configuration. Siemens owns the Benson technology and licenses it to various boiler manufacturers.

2.2 OPERATING HISTORY OF SUPERCRITICAL UNITS

The first generation of supercritical power plants were commissioned in the mid-1950s. These units operated at constant pressure, and were typically designed for steam turbine throttle conditions of 3500 psig and 1000°F main steam and 1000°F reheat temperatures. The second generation of supercritical units were commissioned in the 1960s and used constant waterwall pressure and sliding superheat steam pressure at the same steam conditions as the earlier units. By the mid-1960s, about half of all of U.S. units ordered were supercritical. The purchase of supercritical units in the U.S. dropped off dramatically in the 1970s primarily due to the onset of base-load nuclear power stations. New fossil fuel plants in this period were built to follow load. The subcritical cycle was selected for load following service because experience with cycling supercritical units was minimal. Also, at that time the supercritical units in the U.S. had a poor track record and suffered from a variety of problems.

In 1985, third generation supercritical units began operation primarily in Asia and Western Europe. These units incorporated new technologies and new materials that addressed the maintenance problems of previous supercritical units. Third generation supercritical units incorporated significant changes, including full sliding inlet turbine pressure and higher steam temperatures.

Most supercritical units in the U.S. burn coal. More than half have pressurized furnaces, and one-quarter of the supercritical units are equipped with double reheat sections. During the development of the supercritical unit in the 1960's, the average fossil unit grew in size from 247 MW to 500 MW. The typical U.S. supercritical unit suffered more from the rapid increase in unit size than from the high-pressure technology.

Much of the U.S. utility industry's initial dissatisfaction with supercritical units was actually due to the use of pressurized furnaces and due to furnaces being undersized, which resulted in excessive slagging burning Midwestern U.S. bituminous coals. Initial supercritical designs also operated at constant pressure, which required pressure reduction valves prior to the steam turbine. The pressure drop these valves were required to take proved to be a significant maintenance problem. In addition, the units had complex startup systems that proved to be difficult to operate. Table 2.1 is a summary of some of the typical problems with early generation supercritical units, and the countermeasures taken to address these issues.

Table 2.1: Problems and Countermeasures with Early Generation Supercritical Units

Problems Experienced in Early Generation Supercritical Units	Causes	Countermeasures (As applied in new supercritical units)
Start-up valve erosion	High differential pressure due to constant pressure operation and complicated start-up system.	Sliding pressure operation, simplified start-up system, and low load recirculation system.
Longer start-up times	Complicated start-up system and operation (ramping operation required, difficulty establishing turbine metal matching conditions, etc).	Sliding pressure operation, simplified start-up system, and low load recirculation system.
Low ramp rates	Turbine thermal stresses caused temperature change in HP turbine during load changing (due to constant pressure operation).	Sliding pressure operation.
High minimum stable operating load	Turbine bypass operation and pressure ramp-up operation required.	Application of low load recirculation system.
Slagging	Undersized furnace and inadequate coverage by soot blower system.	Design of adequate plan area heat release rate and furnace height, without division walls. Provision of adequate system of soot blowing devices and/or water blowers.
Circumferential cracking of water wall tubes	Metal temperature rise due to inner scale deposit and fire side wastage.	Oxygenated water treatment (OT). Protective surface in combustion zone of furnace for higher sulfur coal, e.g. thermal spray or weld overlay.
Frequent acid cleaning required	Inappropriate water chemistry	Application of OT
Lower efficiency than expected	High flue gas leakage due to pressurized furnace. RH spray injection required due to complications of RH steam temperature control in the double reheat cycle configuration.	Tight seal construction. Single reheat system with high steam temperature and temperature control by parallel damper gas biasing.
Turbine blade solid particle erosion	Inappropriate water chemistry	OT treatment
Low availability	All of the above	All of the above

2.3 CURRENT SUPERCRITICAL EXPERIENCE

Numerous supercritical units installed in Europe and Asia since the early 1980s allowed the technology to mature and resolved many problems with the early generation designs. Development of high strength materials for elevated temperatures helped to minimize the thermal stresses that caused problems in the early units. Variable pressure operation of all the circuits within the boiler eliminated the need for boiler valves in the fluid transition zone of the boiler. Development of distributed control systems (DCS) helped make the complex starting sequence much easier to control. Newer units also use a steam/water separator during startup to minimize solid particle carryover, which leads to the erosion of the steam turbine blades. These changes corrected many of the early problems with supercritical units. Availability of modern supercritical units closely matches that of similar subcritical units. Further, maintenance for supercritical units is only slightly higher than subcritical, due to thicker tube and pipe walls currently being used.

2.3.1 North American Projects

Currently planned supercritical pulverized coal units in North America are shown in Table 2.2.

Table 2.2: Currently Planned North American Supercritical Plants

Project	Owner	Cycle Parameters	Fuel	MW	Boiler Supplier
Genesee 3	Epcor & TransAlta Alberta Canada	3625 psig/1050F/1050F	PRB	450	Hitachi
Oak Creek	Wisconsin Energy Oak Creek, WI	3625 psig/1050F/1050F	PRB	2 x 600	Hitachi
Council Bluffs	MidAmerican Council Bluffs, IA	3675 psig/1050F/1100F	PRB	790	Hitachi
Weston 4	Wisconsin Public Service Weston, WI	3600 psig/1050F/1080F	PRB	500	Babcock & Wilcox
Prairie State	Peabody Marissa, IL	3670 psig/1050F/1050F	S. IL Bit	2 x 750	Undecided

2.3.2 European Experience

While the U.S. power industry shifted away from supercritical units due to problems initially experienced, the higher fuel costs common in Europe and Asia made the technology attractive. Advancements in the technology reduced significantly the types of problems that plagued the first generation units. By the 1990's supercritical units dominated new capacity projects overseas. Between 1995 and 2000 about 20,000 MW of new coal-fired capacity was installed in Europe. Supercritical boilers represented about 85 percent of that new capacity.

2.3.3 Japanese Experience

The first Japanese supercritical unit was commissioned in 1967. Since that time, the majority of 500 MW and larger fossil-fired power plants in Japan have been supercritical. Supercritical boilers commissioned in Japan in the 1970's operated in a constant pressure mode. In the 1980's, Japan experienced the onset of new base-loaded nuclear power stations and two-shift cycling (on-line during the day and off-line during the night) of some large capacity units was required. Presently, new fossil-fired units in Japan are being designed to cycle and use variable pressure supercritical cycles.

2.4 SUPERCRITICAL BOILER TECHNOLOGIES

Present day supercritical designs are descendants of earlier Benson and Sulzer Monotube once-through boilers from which most U.S. once-through boiler designs originate. Siemens holds the license for Benson boiler technology although they do not manufacture boilers. ABB (Switzerland) owns the Sulzer technology. The differences between these supercritical technologies are minor. A list of manufacturers holding a license for supercritical boilers is listed in Table 2.3.

Table 2.3: Licensed Supercritical Boiler Manufacturers

Manufacturer	Country	Benson - Siemens	Sulzer - ABB
Alstom	France		X
Ansaldo Energia	Italy	X	
Babcock & Wilcox	USA	X	
Babcock-Hitachi	Japan	X	
BWE	Denmark	X	
Deutsche-Babcock	Germany	X	
Formosa Heavy Industries	Taiwan		X
Foster Wheeler	USA	X	
Ishikawajima-Harima Heavy Industries (IHI)	Japan	X	
Korean Heavy Industries	Korea		X
Mitsubishi Heavy Industries	Japan		X
Mitsui Babcock	Britain	X	
Steinmuller	Germany	X	

Note: Combustion Engineering (Alstom) signed with Sulzer. Riley Stoker manufactured supercritical units, but now they are a part of Babcock Borsig and therefore are not currently designing or manufacturing supercritical boilers.

2.5 COMBUSTION CHAMBER WALL DESIGN

The combustion chamber wall designs of the once-through supercritical boiler have undergone significant evolution. First generation designs consisted of vertical and smooth tubes. Second generation designs employed a smooth spiral tube design in order to increase the mass velocity in the tubes and maintain proper heat transfer. Within the last ten years, some boiler manufacturers have designed supercritical units with vertical and rifled tubes.

The evaporator (or combustion chamber walls) in most once-through boilers is lined with tubes spiraling upward from the bottom of the furnace. The spiral wound furnace allows all tubes in the evaporator to be exposed to the heat flux at all four walls. Consequently, differences in tube-to-tube heat absorption are minimized and furnace wall exit gas temperatures are more uniform.

Although the spiral wound furnace offers performance advantages, there are several disadvantages associated with the spiral wound design:

- Due to the high mass flow through the reduced number of tubes in the spiral wound portion of the furnace walls, pressure drop is generally higher (100 psi or greater) than for a vertical wall unit, increasing boiler feed pump power requirements.
- Many designs use the spiral configuration in the lower furnace and a vertical configuration in the upper furnace. A header at the transition between these two portions of the furnace is required with this design.
- Because the angled walls are more difficult to support, and because there are typically four times as many tube-to-tube buttwelds in a spiral tube arrangement, the furnace is more expensive to manufacture and construct.
- Wall penetrations in the spiral walls are also more difficult to manufacture.

Some manufacturers are now offering a vertical wall design with rifled tubes. The vertical wall design offers a reduction in quantity of tubes, allows easier support of the furnace, reduces manufacturing costs, and reduces construction costs. Rifled tube design allows steam film to be dispersed by means of the grooves on the inside surface of the rifled tubes, thereby inhibiting film boiling and maintaining lower metal temperatures. Because the metal temperature of rifled tubes is kept sufficiently low, the design flow velocity can be reduced without difficulty. Mitsubishi first implemented this tube design at Shinchi Unit 2, a 1000 MW supercritical unit in Japan. Mitsui Babcock has also applied this technology at Yaomeng Power Plant in the Peoples Republic of China[2]. In this application, the bottom half of the boiler waterwalls were replaced with rifled vertical tubes in the once through boiler. Due to the operating success of this design, MHI and Mitsui Babcock recommend the use of the vertical rifled tube design to their customers because of its advantages.

Recent advancements have allowed designs up to 4500 psig with steam temperatures exceeding 1100°F. Units in this range of pressure are sometimes referred to as "ultra-supercritical." There is currently very limited operating experience with units at these steam conditions.

Most new supercritical units are being designed for variable pressure operation. This provides better part load efficiency, but complicates the design since the boiler operates at subcritical conditions at reduced loads, which changes the heat transfer in the water walls. Constant pressure operation requires a bypass operation for start-up to maintain minimum flow in the furnace at a constant supercritical pressure. This

complex system requires bypass valves to take a high pressure drop, which results in valve erosion and hence more frequent valve maintenance. In addition, constant pressure operation leads to longer startup times and low ramp rates. The change to variable pressure operation is accountable for several of the performance improvements in third generation supercritical units.

2.6 STEAM TURBINE IMPACTS

The pressure difference between subcritical steam pressures and supercritical steam pressures requires turbine stationary components to be more massive to keep stresses associated with the high pressure steam within allowable limits. Components affected include steam turbine stop and control valves, steam leads to the high pressure steam turbine, steam chest, and inner and outer shells. The higher steam pressure associated with the supercritical cycle reduces steam specific volume, which allows turbine steam path components to be smaller. Overall, the cost of the steam turbine is not significantly different between subcritical and supercritical units.

The impact of throttle pressure on steam turbine availability has been reported to be small. Sliding pressure operation results in minimal variation in first stage shell temperature during operation. Design problems experienced with the early supercritical turbines were attributed to the rapid increase (scale-up) in unit size, not to the supercritical steam cycle being utilized. The most significant problems experienced for steam turbines operating at either subcritical or supercritical pressures are solid particle erosion (SPE) of turbine blades and valves and stress corrosion cracking of low-pressure turbine blades.

Solid particle erosion of steam turbine blades and valves of U.S. units has proved to be more of a maintenance and heat rate concern than a cause of forced outages. Although SPE has caused units to be forced out of service, the erosion (which typically occurs over a two to ten year period) is likely to be discovered during routine inspections prior to the strength of the turbine blades becoming an issue. The likelihood of increasing the length of a turbine inspection outage is increased with the presence of SPE.

SPE in steam turbines has caused serious heat rate degradation, and substantial maintenance costs, in many domestic units. In contrast, European steam turbines with 100 percent steam turbine bypass systems have been mostly free of SPE. Newer supercritical units with integral separators and steam bypass systems to the condenser included in the start-up system design are not expected to experience the same level of SPE. Including a turbine bypass system may reduce SPE induced fuel costs, repair and replacement costs, scheduled outage costs, and forced outage costs.

Stress corrosion cracking is considered the primary cause of low-pressure steam turbine blade failure. Chlorides and other contaminants that enter the feedwater-steam cycle from the condenser cooling water system through condenser tube leaks are usually removed by condensate polishing systems. If a malfunction or improper operation of the condensate polishing system occurs without immediate operator action, these steam contaminants could adversely affect the steam turbine blade material.

2.7 PLANT AVAILABILITY

Most of the U.S. supercritical units were constructed during a time of rapidly increasing unit size, which complicates a comparative assessment of the availability of the U.S. plants with supercritical cycles versus those with subcritical cycles. Various studies of operating data have concluded that the availability of supercritical units should be similar to subcritical units. This tends to be true in other parts of the world. Availability data for a specific unit will depend on specific operational factors, such as a utility's maintenance practices, operating philosophy, and power generation needs.

Several boiler design improvements have lead to the increasing availability of supercritical units. First generation constant pressure supercritical units were susceptible to start-up valve erosion and were required to ramp-up to full pressure. This resulted in longer start-up time and higher minimum stable load. Thermal stresses are reduced with sliding pressure operation and therefore faster ramp rates can be achieved.

Historically, the availability of supercritical power plants in the U.S. has not been as good as noted for subcritical power plants. This is due in a large part to the specific design of the early units. However, the availability of supercritical units has been steadily improving in the past 20 years, as shown by the equivalent forced outage rates in Figure 2.2.

Several studies[1] conclude that, for today's plant designs, there is no significant difference in availability between subcritical and supercritical units. Note that the availability data described in this study is based primarily on supercritical units operating at 3600 psig/ 1000°F/ 1000°F.

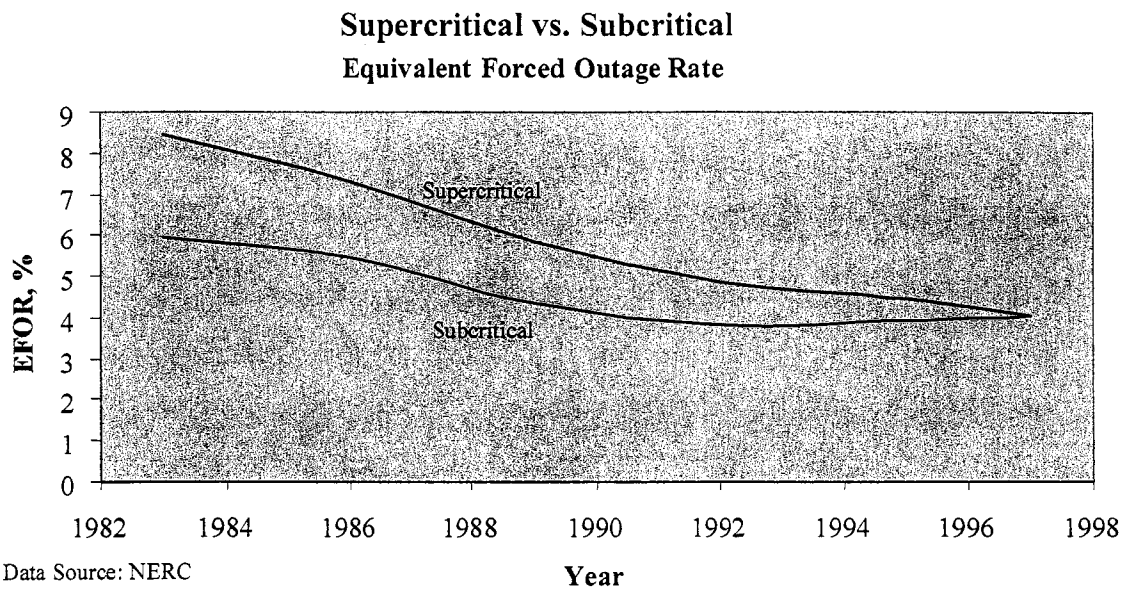


Figure 2.2: Supercritical vs. Subcritical Equivalent Forced Outage Rates

The long-term availability of the recent supercritical units with elevated steam temperatures is still unknown.

2.8 CORROSIVE COAL IMPACTS

Corrosive coals, which typically have greater than two percent sulfur and relatively high levels of vanadium or chlorine, can cause excessive wastage and circumferential cracking in the water walls and liquid phase corrosion in the superheater and reheater when burned in supercritical units with elevated steam temperatures.

Liquid phase corrosion is primarily a superheater/reheater phenomenon. The general mechanism and sequence of events for liquid phase corrosion begins with the formation of an oxide film on the furnace side metal surface. Alkali sulfates and sulfur oxides are deposited over the oxide scale on superheater/reheater materials. Eventually, because of an increasing temperature gradient, the outer surface of the alkali sulfate layer becomes sticky, and particles of fly ash adhere. With further increase in temperature, thermal dissociation of sulfur compounds in the ash releases SO_3, which migrates toward the cooler metal surface, while a layer of slag forms on the outer surface. With more ash in the outer layer, the temperature of the sulfate layer falls, and reaction occurs between the oxide scale and SO_3. Temperature excursions due to de-slagging or soot blowing exposes the alkali-iron tri-sulfates to higher

temperatures and leads to dissociation of sulfate and generation of SO_3. This causes further corrosive attack of the metal surfaces.

The main impacts to the water walls are wall wastage and circumferential cracking. The wall wastage is caused by corrosion due to the sulfur in the fuel. Circumferential cracking is a phenomenon almost exclusively associated with supercritical units and is due to two inter-related effects. A local reducing environment at the furnace wall promotes accelerated wastage of tube metal by an oxidation-sulfation reaction. Compounding this are thermal stresses generated by the rapid change in metal surface temperature due to insulating ash layer being removed from the tube, either by soot blowing or by natural sluffing off of the slag, which causes circumferential cracking in the protective oxide layer on the metal surface. Both of these effects are evident in both sub and supercritical pressure boilers; however, the rate of attack is higher for supercritical boilers due to the higher operating water wall temperatures. One means of counteracting the water wall wastage is to ensure an oxidizing atmosphere at the water wall. For example, Alstom does this by directing a portion of the combustion air along the wall.

Alstom provided the following compilation of NERC data, based on over 450 unit-years for supercritical units and over 1000 unit-years for subcritical units. Figure 2.3 shows the significant difference in boiler forced outage rates for supercritical units burning corrosive coal.

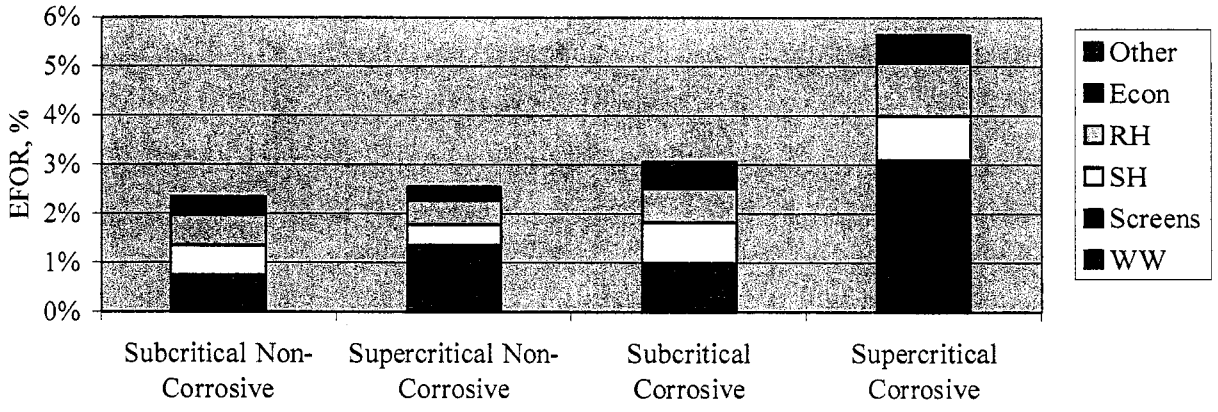


Figure 2.3: Boiler Forced Outage Rates

Boilers account for the majority of coal-fired plant forced outages. Babcock & Wilcox is currently conducting research for the U.S. Department of Energy on new materials that may prove to be more resistant to corrosion in corrosive fuel applications.

Currently there is no experience firing up to 30% pet coke at 1050°F/1050°F steam conditions. However, Santee Cooper is currently adding two 600 MW subcritical units firing 30% pet coke at these steam conditions. According to Alstom, thicker tubes and high nickel overlays are necessary as steam temperature rises to prevent sulfur-induced corrosion. It also may be necessary to increase the furnace size and rearrange the location of the superheat and reheat surface. These modifications all increase the cost of the boiler and may affect maintenance costs.

BMcD has been involved in projects where the boiler manufacturer recommended against using the supercritical cycle for a corrosive coals due to anticipated operating problems and potential reduced availability. However, on one project the boiler manufacturer indicated an availability equivalent to a subcritical unit could be achieved by increasing preventative maintenance and inspections in the water walls, superheaters, and reheaters. Alstom estimated this to require approximately $2 million per year more in boiler maintenance and inspection costs.

2.9 WATER CHEMISTRY

Operation of drum-type and once-through boilers requires that close attention be given to feedwater chemistry. Any condenser cooling water leaks or upset in the makeup water quality can result in contaminants entering the feedwater system. These contaminants and any corrosion products from the condensate and feedwater piping will be transported to the boiler. In the case of a drum-type boiler, a significant portion of these contaminants will be removed by boiler blowdown. However, in the case of a once-through supercritical unit, the boiler water and steam have the same density and the feedwater contaminants are carried directly to the turbine.

Full flow condensate polishing is required for a once-through unit, and is optional for a drum-type unit. For the drum-type unit, the condensate polisher may be either a partial flow side-stream or a full flow condensate polishing system. Since the drum-type unit has phase separation in the drum, it is not essential for every drum-type unit to have a condensate polisher. The drum steam separators will provide a relatively pure steam output and most of the dissolved solids and particulate in the liquid phase will be removed with the boiler blowdown. Once-through units do not have a drum; therefore, any solids in the boiler water will carry

over with the steam. Once-through boilers must have full flow condensate polishers for removal of contaminants from the cycle.

Because the drum-type unit has two distinct water phases in the boiler drum, drum-type units have less stringent feed water chemistry than a once-through unit. Drum-type units can use sodium phosphate solutions to buffer the boiler water while maintaining a small amount of phosphate to react and condition any small amount of hardness that may enter the boiler through condenser tube leaks. Boiler conditioning chemicals such as sodium phosphate should not be fed into once-through boilers. All chemicals fed into a once-through unit must be volatile. The two main all volatile chemical treatment programs used to treat the condensate and feedwater are All Volatile Treatment (AVT) and Oxygenated Treatment (OT).

Either all-volatile treatment method may be used for drum-type and once-through units. However, the majority of new units are being designed based on implementing the Oxygenated Treatment program.

AVT uses an amine for condensate and feedwater pH adjustment with an oxygen scavenger to provide a reducing environment. The OT method feeds oxygen into the condensate and feedwater to maintain an oxidizing environment. The hematite iron oxides that form in the oxidizing environment are less soluble than magnetite formed in the reducing environment which results in reduced corrosion product and contaminant transport. The benefits for OT are lower condensate and feedwater corrosion and less iron transport to the boiler resulting in less frequent chemical cleanings. The cycle makeup water quality and condensate quality must be very high when using the OT method. Poor condensate quality will result in accelerated corrosion rates and excessive transport of corrosion products to the boiler. In addition, copper alloys cannot be used in the condensate and feedwater systems, especially with an OT program. Oxygen in the water reacts with the copper to attack the iron in the waterwall pipes. Since the water quality demand for OT is so pure, the unit generally must include a condensate polisher when using an OT program. Subcritical units, however, may use natural oxygenated treatment. Although in this treatment there is far less oxygen in the water, the small presence still leads to copper induced corrosion. When either OT program is used, it is recommended for both supercritical and subcritical units that the water is free of copper contaminants.

Table 2.4: Water Treatment Methods for Different Boiler Designs

Item	Once-through	Drum-type
Condensate Polisher	Required	Recommended
All Volatile Treatment (AVT)	Allowed	Allowed
Oxygenated Treatment (OT)	Recommended	Allowed w/Condensate Polisher
Phosphate Boiler Conditioning	None	Acceptable
Boiler Blowdown	None	Control Boiler Water Solids

2.10 STEAM TURBINE BYPASS

Steam turbine bypass systems allow steam production to bypass the steam turbine and flow directly to the condenser. Traditional bypass systems typically include two stages. The first stage is a bypass of main steam to the cold reheat and the second stage is bypass of hot reheat steam to the condenser. Turbine bypass systems are most commonly used in cycling fossil steam plants. The transient nature of cycling operation induces high stresses on the boiler, steam turbine, and balance of plant equipment. Additionally, frequent starts require expensive start-up fuel. A turbine bypass system alleviates these stresses and costs by:

- Allowing matching of steam temperatures to turbine metal temperatures during warm and hot starts.
- Allowing continued boiler operation after a steam turbine trip and rapid restart after fault resolution.
- Reducing solid particle transfer to the steam turbine during start-up or load changes.
- Reducing safety/relief valve operation with sudden load reductions.
- Reducing steam venting by redirecting steam production to the condenser saving demineralized water.
- Reducing start-up time and therefore saving start-up fuel.

In addition to reducing cycling operation stresses and costs, the bypass system also provides benefits during commissioning and restarting after extended shutdowns. These benefits include:

- Faster start-up after an extended shutdown.
- Faster cleanup of main steam and boiler water chemistry.
- Testing and commissioning of boiler equipment (pulverizers, gravimetric feeders, etc.) without the need for a functioning steam turbine.

For a 600 MW to 800 MW net supercritical unit, start-up fuel savings alone do not justify the capital cost of adding a turbine bypass system to the condenser when 100 percent base load operation is planned. Significant increases in the number of starts per year would have to occur to justify the addition of a turbine bypass system. This is especially true of once-through boiler designs, which include start-up bypasses within the boiler as standard design.

However, it is recommended for supercritical units that an HP bypass system be included to bypass main steam to the reheater of the boiler. The HP steam bypass provides steam flow through the reheaters to cool the reheater tubes and prevent overheating prior to steam flow being available from the cold reheat section of the steam turbine. Without this bypass, the ability of the boiler to produce steam at elevated temperatures during start-up is limited to around (700 °F to 800°F). These temperatures reflect the impact of typical recommended operating limits in boiler exhaust gas temperatures from boiler manufacturers prior to establishing flow in the reheaters (around 1000°F limit on furnace exit gas temperature). An HP bypass is needed to allow start up following a plant trip without incurring a significant hold period. This bypass would be in lieu of ignoring the steam turbine and boiler manufacturer's recommendations regarding boiler exhaust gas temperatures and temperature mismatches during a hot restart, as has typically been industry practice on existing plants that do not have steam turbine bypasses.

An HP bypass system costs approximately $7/kW for a 600 MW net plant, whereas the full cascading type turbine bypass system will cost approximately $13/kW. Fixed operating costs for a plant with a turbine bypass system are higher than for a plant without a turbine bypass system. Either arrangement requires the same number of operating personnel. However, the turbine bypass system will require bypass and temperature control valve maintenance. Additionally, insurance costs may increase with the bypass system because the cost of insurance is relative to the capital cost. Non-fuel variable operating and maintenance costs however, are identical with or without a turbine bypass system with the exception of start-up fuel cost. Start-up fuel costs typically drive the decision to add a turbine bypass system. However, in a base load plant with minimal starts per year, start-up fuel savings are minimal.

2.11 HEAT RATE BENEFITS

Conventional subcritical steam cycles are based on steam turbine throttle conditions of 2400 psig and 1000°F and 1000°F reheat steam temperature. Steam cycle efficiency improves as pressure and temperature is increased. For a single reheat cycle, increasing throttle pressure from 2400 psig to 4500 psig improves heat rate approximately 2.5 percent, while increasing steam temperatures from 1000°F/1000°F to 1100°F/1100°F improves the heat rate approximately 3 percent. Steam temperature increases produce greater improvements in efficiency than do increases in steam pressure. As steam pressure increases, the marginal improvement diminishes whereas temperature increases continue to pay steady dividends. Figure 2.4 below shows the estimated improvements in cycle efficiency possible with the supercritical steam cycle.

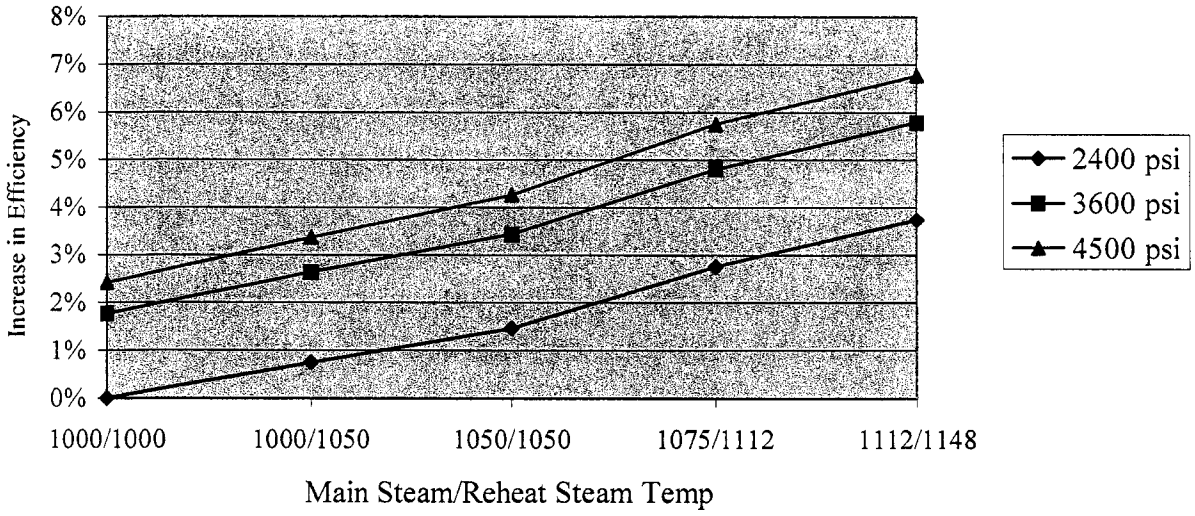


Figure 2.4: Impact of Steam Conditions on Efficiency

Even owners who decide against supercritical units are considering increasing steam temperatures beyond 1000°F. Analysis of recent boiler and steam turbine bids received by Burns & McDonnell concluded that a 2400psig/1050°F/1050°F subcritical steam cycle using single or double reheat is more cost-effective than a 2400 psig/1000°F/1000°F subcritical cycle.

Additional efficiency improvements can be realized by utilizing a double reheat cycle. The double reheat cycle at 1000°F /1000°F /1000°F and 3600 psig has a 2 percent boiler efficiency advantage over the single

reheat cycle at the same pressure. The double reheat cycle at 4500 psig with steam conditions of 1000°F /1025°F /1050°F has an estimated heat rate that is 6 percent better than the 2400 psig /1000°F /1000°F subcritical steam cycle. However, there is limited experience with double reheat cycles and the double reheat configurations are generally cost prohibitive and have higher operational complexities.

2.12 EMISSION BENEFITS

Supercritical units have lower annual emissions than subcritical units. Although the stated emission rate in pounds per million Btu of fuel burned is the same for both units, the reduced fuel consumption for a supercritical unit will result in lower total annual emissions for the same net annual output of power. Therefore, some utilities are considering supercritical units primarily due to their environmental benefits. It may be easier to gain public support for a project if the owner shows they are using proven technology with the lowest annual emissions.

Recent PSD permit applications have been submitted with the BACT emission limits shown in Table 2.5.

Table 2.5: Emission Limits for New Plants

Facility	MW	Steam Cycle	Fuel	SO_2	NO_x	PM_{10}	CO	Hg
Weston 4	500 MW	Supercritical	PRB	0.12	0.08	0.02	0.15	7.50e-6
Longview Power	600 MW	Supercritical	WV Bit. 2.5% Sulfur	0.12	0.08	0.018	0.11	2.39e-6
OPPD	600 MW	Subcritical	PRB	0.10	0.08	0.027	0.16	3.85e-6
Prairie State	2 @ 750 MW	Supercritical	S IL Bit.	0.182	0.08	0.015	0.12	2.00e-6
Santee Cooper	2 @ 600 MW	Subcritical	Bit./Pet Coke	0.25	0.08	0.018	0.17	3.60e-6
MidAmerican	750 MW	Supercritical	PRB	0.10	0.07	0.025	0.154	1.70e-6

*All limits shown in lb/MMBtu

2.13 OPERATIONAL FLEXIBILITY

A common misconception is supercritical units do not operate well at part load conditions and are not suitable for cycling service. In reality, new supercritical units operating with sliding pressure have demonstrated good part load efficiencies.

2.13.1 Startup Times

In cycling service, the boiler is limited with regard to how rapid the temperature of certain components may change. Drum-type subcritical units are limited by thick-walled components like the steam drum and the superheater outlet headers. The drum on a natural circulation boiler is typically 1.2 to 1.3 times larger than that of a forced circulation boiler. The larger drum allows larger volumes of water storage to help minimize level change under rapid downward load and pressure ramping. Because the forced circulation drum is smaller, the wall thickness is smaller and faster load changes are achievable.

Supercritical units do not have drums and, therefore, do not have the same magnitude of load ramp delays associated with component temperature differentials. Integral separators located downstream of the furnace in the supercritical cycle can be relatively thick-walled components. Manufacturers, however, have typically utilized multiple separators in their design, thus reducing the size and required wall thickness.

Supercritical units are typically designed for forced circulation, requiring the use of boiler circulating pumps. During start-up, shutdown, and low load operation (up to 35 percent unit capacity) a boiler circulating water pump (BCP) is used to maintain mass flow in the furnace wall tubes to avoid overheating. Discharge from the furnace walls is directed through one or more separators at all loads, but at low loads (less than 35 percent), the water that is removed from the steam/water mixture exiting the furnace walls is re-circulated by the BCPs. The steam is directed to the superheater and then to the steam turbine.

At about 35-40 percent load the steam separators dry out and the BCPs are removed from service. Water level controls on the separator automatically control when the BCPs are removed from service. The turbine-generator load is raised by increasing the boiler pressure, and supercritical pressures are achieved at about 60 to 70 percent load.

Alstom provided information on hot, warm, and cold startup times for once-through and drum units, which are summarized in Table 2.6. The startup times are based on units with a bypass system. Startup times for units without a bypass system will be considerably longer. The Alstom data is representative of other boiler vendors.

Table 2.6: Startup Times for Alstom Boilers

First Fire to Turbine Synch	Once-Through Minutes	Drum Unit Minutes
Hot Startup, After 2 Hour Shutdown	30	30
Warm Startup, After 8 Hour Shutdown	45	45-70
Cold Startup, After 36 Hour Shutdown	90	140-220

2.13.2 Ramp Rates

Alstom provided expected steam temperature swings for different ramp rates for both drum type and once-through units. The following table assumes the units are operating in sliding pressure mode and with a five minute load ramp. The data is similar to that received from other vendors.

Table 2.7: Steam Temperature Variances at Different Ramp Rates

	Main Steam Temperature	Reheat Steam Temperature
Drum Type		
3% per minute (30-100% load)	±10 F°	±15 F°
5% per minute (50-100% load)	±35 F°	±40 F°
Once-Through		
3% per minute (30-100% load)	±10 F°	±10 F°
5% per minute (50-100% load)	±10 F°	±12 F°

2.14 ECONOMICS

Burns & McDonnell performed a number of analyses of supercritical vs. subcritical cycles for projects in recent years. The economic comparison of supercritical vs. subcritical units typically represents a trade-off of higher capital cost versus reduced operating costs. The economic analyses for a new subcritical and supercritical unit at the Seminole Generating Station are reflected in the study "Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study".

Certain components of a coal-fired unit have a higher initial capital cost for a supercritical unit in comparison to a subcritical unit. The following components are typically more costly in a supercritical unit:

- Boiler
- Steam Turbine
- Boiler feed pumps and startup boiler feed pump
- Feedwater heaters and feedwater piping

- Steam piping
- Condensate polishing equipment, full flow instead of a side-stream partial flow

The steam turbine and steam piping capital cost is typically slightly higher for supercritical than subcritical units. Increases in the steam temperature will have a greater impact on cost than increases in the steam pressure.

The following components are less costly for a supercritical unit since a supercritical unit will burn less fuel and will have less heat rejection from the steam cycle:

- Condenser/cooling water system
- Fuel handling equipment
- Ash handling equipment
- Air pollution control equipment and systems
- Water treatment equipment and systems

In our analyses, typical results show supercritical units compared with subcritical units have a slightly higher capital cost, better efficiency that reduces fuel consumption, lower emissions and sorbent costs, more consumables for the condensate polisher, and comparable operating and maintenance costs. The previously issued report "Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study" contains the O&M estimates for supercritical and subcritical units operating at SGS. Due to the high value of ash and gypsum sales, O&M costs are slightly higher for the supercritical unit.

2.15 FUTURE TRENDS

Boiler manufacturers are working with materials suppliers to investigate and develop new materials that would allow supercritical steam cycles to increase to 5400 psig and 1300°F or greater steam temperature.

2.16 CONCLUSIONS

Modern supercritical units have significant advantages in efficiency and reduced emissions per kilowatt-hour of energy produced. They also have better plant cycling and load ramping than conventional drum type units. Advances in supercritical technology should allow new units to have availability rates similar to subcritical units. Experience worldwide has shown availability can be comparable to subcritical units of the same vintage.

Subcritical units have the advantages of being familiar to U.S. operators and less complex to operate. Control systems on subcritical units are less complex and require less equipment and fewer instruments. Water quality is less critical, and "upsets" in treatment or condenser tube leaks are more easily managed. Drum-type units tend to use materials that are more conventional and the vertical tube configuration in the furnace will be less costly to repair than spiral wound furnaces commonly used for supercritical units.

For projects using low to moderate priced fuels, the life cycle economics of supercritical vs. subcritical units are approximately equal. The results for a specific project will depend on the delivered fuel cost at the specific plant location and the cost of capital for the project. However, as new environmental regulations are passed and limiting emissions becomes more critical, it is anticipated that more owners will select supercritical units.

Table 2.8 summarizes the advantages of supercritical units compared to subcritical units.

Table 2.8: Steam Cycle Evaluation

Criteria	Supercritical	Subcritical
Plant Efficiency	✓	
Simpler Controls		✓
Capital Cost		✓
Fuel Consumption	✓	
Fixed O&M	=	=
Variable O&M	✓	
Fuel Flexibility	=	=
Lower Design Pressure		✓
Startup Time	✓	
Ramp Rates	✓	
Emissions	✓	
Feedwater Quality Requirements		✓
Plant Availability	=	=

2.17 REFERENCES

1. Supercritical Power Plants Evaluation of Design Parameters, The World Bank Group, at http://www.worldbank.org/html/fpd/em/supercritical/ppt_supercritical/index.htm
2. Refurbishment of Yaomeng Power Plant, DTI Publication URN 03/1065 at http://www.dti.gov.uk/energy/coal/cfft/cct/pub/bpb005.pdf

3.0 STEAM CYCLE AND UNIT SIZE ASSESSMENT

3.1 INTRODUCTION

Seminole Electric Cooperative, Inc. is evaluating the feasibility of adding Unit 3 at the Seminole Generating Station with a capacity between 600 to 800 MW net. A previous evaluation was performed by Burns & McDonnell titled "Seminole Generating Station 650 MW Solid Fuel Fired Unit Feasibility Study" which defined the performance, capital costs, O&M costs and levelized busbar costs for a 600 MW net subcritical and supercritical unit. This assessment evaluates the performance, capital costs, and operating costs associated with an incremental increase in net plant output up to 800 MW net.

3.2 STEAM CYCLE ASSESSMENT

This section evaluates the effect of steam parameters, turbine last stage blade length, and feedwater heater configuration on the performance and economics for both subcritical and supercritical units.

3.2.1 Steam Parameters

As discussed in the supercritical assessment, the improvement in heat rate when comparing 1000°F/1000°F steam conditions to 1050°F/1050°F steam conditions will be around 1.5 percent for subcritical and supercritical units. Table 3.1 shows that there is a small capital cost difference for this temperature increase relative to the gain in efficiency. However, as the heat rate improves with steam temperatures over 1050°F/1050°F, the capital cost increases by approximately 0.4 percent for subcritical and supercritical units. With the commercial introduction of new steel alloys with higher allowable stresses and longer life at elevated temperatures, a number of power plants with steam parameters above 1075°F/1100°F have been built in Japan and Europe. New materials have recently emerged commercially that will allow steam parameters to exceed 1100°F/1100°F. However, there is currently no domestic experience with pulverized coal plants operating at these steam parameters. At these higher steam temperatures, high sulfur coal or pet coke may lead to liquid phase corrosion in the boiler.

Table 3.1: Percent Increase in Capital Costs at Different Steam Conditions

Steam Cycle	1000°F/1000°F	1000°F/1050°F	1050°F/1050°F	1075°F/1100°F
Subcritical	BASE	~ 0%	0.12%	0.5%
Supercritical	2.0%	2.0%	2.1%	2.5%

3.2.2 Turbine Last Stage Blades

The critical component of the steam turbine that affects heat rate is the last stage blade (LSB) selection and number of low-pressure steam turbine flow paths. Plants in the 600 MW to 800 MW size range will utilize a four-flow low-pressure steam turbine. The last stage blade selection, however, is not as simple because LSB availability and performance varies significantly by steam turbine manufacturer. The largest last stage blades with any significant operating experience are between 40 inches and 42 inches in length. Smaller blades are also available between 32 inches and 34 inches in length. This evaluation compares GEs 33.5 inch and 40 inch blades.

The economic benefit of using larger last stage blades is dependent on plant output and steam turbine backpressure. For units in the range of 600 MW to 800 MW, economics typically dictate that longer last stage blades are justified. A 600 MW steam turbine capital cost increases approximately $4 million dollars when 40 inch LSBs are used instead of 33.5 inch LSBs. Depending on operating backpressure, the 40 inch LSBs result in an efficiency gain of up to 2%.

The largest last stage blades with any significant operating experience are between 40 inches and 42 inches in length. This range of last stage blade lengths provides a viable option for 600 MW to 800 MW units.

Nearly all steam turbine manufacturers are currently developing longer last stage blades (up to 46 inches). However, there are no units in commercial operation with these longer last stage blades. Several manufacturers have progressed to the point that they are testing or will soon be testing a full scale version of the blades in a test stand. Utilization of these larger last stage blades could result in a significant improvement in plant heat rate and an associated reduction in plant emissions.

3.2.3 Feedwater Heater Configuration

The configuration of feedwater heaters in a steam cycle affects the cycle efficiency. The higher the feedwater temperature entering the boiler the less heat input from the boiler required to heat it to its saturation temperature prior to vaporizing it. The resulting savings from the reduced boiler heat input more than offset the output lost as a result of extracting the steam from the steam turbine. This is because nearly all the energy in the extracted steam heats the water through a series of cascading feedwater heaters. If not used for feedwater heating, nearly 30 – 40 percent of the energy in the steam is lost in the heat rejection system after the steam exhausts from the steam turbine. The addition of a feedwater heater above the reheat point (HARP) offers a substantial increase in efficiency with minimal capital investment, maintenance costs, and risk. In the 600 MW to 800 MW net range, the eighth feedwater heater improves the plant heat rate by approximately 1.0 percent for supercritical units and 0.8 percent for subcritical units. The addition of the HARP feedwater heater usually is economically justified as the operating savings more than offset the additional capital costs. Adding an eighth feedwater heater to both a subcritical and supercritical units increases the total capital cost by approximately $2 - 4/kW. Along with the economic benefits, the eight feedwater heater cycle offers risk mitigation in regards to increases in fuel costs, sorbent costs, and for future emissions legislation.

The addition of a high pressure feedwater heater to the cycle requires no special operating and maintenance considerations. Maintenance requirements are the same as those required for the other high pressure feedwater heaters and are minimal with application of proper materials of construction and proper water treatment practices.

In order to provide steam to the eighth feedwater heater, the steam turbine requires an extraction connection in the high pressure section of the steam turbine. Manufacturers indicate the capital cost is minimal to add the HP turbine extraction for units in this size range. The increased steam flow for the HARP feedwater heater configuration requires increased boiler feedwater flow rates and therefore, larger feedwater pumps and drives which increases the capital cost. Due to increased efficiency, an eight feedwater heater cycle results in lower fuel consumption than a seven feedwater heater cycle. This reduced fuel consumption results in lower exhaust gas flow rates and lower annual emissions. Therefore, the air pollution control system will be smaller by a proportional amount. The improved heat rate of the eight feedwater heater cycle compared to a seven feedwater heater cycle also reduces the size of the cycle heat rejection system. The result of this is that a smaller cooling tower and condenser can achieve the same backpressure.

3.3 UNIT SIZE ASSESSMENT

This section evaluates the capital cost and performance of 600 MW to 800 MW net pulverized coal units with a single reheat steam turbine on a brownfield site. Performance and capital costs identified in this section are based on the following:

- The unit is designed for a 70/30 blend of bituminous coal and pet coke.
- The pulverized coal fired boiler will utilize balanced-draft combustion with single reheat.
- Emission controls include selective catalytic reduction (SCR) for NO_x reduction, activated carbon injection for mercury control, an electrostatic precipitator (ESP) for particulate collection, a wet flue gas desulfurization system (FGD) for sulfur dioxide (SO_2) reduction and a wet ESP for sulfuric acid (H_2SO_4) reduction.
- A circulating water system that includes a natural draft cooling tower and circulating pumps that supply cooling water to a water-cooled surface condenser.
- A 1050°F/1050°F steam cycle with 40 inch steam turbine last stage blades.
- An eight feedwater heater configuration for a supercritical unit and a seven feedwater heater configuration for a subcritical unit.

The estimated performance and cost estimates are based on in-house data and information from similar projects. The basis for the assumptions and scope of supply is identified in the "Feasibility Study for a 600MW Solid Fuel Fired Power Plant" study.

The estimates and projections prepared by Burns & McDonnell relating to construction costs and schedules are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by Burns & McDonnell.

Due to the capital intensive nature of solid fuel generation projects resources and length of construction period, there is capital cost risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact several US boiler manufacturers are currently under financial duress, and the skilled workforce that

constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives, which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

3.3.1 Performance

Estimated performance was developed for 600 MW to 800 MW net subcritical and supercritical pulverized coal units at SGS. Figure 3.1 shows that as plant size increases from 600 MW to 800 MW net, the net plant heat rate increases slightly, assuming constant condenser pressure.

The heat rate advantage of a supercritical unit over a subcritical unit varies slightly with plant size. The velocity exiting the last stage of a 800 MW net steam turbine is higher than a 600 MW net steam turbine. This results in higher losses in the back end of the turbine because the units use the same last stage blades and therefore share a fixed annulus area for the steam to flow. Supercritical cycles require less steam flow than subcritical cycles resulting in overall lower steam turbine exhaust losses. Since the supercritical steam cycle unloads the back end of the steam turbine, the performance benefit for the 800 MW net option will be greater than for the 600 MW net option. The net plant heat rate increases about 0.7% for a subcritical unit compared to a 0.3% increase for a supercritical unit over the 600 MW to 800 MW net size range.

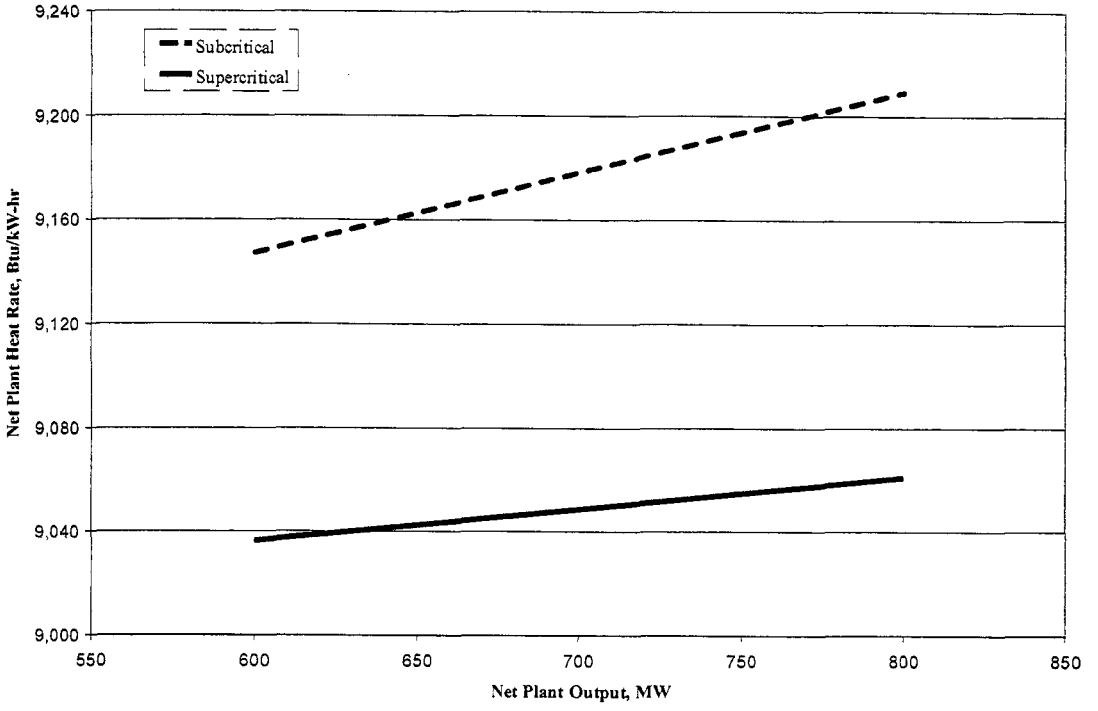


Figure 3.1: Net Plant Heat Rate vs. Net Plant Output

3.3.2 Emissions

A preliminary assessment of the anticipated Best Available Control Technology (BACT) and the anticipated emissions requirements for a new 600 MW net pulverized coal unit at SGS were discussed in the previous study "Feasibility Study for a 600MW Solid Fuel Fired Power Plant." BACT emission levels change with time, unit type, and fuel type. The emission rates are based on Burns & McDonnell's best estimated BACT levels taking into account technology limitations and current expected guaranteed performance levels.

The air pollution control equipment required to accommodate the 70% bituminous coal and 30% pet coke blend is as follows:

- SCR for NO_x control.
- Activated Carbon Injection System for mercury (Hg) control.
- ESP for particulate (PM) control.
- Wet FGD for SO_2 control.
- Wet ESP for sulfuric acid mist (H_2SO_4) control.

The BACT emission limits shown in Table 3.2 are not expected to change between 600 MW and 800 MW net units. The PM emission rate is filterable particulate matter only. The mercury emission limit specified is based on recent test data and does not represent a typical vendor guarantee. In addition, the CO limit is based on the expected byproducts from the combustion process in the boiler and is not a controlled pollutant.

Table 3.2: Preliminary BACT Emission Limits for 600 MW - 800 MW Units

Pollutant	Emission Limit
NO_x	0.07 lb/MMBtu
SO_2	0.18 lb/MMBtu
PM	0.015 lb/MMBtu
Hg	6 x 10^-6 lb/MW-hr
CO	0.15 lb/MMBtu
H_2SO_4	0.005 lb/MMBtu

3.3.3 Capital Costs

The capital costs summarized in this section are based on previous screening-level cost estimates used in evaluating the installation of a 600 MW net pulverized coal unit adjacent to the existing units at the Seminole Generating Station. Burns & McDonnell did not solicit bids from equipment manufacturers or contractors for equipment or construction services.

The capital cost estimates for 600 MW to 800 MW net subcritical and supercritical pulverized coal units are included in Figure 3.2 below. It is shown that as unit size increases from 600 MW to 800 MW net, the capital cost decreases by 9 percent on a $/kW basis. Therefore, there are economies of scale with increases in plant size.

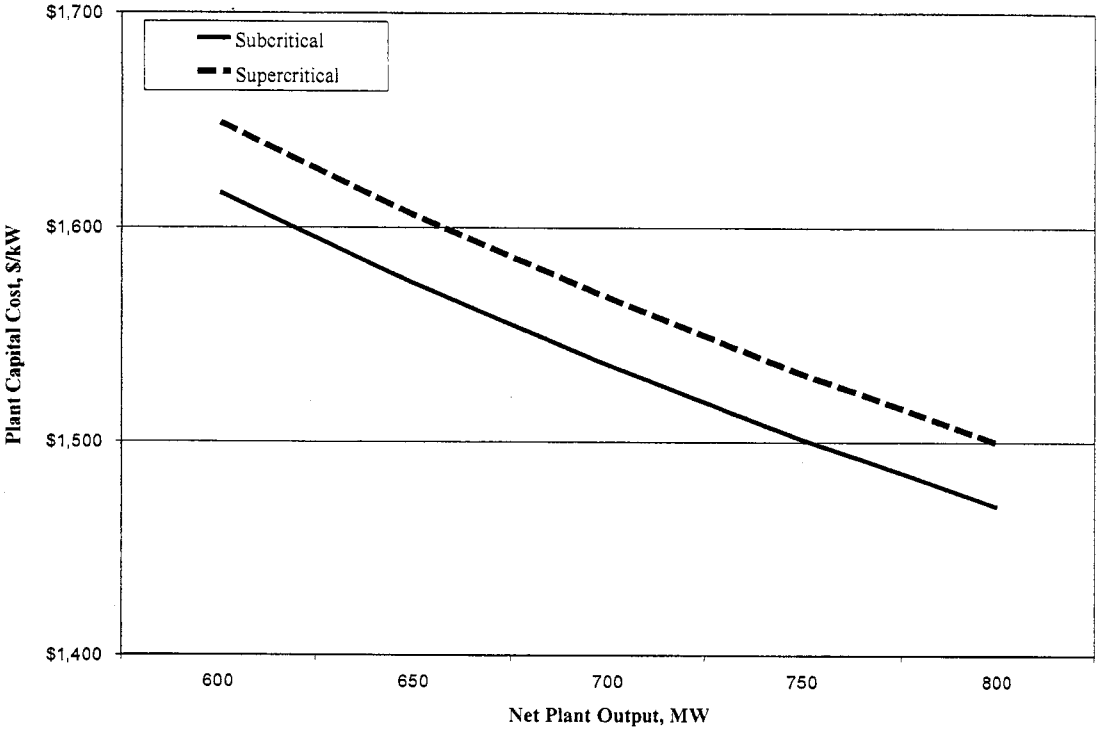


Figure 3.2: Plant Capital Cost vs. Net Plant Output

3.3.4 O&M Costs

A summary of the calculated variable and fixed O&M costs for subcritical and supercritical units between 600 MW to 800 MW net are included in Figures 3.3 and 3.4. These O&M costs were estimated based on the assumptions discussed in the previous study "650 MW Solid Fuel Fired Unit Feasibility Study."

Fixed O&M Cost Basis:

- Subcritical and supercritical plants require an additional staff of 46 people.
- Fixed employee costs include office and administration, contract labor, safety, and training expenses.
- Buildings, grounds, and supply costs are included.
- Steam turbine, boiler, and air pollution control equipment are inspected annually.
- Major annual maintenance costs include steam turbine and boiler tube replacements and overhaul, baghouse bag replacements, SCR catalyst replacements, and water treatment system replacements.
- Property taxes, insurance, and interest during construction are not included.

Variable (Non-Fuel) O&M Cost Basis:

- Water consumption, treatment chemicals, and consumables are included.
- Maintenance costs include SCR, scrubber, water treatment, cooling tower, brine concentrator and spray dryer system general maintenance (material handling, electrical, DCS, etc).
- Emissions controls costs include limestone and ammonia consumption. Gypsum, bottom ash and fly ash are saleable by-products.

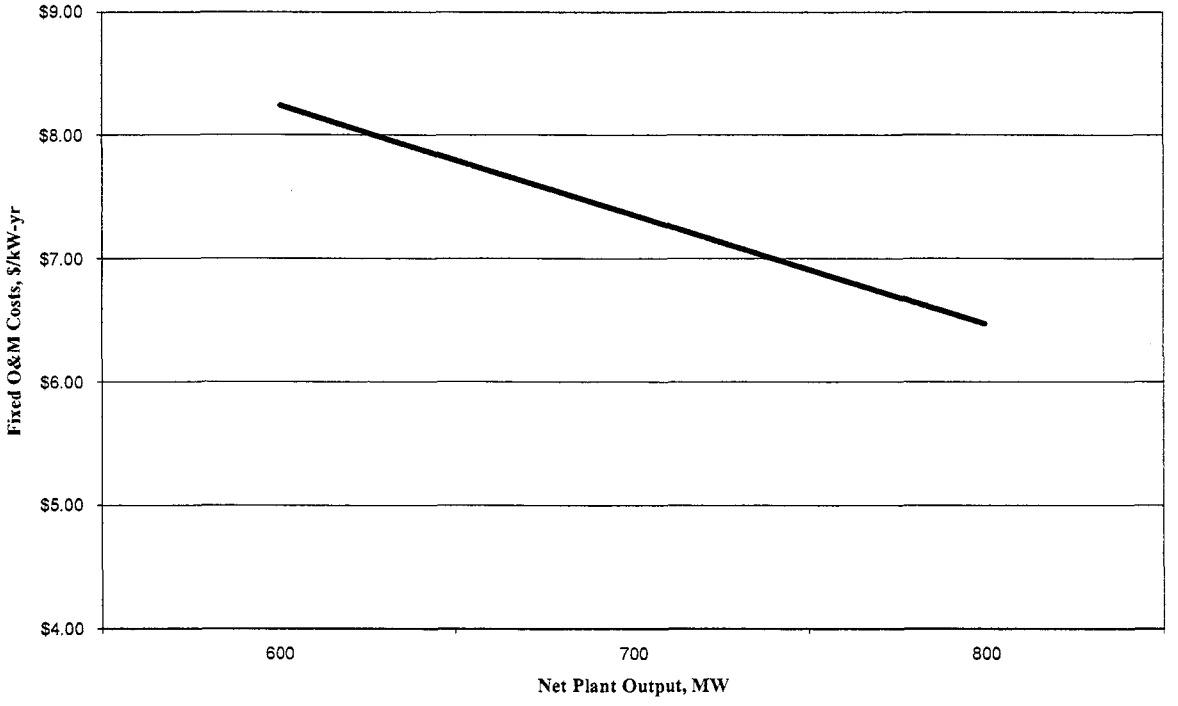


Figure 3.3: Fixed O&M Costs vs. Net Plant Output

As shown in Figure 3.3, the total fixed O&M costs per kW-yr decreases as unit size increases from 600 MW to 800 MW. Equipment inspection costs and staffing requirements remain fairly constant with plants in this size range. Fixed O&M costs do not change between subcritical and supercritical units, assuming property taxes and insurance are not included. Staffing requirements and annual inspection fees are expected to be the same for both subcritical and supercritical units.

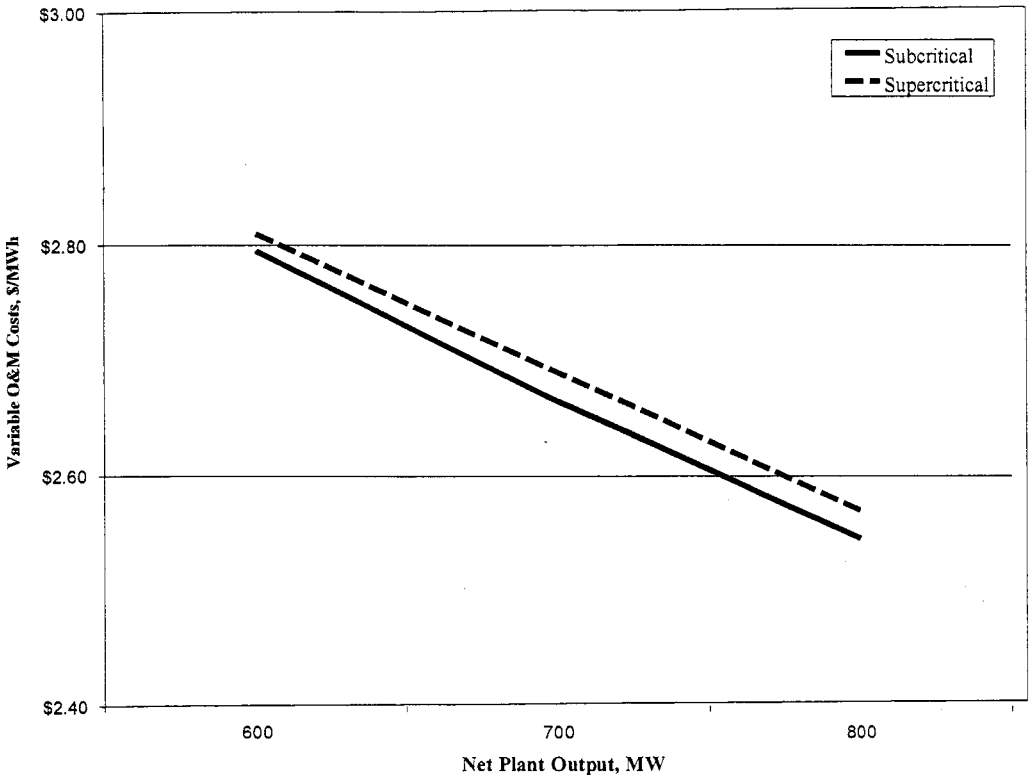


Figure 3.4: Variable O&M Costs vs. Net Plant Output

Variable O&M costs decrease almost linearly as unit size increases. Between 600 MW and 800 MW, the variable O&M cost decreases by $0.23/MWh for both supercritical and subcritical units. The value of gypsum and ash sales at the Seminole Generating Station causes variable O&M costs to be greater for supercritical units. Major maintenance and equipment overhaul expenses only increases slightly as unit size increases. Scrubber and SCR consumable costs increase as fuel consumption increases. However, these cost increases are relatively minor and therefore as plant output increases, variable O&M costs on a $/MWh basis decrease.

3.4 CONCLUSIONS

Domestic operating experience for pulverized coal units is limited to steam cycle conditions of 1050°F/1050°F. High sulfur coals present a greater problem with boiler tube corrosion at elevated temperatures, and there is currently no operating experience with 30% pet coke at steam temperatures above 1050°F. Boiler manufacturers recommend appropriate design and material considerations be made for high sulfur fuels similarly for subcritical and supercritical boilers. There is potentially a greater O&M costs for corrosive coals in supercritical units due to more frequent boiler inspections and material replacements.

In addition to increasing steam temperatures, regenerative feedwater heating is a common method for improving steam power plant efficiency. The addition of a heater above reheat the reheat point offers a substantial increase in efficiency with minimal capital investment, maintenance costs, and risk. Along with the economic benefits, the eight feedwater heater cycle does offer risk mitigation in regards to fuel consumption, sorbent consumption, waste disposal costs, and increased emissions allowance costs when compared to a seven feedwater heater cycle.

Turbine last stage blade selection affects plant performance. SECI should consider the use of 40 to 42 inch last stage blades based upon the improvement in performance and operating experience with this blade size. Longer LSBs are available from several of the large steam turbine manufacturers. However, these longer blades have limited experience in commercial operation between 600 MW and 800 MW.

Between 600 MW and 800 MW net, unit size has a small impact on net plant heat rate. Other design conditions, such as the condenser pressure and feedwater heater configuration have a greater effect on the net plant heat rate than does unit size. Supercritical units require less steam flow than subcritical units and therefore the loss through the back end of the steam turbine is less. Between 600 MW and 800 MW net, this causes the heat rate degradation to be less for supercritical units.

Overall capital cost decreases nearly 9 percent on a $/kW basis for both supercritical and subcritical steam cycles as unit size increases from 600 MW to 800 MW net. Fixed O&M costs are nearly the same for both subcritical and supercritical units. Variable O&M costs for a supercritical unit between 600 MW to 800 MW net are around 0.4 percent higher compared to a subcritical unit due to the high value of ash and gypsum sales at SGS.

4.0 INTEGRATED GASIFICATION COMBINED CYCLE

4.1 GENERAL DESCRIPTION

Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value syngas from coal or solid waste, to be fired in a conventional combined cycle plant. The gasification process in itself is a proven technology utilized extensively for production of chemical products such as ammonia for use in fertilizer. Utilizing coal as a solid feedstock in a gasifier is currently under development for projects jointly funded by the Department of Energy (DOE) at several power plant facilities throughout the United States. The gasification process represents a link between solid fossil fuels such as coal and existing gas turbine technology. The IGCC process is shown in Figure 4.1 below.

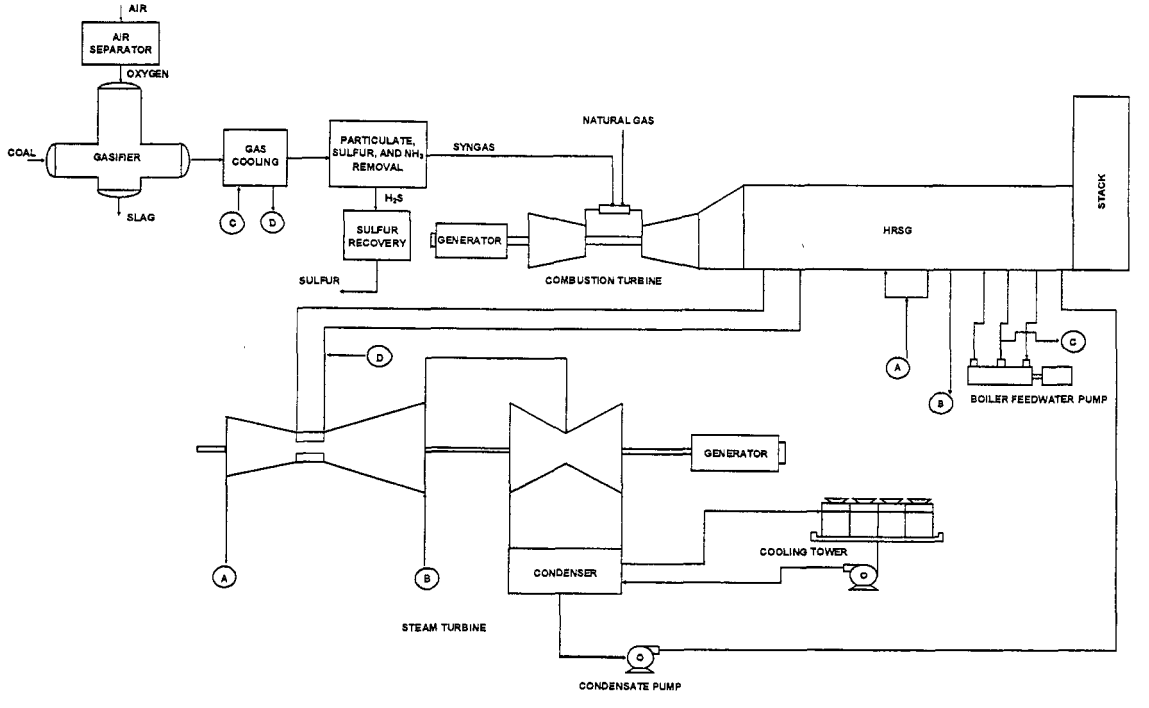


Figure 4.1: IGCC Process Diagram

A 600 MW net IGCC plant would typically be composed of two coal gasifiers, a coal handling system, an air separation unit, a gas conditioning system to remove sulfur and particulate, two gas turbines, two heat recovery steam generators with supplemental duct firing and a single steam turbine. Cooling water for the steam turbine would be based on a mechanical draft cooling tower.

Integrating proven gasifier technology with proven gas turbine combined cycle technology is a recent

development, and continues to be improved at the existing DOE jointly funded power plants. Because gasification-based power generation is a relatively new technology with few operating plants, its unique operating features and its environmental performance capability are not well known.

Gasifiers designed to accept coal as a solid fuel generally fall into three categories: entrained flow, fluidized bed, and moving bed.

Entrained Flow

The entrained flow gasifier reactor design converts coal into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. General Electric (Chevron Texaco), Conoco Phillips (E-Gas), Prenflo, and Shell produce gasifiers of this design.

Fluidized Bed

Fluidized-bed reactors are highly back-mixed and efficiently mix feed coal particles with coal particles already undergoing gasification. Fluidized bed gasifiers accept a wide range of solid fuels, but are not suitable for liquid fuels. The KRW and High Temperature Winkler designs use this technology.

Moving Bed

In moving-bed reactors, large particles of coal move slowly down through the bed while reacting with gases moving up through the bed. Moving-bed gasifiers are not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design and has been utilized both at the Dakota Gasification plant for production of SNG and the South Africa Sasol plant for production of liquid fuels. BGL is another manufacturer of the moving bed design.

The majority of the DOE test facilities utilize the entrained flow gasification design with coal as feedstock. Pulverized coal is fed in conjunction with water and oxygen from an air separation unit (ASU) into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exits at around 2400 °F and is cooled to less than 400 °F in a gas cooler, which produces additional steam for both the steam turbine and gasification process. Scrubbers then remove particulate, ammonia (NH_3), hydrogen chloride and sulfur from the raw syngas stream. The cooled syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to

accept the low calorific syngas. Exhaust heat from the gas turbine then generates steam in a heat recovery steam generator (HRSG) to power a steam turbine. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged the existing IGCC installations. The syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system typical to those utilized in chemical production gasifiers.

4.2 CURRENT STATUS

The following table identifies the DOE jointly funded test facilities constructed in the United States, with various gasification system designs.

Table 4.1: IGCC Test Facilities

Facility	Owner	Capacity (MW)	Commercial Operation Date	Gasifier Manufacturer	Status
Polk County	Tampa Electric	252	1996	Chevron Texaco	Operating
Wabash River	PSI Energy	262	1995	Conoco Phillips	Operating
Pinon Pine	Sierra Pacific	99	1997	KRW	Decommissioned
LGTI	Dow Chemical	160	1987	Conoco Phillips	Decommissioned
Cool Water	Texaco	125	1984	Chevron Texaco	Decommissioned

There are several IGCC projects currently in the development phase, including the 540 MW power station for Global Energy, Inc. located in Lima, OH, and Excelsior Energy's 530 MW Mesaba Energy Project located in Minnesota.

4.3 PLANT CHARACTERISTICS

4.3.1 Performance

Cold start-up times for IGCC plants have typically ranged from 40-50 hours compared to a conventional PC boiler start-up time of 4-6 hours. Hot restart procedures are in testing at several of these facilities, and Eastman Chemical Company has developed a proprietary process that allows a fairly rapid startup. However, the startup process requires flaring the syngas produced until it is adequate quality for introduction into the gas turbine. The gasification plant requires stable operation in order to maintain syngas quality and the technology to support load following continues to be developed.

A performance estimate was supplied by GE for a typical 550 MW IGCC unit firing 100% Illinois coal. The GE performance estimate is at 90°F dry-bulb temperature, 60%RH, and 0 ft. elevation. The estimated performance for a 550 MW IGCC unit is shown in Table 4.2.

Table 4.2: IGCC Expected Performance

IGCC Performance at 90 F, 60% RH, 0 ft. elevation	
Gross Gas Turbine Output, kW	394,000
Gross Steam Turbine Output, kW	282,800
Gross Plant Output, kW	676,800
Total Auxiliary Loads, kW	123,678
Net Plant Output, kW	**553,122**
Net Plant Heat Rate, Btu/kWh (HHV)	**9,106**

Significant design issues have prevented coal gasification units from achieving industry acceptable availability levels. These design issues include fouling within the syngas cooler, design of the pressurized coal feeding system, molten slag removal from the pressurized gasifier, durability of gas clean-up equipment and solid particulate carryover resulting in erosion within the gas turbine. The complexity of the combined cycle unit in conjunction with the reliability of numerous systems, including the gasifier, O_2 generator, air separation unit and multiple scrubbers have contributed to reduced plant availability.

Unit availability at the DOE jointly funded plants has been improving due to design modifications intended to improve equipment life and reliability. Polk County was able to achieve 83% availability for 2003 and Wabash River achieved 83.7% availability for 2003. All of these coal gasification plants have experienced down-time for design modifications and replacement of equipment. Polk County and

Wabash River are the only two coal IGCC plants in the United States that have achieved extended periods of commercial operation. The current generation of IGCC plants should be capable of operation with an availability of around 85 percent compared to around 90 percent for conventional steam electric plants.

4.3.2 Emissions Controls

The IGCC facility includes the following emissions controls equipment:

- Nitrous oxide (NO_x) emission control is achieved by injecting either nitrogen or steam into the gas turbine combustors during syngas operation. During natural gas operation, steam injection is utilized for NO_x control. Selective catalytic reduction (SCR) is not included at this time.
- Sulfur dioxide (SO_2) emission control is achieved through sulfur removal in the syngas. Sulfur removal is accomplished by using an amine scrubber that utilizes a methyldiethanolamine (MDEA) solution to absorb Hydrogen Sulfide (H_2S) from the syngas stream prior to combustion. High levels of sulfur removal are accomplished by first passing the syngas through a carbonyl sulfide (COS) hydrolysis reactor prior to the amine scrubber to convert small amounts of COS in the syngas to H_2S.
- Mercury removal is achieved by passing the syngas through a carbon filter bed prior to combustion.
- The syngas is scrubbed prior to combustion to remove particulate. Post-combustion particulate control is not required due to the inherently low emissions of this pollutant.

GEs proposed emission rates for an IGCC unit firing 100% Illinois bituminous coal are shown in Table 4.3. These emission rates are compared to a 600 MW pulverized coal unit firing a 70/30 bituminous coal and pet coke blend using BACT control technology.

Table 4.3: Pulverized Coal vs. IGCC Emission Rates

Pollutant	600 MW Pulverized Coal Emission Rate	550 MW IGCC Emission Rate
NOx, lb/MMBtu Coal	0.07	0.055
SO2, lb/MMBtu Coal	0.18	0.09
CO, lb/MMBtu Coal	0.15	0.03
Particulate, lb/MMBtu Coal	0.018	0.008

Note: Particulate does not include ambient air or corrosion products.

4.3.3 Waste Disposal

The syngas sulfur removal process can result in 99.9 percent pure sulfur, which is a saleable by-product. The gasifier converts coal ash to a low-carbon vitreous slag and flyash. The slag has beneficial use and can be utilized as grit for abrasives, roofing materials, or as an aggregate in construction. Fly ash entrained in the syngas is recovered in the particulate removal system and is either recycled to the gasifier or combined with other solids in the water treatment system and shipped off site for reuse or to be landfilled.

4.3.4 Water Requirements

An IGCC plant uses approximately one third the cooling water for condensing steam compared to a conventional steam electric plant. However, a large cooling water supply is required for coal gasification and for the air separation unit used to produce pure oxygen and when combined with the steam condensing requirements, the amount of water is comparable to a conventional steam electric plant.

4.3.5 Project Schedule

The permitting process for a greenfield 600 MW net IGCC takes approximately 18 months. The design and construction duration is approximately 48 months. In most cases, the permitting phase and design/construction phase will partially overlap to decrease the overall implementation period; however, this schedule does expose the Owner to some risk if the permit is not approved. Total implementation time for a 600 MW net IGCC including permitting, design, and construction is approximately 52 – 64 months.

4.3.6 Capital Cost Estimates

GE has estimated the capital cost of a typical IGCC plant based on a 550 MW "greenfield" site firing 100% Illinois coal to be approximately $1,640/kW excluding Owner's costs. This capital cost is for the three major blocks (gasification block, air separation unit block, and power block) and EPC contractor costs (including indirect costs, engineering costs, construction management, EPC fee, EPC contingency).

B&McD estimated Owner's costs (excluding interest during construction, financing fees, and escalation) for a typical 550 MW IGCC plant to be $230/kW. The total project cost incorporating GE costs and Owner's costs is estimated to be $1,870/kW based on a 550 MW facility.

4.3.7 Operations and Maintenance

Note that there has not been a long operating history for IGCC units. Scheduled maintenance consists of an outage of approximately 3 weeks/year and 4-5 weeks every five years. Tampa Electric's 250 MW IGCC demonstration facility estimates fixed and variable O&M costs are $32.80/kW-yr and $5.91/MWh, respectively. The plant is staffed by five 10-man O&M teams, and 28 additional support personnel.

4.3.8 Long Term Development

Much of future technology development will be supported through government funding support of Clean Coal Technology within the power industry. A few large scale (550 MW and greater) IGCC power plants are currently in the preliminary project development and/or permitting stage in the United States, however, commercial operation of these plants is at least 4 to 5 years in the future.

4.4 IGCC AT SEMINOLE GENERATING STATION

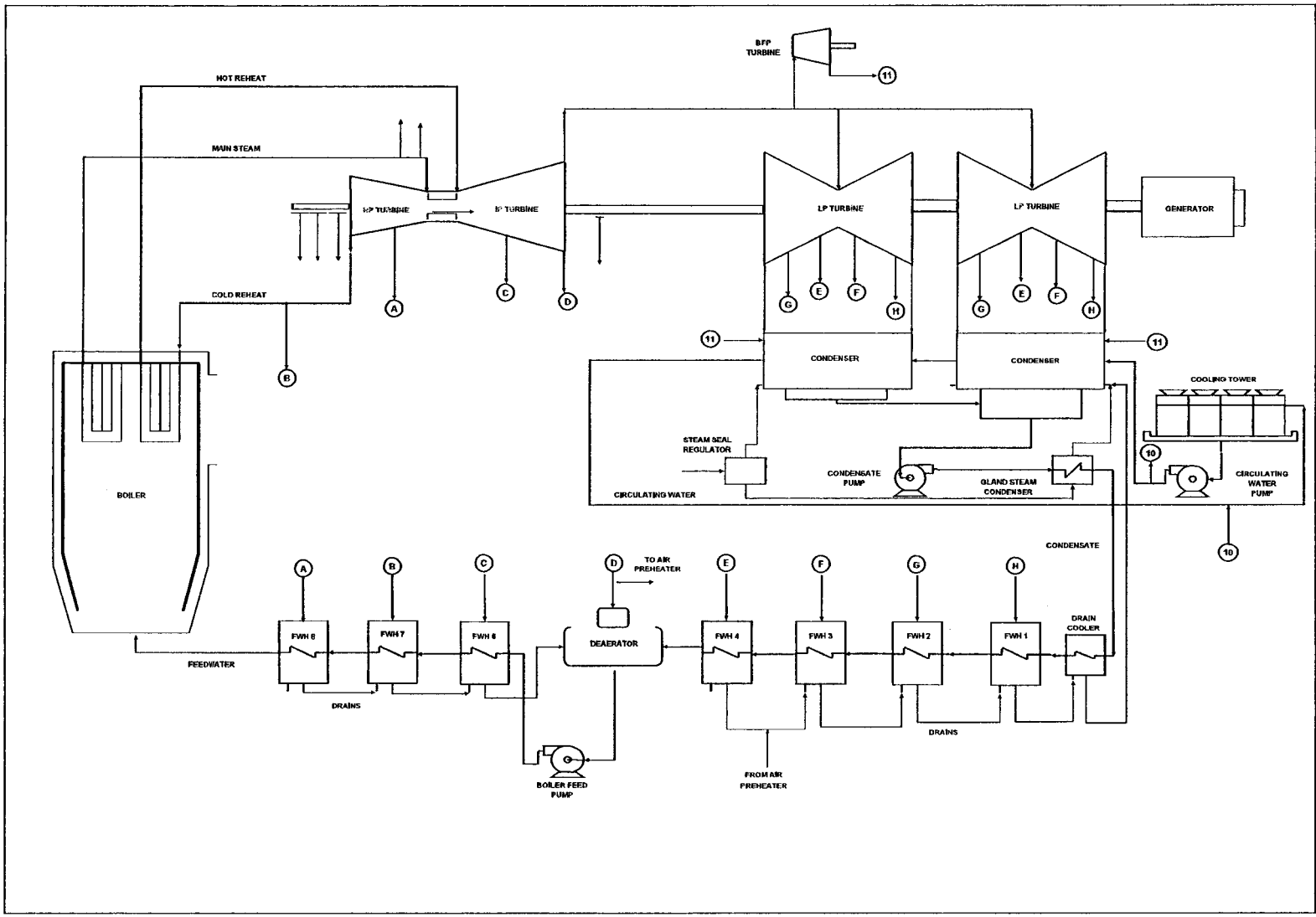
A greenfield 600 MW net IGCC plant requires approximately 120 acres which includes areas for coal handling, construction laydown and parking. The Seminole Generating Station site has existing coal handling infrastructure to support an IGCC plant. The space required for the IGCC power block is approximately 45 acres. The existing site is capable of accommodating an IGCC plant however, some of the remaining permitted landfill area to the east of the existing units may have to be utilized which would reduce the life of that landfill.

The slag from an IGCC plant could be sold similar to the bottom ash from the existing units. In addition, the sulfur byproduct could also be sold if a market exits. Therefore, the potential landfill requirements would be less than a conventional steam electric plant.

The availability and reliability of the current IGCC plants is improving but is not comparable with conventional steam electric plants. The penalty for higher availability is with more redundancy and therefore higher capital costs.

Much of future IGCC technology development will be supported through government funding of clean coal technology in the power industry. Operational flexibility for rapid start-up and load following remains to be demonstrated and may be required for an IGCC plant to compete effectively within the current U.S. power market.

Acceptance of coal within the power industry and the relative price of natural gas will also influence the future development and commercialization of IGCC in the United States. The technical barriers to commercialization remain to be addressed through future generations of government jointly funded coal IGCC facilities. Once the development effort has been successfully completed, coal fueled IGCC technology has the potential to be a reliable clean-coal generation technology.



PERFORMANCE SUMMARY

Seminole Electric Cooperative
Seminole Unit 3
750 MW PC SUPERCRITICAL
BMCD PROJECT 39736

STEAM CYCLE DIAGRAM

DESIGNED BY:
CHECKED BY:
STATUS:

DATE 12-Oct-05 | MODEL REV.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 18
Company/ SEC
Witness: Richard Klover (RAK-6)
Date: 06-07-06

Exhibit RAK-6
1 of 1

EXHIBIT RAK-7

SEMINOLE ELECTRIC COOPERATIVE, INC.
SEMINOLE GENERATING STATION

SGS UNIT 3 FACT SHEET

Plant Design

Megawatt (net)	750 MW
Net Plant Heat Rate (71°F/80% RH)	9,000 Btu/kWh
Steam Cycle Conditions	3700 PSI/1,050 F/1,050 F

Water Supply

Cooling Tower Makeup	St. Johns River
Boiler Makeup	Ground Water
Potable Water	Well System
Average Annual Makeup from St. John's River	33 MGD

Fuels

Type	Eastern Bituminous Coal/Petcoke
Blend	Up to 30% Petcoke
Delivery	Rail
Startup Fuel	Fuel Oil

Air Quality Control Systems

SO_2	Wet FGD
NO_x	Low NO_x Burners/Overfire Air/SCR
PM	ESP
Sulfuric Acid Mist	Wet ESP

Reagent

Wet FGD	Limestone
Limestone Delivery	Truck
SCR	Urea
Urea Delivery	Truck/Rail

Waste Disposal

Gypsum	Lafarge
Gypsum Transport	Conveyor
Fly Ash	Sold/Landfilled
Bottom Ash	Sold/Landfilled
Ash Transport	Truck
Landfill Location	On-site

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DOCKET
NO. 060220-EC Exhibit No. 19
Company/ SEC
Witness: Richard Klover (RAK-7)
Date: 06-07-06

SGS UNIT 3 FACT SHEET Continued

Major Equipment

Boiler	Supercritical Pulverized Coal
Steam Turbine	Tandem Compound/Four Flow/Single Reheat
Cooling Tower	Mechanical Draft
Wet Flue Gas Desulfurization (FGD)	Single Module
Wastewater Treatment System	Brine Concentrator/Spray Dryer
Stack	675 Ft
Selective Catalytic Reduction Unit (SCR)	Dual Train
Electrostatic Precipitator (ESP)	Dual Train
Wet Electrostatic Precipitator (Wet ESP)	Single Train

Exhibit RAK-8
SGS Unit 3 Construction Milestones

Milestone	Date
Start Procurement of Boiler	Aug 2007
Start Procurement of Steam Turbine	Aug 2007
Receive Approvals to Start Construction	Oct 2007
Award of Boiler and Steam Turbine	Nov 2007
Mobilize/Start Site Work	Oct 2008
Start Foundations	Dec 2008
Start Boiler Steel Erection	Jun 2009
Boiler Hydro	Feb 2011
Initial Synchronization	Oct 2011
First Fire on Coal	Oct 2011
Commercial Operation	May 2012

FLORIDA PUBLIC SERVICE COMMISSION
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NO. 060220-EC Exhibit No. 20
Company/ SEC
Witness: Richard Kloer (RAK-8)
Date: 06-07-06

AUGUST 2003 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the March 2003 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (2)

Year	Distillate Oil	GS (1) Natural Gas	Pittsburg Seam 13,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	5.02	5.01	1.79	0.97
2006	5.31	4.84	1.78	0.99
2007	5.51	4.96	1.78	1.00
2008	5.66	5.11	1.80	1.02
2009	5.80	5.21	1.86	1.03
2010	5.97	5.36	1.89	1.05
2011	6.15	5.63	1.91	1.07
2012	6.38	5.83	1.92	1.09
2013	6.73	6.00	1.93	1.11
2014	7.04	6.13	1.94	1.13
2015	7.38	6.33	1.96	1.15
2016	7.72	6.50	1.98	1.18
2017	8.03	6.66	2.00	1.20
2018	8.34	6.86	2.02	1.23
2019	8.70	7.04	2.04	1.26
2020	9.04	7.24	2.06	1.28
2021	9.38	7.49	2.08	1.31
2022	9.75	7.73	2.11	1.34
2023	10.14	7.99	2.13	1.37
2024	10.57	8.24	2.15	1.41
2025	10.97	8.50	2.18	1.44
AAGR (4)				
2005-2025	4.0%	2.7%	1.0%	2.0%
2010-2025	4.1%	3.1%	0.9%	2.1%

Notes:
(1) Natural gas delivered into Florida market area.
(2) Delivered prices represent:
Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.
Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation) delivered prices do not include any FERC transportation capacity reservation charges.
Coal: 1) Commodity price of coal from Pittsburg seam plus
2) rail transportation, freight rate, plus cost of rail cars.
Petcoke: Similar to coal.
(3) AAGR means Average Annual Growth Rate

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 21
Company/ SEC
Witness: Wm. Jack Reid (WJR-1)
Date: 06-07-06

APRIL 2004 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the December 2003 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	6.68	6.30	6.24	1.79	1.06
2006	6.22	5.88	5.83	1.80	1.10
2007	6.06	5.57	5.52	1.84	1.13
2008	5.90	5.47	5.42	1.89	1.16
2009	5.85	5.38	5.33	2.13	1.36
2010	6.25	5.38	5.33	2.20	1.40
2011	6.47	5.60	5.55	2.27	1.43
2012	6.70	5.78	5.73	2.31	1.46
2013	7.05	5.99	5.93	2.35	1.48
2014	7.36	6.16	6.10	2.43	1.54
2015	7.68	6.39	6.33	2.48	1.59
2016	8.01	6.56	6.50	2.53	1.61
2017	8.31	6.77	6.71	2.57	1.62
2018	8.62	7.00	6.93	2.63	1.64
2019	8.97	7.24	7.17	2.72	1.70
2020	9.33	7.49	7.42	2.78	1.72
2021	9.69	7.74	7.66	2.83	1.75
2022	10.07	8.01	7.93	2.89	1.77
2023	10.48	8.27	8.20	2.95	1.79
2024	10.93	8.56	8.48	3.05	1.86
2025	11.34	8.86	8.78	3.12	1.88
2026	11.79	9.16	9.07	3.18	1.91
2027	12.27	9.48	9.39	3.25	1.93
2028	12.76	9.82	9.73	3.31	1.96
2029	13.31	10.16	10.06	3.38	1.99
2030	13.82	10.52	10.42	3.45	2.01
AAGR (4)					
2005-2030	3.0%	2.1%	2.1%	2.7%	2.6%
2010-2030	4.0%	3.4%	3.4%	2.3%	1.8%

Notes:

(1) FGT means Florida Gas Transportation

(2) GS means Gulfstream Natural Gas System

(3) Delivered prices represent:

Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.

Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.

Coal: 1) Commodity price of coal from Illinois basin plus
2) rail transportation, freight rate, plus cost of rail cars.

Petcoke: Similar to coal.

(4) AAGR means Average Annual Growth Rate

DECEMBER 2004 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the October 2004 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	9.95	8.96	8.87	2.61	1.89
2006	8.69	8.27	8.20	2.41	1.61
2007	7.43	7.11	7.04	2.10	1.32
2008	7.28	6.87	6.80	1.78	1.04
2009	7.30	6.62	6.56	2.03	1.24
2010	7.29	6.38	6.32	2.09	1.31
2011	7.23	6.13	6.07	2.15	1.37
2012	7.17	6.27	6.21	2.19	1.40
2013	7.24	6.44	6.38	2.23	1.44
2014	7.48	6.57	6.51	2.30	1.52
2015	7.75	6.76	6.70	2.34	1.56
2016	8.02	6.92	6.86	2.38	1.62
2017	8.29	7.12	7.05	2.42	1.67
2018	8.56	7.17	7.10	2.46	1.72
2019	8.83	7.39	7.32	2.54	1.81
2020	9.10	7.61	7.54	2.58	1.87
2021	9.37	7.81	7.73	2.63	1.91
2022	9.65	8.01	7.93	2.67	1.94
2023	9.92	8.21	8.13	2.72	1.97
2024	10.20	8.42	8.34	2.81	2.04
2025	10.48	8.63	8.55	2.86	2.07
2026	10.76	8.85	8.76	2.90	2.10
2027	11.04	9.07	8.99	2.95	2.12
2028	11.33	9.30	9.21	3.00	2.15
2029	11.61	9.54	9.45	3.06	2.18
2030	11.90	9.78	9.69	3.11	2.22
AAGR (4)					
2005-2030	0.7%	0.4%	0.4%	0.7%	0.6%
2010-2030	2.5%	2.2%	2.2%	2.0%	2.7%

Notes:

(1) FGT means Florida Gas Transportation

(2) GS means Gulfstream Natural Gas System

(3) Delivered prices represent:

Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.

Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.

Coal: 1) Commodity price of coal from Illinois basin plus
2) rail transportation, freight rate, plus cost of rail cars.

Petcoke: Similar to coal.

(4) AAGR means Average Annual Growth Rate

AUGUST 2005 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the June 2005 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	12.70	9.25	9.11	2.16	1.77
2006	12.91	9.36	9.23	2.39	1.55
2007	12.19	8.85	8.73	2.10	1.58
2008	11.64	7.98	7.87	2.10	1.64
2009	11.21	7.11	7.02	2.37	1.92
2010	10.86	6.25	6.16	2.44	2.00
2011	9.28	6.41	6.32	2.49	2.07
2012	9.44	6.56	6.47	2.53	2.12
2013	9.48	6.94	6.84	2.57	2.17
2014	9.49	7.13	7.04	2.60	2.22
2015	9.50	7.26	7.16	2.64	2.28
2016	9.61	7.41	7.31	2.67	2.35
2017	9.74	7.89	7.78	2.74	2.45
2018	9.88	7.41	7.30	2.78	2.52
2019	10.02	7.75	7.64	2.82	2.58
2020	10.16	8.05	7.93	2.85	2.65
2021	10.68	8.16	8.04	2.89	2.70
2022	11.07	8.38	8.26	2.97	2.78
2023	11.56	8.59	8.47	3.01	2.82
2024	11.98	8.81	8.68	3.05	2.86
2025	12.41	9.03	8.90	3.09	2.90
2026	12.80	9.23	9.10	3.13	2.93
2027	13.20	9.44	9.30	3.22	3.02
2028	13.57	9.65	9.51	3.26	3.05
2029	13.95	9.87	9.73	3.30	3.09
2030	14.37	10.06	9.91	3.35	3.12
AAGR (4)					
2005-2030	0.5%	0.3%	0.3%	1.8%	2.3%
2010-2030	1.4%	2.4%	2.4%	1.6%	2.3%

Notes:

(1) FGT means Florida Gas Transportation

(2) GS means Gulfstream Natural Gas System

(3) Delivered prices represent:

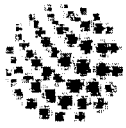
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Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.

Coal: 1) Commodity price of coal from Illinois basin plus
2) rail transportation, freight rate, plus cost of rail cars.

Petcoke: Similar to coal.

(4) AAGR means Average Annual Growth Rate



GLOBAL INSIGHT

Energy Price Forecast

Prepared for
Seminole Electric

June 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 25
Company/ SEC
Witness: Wm. Jack Reid (WJR-5
Date: 06-07-06

GLOBAL INSIGHT, INC.
24 HARTWELL AVE., LEXINGTON, MA 02421

Contributors

Mary Novak
Managing Director, Energy Services & Oil
(781) 860-6057
Fax: (781) 860-6332

Jim Osten
Principal, Natural Gas
(781) 860-6730
Fax: (781) 860-6332

Margaret Rhodes
Manager, Energy Forecasting & Power
(781) 860-6650
Fax: (781) 860-6332

John Dean
Consulting Economist, Coal and Nuclear
(301) 815-5470
Fax: (301) 815-5470

Hongyan Lin
Economist, Oil
(781) 860-6459
Fax: (781) 860-6332

Yanqun Shi
Economist, Natural Gas
(781) 860-6454
Fax: (781) 860-6332

Junya Tanizaki
Economist, Power
(781) 860-6704
(781) 860-6807

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PETROLEUM OUTLOOK

Short-term Outlook

Overview

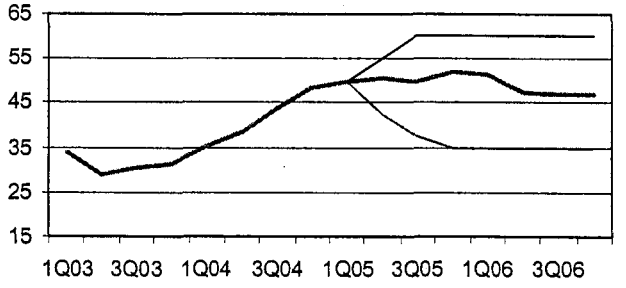
The past month has done little to ameliorate the "anomalies, paradoxes, mysteries, and uncertainties" we commented on a month ago. Crude price have fallen further, scarcely surprising as stocks have risen higher, but despite crude stocks in the United States now at levels last seen in mid 1999, when the price of WTI was around $20/barrel, prices still remain close to $50/barrel. Accepting that the historic relationship between crude prices and stock levels in days cover is currently in abeyance, nevertheless one must ask how much longer can stocks go on building without some major downward adjustment in prices? Latest data from the IEA includes a further upward adjustment to first quarter OECD stock levels so that end March cover is now estimated at some 53 days. If OPEC carries on producing at close to current levels, as it is indicating it will, then total OECD stocks could potentially remain around 53 days all year. If that is so then there is no reason to expect serious problems in the fourth quarter, and one of the key underpinnings of high prices would be removed. For the present, however, the market is likely to remain skeptical of such a potentially rosy outcome and the latest fall in prompt prices has merely served to steepen the contango; clearly concern remains about the fourth quarter.

OPEC's stance cannot be taken for granted. Although Ministers take every opportunity to emphasize their role in promoting market stability and price moderation, the facts are not so clear. Several points should be noted: (1) first quarter production was at least 0.5 million b/d below that in the fourth quarter, (2) April output barely exceeded the new 27.5 million b/d target for the OPEC 10, (3) discussion on the second 0.5 million b/d tranche of extra production agreed at the March 16 meeting was quickly shelved when prices softened in April, despite prices remaining at levels that OPEC spokesmen constantly affirm are "too high", (4) Saudi prices for Western markets for June are set at unattractive levels, possibly not unreasonably as it is in the East that crude stocks are low, but scarcely a factor promoting lower prices. OPEC will have a few weeks to digest the implications of the latest IEA data, and June's data will be published nearly a week before the next Ministerial meeting, on 15 June. We would not be surprised to hear talk of output cuts.

Although global stocks appear to be rising strongly, it is more often US data that moves the market. US refineries have been slow to return from maintenance, but are expected to ramp up output steeply in coming weeks which will pull down crude stocks. Gasoline stocks will decline anyway. Although both of these developments are normal for the time of year, reports of lower stocks could put an end to further falls in the crude price. Moreover, the next bout of speculative pressure could be an upward push.

Our expectation is that prices will not fall much further, will hover around current levels for a month or two and will then begin to rise again. OPEC actions could be the factor that will precipitate the turnaround, but may not be. We expect that concerns about the fourth quarter will remain, and will focus on the increase in call between the third and fourth quarter without looking too closely at the role that stocks might play in alleviating this increase. An outside possibility exists, however, that slowing economic growth and further rises in stocks could see prices plunge sharply.

WTI Price Outlook Scenarios
(Quarterly, dollars per barrel)



Market Review

Average prices in April were lower than in March as the market seesawed downwards. WTI peaked at nearly $57.50/barrel on April 1, fell to around $50/barrel and subsequently spiked to nearly $55/barrel in the middle weeks, and ended the month some $7/barrel below where it started, having briefly dropped below $49/barrel on April 29. In early May prices encountered an important psychological support level at $50/barrel, and tended to rebound quickly whenever they edged below this level. WTI broke through the barrier in mid May and is currently trading n the $47-48/barrel range for prompt crude. The market in the Atlantic basin is still characterized by a steep contango, with August WTI trading at over $2/barrel above June, and December at nearly $4/barrel above June. Although this reflects prompt weakness and expectations of later strength, paradoxically it also helped to underpin the $50/barrel support level as any fall was quickly offset by short covering, which can be profitable in this market structure.

Marker Crude Prices
(Dollars per barrel)

	March	April	May 1-18
WTI	54.28	51.89	49.98
BFO	53.03	52.85	48.78
OPEC Reference Basket	49.49	47.68	46.85

BFO prices have moved broadly with WTI but the differential between the two markers has become very narrow. WTI prices are depressed by very high crude stocks in the Midwest, as refineries have been slow to return fully from maintenance. Meanwhile, BFO prices have been supported by an open arbitrage to Asia

Pacific for Atlantic Basin sweet crudes. Movements of West African crudes to Asia Pacific in May are expected to be at the highest level since last October, when refiners were building stocks for the winter.

A number of factors underlie the downward trend in prices. Rising US crude stocks, seen as a proxy for global stocks, have reached levels not seen since July 1999. Gasoline stocks are also looking healthy, although the market is still nervous about the summer. The prospects for total crude supply look good following upward revisions to OECD stocks data and as OPEC output continues to rise and is seen as rising further, albeit there remains an imbalance in terms of crude quality, with the market looking for light/sweets and only heavier/sours on offer at the margin. Saudi Aramco reports that is has offered its term customers more crude but has had no takers of the quality on offer. There seems to be no shortage of prompt supplies. The belief is developing that demand growth rates are slowing; concern about the impact of high oil prices on economic activity is growing, while the data suggest slowing growth in the United States, and possibly China, the two primary motors of oil demand growth. Speculative support has also faded as strengthening of the U.S. dollar has contributed to the hedge funds moving investments away from commodities and into currency. The net long position of the non-commercial players on NYMEX has fallen very sharply, from a new peak at the beginning of April at over 88 thousand lots, most recent data shows holdings down to less than one hundred lots.

For some weeks, there was a widespread feeling among market analysts and commentators that prices "ought" to have fallen further. Most believed that the $50/barrel support level would eventually be breached and then prices would fall to the mid $40s/barrel, before rising again later in the summer and, in the view of some, reaching new records next winter. Now that the $50 support level has been breached, the market needs to catch its breath and decide where it goes next. The contango structure is still being maintained, however, by strong expectations of tightness later in the year, whether in crude markets as the U.S. and Asia-Pacific compete for available supplies, or in product markets as demand stretches the capabilities of refining systems, especially in the United States, and has actually deepened since mid month.

Demand and Supply Fundamentals

Economics

Doubts about the world economy's short-term outlook have once again increased, mainly because of renewed inflation worries, high global energy prices, and signs of weakness in some G-7 economies. Furthermore, the global economy's growth engine—the US economy—appears to have downshifted this year more than had been anticipated by most forecasters, including Global Insight. This less robust economic outlook is reflected in recent financial market volatility and lower yields on long-term government bonds. While the downside risks have increased, one should not exaggerate them. Despite its slowdown, the US economy still has a considerable

amount of steam, most of Asia outside of Japan is going very strong, and other emerging markets are growing at paces well above their trend. In a similar vain inflation concerns appear to be excessive, since the global economy's persistent gap between potential and actual output should continue to constrain inflationary pressures around the globe, as well as dissuade central banks from tightening their monetary policies too aggressively. Furthermore, periodic currency appreciation in countries that float their exchange rates against the US dollar has further reduced inflationary pressures in many countries, including most major economies in Europe and Asia, giving the monetary authorities a strong reason to delay raising their policy rates. To be sure, the dollar's depreciation does act as a headwind for economies with floating currencies against the greenback, such as the Eurozone members. In a world where the US economy remains the main engine of global growth, however, a depreciating US dollar will be the only remedy for avoiding global stagnation. Given the huge US current account deficit, there can only be two ways of escaping from this predicament. Either the other major industrialized countries adopt policies that put their economies on a much more robust growth path, or there will be a dollar crash and US recession, which would in all likelihood trigger a global recession and unleash deflationary pressures around the globe.

Forecast Highlights: Global Insight's latest bottom-up forecast of the global economy, which was completed 15 May, projects world economic growth to slow from 4.1% in 2004 to 3.1% in 2005. The estimated number for 2004 represents a substantial improvement from the world economy's lackluster performance during the preceding three years; however, it no longer has any significant cushion to allow for potential policy errors or external shocks, since the projected, 3.1% annual pace is equal the global economy's long-term trend growth rate. On a year-on-year basis, we estimate the world economy's quarterly growth decelerated to 3.5% in the fourth quarter of 2004, after having peaked at 4.4% in the second quarter of last year. We estimate global growth further decelerated in the first quarter of this year, to about 3% year-on-year (y/y), but moderating global oil prices and strong international trade growth should sustain the pace close this trend rate for the remainder of 2005. With recent data releases indicating that the US economy is holding up better in the second quarter than had been anticipated, we expect adjustments to our forecasts will elevate our June global GDP growth projections by at least one or two tenths of a point, which puts the world economy in a less-vulnerable position in case there are adverse shocks or policy errors.

Real GDP Growth, World and Major Seven Economies
(Year-on-Year percent change)

	2004	2005				2006
	Q4	Q1	Q2	Q3	Q4	Q1
US	3.9	3.6	3.5	3.4	3.2	3.0
Canada	3.0	2.9	2.5	2.4	2.6	2.7
France	2.3	2.0	1.8	2.3	1.9	2.0
Germany	0.4	0.5	0.5	0.9	1.6	1.3
Italy	0.8	-0.2	-0.3	-0.4	0.5	1.3
UK	2.9	2.8	2.4	2.4	2.2	2.2
Japan	1.0	0.3	0.7	1.1	1.5	1.3

World	3.5	3.1	3.0	3.2	3.2	3.1

Demand

Latest estimates of demand continue to show divergent views of the prospects for this year. Whereas the IEA has made another marginal reduction to its growth estimate, albeit leaving it at 1.8 million barrels per day (b/d) in round numbers, and most other analysts are also tending to hold or even reduce their growth estimates, this month the U.S. Department of Energy (DOE) has *increased* its estimate of growth to 2.3 million b/d. The increase results from a 0.1 million b/d downward adjustment to 2004 actuals, but the effect is to leave the DOE much more optimistic than others.

Provisional demand data for the first quarter shows European demand much weaker than expected, primarily due to very low deliveries of gasoil and diesel in Germany. This may be partly because the timing of Easter meant the reduced number of working days occurred in the first quarter this year, but also reflects the ongoing reluctance of German consumers to restock with heating oil at current prices, and may be indicative of economic weakness. Elsewhere North American demand also shows signs of a slowing in gasoline sales, thought to be a response to high prices at the pump, and in diesel, as truck tonnage movements are reported down. Fuel oil use has been high, however, in response to high natural gas prices, and jet continues to grow strongly. In Asia, Japanese nuclear power station output remains below expectations which results in increased use of low sulfur fuel oil (LSFO) and crude for direct burning, and in South Korea demand has recently been looking up, with higher consumption in both the industrial and transport sectors.

For China, there are the usual conflicting reports. Some reports focus on signs of a slowing in apparent demand, but this is heavily influenced by stocks movements, which are believed to have been abnormal over the past year. If this effect is excluded, it may be that a more steady growth pattern can be seen in which slowdown is scarcely evident. A further complication is the impact of Government price control measures that shield consumers from the full effect of international prices and so diminish the incentive to economize. At the same time, however, the inability to recover their costs discourages traders from importing products, so supply falls short of potential demand. If domestic oil prices were raised and electricity prices de-controlled, that would end one constraint on consumption, but it might also lead to price-induced conservation. What the net result of these two effects would be remains a matter of substantial uncertainty.

Non-OPEC Production

There is general agreement that non-OPEC production will increase this year but views differ concerning the scale and timing of the increase. There is also general agreement that, whatever the increase, it will not match the rise in demand so an increased call on OPEC is inevitable. The uncertainties over timing are significant in that most of the increases are scheduled for the second half of the year. If they come through on time, that will ease the pressure on OPEC and the reduction of its spare

capacity cushion in the winter quarters. If the more pessimistic estimates prove correct -- especially if combined with robust demand growth -- then the winter quarters could be very tight indeed.

Globally production from around 60 new projects is due this year but the location of the largest scheduled increments - Russia, Brazil, and Angola, with increases also due in the U.S. Gulf of Mexico - explains and underlines the uncertainty over timing. In Russia conflicting projections create uncertainty, while in the deep offshore waters of Brazil and Angola the scope for last minute technical problems remains substantial. In the Gulf of Mexico there remains scope for further technical problems and delays, and for summer disruptions from hurricanes; full recovery from hurricane Ivan is still some months away. The BTC pipeline carrying Azeri crude from the Caspian to the Mediterranean is due to start filling and testing in July, with first exports due in the fourth quarter, resulting in further large increments to supply next year, but any problems that come to light during testing could delay first exports into next year. Estimates of total annual growth are between 0.5 million b/d and 1.0 million b/d, but in the light of the record of recent years we are inclined to discount the higher end estimates and continue to include a non-specific downward adjustment averaging some 0.2 million b/d over the balance of the year.

OPEC Production

OPEC output rose by a further 0.5 million b/d in April to approaching 29.5 million b/d (IEA assessment), with the largest increase again in Saudi Arabia but with other countries recording smaller rises, though Iraq remains stuck on some 1.8 million b/d. Although OPEC ministers continue to make much of their efforts to supply what the market needs and to contribute to market stability and a lessening of prices, these protestations need to be tempered by the facts, as emphasized in the Forecast Highlights section; OPEC rhetoric and action continue to be slightly out of sync. In fairness, it should be added that further output increases are expected in May, but any decision on further formal additions now seems scheduled to await discussion at the June 15 meeting.

The IEA's assessment of OPEC capacity is unchanged this month, save for a decision to settle on a figure for Saudi capacity of 10.5 million b/d in place of the 10.0-10.5 range shown for some months, and leaves effective spare capacity at some 1.3 million b/d, almost all in Saudi Arabia. The assessment of OPEC capacity will be raised steadily as the year progresses as a succession of new projects come on stream. By the end of the year, sustainable capacity should be conservatively at least 0.5 million b/d higher than at the beginning. This excludes any increases in Saudi Arabia, where the build up in Qatif and Abu Safah should take the total increment to 1 million b/d or more, while additions from countries where current reliable information is lacking may add more still.

OPEC Compliance in April 2005
(Million barrels per day)

	Target as of Mar.16	Production (1) Apr 2004	Production vs. Target	Estimated Sustainable Capacity (2) (IEA Mar 05)	Spare Capacity
Algeria	0.878	1.35	0.47	1.35	0.00
Indonesia	1.425	0.95	-0.48	1.00	0.05
Iran	4.037	3.90	-0.14	4.00	0.10
Kuwait (3)	2.207	2.45	0.24	2.50	0.05
Libya	1.473	1.64	0.17	1.65	0.02
Nigeria	2.265	2.45	0.19	2.45	0.00
Qatar	0.713	0.78	0.07	0.80	0.02
Saudi Arabia (3)	8.937	9.45	0.51	10.50	1.05
UAE	2.400	2.45	0.05	2.55	0.10
Venezuela	3.165	2.16	-1.01	2.20	0.05
OPEC 10	**27.500**	**27.57**	**0.08**	**29.00**	**1.43**
Iraq (4)		1.83		1.95	0.12
Total OPEC		**29.40**		**30.95**	**1.55**
Excl. Venezuela/Nigeria/Indonesia/Iraq					1.33

1. Secondary source estimates of OPEC production regulary differ. The above reflects the IEA estimate except for Iraq.

2. Capacity figures are levels achievable within 30 days and sustainable for 90 days.

3. Figures for Saudi Arabia and Kuwait each include 50% of the Neutral Zone.

Note: Saudi Arabia capacity figure represents mid point of IEA's estimate of 10.0-10.5. Saudi Arabia itself claims its capacity is now 11 million b/d.

4. Iraq estimate represents the average of the past twelve months. Post war production has not yet exceeded 2.5 million b/d.

Iraq capacity figure represents gross capacity, before any reinjection.

Market Balance

Total OECD Commercial Inventories

Following last month's large upward adjustment to the estimated end January stock position, another large adjustment has been made this month, this time to the end February position. End February stocks are now assessed as 21 million barrels higher than was thought a month ago. The first look at the end March position for total OECD suggests a small stock draw during March, as refinery maintenance allowed crude stocks to rise while product stocks were drawn down, more than off-setting the build in crude. This leaves end March stocks 119 million barrels above those of March 2004. The first quarter as a whole now shows a contra-seasonal build of 0.2 million b/d for total OECD and forward cover at the end of the first quarter is assessed by the IEA at 53 days, two days above year-ago levels. This is the first time since 1996 that total OECD stocks have built in the first quarter; by

comparison, the past five years have seen an average first quarter stock draw of some 0.4 million b/d.

Turning to the global position, the top-down balance still suggests demand exceeded supply in the first quarter, suggesting a stock draw of around 0.5 million b/d was necessary. A stock draw of around 0.7 million b/d in non-OECD areas is thus indicated. Increasing evidence is accumulating that Chinese stocks were drawn down heavily in the first quarter, so a large non-OECD stock draw is certainly credible although the size of the implied draw is quite large. Any reductions in demand estimates for the first quarter in non-OECD areas would reduce the scale of the implied stocks draw.

The table below shows the overview position in each region and illustrates the unbalanced nature of stocks holdings. It also shows the danger of making generalizations about stocks levels. Total OECD stocks are high while those in Asia-Pacific remain low as stocks in OECD Asia Pacific represent only some 17% of total OECD stocks. Moreover, within a region stocks for an individual product can be worryingly lower or higher than for all products taken together.

Crude and Product Stock Levels by OECD Regions at end March
Relative to Average of Previous Five Years

	N. America	Europe	Asia-Pacific	Total OECD
Crude	High	High	Low	High
Products	High	High	Low	High
Total	High	High	Low	High

Atlantic Basin Inventories

US

Crude stocks have continued to rise, notably in PADD 2 and at Cushing, thereby contributing to softening of the WTI price, as well as price more generally. Total stocks at end April reached 327 million barrels according to weekly data, up by 10 million barrels since end March and some 17 million barrels above the average of the previous five years. Imports were again above 10 million b/d, as they have been for eight of the past twelve months, but were scarcely changed from March's level, and the other element of supply, domestic production, fell slightly. The major reason for the further rise in stocks was the slow return of refineries from maintenance: crude throughput in April averaged 15.3 million b/d, below the average of the previous five years, and only 0.13 million b/d above March's level. Runs this year, however, have been atypical, with January to March all well above any previous year's levels, but with April barely above March, whereas the average March-to-April increase of the previous five years was 0.7 million b/d. Runs are still expected to be ramped up sharply once maintenance is finally completed to well over 16 million b/d and utilization later in the summer could again match last year's figures of around 97%. This will inevitably pull crude stocks down and imports will need to

average consistently above 10.5 million b/d over the summer months in order to keep end-summer stocks in line with the average of the previous five years.

Gasoline stocks rose by 2 million barrels in April, to end the month at 214 million barrels, 8 million barrels above the average of the previous five years. A rise like this is around the norm for the time of year. Although the average gasoline yield over April was a new record high for the month, it was eclipsed by the increase in distillate yields as refiners apparently took advantage of the high absolute level of gasoline stocks to maximize distillate yields and thereby benefit from distillate and diesel prices above those of gasoline, as well as contributing to replenishing low distillate stocks.

Despite this unseasonal preference for making distillate over gasoline, distillate stocks still fell by 2 million barrels over the month to 102 million barrels, slightly below the average of the previous five years of 105 million barrels, but above the past two years. A modest stock draw in April is normal, with the stock build in preparation for winter normally beginning in May. Achieving an adequate stock build over the summer still should not prove a problem as gasoline yields are not expected to need to be exceptionally high, allowing distillate yields to move towards the top end of the range.

Europe

According to provisional Euroilstock data, crude stocks in Europe fell slightly during April, but remain very high, close to record levels for the time of year. The narrow differential between BFO and WTI has kept the transatlantic arbitrage closed and penned North Sea crudes into Europe. The arbitrage is expected to open in coming months and North Sea output will reduce with normal summer maintenance, so stocks are expected to drift downwards over the summer but with rising output in Nigeria and Libya, and later in the year from Azerbaijan, Europe should remain well supplied with crude.

Gasoline stocks have been falling since January, following the normal seasonal pattern, after the abnormal rise in January. With continuously declining demand, stocks would be expected to be at the bottom of their historic range, but in fact current gasoline stocks are above the level of three of the past four years as, despite modest yields, total levels of throughput have been high, producing high gasoline output. Stocks of gasoline in independent storage in the Rotterdam area were at the highest early May level of the past ten years.

Gasoil stocks are also high. European refinery production and Russian exports have both been at record high levels for the time of year while demand has been weak as German heating oil consumers continue to avoid buying at high prices. Stocks in independent storage in the Rotterdam area, however, are relatively low.

Prospects for the Global Balance

The upward revisions to the end January and end February stocks positions over the past two months have put a rather different gloss on the global outlook. Stocks in terms of days cover looked low at 50-51 days, but the end March level of 53 days (will next month's data show another upward adjustment, this time to March?) provides a much more secure basis for the remainder of the year. Moreover a recent statement from the OPEC President that OPEC will continue to increase its output to 30.5 million b/d should reassure the market that OPEC is not currently thinking of a cut to output when ministers meet on June 15.

Assuming that OPEC output continues around current levels through the summer in order to allow stocks to build, and that demand and non-OPEC supply turn out broadly as currently projected, then global stocks could remain between 53 and 54 days for the remainder of the year, a level that just a few months ago seemed inconceivable, but now possible because of upward revisions to stocks and a change in OPEC attitude. The exact end year position obviously depends on the particular combination of supply and demand projections, hence a projection based on the IEA's figures plus flat OPEC output implies around 54 days by the end of the year, while the U.S. DOE, which has higher projections for demand growth and lower projections for non-OPEC supply, estimates cover equivalent to 51 days. Our projection, assuming demand might still prove a little stronger than current estimates and that new non-OPEC supply might suffer some deferments, indicates end year cover of around 53 days.

This is all rather different to the way things looked only a short while ago. On these figures the summer stock build should certainly prove sufficient to allow a draw in the winter quarters. Even a fourth quarter stock build is not impossible, indeed balance suggests that unless OPEC cuts back then a small build looks likely. Increases in output from new capacity to be commissioned in Nigeria and Iran over the summer months now look secure, and neither country will be inclined to make compensating cuts elsewhere. The outlook for the fourth quarter could still vary between tight and relatively easy depending on OPEC capacity increments over coming months.

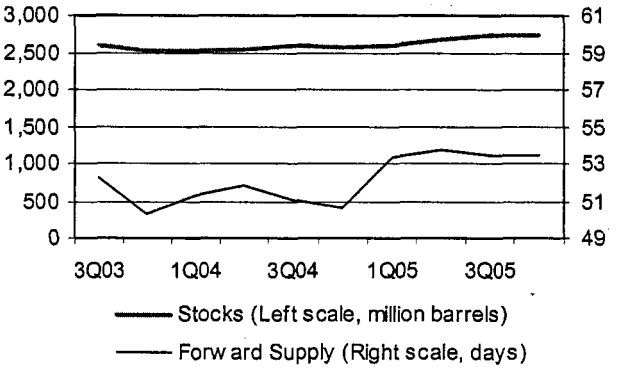
Stock cover of this magnitude would traditionally have been associated with much lower prices, but that link between stocks and prices remains broken, at least as an indicator of absolute price levels. On the other hand, the rising level of stocks in the Atlantic basin is undoubtedly one factor responsible not only for the steep contango in Atlantic basin prices, but also for the decline in the absolute level of prices. How OPEC will view this turn of events remains to be seen.

Turning away from global stocks levels and looking at the regional and quality imbalance, however, yields a different perspective. U.S. refinery runs have been kept low by an extended maintenance season, but could rise by as much as 1 million b/d over coming weeks, which would reduce crude stocks by nearly 30 million barrels over a month unless supply increases to offset the fall. Domestic production should

rise in the third quarter but imports will need to rise too. Much depends on the quality of crude that U.S. refiners will seek. Many are understood to have invested heavily over the past year so as to be able to handle higher volumes of heavy/sour crudes, on which margins are potentially more attractive, and if that enables them to absorb high volumes of Middle East crude without needing to compete unduly with Asia/Pacific refiners for light/sweets then obtaining the necessary levels of imports should not be a problem. Crude stocks would still fall seasonally, but the fall should not cause alarm. Given the unpredictability of market reactions to stocks reports over recent months, however, a rational response is far from assured. Similarly falling gasoline stocks over May to August, although a normal seasonal pattern, could easily spook a market looking for excuses to mark up prices.

Asia/Pacific also remains a wild card. Cold weather in the first quarter has depleted stocks of middle distillate heating fuels in Japan and Korea, and Chinese stocks both of crude and products are believed to have been run down sharply. Refineries in the region are mostly running close to capacity and if China needs to import to replenish depleted inventories and if recent firm demand in Japan and Korea continues, then the call for both crude and products imports from outside the region could prove substantial.

OECD Commercial Stocks and Forward Supply



Crude Price Forecast

Base Case

Now that the $50/barrel support level for WTI has been breached there would appear to be scope for some further downside movement in price in response to stock levels which are looking increasingly healthy, even bloated, in the Atlantic basin. How long such softness might last, however, is a major uncertainty. The global balance now looks easier, and the prospects for the fourth quarter could be seen as less worrying, but the substantial rise in the "call on OPEC crude plus stocks" between the third and fourth quarters could still worry a market focused more on OPEC's output versus capacity and less on the potential contribution of changes in stocks; a

rise of say 1.5 million b/d in the call does not mean OPEC needs to increase output by that amount, as the third quarter will see a stock build and the fourth a draw, so much of the increase in call will be met by stock movements. This is not the popular perception, however, as the steep contango WTI between June and December suggests not just prompt oversupply but continued concern about the winter.

The behavior of non-commercial players on NYMEX could prove important. They have currently reduced their net long holding to virtually nil and if prices fall further might begin buying again, supporting a price rise, though they may wait a while longer to see how things develop. OPEC actions are also uncertain. Now that the balance is looking easier and prices have fallen below $50/barel the more hawkish members may want to press again for output cuts to prevent further falls in response to higher stocks. The Kuwaiti minister and OPEC President reportedly recently suggested, however, that $40/barrel would be an acceptable level for the OPEC basket, some $5/barrel below its current level. If that thinking proves dominant, then no cuts would be expected.

We still expect prices to remain below $50/barrel for a while, reflecting the ready availability of prompt crude and oversupply in the Atlantic basin, but $50/barrel proved a much more resilient support level than we had anticipated, and the hedge funds unexpectedly fast liquidation of their holdings now makes them more likely to support a rise than a fall in prices. Even if OPEC do not make actual cuts, the tone of their pronouncements may change. Accordingly we now think that prices may even recover sooner than previously projected, on the back of falling stocks of crude and gasoline in the United States, and continued concerns about the winter, even despite the easier outlook for the balance.

Short Term Marker Crude Price Forecast
(Dollars per barrel)

	Apr	May	Jun	July	Aug	Sep	Oct
WTI	52.85	50.00	48.50	49.00	49.50	50.00	51.00
BFO	51.89	48.75	47.25	47.50	48.00	48.25	49.00

Alternative Cases

High-Price Scenario: A higher price scenario could result from:

- Further terrorist attacks/political tension in the Middle East;
- Geo-political concerns;
- Renewed Chinese imports;
- Major losses in Nigeria, Iraq, or elsewhere;
- OPEC implementing cuts in fear of prices falling too rapidly;
- Disappointments with increments to OPEC capacity;

- Further disruptions and delays in new non-OPEC production;
- Further upward pressure from financial traders.

The greatest concern remains terrorist action, which could result in price spiking to very high levels. Absent such a development, prices above $60/barrel for WTI now look less likely but remain possible. Any major loss of output anywhere would cause a spike, as the spare capacity cushion will remain thin all year. It is uncertain what scale of loss would drive governments to take emergency action to curb consumption and release strategic stocks, however if they did so we would be in a wholly different world and prices would depend on these reactions and their timing. Cuts by OPEC or a succession of geo-political alarms could push price sharply up.

Low-Price Scenario: A lower price scenario could result from:

- Recession or at least further economic slowdown, and resultant substantially weaker demand, especially from the United States and China;
- Further upward revisions to stocks data;
- Further easing of concerns about loss of supply due to higher stocks and slowing demand growth;
- OPEC are slow to cut as stocks rise due to internal dissent;
- Non-OPEC supply proves more robust than expected;
- Financial traders build net short positions.

In this situation, prices would moderate steadily but would remain above $35/barrel due to the perception of tightness next winter. It will still take some time for a sizeable cushion of spare capacity to be restored.

Oil Product Prices

Gasoline

Weekly data for April show demand growth of 0.9%. Monthly data for the first quarter now shows growth of 1.2%, less than indicated by previous weekly data. Monthly gasoline demand data is very volatile, hence, year-on-year comparisons can be misleading as the growth in any individual month is influenced by developments in the same month a year earlier. Hence, although U.S. gasoline consumption remains on a growing trend, the rate of growth is still highly variable. By removing seasonality and reducing month-to-month volatility by taking a twelve month moving average, it is clear that the rate of growth has been slowing since the middle of last year, when it had reached 2%; it is now down to below 0.9%. Data from the Department of Transportation show a decline in "Highway miles traveled" since around the same time. Moreover, the DOE's "Product Supplied" data does not, strictly speaking, report actual demand, i.e. purchases at the pump, but deliveries from primary storage into the distribution system which take place some weeks in advance of purchases at the pump and are based on assumptions about consumer demand. If motorists reduce consumption, there will be a lag before this shows up

in DOE statistics. Nevertheless, a recent reported survey showed 58% of U.S. motorists saying they would drive less if prices stay high. All these signals seem to suggest that demand is slowing, possibly due to price, but whether this will seriously reduce demand for the summer driving season remains to be seen. The DOE's forecast is unchanged this month at 1.8% growth for the summer quarters.

Stocks at end April were high in absolute terms and closely in line with the average of the previous five years in terms of days cover. As mentioned in the stocks section, refiners achieved a new record high yield of gasoline for April, at 57.1%, and this despite also setting a new record high yield for distillate. Distillate stocks are towards the low end of the range for the time of year but there is plenty of time to raise them before winter, so there is no reason to think that gasoline yields cannot be very high this summer if necessary. Imports of finished gasoline and components, which amount to around 10% of total gasoline supply, have also been high recently, with imports of finished gasoline very high and the 4 week average for total imports including components has been over 1 million b/d for the past three weeks. The issues of unscheduled refinery outages and grade proliferation remain sources of concern, however, despite a supply outlook that looks healthy.

Gasoline prices relative to crude were volatile over April and reports of problems at refineries, mostly on gasoline units, resulted in upward spikes, but latterly high imports and rising stocks have led to a softening. Spreads are currently very close to where we projected for the month. Supplies of high octane components remain tight but this does not seem to be seriously affecting prices of regular grades. The arbitrage from Europe has only been open intermittently as European prices, although falling, have remained stubbornly high, and further adjustments are still expected. We expect U.S. prices relative to crude to continue to soften through the summer as it becomes apparent that supply is adequate, and for European prices to fall further to maintain a (mostly) open arbitrage. The forecast spreads are unchanged.

Distillate

Latest data brings yet another marking down of distillate deliveries. Although March still shows a year on year increase of 4.5% following cold weather early in the month, data for January and February now point to declines in both months. Overall deliveries over the first quarter now exactly match those of last year. Within the total, highway diesel continues to grow, although growth in January and February was well below the trend rate, while deliveries of heating oil were very low, as the weather in the North East in January and February was much milder than in the previous two winters. Weekly data for April shows total distillate deliveries 2.2% up on a year ago.

Stocks are towards the lower end of the historic range but we do not anticipate a problem in replenishing them in time for next winter. Although by this stage of the year distillate yields in the refineries would normally be well down on their early winter peak and moving toward their mid summer low, this year yields have risen steadily since January with April a full percentage point above any previous April, at just over 26%, a level not normally reached till October or later. It appears that,

rowed by some $7-8.barrel. The strength of higher sulfur grades has been caused by the coincidence of higher Mexican demand and reduced exports from Venezuela due to refinery maintenance, and partly by strength of import demand in Asia where refinery maintenance has reduced local supply. With the end of maintenance around the world, the expected summer peak of Russian exports, and with more increases in Middle East crude supply, the supply of high sulfur resid is expected to ease and discounts to widen again. Similarly for the lower sulfur grades the relatively higher price may draw in more exports and push prices down again relative to crude. We are not, therefore, assuming that recent price strength heralds the beginning of an imminent major narrowing of resid spreads, but as crude prices begin to harden again we expect discounts to widen again.

Long-term Outlook

Making the link between the immediate and the longer term is always a challenge in projections that extend some years into the future. Changes in the here-and-now do not necessarily mean that the outlook for say five or ten years hence has changed. However, crude oil prices have stayed at or near $50/barrel since October 2004. Faced by a short term change of this magnitude the requirement to consider the implications for not just the short/medium term is unavoidable. It has become our view, however, that developments over recent months have implications for the longer term.

Changes since January include the following:

- Prices have remained much higher;
- Nevertheless, demand expectations have been stronger;
- Supply expectations have been weaker; with yet more non-OPEC disappointments; and increased uncertainty over OPEC capacity increments;
- The call on OPEC crude has increased;
- OPEC aspirations have changed.

It is the final point that we believe is crucial. Up till early April high there did not seem to be any substantial evidence that prices were having any effect on demand. All the indications were that demand growth estimates for 2005 might again be understated and that OPEC would again be called on to produce at close to capacity. Over the course of April some doubts have begun to creep in regarding the apparent insensitivity of demand to price, but nevertheless the high call on OPEC crude this year seems unlikely to change even if there are no more increases in demand growth estimates. OPEC members have observed the inexorable rise in prices since early 2002, but especially since early 2004, an era when price have consistently exceeded $30/barrel, and have seen demand rising strongly, apparently oblivious to price. If the market could bear $50/barrel, why should OPEC settle for less?

With the formal abandonment of the $22-28/barrel price band, OPEC has set itself free to decide on a new target price. Whilst no formal decision has yet been made, aspirations have risen with rising prices. OPEC now seems to aspire to a price for

its Reference Basket (ORB) of $40-50/barrel. Until the middle of 2004 the value of the ORB was $0.50-$1.50/barrel below Brent. Since mid 2004, however, as prices have risen sharply and as OPEC output increases have put more heavy crude onto the market, the value relative to Brent has fallen to a discount of $3-5/barrel. An aspiration of $40-50/barrel for the ORB therefore implies a range of say $44-54/barrel for Brent and somewhat higher for WTI

With aspirations having ratcheted up, the issue then becomes: if OPEC members now aspire to prices in this range, what is there to stop their achieving them?

Supply Prospects

Non-OPEC output is not expected to be able to respond much in the next few years as oil companies are already fully committed to a number of long lead time projects and do not have the capacity in terms of manpower to start additional projects. Oil companies anyway remain cautious and will not assume that high prices are necessarily here to stay, but will stick with lower "screening values" for assessing the profitability of projects.

As for OPEC, with production close to capacity the old problem of cheating on quotas has, for the present, ceased to be an issue. Even if those members with increments to capacity scheduled to come on stream over the next year or so choose to produce from those increments, regardless of any agreements on production restraint, that might still have little impact on prices, as many of the increments are of light sweet crudes that can be easily placed in the market without depressing prices. Relatively few increments to capacity are definitely expected in the Middle East, and even if those that are expected produce at maximum, Saudi Arabia could easily cut back its own output by sufficient to keep prices from falling, and would probably involve other Arab Middle East producers in the policy.

It has been observed that OPEC has been powerless over recent months to stop prices from rising. That is largely true, but it remains far from powerless to stop them from falling. Even just the threat from Saudi Arabia to cut back on output would probably be sufficient to end a fall in price in current circumstances. So how far would the Saudis be prepared to allow prices to fall before stepping in and cutting output?

In recent high level discussions with the U.S. Government prominent Saudis have opined that prices around $55/barrel are "too high". Such references are probably to WTI rather than the ORB. That would suggest that currently it is recognised that the upper end of the potential $40-50/barrel band for the ORB is regarded as too high, too liable to induce economic slowdown at this stage of the economic cycle, and too liable to induce measures that might undermine the long term demand for oil. On the other hand it is unlikely that $40/barrel as a floor has been conceded. We therefore believe that for the next two to three years OPEC will seek to defend a floor for the ORB around $40/barrel, say $45/barrel for WTI.

Over the next few years every member of OPEC will see increments to capacity from developments already under way. The list of projects is long and includes light, medium, and heavy crudes. Longer term, however, OPEC members will have to decide how much to invest in adding more new capacity. They all recognise that most projections of the longer term future indicate an increased call on OPEC crudes, as the rate of growth of non-OPEC output falls short of that of demand. On the other hand no-one wants to spend money on adding to capacity that will then sit idle as part of the spare capacity cushion that the present world oil market seems to require. In addition growing budgetary requirements from areas other than oil, notably welfare expenditure as many countries are facing high levels of youth unemployment, create increasing competition for revenues from oil. One policy option therefore would be to delay investments, just sufficient to keep the market tight and prices high. That would increase the probability of being able to utilise new capacity and not keep it idle, while also maximising the price, and making money available for other projects. The difficulty, however, is that such a policy, whilst nominally possible, would require OPEC members to show a degree of co-ordination that has historically not been seen. While competition for revenue may delay investments to a certain degree, therefore, nevertheless individual states are still likely to make their own independent decisions, each member believing that in its own uniqueness and in its ability to sell all its production without depressing the price; the problem of having to maintain idle capacity will be someone else's. Indeed, there may be some truth in this: many members face circumstances that mean that there is always a strong demand for their particular production, provided it is competitively priced relative to other crudes, and therefore that their production can be maximised with little impact on general price levels. For example:

Libya, Algeria, Nigeria	All produce light sweet crudes that are in strong demand for their quality in both Europe and North America, and increasingly even in Asia Pacific as regional production of such qualities is static while demand is rising.
Venezuela	Is close to the US, meaning freight costs are low and output can respond more quickly to demand. Supply is regarded as secure despite political differences. Many US refineries have been built specifically to use cheap extra-heavy Venezuelan crudes.
Indonesia	Produces sweet crudes and enjoys proximity to fast-growing Asian markets. Indonesia is anyway now a net importer of oil.
UAE	Most of its grades are lighter than other Middle East crudes and some are particularly highly prized in Japan for their quality.

This means that it is predominantly the Middle East producers of heavier, more general purpose crudes, Saudi Arabia, Kuwait, Iran, Iraq, and Qatar, who could face greater difficulties with marketing their output, and on whom the burden of maintaining spare capacity would primarily fall. Neither Iran nor Qatar have good

track records on quota compliance, but equally neither is expected to be able to add very much to its capacity. When Iraq manages to restore and build up its output it is likely to be granted special status in relation to quotas. Thus the burden may come to rest mostly on Saudi Arabia, possibly aided by Kuwait, a situation not that different from today.

Against this background, in the longer term the spare capacity cushion could increase in size again, easing market concerns, while individual OPEC members choose to utilize the capacity on which scarce revenue resources have been spent. All the more would this be so if, as a response to price, demand does not grow as strongly as previously projected.

Demand Prospects

At price levels around or below $50/barrel we do not believe that the resultant retail prices to consumers in OECD countries, or even in China or other richer non-OECD countries, will be high enough to provoke widespread "don't consume" decisions. Such prices may be high enough to encourage consumers to consider investing in more energy efficient appliances when those appliances are next due for replacement, but are probably not high enough to bring forward that date. The progressive introduction of more efficient appliances, notably cars, will eventually impact on demand, but it will take some years before that impact becomes sizeable. Nevertheless there are early indications that behaviour is moving in that direction, for example a downsizing by US motorists from large SUVs to medium and small SUVs. Even small SUVs may be rather fuel inefficient, but less so than their larger counterparts. With around 50% of new car sales in the US in terms of SUVs the impact of this over time could be significant. In Brazil sales of dual fuel vehicles able to run on cheap locally-produced ethanol, as well as on gasoline, have increased dramatically. In the longer term, therefore, even in OECD countries the cumulative effect of individual decisions to use energy more efficiently, aided by continuing technological progress in improving efficiency, and possibly abetted by a variety of regulatory, fiscal, or policy measures, may result in slower demand growth.

Outside OECD, however, even short term reactions to high prices may be different. Here prices may prove high enough to provoke "don't consume" decisions among poorer consumers. More importantly, however, in many such countries retail prices of fuels to households are subject to price control and are kept well below international market levels by systems of subsidies. There are signs that the burden of maintaining these subsidies at current prices is becoming intolerable for some governments. Hence there have been reports of increases in retail prices recently in a number of Asian countries, China, Malaysia, Thailand, Indonesia, Vietnam. If this trend spreads, which we expect to occur, it will have an impact on demand. Subsidies, once removed, are unlikely to be reinstated, so an increasing proportion of consumers will progressively be exposed to the true international cost of the fuels they use.

Implications for Price

Beyond the next few years, therefore, we still expect OPEC to seek to defend a price in the $40-50/barrel band, but with the progress of time this may become more difficult.

- Demand may be trimmed both by income-elasticity and price-elasticity effects, aided by technology improvements and the turn-over of the capital stock, and policy measures;
- Non-OPEC capacity will continue to rise and while we do not expect significant supply responses to price in the early years, nevertheless high prices will provide an incentive to get projects on stream as quickly as possible;
- Later, additional non-OPEC supply may result as settled high prices are progressively factored into project evaluations;
- OPEC's own output capacity will rise, and there will be increasing pressures to use that capacity rather than keep it idle;
- The spare capacity cushion may rise, easing market concerns.

Against this background we have decided to raise our projection of prices beyond just the short term. We have projected the price of WTI to fall to around $45/barrel by 2008 and then staying fairly constant in nominal terms for some years. This implies a falling real terms price, reflecting the difficulties we believe OPEC will face in maintaining high prices; they will be forced to accept broadly flat nominal prices but will be unable to maintain their real-terms value.

NATURAL GAS OUTLOOK

Short-term

Natural gas supply trends remain negative in the United States, but slightly positive for Canada. The most recent supply-and-demand indicators show a neutral position of the market in March and April after it tightened this winter.

Canadian receipts into Alliance and Nova slightly exceeded year-ago levels while Canadian demand is down; thus exports to the United States are up. Also, Mexico is reported as having reduced its imports of natural gas from the United States. Natural gas demand appears weak, while fuel oil demand rises despite high oil prices. Although this usually signals some inter-fuel substitution away from gas, there cannot be much remaining capacity to switch. Almost all the indicators are now showing supply difficulties.

US natural gas demand fell about 6% in January and February according to EIA monthly reports. Canadian demand was also down, as high prices and weather trends contributed to weaker consumption. Most of the decrease was in the core sectors, with industrial demand down about 5%, and power generation demand actually neutral. These trends could be reflective of 2005 as a whole. Industrial natural gas consumption has been lagging output since 2003, and with manufacturing growth slowing in 2005, natural gas consumption could decrease. The power-generation sector is expected to increase demand for natural gas 6% in 2005. Significant new power generation is coming on line in Florida, and along with stringent environmental regulations, high oil and coal prices, and limited hydroelectric availability, natural gas has room to grow even with $7 prices. Overall natural gas demand will decrease by 1.6% in 2005, reflecting near $7-prices.

US natural gas prices fell to less than $7 in mid-April, and then battled back and forth, finally entering May headed lower. The June bid week price is expected to also hold at $6.62. The daily shifts in natural gas prices have apparently been following the movements of the crude oil market. Summer prices are expected to remain at $6.50–$7, as high oil prices, negative trends in U.S. supply, and the start of storage injections all contribute to a tightening market and sustained, high expectations.

The outlook for North American natural gas supply remains negative, as the huge decline in offshore production in 2004 and the recent drop in onshore Texas production would have to be reversed for it to be otherwise. Net imports of natural gas will increase in 2005, but this will only offset part of the U.S. production drop. During 2004, offshore gas production declined more than 1 billion cubic feet per day (bcf/d). In January and February 2005, Texas onshore production also fell more than 1 bcf/d. It is increasingly likely that U.S. production will decline more rapidly in 2005 than in 2004. Other information—such as expansive reserves additions in the United States, high levels of drilling, recovery from hurricane damage, and high

natural gas prices—suggest some possible offsets to the recent negative trends in production later in 2005 or in 2006. A small gain in LNG imports is expected for 2005, to a more than 2-bcf/d level.

The supply and demand balance occurs at a lower volume level in 2005 and at a higher price than in 2004. LNG imports are expected to change this deteriorating balance, but a surge in LNG imports is still several years away.

Supply

If the decline in Texas onshore production is correct, U.S. natural gas supply will decrease 2–4% in 2005. This follows a drop of 1.3% in 2004, mostly in the second half of 2005, and primarily from the offshore markets. The trends in other U.S. regions are more down than up, although the Rocky Mountains region continues to expand.

Still, there are positive trends for some areas of the US production outlook for 2005:

- Reserve additions continue to exceed production. Part of the reserve additions reflects higher prices rather than additions to discoveries or producing wells.
- The Cheyenne Plains pipeline will add 540 million cubic feet/day (mmcf/d) of takeaway capacity for the Rocky Mountains. Production is increasing in Colorado and Wyoming. Rocky Mountain production is growing around 0.3–0.5 bcf/d per year.
- Drilling activity will remain strong at 2,000 gas wells/month and a 160 increase in the rig count as of May 2005.
- Recovery from Hurricane Ivan will restore most of the 150 bcf of offshore production lost during 2004.
- Deepwater gas production continued to increase in 2004, with 14 new projects coming online. Several large offshore projects are expected to come online this year, including Thunder Horse. Shallow-water declines overwhelm the deep-water increases, however. The Minerals and Management Service (MMS) expects total offshore production to increase after 2007.

The MMS has released a forecast showing that the production from the Gulf of Mexico will increase substantially after 2007. This will be a welcome change, as Gulf production fell 500 bcf in 2004, and may continue to fall in 2005. Trends in onshore production are generally ambiguous in 2005, while trends in total production are negative. Most other onshore basins will experience neutral to net decreases in supply; thus, it is becoming more difficult to find evidence that production will reverse these negative trends in 2005.

Although net imports will increase in 2005, most of this is expected to come from Mexico and Canada rather than from LNG. For 2006, LNG will provide most or all of the gain from net trade. Although LNG imports will increase in 2005, most of the growth will come at the end of 2005 and continue into 2006.

Demand

Demand destruction is likely to occur in 2005, as a decrease in overall availability coupled with growing demand in the power sector squeeze consumption in energy-intensive industry. Thus, several sectors will be squeezed, such as fertilizers, chemicals, paper and other energy-intensive industry. Consumption levels are expected to decline despite both economic and weather trends favorable to growth. Early indicators for 2005 show a decrease in consumption of natural gas.

Power generation is growing about 1% so far into 2005. The growth rate is expected to increase this summer with hot weather. Also, low hydro levels will support an increase in natural gas use. Cooling degree-days will increase at the national level, but this will not have as great an impact on gas generation. In 2004, the Northeast and some other northern states had a very mild summer, while the South experienced fairly normal temperatures. Since most of the nation's gas generation occurs in Texas, Louisiana, Florida, and California, and since these states had nearly normal weather in 2004, the increase in gas demand in 2005 will be lower than extrapolating from national degree days.

Natural gas demand in the power sector is expected to increase in 2005, as a result of growing demand and constraints from other power sources. From 2003 to 2010, the power sector will account for nearly 80% of US natural gas demand growth. Utilization of baseload coal and nuclear plants has been trending up. During periods of slow growth, increased utilization of coal plants has meant weaker gas demand, as seen in 2004. The difference for 2005 is that demand growth of 1.2% will be higher than the increases in coal and nuclear generation, implying greater gas usage.

Price

U.S. natural gas prices fell to less than $7 in mid-April, and then battled back and forth, finally entering May headed lower before turning back up in June. The daily shifts in natural gas prices have apparently been following the movements of the crude oil market. Although other fundamentals for natural gas have slowly been shifting to a more neutral position, oil prices remain near $50/barrel and supply difficulties support high prices.

- The weather adjusted changes in storage suggest a neutral supply-and-demand balance for recent months.
- Working gas in storage remains 200 bcf better than year-ago levels.
- Although production trends are negative, the rig count has risen 160 during the past year.
- Demand growth is negative for the first part of 2005, although forecasts of gas use for power generation show significant growth for 2005.
- Although natural gas demand is down, fuel oil consumption is up, suggesting some additional switching capacity has come to the market.
- Natural gas net imports are up so far in 2005, with LNG, Canada, and reduced exports to Mexico all contributing.

- Natural gas production is reportedly up in Mexico and Canada so far in 2005, although the increase is minor, and could be reversed.
- Weather effects are supportive of high prices, as water flows in the Pacific Northwest are expected to be about 70% of normal, while summer temperatures could be warmer.
- In the longer term, energy policy is evolving towards clean coal and new nuclear as well as opening up areas for drilling.

The most recent data on U.S. natural gas production is showing a sharp decline in January and February in Texas that contributes to a 2% decrease for the country as a whole. Although high frequency data is often revised, the simultaneous decrease in consumption, the increase in net imports, and the relative neutrality of the storage indicator support rather than contradict a downward trend in U.S. production. Since the United States still supplies 85% of its own natural gas consumptions, this remains quite serious. The implication is that high natural gas prices will be with us for a longer time than would be the case if production were increasing. Summer prices are expected to remain at $6.50–$7, as high oil prices, negative trends in U.S. supply, and the start of storage injections all contribute to a tightening market and sustained, high expectations.

Long-term Outlook

LNG's Importance Will Increase. Although demand growth has been restrained by high prices recently, a steady pace of growth is expected over the long term. Annual increases are expected to average about 1 bcfd between 2005 and 2030. With prospects for traditional gas supply sources bearish, natural gas prices will evolve to reflect the interaction between new domestic and imported sources of natural gas. Supply costs for potential incremental supplies are all higher than supply costs during the previous decade. LNG will be the predominant source of incremental supplies, owing to more limited growth prospects for other domestic and import sources.

The contribution from new supply sources in size, timing, and cost will be a major determinant of long-term natural gas prices. Although LNG imports are already increasing, the first big test of the impact of LNG on prices will come later this decade when several LNG terminals come on-line. Prices could fluctuate temporarily, depending on how trends in domestic production and Canadian imports evolve between now and then. Continued weakness in North American supplies would provide a supply gap large enough for the higher LNG supplies to fill, while improvements in those other supplies could cause supply capacity surpluses during this period that would drive down prices temporarily. We are currently anticipating that this buildup in LNG supplies will supplement North American supplies sufficiently to enable prices to drop down to a more sustainable level. Fluctuations are not depicted in our projections because they cannot be timed with precision.

Prospects for North American supplies are somewhat uncertain in the near term, but generally weak in the long term. The Minerals and Management Service has

recently projected that production from the Gulf of Mexico, which has been declining, will increase after 2007. Onshore U.S. production in general is ambiguous, with Rocky Mountain increases offsetting declines in most other areas.

The Gap Between Demand and Traditional Supplies Will Grow. With the Canadian gas industry facing struggles similar to those confronting U.S. producers, imports from Canada have little scope to rise, and are most likely to decline in the long term. Canadian natural gas reserve additions have lagged production for several years, implying lower gas production in the future. Canada is planning to undertake the Mackenzie Delta pipeline project, with construction starting in 2006. However, this project is relatively expensive, at $7 billion, and the established reserves are still lagging the desired level to support the pipeline. Rising costs and lagging reserves may delay this project.

Alaskan North Slope gas will begin to flow to the lower-48 states during the second half of the forecast period, eventually rising to 3 trillion cubic feet (tcf) per year. The required increase in LNG imports will be more than twice this amount.

LNG currently makes up a very small portion of U.S. supplies, just 2% in 2003 and 3% in 2004. That share will grow substantially, potentially exceeding one-fourth of total supplies by 2030. There will be a market for 5-9 additional LNG terminals by 2010 and 15–20 new LNG terminals by 2030. Imports projected for the medium term reflect analysis of known projects, as discussed in detail in a separate section below.

Long-Term Prices Will Average $4.00-4.50. While expanding LNG imports will fill most of the growing gap between domestic demand and domestic supply, it is unclear if LNG will actually displace U.S. production. The difference is important for pricing. When demand and supply increase at about the same rate, the impact on prices would be less. If LNG displaces lower-48 production, the resulting price competition would drive prices down. Global Insight expects that the process will be a combination of the two; LNG will meet all growth other than that met by Arctic pipelines. Also, LNG will cost a little less to produce that the marginal U.S. supply. LNG will thus displace a small part of U.S. lower-48 production, thereby lowering prices. The supply cost of incremental supplies of U.S. lower-48 gas is expected to be between $4 and $5 per mmBtu in 2003 dollars. Future LNG supply costs are about $3.00 to $3.75 at a 10% rate of return. At a normal 16% return and with a higher level for sovereign take, LNG will price closer to $4.50. Thus the interaction between the two supply sources is expected to produce prices in the middle of this range of supply costs, at around $4.00–4.50.

Technically speaking, there will be no "supply gap" per se, but rather, a market niche for LNG *at a given price*. This is because demand and supply eventually balance at a given price level. A much higher price than projected here would both destroy more demand and attract more domestic supplies, requiring fewer LNG supplies. With ample LNG supplies available at lower prices, though, competition would eventually drive prices back toward the levels projected here. Given our expectation of the prices of competing fuels and competing sources of natural gas, the

projection of long-term wellhead prices in the $4.00–4.50 range reflects our estimation of the point at which a stable long-term supply/demand balance could best be achieved.

Prices are expected to decline toward this range as LNG supplies build up later this decade. Prices will then gradually shift to a slow growth within this range, as supply costs gradually rise. Although below current prices, this expected long-term price level is nevertheless about $2.00 above 1990s levels. Not only were there more incremental supplies available at lower costs then, but there was an overhang of spare producing capacity.

How LNG Will Help Set the Price Level. The interaction between domestic gas and LNG in setting the price level is complex. LNG costs are a bit lower than current U.S. supply costs, and LNG is the principal marginal supply on an annual average basis. Domestic production will continue to account for the majority of gas supply, such that it will remain the swing supply source—at least at times—in many U.S. regions. Thus, the costs of both supplies will contribute to the general natural gas price level, with LNG costs setting a floor price while domestic supply conditions determine the peak and seasonality of prices. Prices will hold close to the supply cost at which domestic supply can be sustained but above the supply costs for new LNG facilities. Thus LNG will be able to pick up market share by providing for demand growth and also a small amount of displacement.

The five to eight year gestation period for LNG projects and the relatively high cost of some projects will make it difficult for LNG to substantially displace U.S. conventional production. There are many reasons why the costs of conventional domestic supplies should remain a key driver of U.S. natural gas prices. While LNG and Arctic gas supplies are expected to meet most of the increase in U.S. demand, conventional production from the lower-48 is still expected to provide the majority of required supplies. U.S. conventional production can adjust quickly downwards (though only slowly upwards) to changes in market balances, thanks to the rapid decline rate for existing U.S. conventional production, which in 2001 averaged 27%. Because about one-fourth of U.S. production has to be replaced each year, a slowdown in exploration would quickly eliminate any oversupply. Also, because production now operates at high rates throughout the year while U.S. demand is strongly seasonal with a high variability depending on weather, prices will be influenced by the value placed upon firm supply during the peak winter heating season. Storage supplements production and imports during the winter peak, but storage capacity is not unlimited. Thus, U.S. natural gas prices in peak periods rise until prices constrain demand to available supply, which at times in recent winters has been far above domestic supply costs. Estimates of LNG supply costs are a measure of the lower price in the market rather than the average natural gas price. That LNG will be on the margin does not mean that seasonal price variations will disappear. Rather, most LNG producers will be able to obtain some rent in the U.S. market from the occasional seasonal peaks.

LNG Projects

Because of the rising importance of LNG in natural gas pricing, this section provides detail on LNG projects. LNG infrastructure in the United States is already expanding, and increases in LNG imports are expected to accelerate in the next few years as multiple new projects come into operation. Increases over the latter part of this decade will be equivalent to one new LNG terminal per year.

Increases in LNG Imports Expected This Decade

Year	LNG Imports (TBTU)	LNG Imports (Bcf/day)	LNG Imports Change from Prior Year (Bcf/day)
2003	506	1.38	0.6
2004	649	1.78	0.4
2005	740	2.0	0.2
2006	1247	3.3	1.3
2007	1744	4.7	1.3
2008	2072	5.9	1.2
2009	2579	7.1	1.2
2010	3018	8.3	1.2

LNG receiving and regasification terminals in this country are being proposed in conjunction with development of LNG supply projects in producing countries. Considering the LNG terminals in conjunction with the supply projects is useful in determining whether and when the projects might proceed. Some LNG industry participants are choosing to specialize. Marathon has decided to develop the LNG project in Equatorial Guinea and sell the LNG to BG Group. Other companies, such as Cheniere, Main Pass Energy, and Excelerate Energy, are developing LNG import terminals for the United States. These are specialized companies. While most world trade in LNG is supplied by integrated companies such as Royal Dutch Shell, this is not the case for the United States at present. By 2010, the major oil companies could reassert their dominance, since they have a large stake in many of the projects that are likely to be developed.

The United States imported 506 bcf of LNG in 2003 and will likely import 3 tcf by 2010 if most of the approved projects and several of the proposed projects go ahead. In order to support our market balance forecast that relies upon LNG, Global Insight surveyed the potential supply to ensure that the timing of supplies to satisfy needed increases is feasible.

Construction is under way on several projects. The projects that are judged most likely to go forward are those that (1) have sufficient reserves of natural gas to support world-scale LNG plants, (2) have the active support of a coalition of international oil companies and support of the host country, (3) have plans and progress on developing an LNG terminal, and (4) have a likely market. Projects now under construction will increase U.S. LNG imports to about 40 billion cubic meters (bcm) by 2007. Likely projects should add about 60 bcm to imports by 2010. These projects are not definite, and there is room for more projects or replacement projects. Also,

there will be a significant short-term trading in LNG that could provide 10 to 20 bcm to the United States by 2010 from other projects.

LNG Terminals

The United States has expedited the LNG terminal approval process so that decisions will be made within a definitive time frame. Several LNG terminals have already received licenses from FERC. Offshore terminals are regulated by the U.S. Coast Guard, while FERC permits are required for the pipeline facilities. International projects require only pipeline permits from FERC to serve the U.S. market. LNG terminals in Canada that use existing export pipelines to the United States would not be subject to any U.S. permitting requirements.

There are four existing LNG terminals in the United States, and all have applied for expansions. Approvals have either been received or are in process for all four existing terminals: Lake Charles, Elba Island, Cove Point, and Distrigas. In addition, several proposed LNG terminals have received approvals:

- Sempra: Hackberry LNG in Louisiana has its FERC license but construction was deferred until later in 2005.
- Cheniere: Freeport Texas LNG terminal is licensed and under construction; Sabine Louisiana LNG terminal has FERC approval.
- Excelerate Energy: Energy Bridge platform, 100 miles offshore Texas, will receive its first cargo in mid-March 2005.

Many other terminals are at various stages of the permitting process. Over 40 terminals have been proposed, and 5–9 new LNG terminals will be constructed in the United States by 2010. In addition, LNG terminals are being developed in the Bahamas, Baja California, and eastern Canada to serve the U.S. market.

LNG Supply Projects

There are six LNG plants under construction that will supply the U.S. gas market. More than 15 additional LNG plants that are either planned or proposed could be operational by 2010. In total, these projects have the potential of adding up to 5.7 tcf to U.S. gas supplies within seven years, more than twice the amount that will be required within this time frame. Their level of commitment to the U.S. market at this point varies from project to project.

World LNG Projects with Potential to Supply the U.S. Market This Decade

Country and LNG Project	2005-2006 Under Construction (Bcf/Year)	2006/2007 Planned (Bcf/Year)	2008+ Planned or Proposed (Bcf/Year)	Planned or contracted U.S. LNG Terminal
Algeria-Arzew			194	U.S., Europe
Angola-Soya			390	CVT, U.S.
Egypt-Idku II	175			Europe, BG Lake Charles, Elba Island
Egypt-Idku III			175	BG, U.S., Europe
Equatorial Guinea- Boiko Island		165		BG, Lake Charles
Nigeria-Trains IV&V	399			Shell,Total Europe, U.S.
Nigeria-Train VI		200		Shell, Total U.S.
Nigeria-Brass River			487	CP, CVT
Nigeria-West Niger Delta			240	U.S.
Nigeria-Floating LNG			250	Shell
Norway-Snohvit	199			Europe, Statoil, Cove Point
Norway-Snohvit II			200	Statoil, Cove Point
OMAN-Qalhat	160			BP, Shell Cove Point
PERU-Camisea		194		Hunt Oil
Qatar-Qatargas III			380	Conoco Phillips Freeport
Qatar-RasLaffan V&VI			730	Exxon Mobil Sabine
Russia-Sakhalin II	233	233		Shell Baja, Mexico
Trinidad-Train IV	253			Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Trinidad-Debottlenecking trains I,II and III		100		Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Trinidad-Trains V&VI			500	Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Venezuela			228	Shell U.S., Mexico
Total	**1741**	**892**	**3190**	

COAL OUTLOOK

Short-term Outlook

- We're in the shoulder months, but coal prices are still firming
- The first signs of coal-on-coal competition are beginning to emerge
- Production is rising but must grow more to meet rising demand
- Imports are booming as foreign coal prices look more attractive

Market Outlook

We are still officially in the shoulder months, when markets are traditionally soft, but we are seeing a slight firming in most markets and strong upward price movement in the Western coals. Even though Appalachian (both North and Central) coal prices are currently high, low inventories throughout much of the East have kept coal purchases moving at a steady pace. For Western coal regions, improvements in rail shipments are allowing demand to expand throughout the Midwest and East in response to $800+ SO2 prices and those high Appalachian prices.

Indeed, we are seeing significant price shifts in both the Powder River Basin and Western Bituminous coals. We have been expecting the PRB move for some time, and the price of the 8800 Btu coal from that region, which began the year below $6/ton, has now moved into the $8 range. Earlier in the year, we were less confident that the Western Bituminous coal price would rise as quickly, but events have transpired that have led us to revise our outlook for this year by adding a few dollars per ton to the outlook, as opposed to dropping the price several dollars over the year. Specifically, the Western Bituminous coals have benefited from the second surge in SO2 prices that created greater urgency among Eastern/Midwestern buyers, the belief that buying out of the West should be diversified due to transportation issues, and the continued uncertainty on the environmental front due to significant doubts as to the viability of the mercury regulations.

For Eastern and Midwestern coal buyers, the question of buying coal from the West means greater concern about transportation rates and service than mine-mouth prices. Not that the latter is insignificant; as mentioned last month, the precipitous rise in PRB prices in early 2001 sent many prospective coal buyers who were looking at that region into a hasty retreat. Yet there is no doubt that the rail rate is the major component of the delivered coal price as Western coal tries to penetrate further east. Several recent developments are being watched carefully by Eastern/Midwestern coal buyers in that regard, specifically the suits against the BNSF and UP pricing practices out of the PRB (filed separately by the WCTL and the U.S. Department of Justice) and a major approval by the Surface Transportation Board for the DM&E to be a third option out of the PRB.

In this *Coal Monthly* issue, we have expanded our price coverage out through the end of December 2008. With natural gas prices so high and very little excess coal capacity in evidence, most observers agree that we are there is nothing to constrain coal prices in the current market. Yet, as shown in our forecast, we do foresee a moderation in prices coming down the road. This will not arrive overnight, but already we are beginning to see the first signs of coal-on-coal competition beginning to emerge. Specifically, foreign import prices have been falling dramatically and the volume moving into the United States is already rising sharply. We are forecasting imports of 31.3 million tons for this year (up from 27.3 million last year), but this figure is less than half what could ultimately be imported if there is no downward price response from Central Appalachia. Likewise, we are just now starting to see PRB coal moving further east, posing the question of how much market share Appalachian producers are willing to cede before adjusting their price as well. The coal-on-coal situation only intensifies as scrubbers are added, allowing buyers to leverage off a number of competing regions as well as alternatives such as petroleum coke.

Coal Production

Higher electricity generation, coupled with greater tonnage needed due to more use of lower Btu western PRB coal, leads us to forecast a roughly 22 million ton increase in production for 2005, nearly 2% above last year's output. We show lower exports and higher imports for both 2005 and 2006, but these are offset by anticipated growth in stockpile levels as many power companies seek to get out from underneath the hand-to-mouth lifestyle they have been forced to deal with due to extremely low inventory numbers.

We anticipate that electricity demand will drive coal demand even higher in 2006, aided in part by a few new units (Gilbert, Hardin) and greater transmission access by coal-fired generators to areas such as PJM.

Output in the **East** dropped significantly in the first quarter, but we are expecting a gradual recovery to slightly higher levels over the next several quarters. Growing imports continue to cut into the (largely Central) Appalachian market share, but Powder River Basin coal is also beginning to show signs of impacting Northern Appalachian markets in light of high SO2 prices coupled with generally high Appalachian coal prices. By 2006, however, we anticipate stronger growth in the Appalachian market as come coals are forced to become more price-competitive and demand for coal-fired electricity generation continues to rise.

Production from the **Interior** region began with a very strong push in the first quarter of this year, but now appears to have settled to a more sustainable level for the short term. While many observers (such as the Department of Energy) are looking for a relatively substantial decline in output from this region, we are projecting a modest increase. This more optimistic outlook is based less on any intrinsic superiority of Interior coals, and more on the inability of other regions to increase their production any more than we are currently forecasting.

Production in the **West** has been increasing at the rate of about 20 million tons annually, a development pushed by high SO2 prices, high Eastern coal prices, and a grudgingly slow improvement in transportation out of the region. We anticipate a strong near-term market for coals out of both the PRB and Western Bituminous regions for the same reasons.

The Stock Situation

"Exceeding low inventories" has been the catchphrase in describing the coal stockpile situation over the last six months, but the situation is not necessarily as clear-cut as that term implies. A first glance at the first-quarter 2005 consumption and production estimates suggests that very little was actually added to inventory levels, but we question that assumption in light of the lower burn (relative to the first quarter of 2004), even after adjusting for more Western coal in the mix (due to lower heating values). In any event, we are anticipating inventories rising to just short of 165 million tons by the end of June, a level that actually exceeds last year's level. With a normal summer drawdown, however, we are looking at about 155 million tons by the end of the year. Nevertheless, unless several regions ante up with increased production, this will be a stretch and we may end 2005 with an inventory level no larger than the 147 million tons registered at the end of 2004.

Coal Stocks (million tons)

Jan 2005	Jan 2004	Percent Difference	EOY 2004	EOY 2005	Percent Change
146.1	152.0	-3.9%	147.3	154.9	5.2%

Exports & Imports

Coal exports slowed considerably in the first quarter of 2005 after a very fast start in January, but are still running about 5% ahead of the 2004 pace. Met coal shipments continue to lead the way and we expect demand for this component of steelmaking to remain strong throughout the year. On the steam coal side, there is still very little interest in Atlantic markets. Indeed, global markets have not really responded with higher prices to a series of supply disruptions in South Africa (major rail delays), a roof fall at a major Australian mine, and adverse weather disrupting Indonesian operations. Canadian imports are down so far this year and U.S. coal exporters continue to watch the Ontario deliberations carefully, but the likelihood that all coal plants could be closed even within several years of the 2007 target date set by the new provincial government appears remote at this time.

The major price decline that has occurred in Colombian and most other Atlantic coals has not been met by reciprocal reductions in Central Appalachian coals, so interest by U.S. power companies is mounting. Preliminary data for March, released on May 11, suggests that imports topped 3 million tons in a single month for the first time. This greater interest in imports is beginning to manifest itself in the form of inland plants, as in the case of the Gainesville (Florida) Deerhaven station,

which is starting to solicit foreign bids for the first time. U.S. railroads are reportedly being more cooperative in considering these kinds of shipments, although the railroads will still likely evaluate them on a case-by-case basis.

U.S. Exports and Imports (Million Tons)

	YTD 2005*	YTD 2004*	Percent Change	Forecast 2005	Forecast 2006
U.S. Exports-Total	10.1	9.7	4.6%	43.8	38.8
U.S. Imports	7.7	5.3	43.9%	31.3	34.1

**YTD is through March 2005*

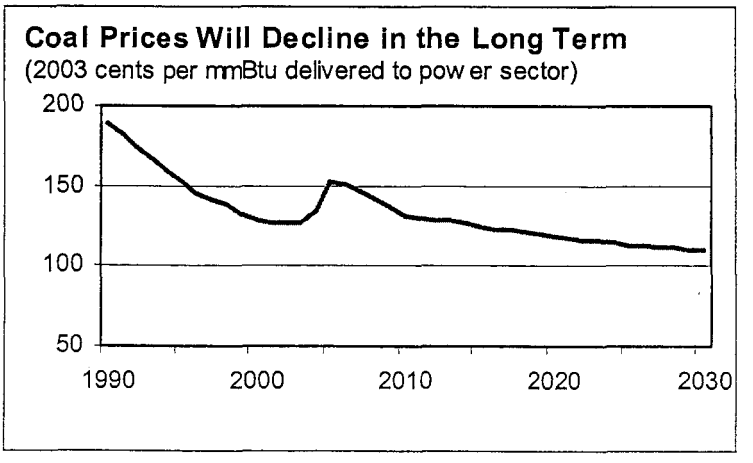
Long-Term Outlook

The issue of long-term coal pricing is one lacking widespread consensus, perhaps a problem common to more fuels than just coal. In this article, we will critically examine our contention that most coal prices will eventually decline in real terms, with a start date perhaps sooner than most expect. We review the major issues that lead us to the conclusion that the kind of pricing we have seen recently in many mining regions of the country is not sustainable.

A number of well-versed coal consultants believe that high coal prices are a permanent fixture of the energy landscape. They point to:

- the absence of any meaningful competition from natural gas in the electricity dispatch order due to high fuel prices,
- the rise in production costs in coal mining, and
- the consolidation of the coal industry that has led to unprecedented market power for a very small number of suppliers.

In this article, we will address these issues and explain why we believe they will ultimately work in the direction of lower prices.

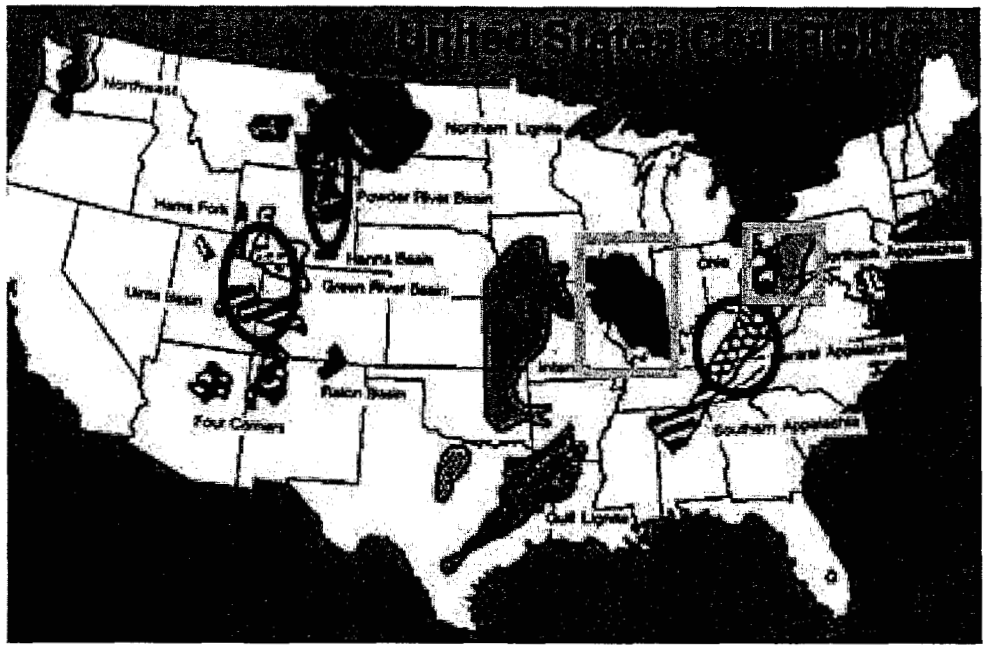


What do we mean by high or low prices? In discussing coal prices in general, this may be little more than a semantic problem. Our perspective is that prices will and must be considerably higher than they have been historically (pre-2000), but that current pricing levels are too high to be sustained. Yet we continually encounter the assumption that prices will not move too far from the current markers, so we do believe there exists a strong professional difference on this point.

The high energy price environment. There have been major price increases in virtually every fuel source since 2000, including coal, oil, natural gas, and uranium. There is a feeling among many observers that high prices in other energy sectors breed high prices in all of them, and to a limited extent, we concur. Certainly the very high price of natural gas lifts the ceiling on how high coal prices can be (although, as we will explain further, they do not necessarily mean that coal prices will rise significantly). Yet we also believe that each of those four fuels have individual industry structures, resource availabilities, and production differences that, under the right circumstances, would allow one or more to break from the pack. With regard to coal, we believe that is the case. Its abundance in the United States allows for potentially strong competition (which currently does not exist) so long as the return on new coal investment appears promising, which we think it will.

What about a lack of competition from other fuels? Indeed, natural gas prices at $6.00–7.00 per million Btu (mmBtu) will do nothing to strike fear into the hearts of coal producers. Yet we anticipate gas prices to subside to levels at which we believe coal suppliers will have to exercise some pricing restraint if they still wish to capture a significant share of the new generation market, factoring in the cost of high capital investment in boiler equipment and environmental compliance. Moreover, if coal prices really do remain as high as current levels, how much more attractive does that make nuclear power, which is already gaining significant momentum on the bases of both improved plant performances and, perhaps more importantly, concern over global climate change? Yet, as described in the next paragraph, it is really the prospect of coal-on-coal competition—not competition with natural gas—that leads us in the direction of lower prices.

Coal-on-coal competition. Our theory of coal-on-coal competition as a principal source of lower coal pricing rests heavily on the additional leverage power companies can attain by accessing coal from beyond their current procurement areas. In the near term, this may mean bringing Powder River Basin or western bituminous coal into the Midwest and East, a trend now well under way. Over the next few years, however, a much broader form of inter-regional coal competition should emerge as power plants add pollution control equipment, particularly scrubbers for SO2 control. Plants that currently rely on low-sulfur coal are highly restricted to three coal regions—the Powder River Basin (PRB), the western bituminous regions (Uinta and Green River Basins), and Central Appalachia. Installing scrubbers gives plants in the Midwest and East a good shot at using coal from two regions of low mining cost and high reserves, the Illinois Basin and Northern Appalachia. The low-sulfur areas are highlighted on the map in ovals and the high-sulfur areas are depicted with rectangles.



Critics of this theory often counter that the extreme consolidation in the coal industry simply means that everyone's prices will remain high and that competition will not actually develop. That certainly is a possibility. Yet as we look at major battlegrounds as to where we think this competition might develop (the Carolinas, for example), we find it hard to accept that coal companies will "stick to their guns" on high pricing when they are reaping such strong profits and face losing a massive market opportunity. With regard to the Carolinas, we foresee strong competition involving both two high-sulfur regions (Northern Appalachia and Illinois Basin). In looking at Central Appalachia producers, the current "incumbents" in the Carolina market, we also find it difficult to believe that they will be willing to give up their current status without a fight, especially considering that the Carolinas are their own backyard in market terms.

Finally, we expect foreign (import) coal prices to be much more attractive as prices fall in the face of lower ocean freight rates and declining demand as the Kyoto greenhouse-gas treaty begins to take a toll on European coal demand. To that end, with regard to our recent example, it is noteworthy that Progress Energy (Carolina) is currently testing foreign coals at stations other than their Sutton plant, which has taken South American coal for the past few years. Finally, we are aware of a large number of companies exploring in earnest the possibility of burning petroleum coke (petcoke). As production of that byproduct of the refining process continues to ramp up, power companies are finding it an attractive source of lower-than-coal cost fuel. Its (generally) much higher sulfur content becomes largely a non-issue when units are equipped with scrubbers. While certain qualities of petcoke (e.g., volatile matter) may prohibit 100% burning in existing coal-based units, a substantial percentage of the fuel can in fact be burned in most instances.

The theme of this argument is that following the 2005–06 period, power companies are likely to have a much wider array of coal opportunities at their disposal. While we do not expect this development to lead to "low" coal prices, we do anticipate that the prices we project in our long-term forecasts accurately portray achievable pricing levels we will see in a more competitive environment.

Production costs. The final component of the argument that coal prices will not fall is based on the premise that production costs have risen and will not be coming down. We counter with three items in this regard.

First, a good deal of the rise in production cost increase has been based on the rise in diesel fuel and steel markets (affecting a wide array of items, such as mining machinery parts). These material costs, like energy, have also experienced major price spikes. While certain contributors to production costs, such as trucking in Central Appalachia, will not be retreating from their recent rises, the majority of the material costs that increased substantially in the past few years are going to decline in the years ahead, although they will not reach their pre-2000 levels.

Second, in looking at "production costs," many analysts include the various fees and taxes to which coal is subjected. Yet some of these, such as royalties and severance taxes, are based on a percentage of the selling price. If the selling price were to decline, so would these so-called "production costs," with virtually no impact on the profit picture for the coal company.

Finally, and most importantly, production costs are heavily affected by productivity changes, and we expect this picture to improve for most of the coal industry. There has always been a strong correlation between capital investment and productivity levels in the coal industry, and as coal prices began to wane in the late 1990s, we saw capital investment decline markedly as well. The failure of new capital investment to return until just recently has had a major, negative impact on productivity levels in virtually all regions. There may be some regions where reserve degradation argues against any productivity improvement (notably Central Appalachia), but we expect most regions to respond as investment recovers. We are not looking for the historical productivity gains that were registered in much of the 1980s and 1990s, because many of those gains were achieved by simply closing less-efficient mines. We do expect, however, that the targeted, selective investment that is now becoming the trademark of the coal industry will produce worthwhile returns in both financial and productivity terms that will result in a lowering of production costs for coal mines.

Conclusion: In conclusion, we do not expect a return to the low pre-2000 coal price levels; however, we do see a substantial set of factors that will lead coal pricing away from the very high levels we have experienced over the last year or so. These reasons include potential competition from other fuel sources (natural gas and nuclear), lower production costs in the future, and—most importantly—competition from within the coal industry itself.

U.S. ECONOMIC OUTLOOK[1]

Highlights

- Real GDP growth will average 3.0% per year in 2004–30.
- The outlook for inflation remains moderate. Consumer price index (CPI) inflation will average 2.6% per year over the forecast period. Core inflation will average 2.7%.
- High investment and a slower growing labor force should result in higher productivity growth. Nonfarm business productivity growth averages 2.4% over the forecast period, compared with the 2.2% average experienced since 1953.
- The current account deficit is negative through 2025. Afterward, the current account surpluses grow.
- Real oil prices will creep up over the forecast period. The real price of imported oil is $26.3 per barrel in 2003 to $30.4 per barrel in 2030.
- The labor market improves over the forecast period, with the unemployment rate eventually settling at 4.95%.
- The federal budget deficit remains in deficit throughout the forecast period.

Long-Term Forecast

Real GDP. The trend projection assumes that the U.S. economy experiences no major mishaps between now and 2030. The projection is identical with our February 2005 baseline forecast through 2015, and represents Global Insight's best estimate of the economy's path over that period. Beyond 2015, the projection should be interpreted as the mean of all possible "near-full-employment" paths the economy could follow. The smooth-growth characteristics of the trend projection make it most useful for tasks largely impervious to short-term cyclical fluctuations, such as planning capacity additions and evaluating new markets. This projection is also the best base from which to evaluate the effects of various assumptions about key exogenous elements, such as fiscal policy or energy prices, on the overall economic outlook.

Annual real GDP growth averages 3.0% in 2004–30, about the same rate as the average of the past 25 years. The economy's underlying growth will slow after 2011, as baby boomers begin to retire, slowing labor force growth. Potential output growth should hold up fairly well in the future, with greater business fixed investment and R&D spending offsetting the slowdown in labor force growth. Eventually, though, the effects of weaker labor force growth become dominant and, in a sense,

[1] Global Insight's Long-term US Economic Outlook, February 2005.

self-perpetuating. As output growth drops off, business fixed investment rises more slowly, limiting capital stock growth and thus future output gains.

Employment. Slower long-run increases in the labor force indicate more moderate long-run employment growth in the future. Total civilian employment will rise at an average annual rate of 1.0% from 2004 to 2030. Total establishment employment will rise from 131.5 million in 2004 to 172.0 million in 2030, an increase of 31%. Manufacturing's share of total employment will continue to decline over the forecast period, falling to 7.3% in 2030, from 10.9% in 2004. The broad service sector will generate an increasing share of employment growth in the forecast period, although the federal government's share of employment will decline during the forecast period.

Inflation. Over the long run, inflation is a monetary phenomenon. Its future course will be determined by policies implemented by Alan Greenspan and his successors. Since we do not know who his successors will be, we assumed the Fed will try to stabilize the inflation rate in the second half of the forecast.

The CPI is expected to average 2.6% annual increases in 2004–30, somewhat less than the 4.4% average in 1977–2003. The broader-based GDP deflator will rise 2.3% per year.

Consumption. Expenditures, in the long term, are primarily determined by the growth of real permanent income, demographic influences, and changes in relative prices. The share of personal consumption expenditures in GDP will stabilize at just under 70% of GDP. Real consumption expenditure growth will average 2.7% per year over the forecast. In per capita terms, growth will advance about 1.9% per year, down 0.3 percentage point from the 1978–2004 rate. The share of consumption devoted to services will rise, mainly because of rising health expenditures, while that for goods will fall over the forecast period.

The long-term outlook for auto and light truck sales calls for a slowdown in the rate of increase relative to past performances. Vehicle sales growth will average close to 1.0% over the next 25 years. Light-vehicle sales are forecasted to reach 21.4 million units by 2030. Although the number of vehicles per person has increased significantly in the past 20 years, the United States is approaching a saturation point in the rate of vehicle ownership. Future growth in vehicle sales will be primarily driven by growth in population and demand for replacement vehicles. Automobile sales should be relatively strong throughout the projection period, averaging 7.9 million units per year.

Energy conservation efforts will continue. This stems partly from a stock/flow phenomenon: despite the trend toward minivans and sport/utility vehicles, for example, the average new vehicle is still more fuel-efficient than the existing stock. Gasoline usage per vehicle should fall for several more years, even if relative energy prices remain flat. Similar considerations apply to business capital and housing stocks. The ongoing employment shift from manufacturing to services also implies lower energy usage per unit of output.

Real personal disposable income, which climbed 3.2% in 1970–2003, will rise 3.1% annually over the next 25 years. This does not take into account the rising volume of withdrawals from existing retirement plans.

Housing. Household growth clearly depends on population growth, but real incomes, employment, the age distribution of the population, and societal values also influence it. Net additions to the housing stock are closely linked to household growth, which is the primary driver of housing starts. Many analysts tend to overlook another key factor for housing starts: the geographic location of the demand for net additions.

The 25–34-age cohort is key for the demand for new housing. This is the age group where individuals typically purchase their first home. The demand for new housing was boosted by the large gains in this age group in the late 1960s and 1970s, as the baby-boom generation entered the housing market. Unfortunately for the housing sector, the baby-boom generation began to pass through this age bracket in the mid-1980s, limiting the demand for additions to the housing stock. The number of households in this cohort will begin a modest increase after 2005. The overall headship rate will gradually increase toward older segments due to the shift in the age composition.

The demographic demand for housing will be about the same over the next 25 years as over the past 25 years. Thus, housing starts are projected to average 1.6 million units annually in 2003–29, about the same as during 1972–2004. Meanwhile, the housing stock will climb from 111.4 million units in 2004 to 142.5 million units in 2030.

Business Fixed Investment. Good profitability and solid demand growth should keep investment healthy over the next 25 years. The share of GDP devoted to business fixed investment will hover around 10.0–12.5% of GDP through most of the forecast period. The effective capital stock (in 2000 dollar terms) is projected to increase 3.7% annually, below the average growth rate recorded for 1970–2003. Inventory investment will remain a small percentage of GDP. Although inventories have played significant roles during past business cycles, inventory investment represents an average in the stable growth scenario and is thus artificially smooth. Capital inflow will contribute to net domestic investment throughout the forecast period, although the federal debt clearly hurt it in the later years of the forecast. The government saving projection assumes that state and local governments continue to run modest operating surpluses.

The composition of investment will continue to change in the forecast period; both structures' share of investment and equipment's share rises over the forecast period.

International Trade. A decline in the dollar relative to industrialized-country-currencies, combined with modest unit labor cost growth, will stimulate U.S. exports abroad and result in an eventual improvement in the U.S. current account balance. Global Insight projects that real exports will expand at an average annual rate of 7.3% over the entire forecast period. Real imports, meanwhile, will grow at an average annual rate of 5.2%.

FORECAST TABLES

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	SULFUR CONTENT		
	0.7%	1.0%	3.0%
Jan-99	11.08	10.28	8.14
Feb-99	9.77	9.06	7.60
Mar-99	11.58	10.80	10.10
Apr-99	14.04	13.22	12.72
May-99	14.39	14.12	12.90
Jun-99	14.39	14.09	13.34
Jul-99	16.49	15.57	15.02
Aug-99	19.36	18.49	17.71
Sep-99	20.57	19.95	19.01
Oct-99	20.24	19.56	18.51
Nov-99	21.15	20.37	18.13
Dec-99	18.86	18.47	18.03
Jan-00	20.03	19.40	19.09
Feb-00	22.19	21.11	20.79
Mar-00	23.80	22.91	21.38
Apr-00	23.18	22.28	18.70
May-00	26.12	24.93	20.99
Jun-00	28.89	27.70	22.66
Jul-00	27.78	26.58	20.37
Aug-00	28.89	27.24	20.28
Sep-00	32.49	31.06	23.48
Oct-00	32.47	31.26	22.98
Nov-00	33.45	30.41	20.56
Dec-00	31.18	27.74	16.48
Jan-01	30.09	27.52	18.48
Feb-01	26.86	25.33	20.62
Mar-01	25.09	24.14	18.62
Apr-01	25.11	23.85	15.10
May-01	24.69	23.52	16.76
Jun-01	22.96	21.77	17.54
Jul-01	21.46	20.51	17.34
Aug-01	21.38	19.88	17.57
Sep-01	23.16	22.24	19.57
Oct-01	19.34	18.84	15.54
Nov-01	16.83	16.17	13.64
Dec-01	17.78	16.44	14.63
Jan-02	16.40	15.43	14.65
Feb-02	16.44	15.28	15.00
Mar-02	20.42	19.28	18.92
Apr-02	23.46	22.60	21.66
May-02	24.03	22.89	21.64
Jun-02	24.49	23.30	21.26
Jul-02	23.25	22.40	21.83
Aug-02	25.24	24.15	22.50
Sep-02	26.45	25.53	24.66
Oct-02	28.57	27.36	22.90
Nov-02	24.92	23.68	18.73

Dec-02	27.28	25.89	22.21
Jan-03	32.01	30.90	29.37
Feb-03	34.77	33.75	27.76
Mar-03	33.60	32.71	22.70
Apr-03	25.25	24.30	19.64
May-03	26.61	25.65	21.10
Jun-03	28.11	27.15	22.38
Jul-03	29.95	28.98	25.51
Aug-03	29.13	28.14	25.84
Sep-03	25.73	24.78	22.31
Oct-03	28.37	27.42	24.27
Nov-03	28.02	26.78	23.96
Dec-03	26.98	25.63	22.29
Jan-04	26.78	25.86	22.55
Feb-04	25.41	24.66	21.99
Mar-04	25.24	24.57	23.36
Apr-04	28.70	27.63	24.65
May-04	32.23	31.07	27.25
Jun-04	31.98	30.89	24.97
Jul-04	30.36	29.38	24.87
Aug-04	29.64	28.63	25.42
Sep-04	29.61	28.52	25.98
Oct-04	34.42	33.27	31.29
Nov-04	31.08	29.71	22.01
Dec-04	28.76	27.32	22.44
Jan-05	30.89	29.83	26.66
Feb-05	29.91	29.03	27.01
Mar-05	34.70	33.77	30.56
Apr-05	39.92	38.43	34.57
May-05	40.01	38.57	36.83
Forecast			
Jun-05	39.04	37.70	32.50
Jul-05	38.43	37.19	32.00
Aug-05	37.97	36.67	32.45
Sep-05	37.54	36.16	31.01
Oct-05	37.40	36.16	31.01
Nov-05	38.37	36.67	31.51
Dec-05	39.69	37.70	32.50
Jan-06	39.05	37.70	32.50
Feb-06	38.32	37.19	32.00
Mar-06	36.08	35.12	30.02
Apr-06	35.41	34.09	29.02
May-06	36.43	35.12	30.02
Jun-06	37.97	36.67	31.51
Jul-06	36.83	35.64	30.51
Aug-06	35.29	34.09	29.02
Sep-06	34.32	33.06	28.03
Oct-06	33.66	32.54	27.54
Nov-06	34.58	33.06	28.03
Dec-06	35.34	33.57	28.53

DISTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	Posted Price at Tampa, FL	Spot Price at Gulf Coast
Jan-99	35.77	30.99
Feb-99	33.25	28.35
Mar-99	40.99	36.09
Apr-99	47.19	40.60
May-99	45.91	39.66
Jun-99	n.a.	41.27
Jul-99	n.a.	48.07
Aug-99	n.a.	53.20
Sep-99	n.a.	58.25
Oct-99	n.a.	56.47
Nov-99	n.a.	62.15
Dec-99	n.a.	64.41
Jan-00	n.a.	72.16
Feb-00	83.88	74.76
Mar-00	83.85	72.63
Apr-00	76.39	69.74
May-00	80.82	73.09
Jun-00	81.74	75.97
Jul-00	80.43	76.30
Aug-00	89.42	86.47
Sep-00	100.97	96.53
Oct-00	98.35	93.98
Nov-00	101.93	96.33
Dec-00	92.03	82.25
Jan-01	103.51	84.73
Feb-01	88.49	76.81
Mar-01	74.88	69.07
Apr-01	80.39	73.11
May-01	82.43	75.24
Jun-01	79.36	74.12
Jul-01	71.69	68.09
Aug-01	74.74	71.68
Sep-01	74.45	71.31
Oct-01	64.11	60.32
Nov-01	56.10	52.39
Dec-01	53.28	50.04
Jan-02	54.19	50.82
Feb-02	54.70	51.63
Mar-02	64.01	61.17
Apr-02	67.49	64.22
May-02	67.58	63.93
Jun-02	65.24	62.03
Jul-02	68.76	65.38
Aug-02	71.23	68.03
Sep-02	78.89	75.62
Oct-02	79.64	75.46

Nov-02	75.21	70.03
Dec-02	82.86	79.36
Jan-03	90.54	87.52
Feb-03	114.35	104.68
Mar-03	104.61	87.83
Apr-03	84.95	71.96
May-03	78.53	70.10
Jun-03	77.56	73.50
Jul-03	80.30	76.19
Aug-03	83.36	79.29
Sep-03	75.68	71.30
Oct-03	83.49	79.44
Nov-03	84.52	80.72
Dec-03	88.52	84.57
Jan-04	98.46	94.42
Feb-04	91.87	87.36
Mar-04	97.39	88.77
Apr-04	99.40	89.42
May-04	105.92	99.00
Jun-04	104.79	96.83
Jul-04	111.93	106.59
Aug-04	119.05	114.41
Sep-04	127.25	124.23
Oct-04	151.41	145.98
Nov-04	138.64	131.90
Dec-04	126.44	118.95
Jan-05	134.16	126.60
Feb-05	135.75	129.55
Mar-05	159.35	151.48
Apr-05	158.95	149.27
May-05	148.36	138.87
Forecast		
Jun-05	136.24	125.77
Jul-05	134.97	124.61
Aug-05	136.24	125.77
Sep-05	138.78	128.07
Oct-05	143.22	132.11
Nov-05	145.76	134.42
Dec-05	148.30	136.73
Jan-06	148.30	136.73
Feb-06	139.41	128.65
Mar-06	133.70	123.46
Apr-06	129.90	120.00
May-06	126.09	116.53
Jun-06	123.55	114.23
Jul-06	124.31	114.92
Aug-06	127.36	117.69
Sep-06	132.94	122.77
Oct-06	131.93	121.84
Nov-06	131.67	121.61
Dec-06	131.48	121.44

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	NOMINAL			*CONSTANT 2004 DOLLARS*		
	0.7%	1.0%	3.0%	0.7%	1.0%	3.0%
1995	15.18	14.69	13.77			
1996	18.04	17.47	15.58			
1997	16.59	16.15	14.41			
1998	12.85	12.14	9.69			
1999	15.99	15.33	14.28			
2000	27.54	26.05	20.65	29.82	28.21	22.36
2001	22.90	21.68	17.12	24.21	22.93	18.10
2002	23.41	22.32	20.50	24.35	23.21	21.32
2003	29.04	28.02	23.93	29.67	28.62	24.44
2004	29.52	28.46	24.73	29.52	28.46	24.73
2005	36.99	35.76	31.44	36.34	35.13	30.88
2006	36.11	34.82	29.73	34.87	33.63	28.71
2007	34.90	33.66	28.61	33.08	31.90	27.12
2008	34.59	33.36	28.32	32.12	30.97	26.30
2009	38.24	36.88	31.00	34.79	33.55	28.20
2010	37.40	36.07	29.94	33.28	32.10	26.64
2011	38.36	37.00	30.41	33.34	32.15	26.43
2012	38.82	37.44	30.50	32.93	31.76	25.87
2013	38.69	37.31	30.15	32.05	30.91	24.97
2014	38.49	37.12	29.72	31.15	30.04	24.06
2015	38.26	36.90	29.28	30.25	29.17	23.15
2016	38.48	37.11	29.18	29.71	28.65	22.53
2017	38.78	37.39	29.13	29.22	28.18	21.96
2018	39.09	37.70	29.10	28.74	27.72	21.40
2019	39.39	37.99	29.04	28.26	27.25	20.84
2020	39.71	38.29	29.00	27.80	26.81	20.30
2021	41.56	40.07	30.05	28.39	27.38	20.54
2022	42.85	41.32	30.68	28.57	27.55	20.46
2023	44.53	42.94	31.57	28.97	27.94	20.54
2024	45.91	44.28	32.23	29.15	28.11	20.46
2025	47.33	45.64	32.88	29.32	28.28	20.37
2026	48.87	47.13	33.95	29.54	28.49	20.53
2027	50.45	48.66	35.05	29.76	28.70	20.68
2028	51.94	50.09	36.08	29.89	28.83	20.77
2029	53.47	51.56	37.15	30.02	28.95	20.86
2030	55.12	53.16	38.30	30.20	29.12	20.98

DSTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	NOMINAL		CONSTANT 2004 DOLLARS	
	Posted Price at Tampa, FL	Spot Price at Gulf Coast	Posted Price at Tampa, FL	Spot Price at Gulf Coast
1995	50.68	47.48		
1996	63.75	58.98		
1997	58.57	54.10		
1998	42.17	38.19		
1999	50.99	47.07		
2000	88.17	80.85	95.47	87.55
2001	75.28	68.91	79.61	72.87
2002	69.15	65.64	71.93	68.28
2003	87.20	80.59	89.08	82.32
2004	114.38	108.16	114.38	108.16
2005	137.70	133.38	135.28	131.03
2006	126.06	121.65	121.74	117.49
2007	122.21	117.91	115.85	111.76
2008	119.66	115.41	111.11	107.16
2009	121.29	116.94	110.34	106.38
2010	118.00	113.72	105.01	101.21
2011	122.67	118.18	106.62	102.72
2012	124.96	120.34	105.99	102.08
2013	125.47	120.80	103.94	100.06
2014	125.62	120.89	101.67	97.85
2015	125.72	120.96	99.40	95.63
2016	127.30	122.43	98.28	94.52
2017	129.14	124.15	97.32	93.56
2018	131.06	125.96	96.37	92.62
2019	132.94	127.72	95.38	91.63
2020	134.90	129.56	94.46	90.72
2021	142.12	136.44	97.11	93.23
2022	147.50	141.56	98.36	94.40
2023	154.31	148.04	100.41	96.33
2024	160.15	153.59	101.68	97.52
2025	166.18	159.32	102.96	98.71
2026	171.53	164.49	103.70	99.44
2027	177.06	169.83	104.44	100.18
2028	182.22	174.82	104.88	100.62
2029	187.54	179.97	105.32	101.07
2030	193.31	185.55	105.90	101.65

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Dollars per Million Btu)

Year	Henry Hub	(Current) FGT Bidweek	FGT Cash	Deflator (2004=1.0)	Henry Hub	(2004$) FGT Bidweek	FGT Cash
1998	2.11	2.09	2.00	0.891	2.31	2.29	2.19
1999	2.27	2.26	2.21	0.904	2.45	2.44	2.39
2000	3.88	3.89	4.22	0.924	4.10	4.11	4.46
2001	4.26	4.26	3.81	0.946	4.39	4.40	3.93
2002	3.22	3.24	3.33	0.961	3.27	3.29	3.38
2003	5.38	5.39	5.49	0.979	5.38	5.39	5.49
2004	6.13	6.15	6.10	1.000	6.02	6.04	5.99
2005	6.79	6.75	6.89	1.018	6.56	6.52	6.65
2006	6.81	6.81	6.78	1.035	6.48	6.48	6.45
2007	6.57	6.57	6.47	1.055	6.13	6.14	6.04
2008	5.69	5.69	5.61	1.077	5.21	5.21	5.13
2009	4.89	4.89	4.85	1.099	4.38	4.38	4.34
2010	5.13	5.13	5.09	1.124	4.49	4.49	4.46
2011	5.28	5.29	5.26	1.151	4.52	4.52	4.49
2012	5.43	5.43	5.41	1.179	4.53	4.53	4.52
2013	5.79	5.79	5.77	1.207	4.72	4.73	4.71
2014	5.98	5.99	5.96	1.236	4.76	4.77	4.75
2015	6.11	6.11	6.09	1.265	4.74	4.75	4.73
2016	6.25	6.25	6.26	1.295	4.74	4.74	4.75
2017	6.71	6.72	6.69	1.327	4.97	4.97	4.95
2018	6.25	6.25	6.25	1.360	4.50	4.51	4.50
2019	6.57	6.58	6.59	1.394	4.62	4.62	4.63
2020	6.86	6.87	6.87	1.428	4.70	4.71	4.71
2021	6.97	6.97	6.98	1.464	4.65	4.66	4.66
2022	7.18	7.18	7.19	1.500	4.67	4.67	4.68
2023	7.39	7.39	7.39	1.537	4.68	4.69	4.69
2024	7.60	7.60	7.60	1.575	4.69	4.70	4.70
2025	7.81	7.81	7.82	1.614	4.70	4.70	4.71
2026	8.01	8.01	8.02	1.654	4.70	4.70	4.70
2027	8.21	8.21	8.21	1.695	4.69	4.69	4.69
2028	8.41	8.41	8.42	1.737	4.68	4.68	4.68
2029	8.62	8.62	8.63	1.781	4.67	4.67	4.67
2030	8.80	8.80	8.81	1.825	4.65	4.65	4.65

Table B-1

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-98	2.27	2.28	
Feb-98	2.04	2.01	2.17
Mar-98	2.26	2.25	2.19
Apr-98	2.33	2.29	2.38
May-98	2.27	2.25	2.09
Jun-98	2.03	2.01	2.06
Jul-98	2.36	2.36	2.06
Aug-98	1.93	1.92	1.75
Sep-98	1.63	1.61	1.91
Oct-98	2.07	2.03	1.79
Nov-98	2.00	1.99	2.02
Dec-98	2.12	2.10	1.64
Jan-99	1.80	1.79	1.80
Feb-99	1.81	1.78	1.72
Mar-99	1.64	1.62	1.75
Apr-99	1.88	1.89	2.12
May-99	2.35	2.35	2.20
Jun-99	2.23	2.23	2.24
Jul-99	2.28	2.27	2.23
Aug-99	2.62	2.62	2.73
Sep-99	2.90	2.90	2.47
Oct-99	2.55	2.54	2.67
Nov-99	3.06	3.03	2.30
Dec-99	2.14	2.14	2.31
Jan-00	2.36	2.35	2.36
Feb-00	2.61	2.63	2.61
Mar-00	2.61	2.63	2.74
Apr-00	2.88	2.90	2.98
May-00	3.08	3.08	3.55
Jun-00	4.37	4.41	4.21
Jul-00	4.36	4.38	3.88
Aug-00	3.83	3.83	4.32
Sep-00	4.62	4.62	4.96
Oct-00	5.29	5.29	4.92
Nov-00	4.50	4.51	5.39
Dec-00	6.02	6.03	8.70

Table B-1

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-01	9.91	9.94	8.00
Feb-01	6.22	6.27	5.37
Mar-01	5.03	5.05	5.01
Apr-01	5.35	5.34	5.08
May-01	4.87	4.86	3.90
Jun-01	3.73	3.74	3.42
Jul-01	3.16	3.21	2.99
Aug-01	3.19	3.18	2.87
Sep-01	2.34	2.35	2.11
Oct-01	1.86	1.86	2.40
Nov-01	3.16	3.13	2.27
Dec-01	2.24	2.26	2.31
Jan-02	2.61	2.61	2.19
Feb-02	2.03	2.06	2.23
Mar-02	2.39	2.41	2.96
Apr-02	3.41	3.44	3.42
May-02	3.36	3.40	3.55
Jun-02	3.37	3.42	3.29
Jul-02	3.26	3.30	3.07
Aug-02	2.95	3.01	3.14
Sep-02	3.27	3.30	3.58
Oct-02	3.72	3.72	4.13
Nov-02	4.13	4.26	3.85
Dec-02	4.13	3.93	4.55
Jan-03	4.96	4.94	5.44
Feb-03	5.66	5.68	7.73
Mar-03	9.11	8.85	5.94
Apr-03	5.14	5.11	5.26
May-03	5.12	5.13	5.81
Jun-03	5.95	5.98	5.81
Jul-03	5.30	5.49	5.03
Aug-03	4.69	4.73	4.99
Sep-03	4.93	4.96	4.61
Oct-03	4.43	4.43	4.63
Nov-03	4.45	4.48	4.47
Dec-03	4.86	4.86	6.14

Table B-1

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-04	6.16	6.16	6.14
Feb-04	5.76	5.78	5.37
Mar-04	5.15	5.17	5.40
Apr-04	5.37	5.37	5.71
May-04	5.94	5.95	6.33
Jun-04	6.68	6.69	6.27
Jul-04	6.14	6.17	5.93
Aug-04	6.04	6.07	5.41
Sep-04	5.08	5.10	5.17
Oct-04	5.81	5.75	6.96
Nov-04	7.67	7.64	7.76
Dec-04	7.81	7.97	6.80
Jan-05	6.21	6.24	6.26
Feb-05	6.29	6.30	6.30
Mar-05	6.30	6.24	6.96
Apr-05	7.33	7.33	6.98
May-05	6.80	6.75	6.66
Jun-05	6.10	6.14	6.68
Jul-05	6.76	6.79	6.59
Aug-05	6.53	6.55	6.38
Sep-05	6.35	6.37	6.51
Oct-05	6.66	6.65	7.27
Nov-05	7.65	7.64	7.88
Dec-05	8.02	8.01	8.17
Jan-06	8.23	8.22	7.89
Feb-06	7.66	7.65	7.48
Mar-06	7.34	7.33	6.73
Apr-06	6.39	6.37	6.27
May-06	6.23	6.23	6.23
Jun-06	6.29	6.30	6.20
Jul-06	6.21	6.25	6.03
Aug-06	5.99	6.01	5.89
Sep-06	5.90	5.92	6.08
Oct-06	6.25	6.25	7.07
Nov-06	7.58	7.57	7.63
Dec-06	7.66	7.66	7.88

Table B-1

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-07	7.98	7.97	7.44
Feb-07	7.11	7.10	7.14
Mar-07	7.15	7.13	6.65
Apr-07	6.38	6.36	6.30
May-07	6.30	6.29	6.25
Jun-07	6.29	6.30	6.08
Jul-07	6.02	6.06	5.83
Aug-07	5.79	5.81	5.68
Sep-07	5.69	5.71	5.84
Oct-07	6.00	6.00	6.58
Nov-07	6.98	6.96	7.08
Dec-07	7.17	7.16	6.75
Jan-08	6.51	6.51	5.95
Feb-08	5.64	5.63	5.64
Mar-08	5.65	5.64	5.68
Apr-08	5.73	5.71	5.62
May-08	5.61	5.61	5.71
Jun-08	5.84	5.85	5.49
Jul-08	5.37	5.40	5.24
Aug-08	5.24	5.27	5.13
Sep-08	5.15	5.17	5.30
Oct-08	5.47	5.47	5.73
Nov-08	5.96	5.94	6.04
Dec-08	6.13	6.13	5.75
Jan-09	5.55	5.55	5.01
Feb-09	4.73	4.73	4.75
Mar-09	4.79	4.78	4.85
Apr-09	4.94	4.92	4.84
May-09	4.86	4.86	4.97
Jun-09	5.12	5.13	4.75
Jul-09	4.63	4.67	4.50
Aug-09	4.51	4.54	4.39
Sep-09	4.41	4.43	4.54
Oct-09	4.71	4.71	4.91
Nov-09	5.11	5.10	5.17
Dec-09	5.27	5.26	5.46

Seminole Electric
Coal Prices (FOB CSX)
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb	Venezuelan Low Sulfur 12200 Btu/Lb
1998	21.85	19.90	25.77	22.74		26.01	28.45
1999	21.42	18.81	24.30	20.84		23.47	27.32
2000	21.26	17.51	24.70	22.25	14.75	25.12	28.44
2001	31.96	29.93	46.71	36.31	14.03	32.08	38.75
2002	25.45	23.34	28.96	27.75	9.45	25.36	31.51
2003	24.10	22.09	34.00	28.93	14.07	30.60	32.61
2004	**34.22**	**31.83**	**58.15**	**48.33**	**12.17**	**53.96**	**45.76**
2005	40.16	31.52	63.31	51.77	16.01	46.38	51.13
2006	37.48	29.66	58.13	41.47	9.33	36.84	42.42
2007	35.48	29.33	49.12	33.11	9.33	36.13	41.53
2008	36.03	28.74	46.67	32.73	10.46	36.55	40.76
2009	36.36	28.53	46.21	33.11	11.66	36.41	40.59
2010	36.70	28.85	46.26	34.24	13.30	34.58	38.56
2011	37.18	30.02	47.21	34.92	14.69	34.29	38.23
2012	37.93	30.87	48.50	35.53	15.56	34.29	38.23
2013	38.77	31.52	49.74	35.88	16.43	34.51	38.49
2014	39.62	32.12	50.73	36.20	17.39	34.94	38.96
2015	40.49	32.74	51.46	36.52	18.45	35.43	39.51
2016	41.40	33.37	52.59	36.85	19.93	36.28	40.45
2017	42.35	34.03	53.96	37.17	21.10	37.19	41.47
2018	43.33	34.72	55.36	37.51	22.27	38.18	42.57
2019	44.35	35.42	56.78	37.86	23.43	39.21	43.72
2020	45.38	36.12	58.21	38.20	24.89	40.28	44.91
2021	46.44	36.84	59.69	38.52	25.59	41.06	45.78
2022	47.53	37.58	61.21	38.83	26.11	41.90	46.72
2023	48.64	38.33	62.77	39.15	26.58	42.78	47.71
2024	49.79	39.10	64.37	39.50	26.98	43.72	48.75
2025	50.95	39.88	66.01	39.85	27.39	44.68	49.82
2026	52.15	40.68	67.33	40.19	27.62	45.21	50.41
2027	53.38	41.50	68.68	40.53	27.86	45.76	51.03
2028	54.63	42.34	70.07	40.89	28.10	46.35	51.68
2029	55.92	43.19	71.48	41.25	28.35	46.95	52.35
2030	57.25	44.06	72.93	41.61	28.60	47.57	53.04

Price Deflator (2004=1.0)
0.891
0.904
0.924
0.946
0.961
0.979
1.000
1.018
1.035
1.055
1.077
1.099
1.124
1.151
1.179
1.207
1.236
1.265
1.295
1.327
1.360
1.394
1.428
1.464
1.500
1.537
1.575
1.614
1.654
1.695
1.737
1.781
1.825

Seminole Electric
Coal Prices (FOB CSX)
($2004 Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb	Venezuelan Low Sulfur 12200 Btu/Lb
1998	24.52	22.34	28.92	25.52		29.19	31.93
1999	23.70	20.81	26.89	23.05		25.96	30.23
2000	23.02	18.96	26.75	24.09	15.97	27.20	30.80
2001	33.79	31.64	49.39	38.40	14.84	33.93	40.97
2002	26.48	24.28	30.13	28.87	9.83	26.38	32.77
2003	24.62	22.56	34.73	29.55	14.37	31.26	33.31
2004	**34.22**	**31.83**	**58.15**	**48.33**	**12.17**	**53.96**	**45.76**
2005	39.46	30.97	62.19	50.86	15.73	45.56	50.23
2006	36.19	28.65	56.14	40.05	9.01	35.58	40.97
2007	33.63	27.80	46.56	31.39	8.85	34.24	39.37
2008	33.45	26.68	43.34	30.39	9.71	33.94	37.85
2009	33.07	25.95	42.04	30.12	10.61	33.12	36.93
2010	32.66	25.67	41.17	30.47	11.84	30.78	34.32
2011	32.31	26.09	41.03	30.35	12.77	29.80	33.23
2012	32.18	26.19	41.14	30.14	13.20	29.08	32.43
2013	32.12	26.11	41.20	29.72	13.61	28.59	31.88
2014	32.07	25.99	41.06	29.30	14.08	28.28	31.53
2015	32.01	25.89	40.68	28.87	14.59	28.01	31.24
2016	31.96	25.76	40.60	28.45	15.39	28.01	31.23
2017	31.92	25.65	40.66	28.01	15.90	28.03	31.25
2018	31.86	25.53	40.71	27.58	16.37	28.07	31.30
2019	31.82	25.41	40.74	27.16	16.81	28.13	31.37
2020	31.78	25.29	40.76	26.75	17.42	28.20	31.45
2021	31.73	25.18	40.79	26.32	17.49	28.05	31.28
2022	31.69	25.06	40.81	25.89	17.41	27.94	31.15
2023	31.65	24.94	40.84	25.48	17.30	27.84	31.04
2024	31.61	24.83	40.87	25.08	17.13	27.76	30.95
2025	31.57	24.71	40.90	24.69	16.97	27.68	30.87
2026	31.53	24.60	40.71	24.30	16.70	27.33	30.48
2027	31.49	24.48	40.52	23.91	16.43	27.00	30.10
2028	31.45	24.37	40.33	23.53	16.18	26.68	29.75
2029	31.41	24.25	40.14	23.16	15.92	26.36	29.40
2030	31.36	24.14	39.95	22.80	15.67	26.06	29.06

Florida
Delivered Coal Prices
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB from Farmersburg Indiana	Illinois Basin High Sulfur 12,000 Btu/Lb from Providence, Kentucky	Central Appalachia 12,400 Btu/Lb from Pike County, Kentucky	Pittsburg Seam 13100 Btu/Lb from Waynesburg, Pennsylvania	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb from Puerto Bolivar	Venezuelan Low Sulfur 12200 Btu/Lb from Lake Maricaibo
2000	38.17	36.72	40.97	45.05			
2001	49.18	49.49	63.29	59.54			
2002	42.65	42.41	45.51	50.94			
2003	41.90	41.56	51.13	52.92	25.69	38.72	44.23
2004	**52.63**	**51.46**	**75.86**	**73.15**	**30.54**	**66.81**	**64.14**
2005	59.06	51.33	81.49	77.25	35.19	59.79	70.31
2006	56.34	49.68	76.27	66.90	20.84	44.89	53.93
2007	54.52	49.52	67.44	58.79	16.03	40.81	48.23
2008	55.28	49.17	65.20	58.70	16.58	40.83	46.88
2009	55.92	49.25	65.03	59.48	18.22	40.99	47.15
2010	56.54	49.85	65.35	60.99	20.18	39.39	45.44
2011	57.36	51.32	66.62	62.13	21.94	39.35	45.48
2012	58.45	52.49	68.24	63.19	23.09	39.55	45.77
2013	59.63	53.48	69.81	64.01	24.23	39.97	46.29
2014	60.84	54.42	71.14	64.81	25.46	40.58	47.03
2015	62.07	55.37	72.22	65.62	26.80	41.27	47.86
2016	63.36	56.34	73.72	66.45	28.51	42.28	49.04
2017	64.69	57.37	75.46	67.30	29.80	43.27	50.17
2018	66.07	58.48	77.24	68.17	31.14	44.38	51.44
2019	67.50	59.61	79.05	69.07	32.50	45.54	52.78
2020	68.95	60.76	80.89	69.98	34.15	46.76	54.18
2021	70.46	61.94	82.80	70.90	35.37	47.89	55.56
2022	71.99	63.13	84.75	71.81	36.45	49.12	57.05
2023	73.56	64.36	86.74	72.75	37.36	50.32	58.49
2024	75.17	65.62	88.80	73.73	38.19	51.55	59.96
2025	76.81	66.90	90.89	74.72	39.04	52.82	61.47
2026	78.50	68.21	92.68	75.71	39.71	53.66	62.50
2027	80.22	69.55	94.51	76.72	40.32	54.47	63.49
2028	81.98	70.92	96.37	77.75	40.75	55.19	64.33
2029	83.78	72.32	98.28	78.80	41.28	55.99	65.28
2030	85.63	73.75	100.23	79.87	41.82	56.81	66.26

NOTE: All transportation rates are assumed to be from the CSX origin points listed above except for the petroleum coke and South American shipments made by ocean vessel.

Florida
Delivered Coal Prices
($2004 Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB from Farmersburg Indiana	Illinois Basin High Sulfur 12,000 Btu/Lb from Providence, Kentucky	Central Appalachia 12,400 Btu/Lb from Pike County Kentucky	Pittsburg Seam 13100 Btu/Lb from Waynesburg, Pennsylvania	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb from Puerto Bolivar	Venezuelan Low Sulfur 12200 Btu/Lb from Lake Maricaibo
2000	41.33	39.76	44.36	48.78			
2001	52.01	52.33	66.92	62.96			
2002	44.37	44.11	47.34	52.98			
2003	42.80	42.45	52.22	54.06	26.24	39.55	45.18
2004	**52.63**	**51.46**	**75.86**	**73.15**	**30.54**	**66.81**	**64.14**
2005	58.02	50.43	80.05	75.89	34.57	58.73	69.07
2006	54.41	47.98	73.66	64.61	20.13	43.35	52.08
2007	51.68	46.94	63.93	55.73	15.20	38.68	45.72
2008	51.33	45.66	60.54	54.50	15.39	37.91	43.53
2009	50.87	44.80	59.16	54.11	16.58	37.29	42.89
2010	50.32	44.37	58.16	54.28	17.96	35.06	40.44
2011	49.85	44.60	57.91	54.00	19.07	34.21	39.53
2012	49.58	44.52	57.89	53.60	19.59	33.55	38.82
2013	49.40	44.30	57.83	53.02	20.07	33.11	38.35
2014	49.24	44.04	57.58	52.45	20.61	32.84	38.06
2015	49.07	43.78	57.10	51.88	21.19	32.63	37.84
2016	48.91	43.50	56.91	51.30	22.01	32.64	37.86
2017	48.75	43.24	56.86	50.72	22.45	32.61	37.81
2018	48.58	43.00	56.80	50.13	22.89	32.63	37.82
2019	48.42	42.77	56.72	49.55	23.31	32.67	37.87
2020	48.28	42.54	56.64	49.00	23.91	32.74	37.93
2021	48.14	42.32	56.58	48.44	24.17	32.73	37.96
2022	48.01	42.10	56.51	47.89	24.30	32.76	38.04
2023	47.87	41.88	56.44	47.34	24.31	32.74	38.06
2024	47.73	41.66	56.38	46.81	24.25	32.73	38.07
2025	47.59	41.45	56.31	46.29	24.19	32.73	38.08
2026	47.46	41.24	56.03	45.77	24.01	32.44	37.78
2027	47.32	41.03	55.75	45.26	23.78	32.13	37.45
2028	47.18	40.82	55.47	44.75	23.45	31.76	37.02
2029	47.05	40.61	55.19	44.25	23.18	31.44	36.66
2030	46.91	40.40	54.91	43.76	22.91	31.12	36.30

NOTE: All transportation rates are assumed to be from the CSX origin points listed above except for the petroleum coke and South American shipments made by ocean vessel.



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4401 Fair Lakes Court, Suite 400
Fairfax, Virginia 22033-3848 USA
Phone: 703-818-9100
Fax: 703-818-9108

Long-Term Solid Fuel Availability Analysis

Prepared for:

Seminole Electric Cooperative, Inc.

July 19, 2005

F-I-N-A-L

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NO. 060220-EC Exhibit No. 26
Company/ SEC
Witness: Wm. Jack Reid (WJR-6)
Date: 06-07-06

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EXECUTIVE SUMMARY

BACKGROUND & OVERVIEW

Seminole Electric Cooperative, Inc. ("Seminole") retained Pace Global Energy Services, LLC ("Pace Global") to assess from the present through the year 2040 (the "Study Period") the supply availability of petroleum coke, low-sulfur coal, and mid- to high-sulfur coal (collectively referred to as "solid fuel") for proposed new electric generation facilities in Florida. Pace Global analyzed the availability of petroleum coke supply and engaged Hill & Associates Inc. as a subcontractor to evaluate the availability of coal supply for Seminole's new generation. Key findings providing an integrated view on solid fuel availability are presented below; the supporting analysis and commentary underpinning these statements follows in individual reports dedicated to petroleum coke and coal.

KEY FINDINGS

1. Seminole's proposed new solid-fuel-fired generation in Florida is expected to require on an annual basis 0.6-8.0 million short tons ("mmt") of petroleum coke and 1.2 mmt or more of coal, in addition to its existing annual requirements of approximately 4.0 mmt of solid fuel. These estimates assume certain fuel heat contents and blends. Seminole's existing and new generation's actual fuel requirements will likely vary from these estimates, but not significantly enough to change materially the conclusions of this report.

2. The supply of solid fuel from domestic and foreign sources will be adequate over the Study Period to meet the requirements of Seminole's existing and new generation.

3. Seminole's existing and new generation will most likely access petroleum coke supply from Gulf Coast, Midwest, and Caribbean refineries. These facilities currently supply quantities of fuel adequate to meet Seminole's existing and new generation's projected annual requirements.

4. Over the Study Period, refineries in the aforementioned regions are anticipated to add incremental coking capacity in response to the increased demand for transportation fuels and more sour, heavy crude streams.

5. Coal supply for Seminole's new generation is expected to come from Central Appalachia, Illinois, Northern Appalachia, Colombia, and Venezuela. These coal supply basins over the Study Period are expected to produce at levels sufficient to meet the incremental demand resulting from the commercial operation of Seminole's new generation.



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6. All of the aforementioned coal supply basins, with the exception of Central Appalachia, are expected either to increase their level of production or have the capability to do so in the future.

7. Supply from Central Appalachia will decrease over the Study Period from its present level of 190 mmt, but growth in production in Illinois and Northern Appalachia as well as increased imports will offset the decline in Central Appalachian production.



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4401 Fair Lakes Court, Suite 400
Fairfax, Virginia 22033-3848 USA
Phone: 703-818-9100
Fax: 703-818-9108

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July 19, 2005

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KEY FINDINGS

1. Pace Global expects over the period 2005-2040 (the "Study Period") adequate supplies of petroleum coke ("pet coke") will be available from domestic and foreign suppliers to meet the partial or full fuel demand requirements of new solid-fuel-fired generation in Florida.

2. The world's supply of pet coke will increase from current production levels in response to the increased production of transportation fuels from an increasingly heavy and sour quality crude oil stream.

3. New solid-fuel-fired generation in Florida will most likely access pet coke supply from Gulf Coast, Caribbean, and Midwest refineries. These facilities are expected to add additional coking units in response to the increased demand for higher value transportation fuels.

4. Although increased worldwide demand for and utilization of pet coke is expected over the Study Period, particularly in Asia, Pace Global anticipates that Gulf Coast, Caribbean, and Midwest supply will largely remain in the Atlantic Basin.

5. Due to the Kyoto Protocol, pet coke demand in Northern Europe and the Mediterranean region, the alternative market for Gulf Coast and Caribbean supplies, is expected to stagnate or decline gradually over the Study Period.

6. The cement industry is expected over the Study Period to remain the dominant end user of pet coke, however, the paper and fertilizer industries, which have relied extensively on natural gas as an energy and feed stock have recently shown increasing interest in pet coke as a source of energy and raw material for their plants. Power generators are expected to increase their share of pet coke consumption, as they increasingly install fluidized-bed boilers and scrubbers to comply with emissions restrictions.

7. The majority of pet coke production in the Gulf and Caribbean will be only water accessible, while pet coke shipments in the Midwest region will continue to rely on railroads and river barges.

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INTRODUCTION

Seminole Electric Cooperative, Inc. ("Seminole") has retained Pace Global Energy Services, LLC ("Pace Global") to assess from the present through the year 2040 the supply availability of pet coke to meet the partial fuel requirements of new base-load electric generation facilities in Florida whose development is under consideration. Based on information previously conveyed by Seminole, Pace Global has for the purposes of this report assumed that Seminole is contemplating a new plant of approximately 800 megawatts that has the capability to burn both coal and pet coke starting around 2012.

A number of variables will determine the plant's actual pet coke consumption—including, but not limited to its: efficiency, annual capacity factor, and heat content of its fuel. For the purposes of this report, it is assumed that Seminole's new generation will consume annually 0.6-0.8 million short tons ("mmt") of pet coke,[1] in addition to Seminole's existing annual requirement of approximately 1.0 mmt of pet coke. This projection is included to serve as a very high-level estimate of what Seminole's proposed plant might require and to facilitate discussion in the report. Seminole's new generation's actual fuel requirements will likely vary from these estimates, but not significantly enough to change materially the conclusions of this report.

Given the estimated requirements established above, Pace Global in the four sections of the report that follow: 1) provides background discussion on pet coke qualities which make it desirable as a fuel; 2) reviews current pet coke supply; 3) identifies pet coke end uses; and 4) details pet coke market dynamics. The Study Period covers a lengthy span of time—the present, the projected start up of Seminole's new generation facility in five years, and the distant future. In the commentary that follows, Pace Global provides a review of the current market, expectations for the period 2006 through 2025, and probable trends for the period 2026-2040.

[1] All tonnage figures used throughout this report are expressed in tons of 2,000 pounds (so-called "short tons"). Pet coke internationally is priced and sold in metric tons. One short ton is equivalent to 0.907 metric tons.

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PET COKE BACKGROUND

When discussing pet coke, it is important to remember that pet coke is a by-product of the process to refine crude oil into more valuable finished products, such as gasoline and jet fuel. The supply of pet coke results from the demand for refined petroleum products, not for pet coke itself. Refiners continuously monitor and adjust their refinery processes to accommodate differing crude slates; consequently, pet coke quality varies considerably making it impossible to identify pet coke with a single set of specifications. The typical specification ranges for pet coke are as follows:

- Moisture: The water content of pet coke is usually low, (less than 0.5 percent to 10.0 percent);
- Ash: Pet coke has less than 1.0 percent ash;
- Energy content: Pet coke averages approximately 14,000 British Thermal Units per pound ("Btu/lb."); and
- Hardness: Pet coke ranges on the Hardgrove Grindability Index ("HGI") from 32 to 70.[2]

In addition to these physical properties, sulfur content also plays a key role in determining how pet coke supply is used. Exhibit 1 provides an overview of the typical sulfur content of pet coke used in various applications.

Exhibit 1: Typical Pet Coke Sulfur Content by Application

Sulfur Content	Application	Industry
High-Sulfur (>4.5 %)	Fuel	Cement Electric Utilities
Mid-Sulfur (>2.5 %)	Manufacturing	Aluminum Steel
Low-Sulfur (>1.00%)	Product Component	Additives Modifiers

Source: Pace Global.

Seminole intends to utilize pet coke as a fuel; therefore, this report will focus on "fuel-grade" pet coke as opposed to "anode-grade" coke, which typically has sulfur content of 2.5 percent or less. Through blending, however, the sulfur level in some fuel-grade product can be reduced to levels

[2] The HGI test attempts to mimic the operation of a continuous solid-fuel pulverizer. The test results in a value generally between 30 and 100. The higher the HGI value of the material input into a solid-fuel processing mill, the closer that mill will operate near its design capacity. The HGI test is highly non-linear, such that a change in HGI from 90 to 80 results in a small decrease in mill capacity while a change from 50 to 40 leads to a considerably greater decrease in mill capacity.



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suitable for anode-grade applications. Consequently, in practice, there is not a bold distinction purely on the basis of sulfur content between fuel-grade and anode-grade product. Other parameters, such as HGI and metals content also determine how pet coke is utilized.

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SUPPLY

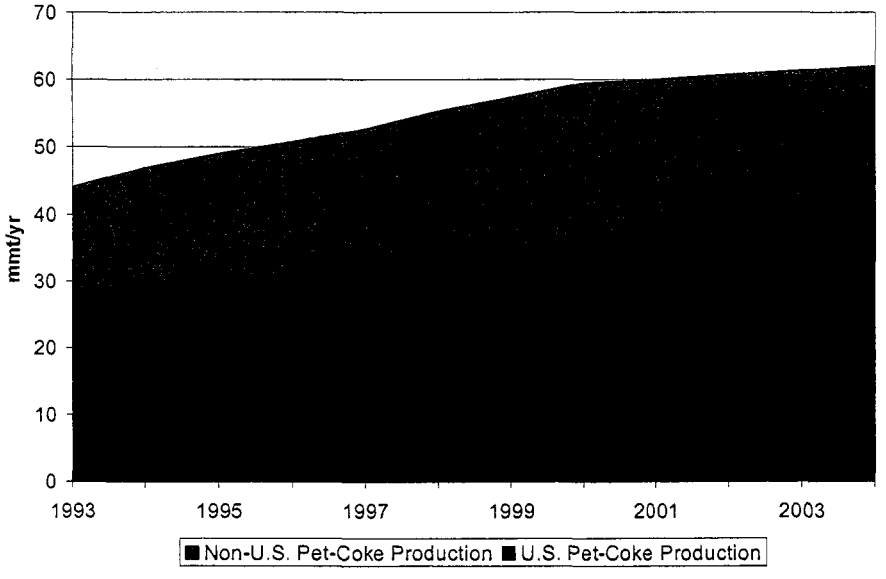
PRODUCTION

In 2004, total worldwide pet coke production is estimated to have totaled around 62 mmt. The major centers for pet coke production are North America producing slightly less than 42 mmt, South America producing almost 10 mmt, Asia producing just less than 6 mmt, and Europe producing 4 mmt. U.S. marketable pet coke production in 2004 was slightly more than 43 mmt (37 mmt of fuel-grade product and 6 mmt of anode-grade product).

Given transportation costs, Pace Global anticipates the pet coke for Seminole's proposed new generation will come from refineries: situated on the Gulf Coast, in the Caribbean, and in the Midwest. These three regions currently produce approximately 66 percent of the world's supply pet coke. When combined, the Gulf Coast and Midwest regions account for 82 percent of pet coke production in the U.S.

Worldwide production of pet coke has increased over the past ten years at a compound annual growth rate of slightly more than three percent. Exhibit 2 provides an overview of domestic and foreign pet coke production over the past decade.

Exhibit 2: Pet-Coke Production, 1993-2004



Source: Pace Global



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The primary drivers behind this growth are increasing demand for refined products and deteriorating qualities of crude oil. Currently, the U.S. is the single largest producer of pet coke; its world market dominance results from high U.S. demand for transportation fuels and light petroleum products and the ability of its Gulf Coast refineries to process cheaper, heavier crude oils located in nearby countries, such as Venezuela and Mexico.

PRODUCTION CAPACITY

There are 674 refineries in the world, 108 of them currently have coking units. Worldwide annual pet coke capacity at the end of 2004 was estimated to stand at approximately 82 million mmt, with just over 48 mmt of this capacity located in the U.S.

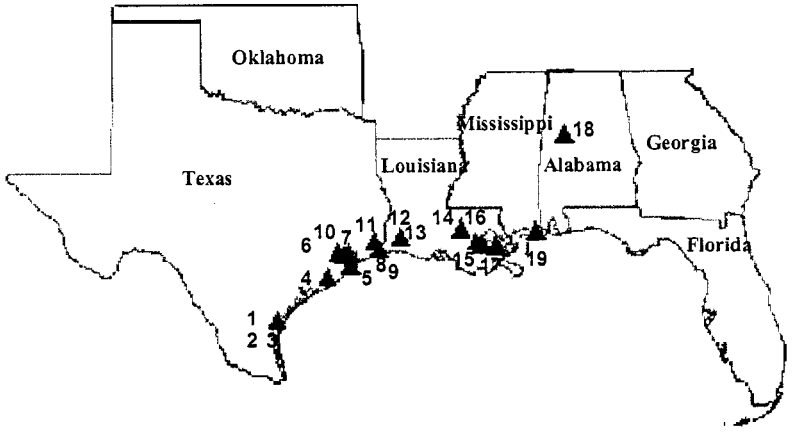
With more than 24 mmt/year of installed production capacity, the U.S. Gulf Coast is home to the largest concentration of fuel-grade coking facilities in the world. The Caribbean region contains an additional 8 mmt/year of fuel-grade production capacity. Refineries in the Midwest are currently shipping pet coke to end users in Florida; therefore, Pace Global has also views these production facilities as possible supply sources for Seminole's new generation. The Midwest thus offers an additional 8 mmt of capacity. Seminole's proposed new generation in Florida would at present likely have access to over 40 mmt of production capacity.

In Exhibits 3, 4, and 5, Pace Global details annual fuel-grade pet coke production capacity by the major regions expected to supply Seminole's proposed new generation.

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Gulf Coast

Exhibit 3: Gulf Coast



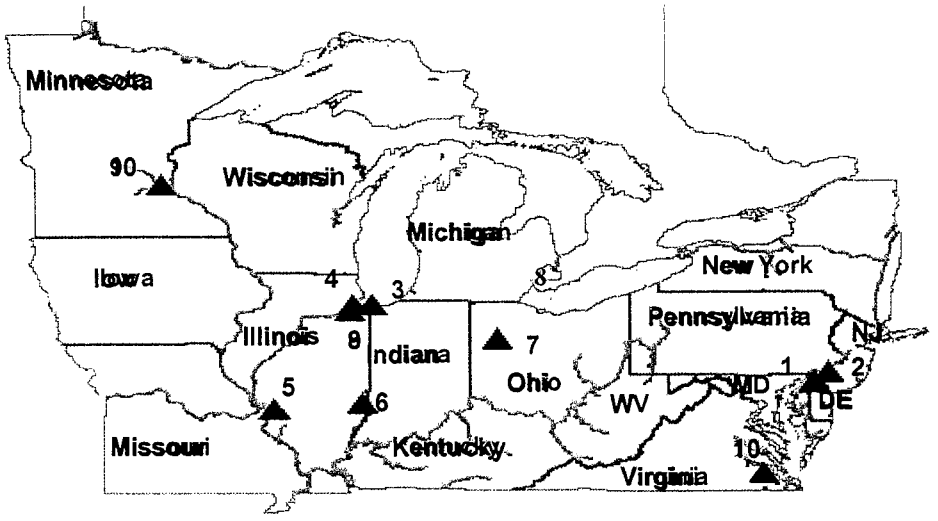
No.	Company	Facility	Annual Production Capacity (mmt)	Sulfur (%)	HGI
1	Citgo	Corpus Christi, TX	0.8	3.9	45-50
2	Flint Hill Resources	Corpus Christi, TX	0.3	3.0-5.5	70
3	Valero Refining Co.	Corpus Christi, TX	0.4	n/a	n/a
4	Phillips 66	Sweeny TX	1.5	4.3	52
5	BP	Texas City, TX	1.0	6.0	80
6	Deer Park Refining LTD Partnership*	Deer Park, TX	1.5	6.3-6.5	38-42
7	Exxon Mobil	Baytown, TX	0.9	6.0-7.0	35
8	Motiva	Port Arthur, TX	1.2	6.0-6.5	60-65
9	Premcor	Port Arthur, TX	1.9	6.5	30-35
10	Lyondell / Citgo	Houston, TX	2.1	3.8-4.0	55-60
11	Exxon Mobil	Beaumont, TX	1.1	6.0	48-55
12	Citgo	Lake Charles, LA	2.4	4.5-5.0	50-65
13	Conoco	Lake Charles, LA	1.2	6.0	40
14	Exxon Mobil	Baton Rouge, LA	2.6	5.0-7.5	45-90
15	Chalmette Refining, LLC**	Chalmette, LA	0.8	4.5	45-50
16	Marathon	Garyville, LA	0.8	7.5	30
17	Orion	Good Hope, LA	1.5	4.5	45-55
18	Hunt	Tuscaloosa, AL	0.3	5.0	40
19	Chevron Texaco	Pascagoula, MS	1.8	5.0	65
Total Fuel-Grade Pet Coke Production Capacity			**24.1**		

*Joint venture between Shell and Petroleos Mexicanos (PEMEX)
**Joint venture between ExxonMobil and PDV Chalmette, Inc.
Source: Energy Argus Petroleum Coke, EIA, and Pace Global.

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Midwest

Exhibit 4: Midwest



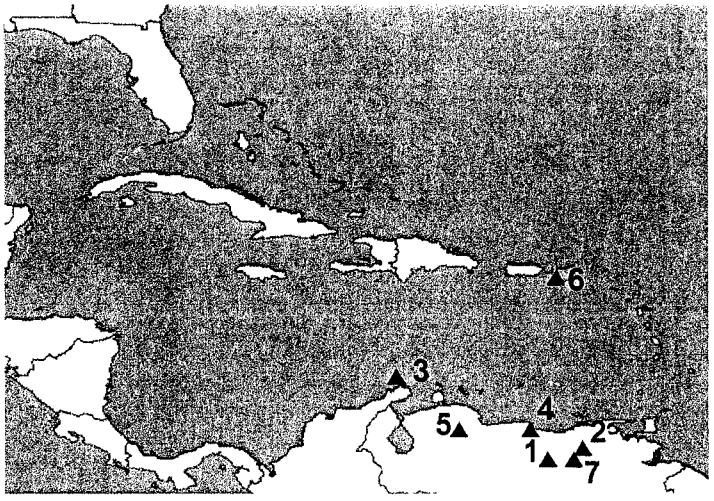
No.	Company	Facility	Annual Production Capacity (mmt)	Sulfur	HGI
1	Motiva	Delaware City, DE	1.1	4.0-6.0	37
2	Valero	Paulsboro, NJ	0.6	6.0-6.5	<50
3	BP	Whiting, IN	0.8	4.0-5.0	n/a
4	Citgo	Lemont, IL	0.8	4.5-5.5	50
5	Conoco Phillips	Hartford, IL	0.4	6.5	30-35
6	Marathon	Robinson, IL	0.6	4.1	65
7	Premcor	Lima, OH	0.5	6.5	30-35
8	ExxonMobil	Joliet, IL	1.3	5-5.5	45-50
9	Flint Hill Resources	Rosemount, MN	1.6	6.0	40
10	Giant Industries	Yorktown, VA	0.5	1.5	80
Total Fuel-Grade Pet Coke Production Capacity			**8.2**		

Source: RDI, Energy Argus Petroleum Coke, and Pace Global.

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Caribbean

Exhibit 5: Caribbean Region



No.	Company	Annual Production Capacity (mmt)	Sulfur	HGI
1	Conoco Petrozuata	1.2	4.00%	65
2	Exxon Cerro Negro	0.9	4.50%	60
3	Valero Aruba	1.7	6.00%	50
4	PDVSA Lagoven	0.7	4.20%	55
5	PDVSA Maraven	1.5	4.00%	45
6	Hovensa	1.3	4.50%	30
7	Hamaca Project	1.3	4.00%	40
Total Fuel-Grade Pet Coke Production Capacity		**8.6**		

Source: Energy Argus Petroleum Coke and Pace Global.

The majority of coking capacity additions are expected to take place in the U.S. (particularly along the Gulf Coast to handle sour imported crude and in the Midwest to process heavy crude from Canada) and the Caribbean. Over the longer-term, e.g., the next 20 years, Pace Global expects additional delayed coking capacity to come on-line throughout the world with continued emphasis on the North America due to its proximity to large heavy sour crude oil reserves and the lower investment cost of adding coking capacity, instead of other technological solutions, to serve growing transportation fuels demand.

In Exhibit 6, Pace Global details the nine fuel-grade coker additions that are either being planned or considered for the Gulf Coast, Midwest, and Caribbean.

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Exhibit 6: Potential Fuel-Grade Pet Coker Additions

Producer	Refinery Location	Status	Expected Onstream Year of Incremental Capacity
Premcor	Port Arthur, TX	Under construction	2006:Q2
Citgo	Lake Charles	Planning	2008
ConocoPhillips	Hartford, IL	Planning	2008
Premcor	Lima, OH	Planning	2008
Marathon	Robinson, IL	Under review	2008
Hamaca	Venezuela	Under review	2010
El Palito	Venezuela	Under review	2010
Puerto La Cruz	Venezuela	Under review	2010

Source: Pace Global

Through its industry sources, Pace Global has learned that the refineries listed above intend to increase their pet coke production capacity in the next five to ten years. For instance, ConocoPhillips has recently confirmed budgeting to expand their coking operations at its Wood River, Illinois refinery.

PET COKE QUALITY

Pace Global expects that pet coke quality will continue to deteriorate as refineries process increasingly heavy-sour crude oils. Within the past decade, the gravity, as measured on the American Petroleum Institute ("API") Scale, of the crude processed at refineries in the U.S. has decreased at a rate in excess of 0.10 degree per year. This decline in crude quality is expected to accelerate in the future and will produce pet coke, which is generally harder and contains higher quantities of sulfur and metals. Any plant adding pet coke to its current fuel mix will likely require additional crushing capacity to handle supply that is often harder than coal.

The level of sulfur content, hardness, and metals concentrations determine the pet coke's application and thus its market value. A carbon usage pet coke generally requires a sulfur content of less than 2.5 percent and low metals content. When the sulfur content exceeds 2.5 percent, the pet coke becomes less suitable as a carbon source. The higher sulfur, fuel-grade pet cokes have been categorized into four price ranges based on their sulfur content and hardness. The best quality fuel-grade pet coke has sulfur content of 4.5 percent and an HGI of less than 50. The next best pet coke quality has the same sulfur limit, but is has a hardness of greater than 50 HGI. The other two fuel-grade pet cokes have a higher sulfur level of 6.5 percent and HGI's of less than 50 or greater than 50.

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Pace Global anticipates that the average sulfur and metal contents of the fuel-grade pet coke will continue to continue increase through the Study Period. Currently, 33 percent of U.S. pet coke production is "shot pet coke." Shot pet coke has a HGI of less than 50, usually in the range of 35 to 45. It is expected that within 10 years, the U. S. production of shot pet coke will increase to 55 percent of the country's pet coke supplies. Consumers of fuel-grade pet coke will need to plan on grinding a harder pet coke between 2005 and 2040.

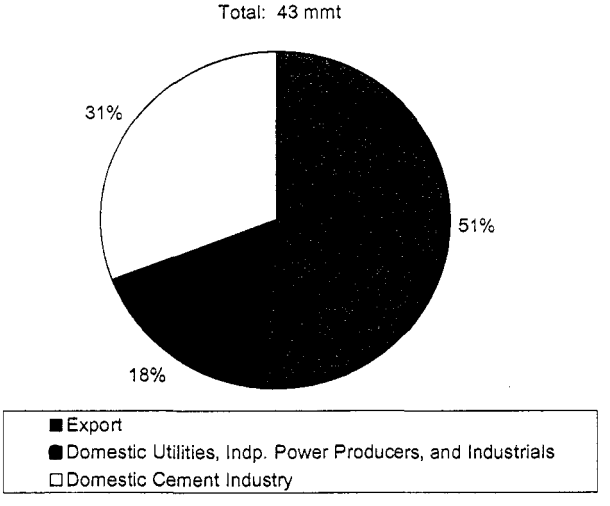
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CONSUMPTION

The global cement industry is the largest purchaser of fuel-grade pet coke. It accounted for 71 percent of traded fuel-grade pet coke in the last decade. The cement industry has limited flexibility when using pet coke as a fuel because the pet coke's ash becomes part of the cement clinker during process. Pet coke is considered important fuel, but not a critical fuel to the cement industry.

Exhibit 7 provides a snapshot of pet coke consumption in the U.S. in 2004 and shows approximately 22 mmt of supply exported abroad.

Exhibit 7: U.S. Pet Coke Consumption by Sector, 2004

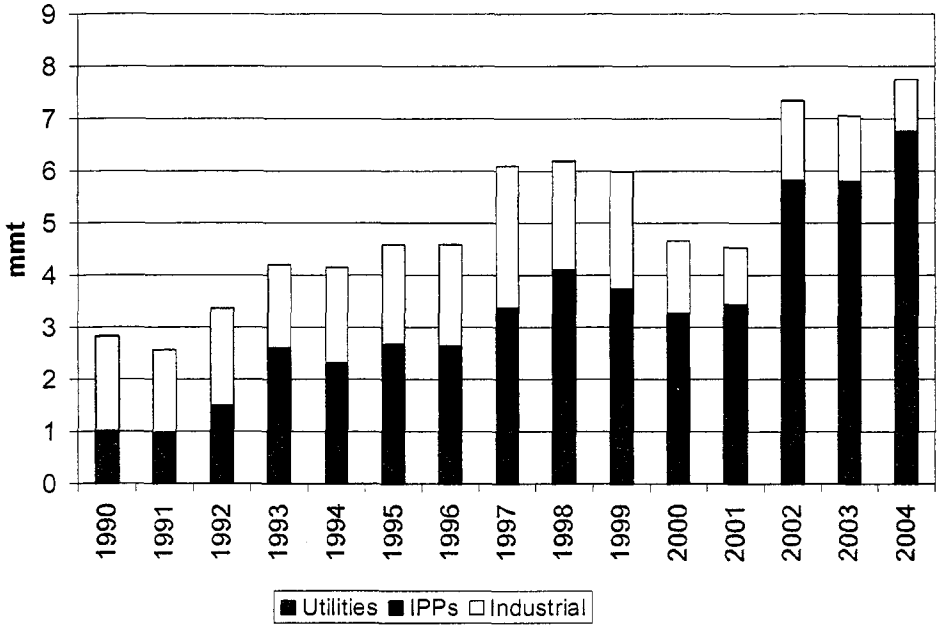


Source: Pace Global & Energy Argus Petroleum Coke Report.

Total non-cement industry consumption of pet coke in the U.S. market was just over 7 mmt in 2004, with approximately 46 percent of non-cement-industry pet coke consumption coming from utilities. Exhibit 8 depicts by end-use type domestic pet coke consumption.

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Exhibit 8: U.S. Pet coke Consumption, 1990-2004



Source: EIA

In the U.S., the power generation sector is a growing consumer of pet coke and is assuming a "swing" role in the market. Utilities over the past five years have increased their consumption of pet coke at a compound annual growth rate of almost 33 percent. Power stations have the flexibility of storage and fuel switching since pet coke is generally considered a secondary (opportunity) fuel to a station's overall fuel needs.

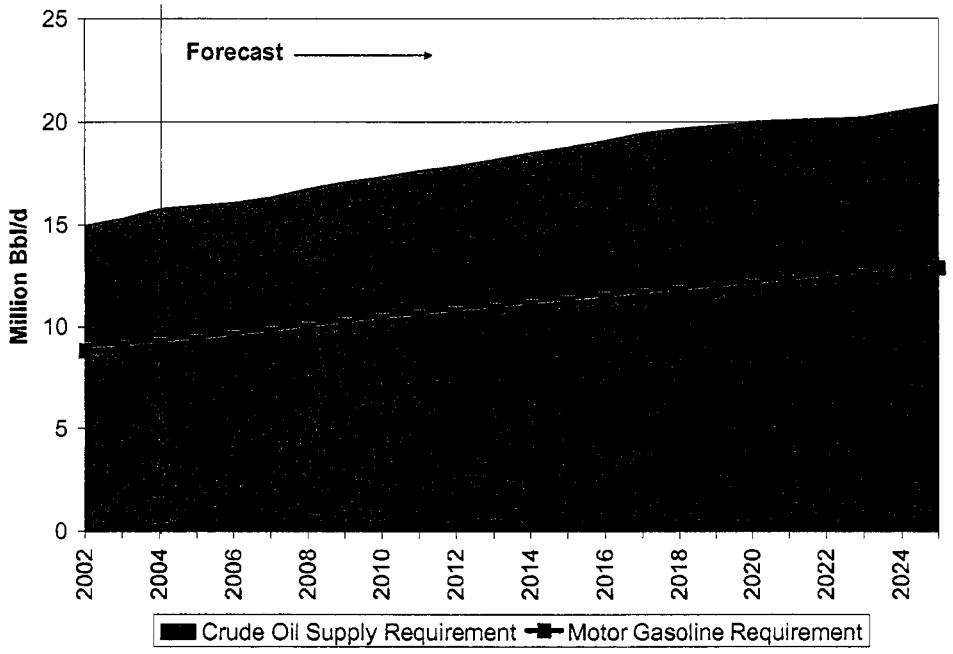
Power generators remain concerned about their existing plants' ability to use pet coke due to the tighter NO_x emission restrictions as well as expected tightening of the SO_2 emission allowance market towards the end of the decade. Due to these environmental concerns and the volatility of market-based pet coke prices, many end users consider pet coke as an "opportunity" fuel, e.g., they only use it to blend with coal, when pet coke is cheap. Hence, Pace Global expects pet coke demand from power generators to grow, though such demand is also expected to exhibit a high degree of price elasticity.

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MARKET DYNAMICS

It is Pace Global's view that pet coke production capacity will be added regardless of projected pet coke demand or pricing. The production of fuel-grade pet coke is dependent on the world's demand for transportation fuels, especially motor gasoline, produced from increasingly heavy sour crudes. EIA has forecast that the world's demand for crude oil will continue to grow at an average of 1.9 percent per year until 2025. As shown in Exhibit 9, the consumption of crude oil in the U.S. is expected to grow from almost 16 million barrels per day ("Bbl/d") in 2004 to slightly more than 20 million Bbl/d in 2025, a compound annual growth rate of 1.3 percent. U.S. motor gasoline supply is expected over that same period to increase at a compound annual growth rate of 1.7 percent.

Exhibit 9: U.S. Crude Oil and Motor Gasoline Consumption Forecast



Source: EIA

Growth in world oil demand will move from the industrialized countries and regions, such as the United States, Western Europe, and Japan, to emerging areas such as Eurasia and the developing countries in Asia, South America, and Africa. The quality of annual crude production is expected to continue its decline to heavier and more sour crudes in all areas of the world. Thus the world's refineries will be under pressure to increase their coking operations to accommodate the poorer crude qualities.



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As the demand for transportation fuels increases during the next two decades it is likely new refineries, with cokers, will be built nearer these emerging markets. As this trend accelerates, the U.S. will gradually lose its dominant position as the world's leading producer of pet coke but will likely continue to produce 45 to 55 mmt of fuel-grade product because of its transportation fuel requirements.

The demand for fuel-grade pet coke as a combustion fuel is likely to decrease in the industrialized countries and reduce U.S. exports. Due to the Kyoto Protocol, demand in Northern Europe and the Mediterranean region, the alternative market for Gulf Coast and Caribbean supply, is expected to stagnate or decline gradually over the Study Period. Similarly in Japan, a drop of 3 percent in in its current usage of pet coke (approximately 3.4 mmt annually) is anticipated to result from its emissions reduction programs. Due to transportation costs, displaced supply from Europe is likely to stay in the Atlantic Basin and enter the domestic market.

FUTURE PET COKE PRODUCTION

2005-2025

By 2010, annual pet coke production worldwide is forecast to exceed 85 mmt. The supply of pet coke in the following 15 years will continue to increase as the world's demand for crude oil is anticipated to to grow at a 1.9 percent compound annual growth rate. Much of the incremental crude supply will come from heavy sour crudes. Between 2010 and 2025, pet coke production is expected continue to increase at an annual average growth rate in excess of 3 percent, with annual production of pet coke production reaching just over 138 mmt in 2025. Pet coke production in the U.S. will likely reach its maximum during these two decades.

2026 to 2040

The world production of fuel-grade pet coke during this period will likely flatten out as the conservation of transportation fuels picks up its pace. Alternative methods of transportation, such as the hydrogen-based fuel cells, may begin to replace carbon-based fuel consumption. However, the decline of fossil fuels consumption will be slow and not reach significantly lower levels until the turn of the century.

COAL BASIN SUPPLY AVAILABILITY EVALUATION TO 2040

Prepared for:
SEMINOLE ELECTRIC COOPERATIVE, Inc.

By:
Hill & Associates, Inc.

June 24, 2005



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COAL BASIN SUPPLY AVAILABILITY EVALUATION TO 2040 FOR SEMINOLE ELECTRIC, FLORIDA

INTRODUCTION

Hill & Associates (H&A) was retained as a subcontractor to Pace Global Energy Services, Fairfax, VA to provide an evaluation of coal supply availability to 2040 for the following coal basins and supply countries:

- Central Appalachia
- Illinois Basin
- Northern Appalachia
- Colombia
- Venezuela

The report generated in response to this assignment is organized in the following manner. First, an **overview** of each basin is provided at the beginning of the section. The overview provides a description of the region from geologic and coal mining perspectives.

Then, a section is devoted to **production** for each basin, including historical and projected production according to sub-region (if applicable) and coal quality type. This section also contains discussion on current mining technologies employed in the basin and trends for future mining.

The section on **reserves** attempts to respond to the issue of availability of reserves to satisfy mining to 2040. Tables are included in this section that display reserves by coal quality type or level of reserve definition (e.g., measured, indicated, inferred, etc.).

The last section of each basin presentation provides a review of **key issues and drivers** impacting current and future mining in that basin.

Tonnage references throughout this report relate to short, or net, tons of 2000 lb. For all coal basins, reference to *mmt* references "million short tons."

KEY FINDINGS

Summary comments. The evaluation of the several coal sources reviewed in this study shows adequate reserves available to produce low-, mid- and high-sulfur coals at current levels far beyond 2040. Coal production will continue in all of the U.S. coal basins and will be increasingly supplemented by foreign sources evaluated in this review through year 2040. There are variances among the sources in sustainability by product type but, with prudent and strategic purchasing policies in place, the overall supply of coal to Florida generating plants should present no serious problem.

All of the basins either are expanding or have adequate expansion potential beyond 2040, with the exception of Central Appalachia which has been declining since 1998. Hill & Associates' outlook for the basins indicates that Central Appalachian coals will continue to be displaced in utility blends in the future. Illinois Basin and Northern Appalachian mid- and high-sulfur coals will move into the south and southeastern markets to serve those plants that install scrubbers. Both of these basins are likely to expand production to meet this new demand. Imported coals will compete in utility blends to free up SO_2 credits, to offset higher sulfur coals or, displace Central Appalachian coals. The penetration of imports will occur along the coastal regions from the northeast down and across the Gulf region. As railroads begin to embrace the import concept, H&A predicts that more imports will arrive at inland plants by rail in coming years.

Table 1 shows the production alignment of each coal source according to coal type for 2005:

Table 1

Coal Basin Production Alignment by Coal Type – 2005

Coal Source lb. SO_2/mmBtu	Compliance <1.2	Near-Compliance 1.2-2.5	Mid-sulfur >2.5-5.0	High-Sulfur >5.0	Total
Central Appalachia - mmt	53.2	133.0	3.8	0.0	190.0
percent	*28*	*70*	*2*	*0*	*100*
Northern Appalachia	1.5	29.3	54.8	37.7	123.3
percent	*1*	*24*	*44*	*31*	*100*
Illinois Basin	2.1	23.1	18.5	52.0	95.7
percent	*2*	*24*	*20*	*54*	*100*
Colombia	24.3	49.4	0.0	0.0	73.7
percent	*33*	*67*	*0*	*0*	*100*
Venezuela	8.0	2.0	0.0	0.0	10.0
percent	*80*	*20*	*0*	*0*	*100*

The table shows that mid- to high-sulfur coals are most prevalent in the Northern Appalachian region and Illinois Basin region. Lower sulfur, compliance and near-compliance coals are found in all coal sources but the important volumes of compliance grade coals from Central Appalachia, which are declining, will, when replacement is required, be most available from Colombia. Near-compliance coals are also prevalent in

all coal sources in sufficient amounts that would indicate less difficulty in the long term to obtain supply of this type of coal from several sources.

The following paragraphs summarize the key findings by source region or country. Full basin/country presentations follow this summary.

Central Appalachia. This basin is in decline and few large-scale economic reserve blocks remain. There are higher-cost reserves in deeper seams that can be developed and certain producers will be able to expand production at or near existing mine operations. CAPP will decline significantly by 2040 but, even then, we expect production at levels in the range of 50 to 100 mmt per year. Low-sulfur CAPP production will be replaced by Powder River Basin coals and imported coals from Latin America, Indonesia, South Africa and Russia.

Illinois Basin. Tremendous coal reserves exist and significant expansion is possible in the ILB. At existing or even greatly expanded production the basin will continue production well past year 2040. The ILB produces high-sulfur coals and will be positively impacted by the shift in demand to high sulfur coals that will occur in U.S. generating stations that will be adding scrubbers to meet emissions standards.

Northern Appalachia. Remaining Pittsburgh seam reserves would support production at existing levels for over 36 years. There are large reserves blocks controlled by major producers such as Consol and Foundation Coal that must be developed to sustain production. At present, H&A's forecast indicates NAPP production could begin to decline around 2015 but should still be producing at levels near 100 mmt per year by 2040. This source of mid- to high-sulfur coals will compete with the ILB in scrubber markets but both sources are capable of movement to Florida plants.

Colombia. Ample reserves and production will be available to ensure adequate supply of Colombian coals beyond 2040. This source is still in the developing stage and enormous reserves of low-sulfur thermal coals exist. Major producers Drummond and Cerrejon Coal are targeting aggressive expansion plans at generating and industrial plants in the U.S.

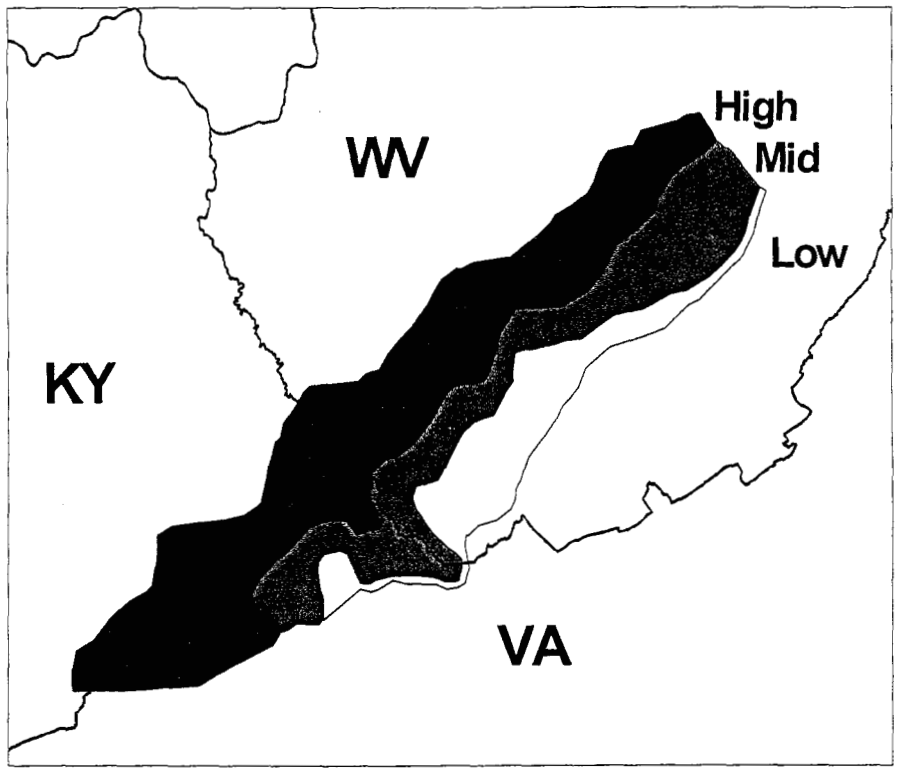
Venezuela. Like Colombia, Venezuela is only just developing its coal reserves. There are enormous reserves in Venezuela and the few producers there have solid plans to increase production significantly from around 8 mmt per year to over 20 mmt per year by 2014. This increase will come about after development of rail/port infrastructure which is now being undertaken. This coal source produces a high-calorific value, low-sulfur product that will compete with and replace dropping CAPP coal in the future. Supply availability beyond 2040 is assured unless there is a political upheaval that disrupts trade.

CENTRAL APPALACHIA

CENTRAL APPALACHIA OVERVIEW

The Central Appalachian coal region (CAPP) is comprised of bituminous coal production, principally from mines in southern West Virginia, eastern Kentucky, southwestern Virginia, and Tennessee (see Figure 1). The coal is generally high in Btu value, ranging from 12,000 – 13,000 Btu, and is low in sulfur content, ranging from 0.7% compliance coals up to 2.0% sulfur coals. The CAPP basin is the second largest producing region in the U.S., accounting for about 232 million tons of annual coal production. This is almost 20% of all U.S. coal production.

Figure 1
Central Appalachian Coalfields by Volatile Content



As the figure shows, the coal mining area of CAPP is aligned northeast to southwest. The region is the primary U.S. source of high quality metallurgical coals and low-sulfur, high-Btu thermal coals. Most of the thermal coals are high volatile content coals (i.e., greater than 32% volatile matter) and are produced in the areas shown in red in the figure.

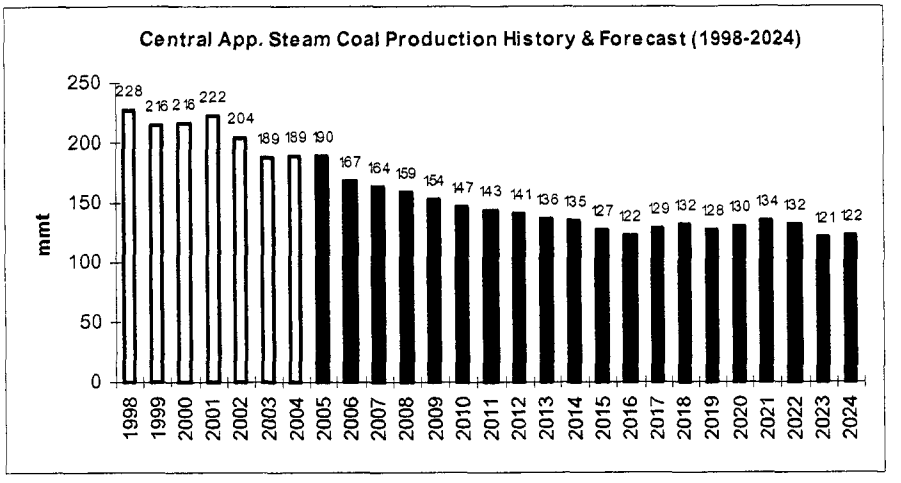
A brief description of the geology of the coal measures of each CAPP production area, by state, follows.

- **Southwestern West Virginia.** The major producing sub-region, SW WV produces about 45.6% of CAPP production. The rugged landscapes of West Virginia are held up by the presence of a series of rocks that thickens to the Southeast. When the coals were deposited, the southern part of the state subsided at a more rapid rate than the northern part. This resulted in a thicker rock package that contained more coal seams in the south. This is one of the key reasons why mountaintop removal is a popular form of mining in southern West Virginia.
- **Kentucky,** the second-largest producing CAPP state, contributes about 39.6% of CAPP production. The stratigraphic section of the eastern Kentucky coalfields is composed of a thick series of rocks that form a wedge shape, which thickens to the southeast. The rock package contains a few widespread shales with distinctive marine fossils that are easy to correlate. These zones aid geologists in determining the position of coal seams, how they relate to each other and include the Betsie, Kendrick and Magoffin shales. Most of the mineable coals in Kentucky occur within Breahitt Group. Most of the sub-groups of the Breahitt Formation start at the base of one of these shales.
- **Virginia** produces 13.7% of CAPP production. The coal-bearing portion of Virginia consists of a thick package of rocks that includes numerous coal seams. The following formations are present: Pocahontas, Lee, Norton and Wise.
- **Tennessee** produces a minor amount of coal (<2%). The Tennessee coalfields occupy the area where the Appalachian coalfields are very narrow (about 40 miles). In general, Tennessee coals contain higher sulfur content; the most significant coal seams include: the Walnut Mountain, Jellico, Sewanee and Richland seams.

CENTRAL APPALACHIA - PRODUCTION

Figure 2 shows that CAPP steam coal production is forecast to decline from 228 mmt in 1998 to 190 mmt in 2005, a 17% decrease. H&A's forecast predicts that CAPP will continue to experience a decline in production to as low as 121 mmt in 2024, a 46% decrease from 1998. Beyond H&A's formal forecast to 2024, our expert opinion is that coal production will continue well beyond 2024 in CAPP across all coal types in the remaining reserves of CAPP. Production is expected to continue to decline, possibly to a level of around 100 mmt by 2040, unless higher prices stimulate new projects in deeper, thinner seam coal resources in the future as described below.

Figure 2



About 28% of the Central Appalachian coals that are sold to utilities are compliance grade, containing less than 1.2 $LBSO_2$ per million Btus. 70% of the coals sold to utilities are "near-compliance grade", ranging between 1.2 and 2.5 $LBSO_2$ per million Btus. The remaining 2% of steam coals from the region are mid-sulfur coals, which contain greater than 2.5 $LBSO_2$ per million Btus.

The following figures depict H&A production projections across different coal quality types for S.WV, E.KY and VA coals:

Figure 3

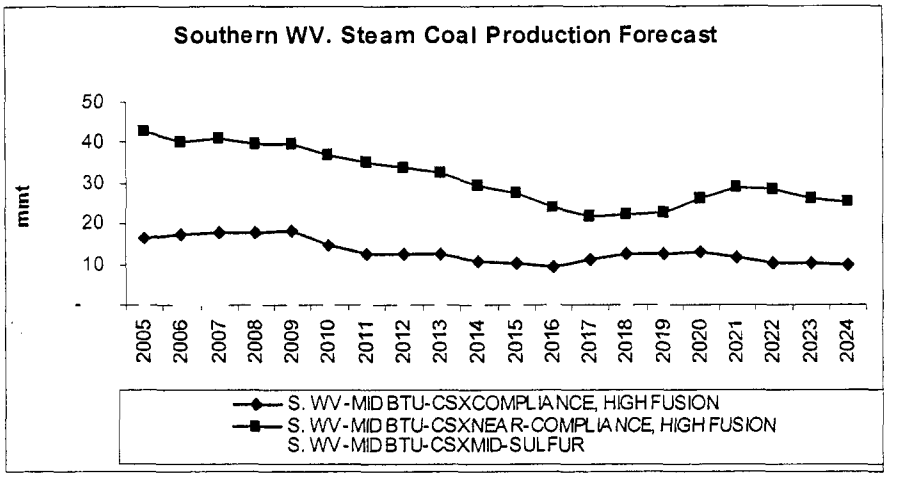


Figure 4

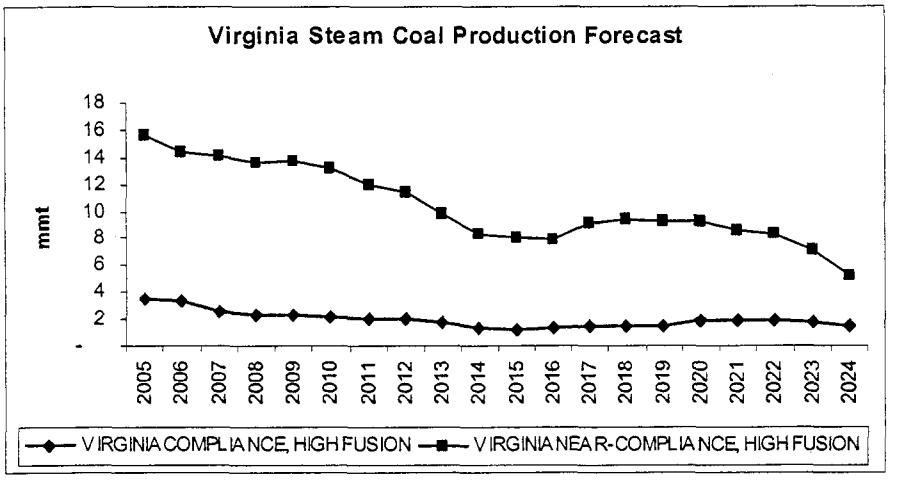
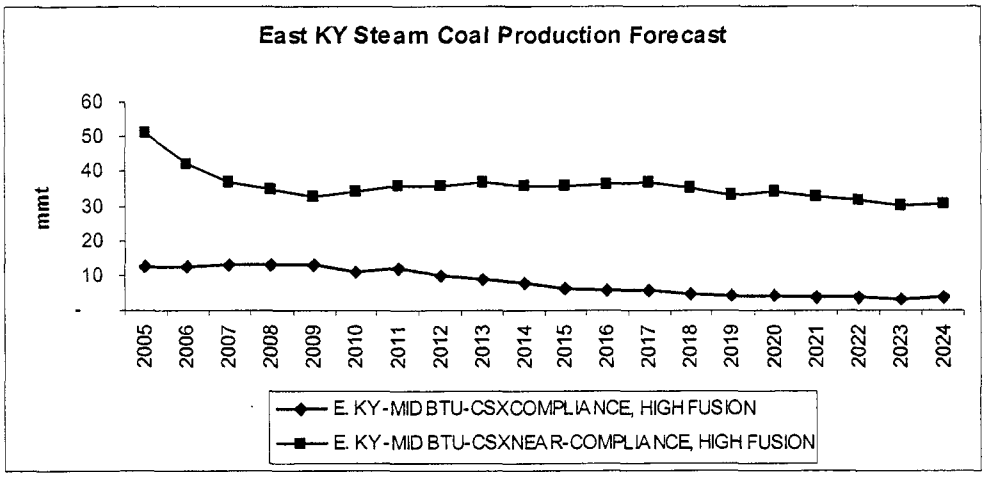


Figure 5



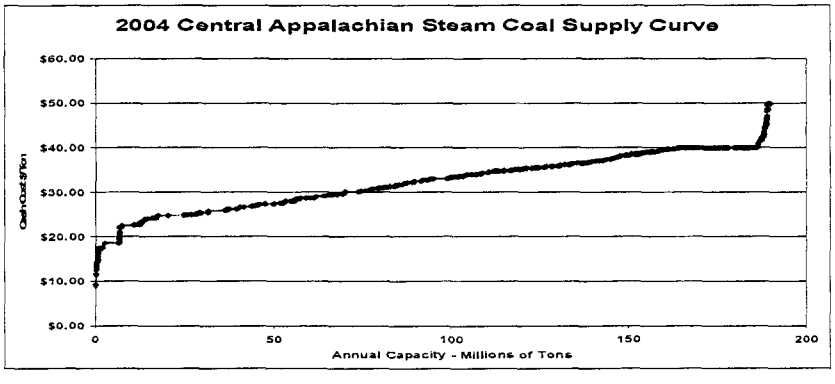
CAPP coal production is approximately 57.2% underground mined and 42.8% surface mined. Up until the past few years surface mined coal was increasing rapidly. However, the issue of mountain-top removal and legislation covering permitting and environmental compliance has caused this trend to stall. The future of surface mining in the region is threatened. Environmental groups and the general public have gained momentum in their challenges to the coal industry, on issues such as refuse impoundment stability; coal truck weight limits (especially in West Virginia); cumulative hydrological impact assessments.

In the past two years, with higher prices prevailing, there is renewed interest in accessing underground mineable reserves that are deeper and more difficult than those previously mined. Some operators are considering developing slopes to access coal seams in areas where the coal is below the drainage and does not outcrop. This type of mining, obviously, is more expensive and requires significant capital expenditure even to get into the producing coal.

The majority of underground mines utilize continuous miner technology although there are some productive longwalls remaining in CAPP. However, it is not likely that many, if any, new longwall mines will be developed in CAPP because there are no large reserve blocks remaining where a longwall could be employed. Many of the larger producers have adapted a specialized continuous mining technology, called "super-section" mining where two continuous miners are used on one section of a coal mine with one crew. This is more expensive in terms of initial equipment investment, but much more productive than a standard continuous miner section.

Cash costs for production CAPP have been steadily increasing due to mining regulations, decreasing productivity, thinner coal seams, reserve depletion, and deeper coal reserves. There was a significant increase in cash costs in 2004. Figure 6 shows the 2004 steam coal mine cash costs for the cumulative potential production capacity in Central Appalachia. The figure shows FOB cash costs ranging from about $10 – $40 per ton.

Figure 6



The supply curve suggests that the marginal cost of production will be about $40 per ton at the 190 million tons per year production level. Coal prices above the $40 per ton range will be required for marginal producers to remain viable. Some of the higher cost production is supported with high priced contracts or industrial sales, and some of the higher costs are at mines that have closed.

Industry consolidation in the CAPP region has been robust. Sine 1998, the consolidation of large producers changes dramatically as: Massey added to its portfolio of properties, AEI Resources added substantial holdings in the late 1990's Arch and

Ashland merged into Arch Coal. AEI Resources purchased Zeigler Coal and Cyprus Amax's eastern operations which were later acquired by RAG American which, in turn, has become an IPO named Foundation Coal Corp.; James River bought Blue Diamond, much of Transco and Sun; Alpha Natural Resources Partners acquired the Pittston assets and several other producing entities; and there have been others.

Massey has increased production in 2004 and now holds a firm lead on Central Appalachian production of 42 million tons. Arch's production was 29.9 million tons in 2004, about 3.6 million tons more than it was in 2003; Peabody's production was 11.8 million tons. James River Coal produced 8.8 million tons. TECO increased production with the addition of Perry County Coal and "pushing more coal" through synfuel plants and was 8.1 million tons of production in 2004. Foundation produced 6.9 million tons. In summary, concentration in the region has been significant. This has allowed some of the companies, such as Massey, to command higher prices in the market due to their control of so much CAPP coal.

When prices went sky high in 2001, CAPP producers (as well as the rest of the country) opened higher cost mines to meet the demand. A similar occurrence again happened in 2003-2004, with prices even higher. CAPP steam coal was at 189 million tons in 2004; however, despite higher prices, the region is not able to further respond to the strong demand and H&A now projects that CAPP steam coal production will end up at 190 million tons in 2005.

We continue to project that production in the region will continue to decline in the long run, as the relatively easily accessible reserves are quickly depleting. However, if higher price levels are sustained in the long term, albeit at lower levels than today's prices, then investment groups will look favorably on big mining projects that will access deeper coal resources than are feasible today.

CENTRAL APPALACHIA – COAL RESERVES

The bulk of the remaining reserve base in Central Appalachia is characterized by thinner seams and associated geological problems. Most of the high-quality thick coal has been mined. There are few large blocks of coal remaining that can be extracted using longwalls or draglines. Over time, mines in this region will have trouble maintaining the productivity growth of the past few decades. Productivity levels and production will decline in the future and productivity growth is likely to slow significantly.

Table 2 summarizes CAPP's economic reserves across different sulfur content categories. The bulk of the reserves are in the near compliance bracket. These reserves exhibit the following characteristics:

- Depleting
- Long-term mining has extracted the thicker and more accessible coalbeds, the remaining thinner and deeper coal deposits are or will be progressively less competitive.

Table 2
CAPP Estimated Economic Reserves (mmt) by Sulfur Content (lbs/mmBtu)

State/SO2 Content	<1.2	1.21-2.49	2.5-4.49	Totals
E.KY	682	2,054	72	2,807
TN	25	95	30	150
VA	192	589	33	814
S.WV	1,348	2,525	317	4,190
Totals	**2,247**	**5,263**	**452**	**7,961**

The table indicates that reserves in southern West Virginia and eastern Kentucky combined could support production levels at current rates well beyond 2040, particularly for a near-compliance product. H&A predicts that, indeed, mines will continue to operate in this region. However, the increasing cost structure could diminish the amount of economic reserves in the future and will definitely do so, should prices drop significantly. Prices, according to our estimates, must sustain the range of $35 to $40 dollars, minimum or higher, in the future to sustain mining and encourage new investment.

KEY ISSUES AND DRIVERS FOR CAPP

- Rapid depletion of coal reserves is occurring (substantial decreases have occurred in the past 3 years and more are to come);
- Coal production costs are high, primarily due to deteriorating geologic conditions;
- Bonding, permitting problems and labor shortages will make it harder to expand existing mines or develop new ones;
- Increased competition from Western coal;
- With CAIR kicking in, more plants are investing in SO_2 clean-up equipment, which would allow them to use cheaper mid- and high-sulfur coals or even completely switch to PRB coal;
- Large mines are controlled by a few major coal producers (Peabody, Arch, Massey, etc.), but there are many smaller mines in the region;
- Most mines have either CSX or NS rail service, but not both;
- Productivity is declining because operations are moving into harder-to-reach coal; and
- There are significant coal mining regulatory and environmental issues in West Virginia (hollow-fills and Section 404 permits).

ILLINOIS BASIN

ILLINOIS BASIN - OVERVIEW

The coalfields of Illinois, Indiana, and western Kentucky lie in the Eastern Region of the Interior Coal Province, better known as the Illinois Basin (ILB). The ILB coal region is comprised of bituminous coal production, principally from mines in western

Kentucky, Indiana, and Illinois. The coal is wide ranging in quality, generally spanning from 10,000 to 12,800 BTU, and from about 0.5 % to 5.0 % sulfur. The ILB is the fourth largest coal-producing region in the U.S., accounting for about 91 million tons of coal production in 2004.

The entire Basin covers more than 50,000 square miles, which are underlain by the coal bearing sequence of rocks that constitute the Pennsylvanian System. Numerous coal beds are exposed at depths ranging from a few feet to over 1,500 feet in the center of the Basin. In Illinois, the beds outcrop in the southern, western, and northern portion of the field and gradually become deeper in the center of the Basin. The coal bearing strata in western Kentucky generally dips to the northwest, but is interrupted by major fault systems. In Indiana, the beds crop out in the eastern portion of the field and gradually become deeper westward.

The mineable beds are relatively thick, flat lying and continue over extensive areas. Beds one to ten feet thick (5.5 feet average) are mined utilizing surface and underground mining methods. The remaining large surface reserve blocks at low (< 19:1 clean) ratios are mainly controlled by Peabody, who has done a tremendous job of maximizing production from these reserves. However, these low-ratio, surface mineable reserves are depleting fast. Over the next 5-10 years most of the large surface mines will have depleted their reserve base and will likely close. Abundant reserves exist with ratios in the 19:1-24:1 range; however, these will probably not be mined due to the high cost versus expected future prices. There are only a few remaining draglines that can mine economically at these depths. Peabody controls most of these machines.

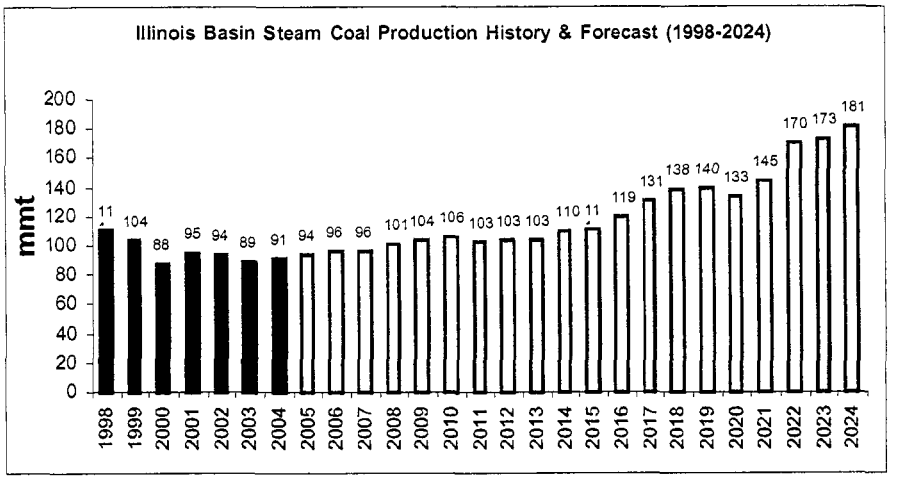
The Basin contains a tremendous underground reserve base, which is about 5 times larger than the Pittsburgh 8 seam reserve base in Northern Appalachia. As the surface reserves deplete and as demand increases and assuming prices justify, these reserves will likely be developed in the next ten years and will be able to support production from the basin well beyond 2040. The deeper reserves, however, contain higher chlorine content than those closer to the surface. And, even though the deeper reserves tend to support low-cost longwall technology, such technology may not be applied if the reserve is below prime farmland where subsidence could present problems.

The strongest companies in the future will be those with large reserve positions that can be developed as non-union mines or mines under modified United Mine Workers of America (UMWA) contracts. Peabody is the largest holder of resources with Alliance, Freeman, Consol, Addington, Horizon, Arch, Freeman, and ExxonMobil also having large reserve positions.

ILLINOIS BASIN - PRODUCTION

As illustrated in Figure 7 below, ILB production is forecast by H&A to increase from 94 mmt in 2005 to about 181 mmt in 2024. Beyond 2024, and prior to 2040 the basin production is expected to peak and begin a slow decline. This is because the existing mining operations begin to deplete and basin production begins to rely more on deeper, more costly operations to sustain production.

Figure 7



In the 1970s and early 1980s, approximately 63% of the Basin's production came from surface mines. Since 1983, there has been a trend toward more underground production, because many of the large surface mines have closed due to reserve depletion. In 2000, surface production reached a low and only represented 38% of the total Illinois Basin production in that year. As predicted by H&A in its 2001 study and thanks to a strong market and expansions by Peabody's non-union operations, surface production increased by 6-8 mmt in 2001 and 2002. It now represents 40-43% of the Basin's production.

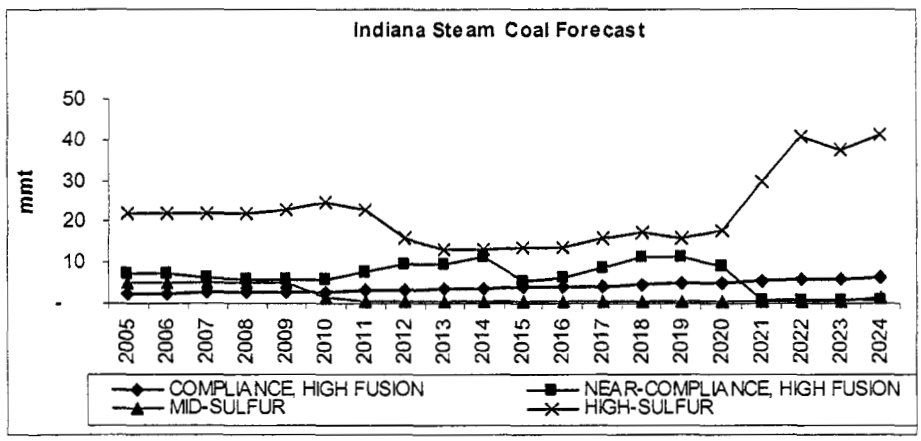
H&A's analysis has identified enough projects to suggest that Illinois Basin capacity could potentially increase to more than 200 million tons per year by 2013, if such demand is present; however, production will probably only be in the 100-105 million tons per year range. Peabody, the dominant producer in the region, is expanding its southeastern operations, and Jim Bunn/Steve Carter (Knighthawk) is consolidating holdings in the southwestern part of the state and could expand soon. Arc Light is under pressure to develop its TVA Franklin County reserve in the next two years.

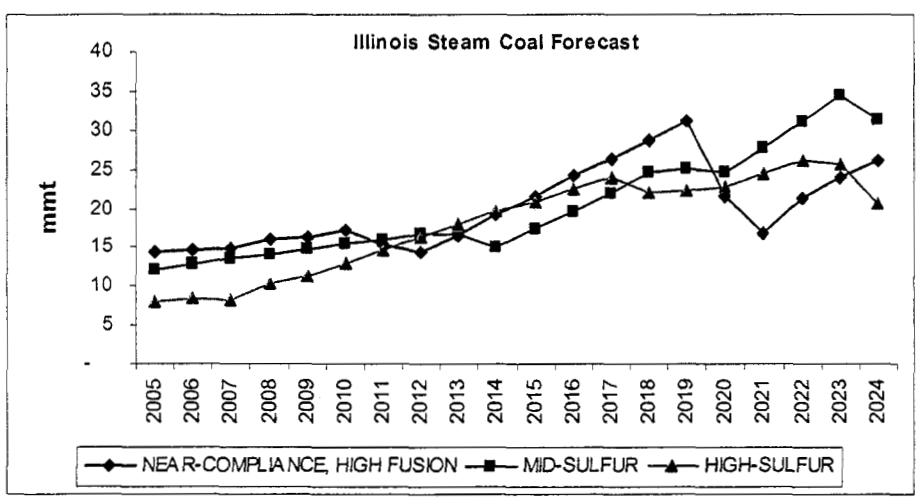
A significant amount of consolidation took place in the Basin during the 1990s and, as a result, several operations have been closed or idled. Overall mine productivity has dropped by 10-15% over the last two years, mainly due to underutilized mines, and the higher prices of 2001, which allowed new mine development in higher cost reserves. In 2004, costs went up also due to raw materials and fuel cost increases. Mine costs are up 35% as a result of this, which will hurt Illinois Basin demand in the future, as it has to compete with lower cost alternatives.

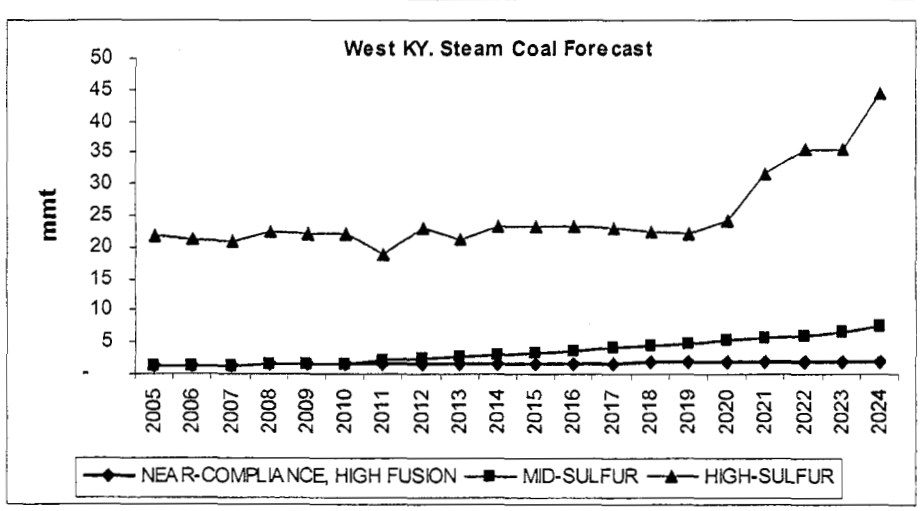
Figure 8 provides three graphs to show the production forecast for Indiana, Illinois and western Kentucky coal, according to coal quality type. The charts indicate that Illinois is likely to produce the majority of the coals across all coal types. Indiana and western Kentucky have the potential to develop significant production of high-sulfur coals.

Figure 8

Illinois Basin Production Forecast to 2024 by State and Coal Quality Type





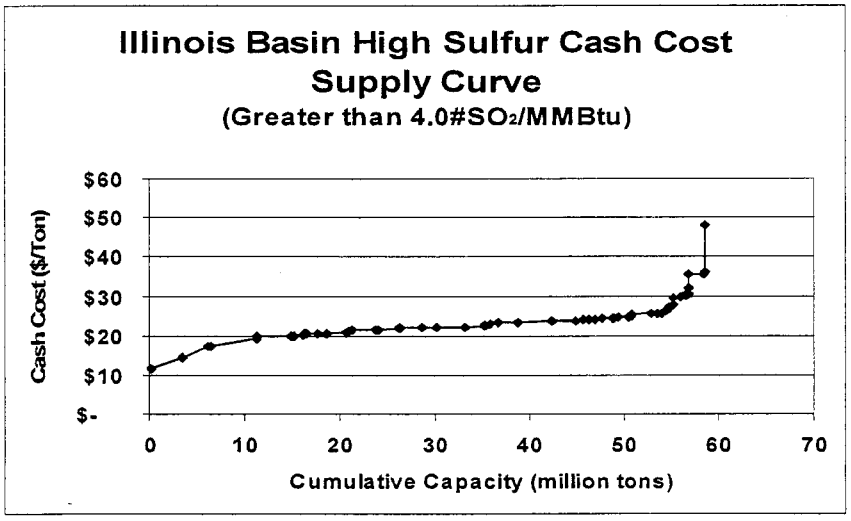


The above charts, if extended to 2040, would all display production at sustained levels or depleting marginally. As mentioned previously, the Illinois Basin is expected to produce adequate amounts of coals of near-compliance, mid-sulfur and high-sulfur type to sustain well beyond 2040.

Marginal mine cash costs for high sulfur Illinois Basin coals are shown in Figure 9. This figure shows that the cash costs for 11,700 Btu/lb. Western Kentucky production ranges from around $11.70 per ton to over $36.00 per ton. There are 55 million tons of high-sulfur coal capacity in the basin at under $30 cash cost in the railcar.

There are other, lower sulfur, products in the Illinois Basin, which could be considered also. However, the capacity for the other coals is far lower than that of the high-sulfur products. There is approximately 13 million tons of capacity of mid-sulfur coal (greater than 2.5/less than 4.0#SO_2/MMBtu) at mine cash costs below $27 per ton. Similarly, there is 25 million tons of capacity of low-sulfur coal (less than 2.5#SO_2/MMBtu) at mine cash costs of $32 or less.

Figure 9



ILLINOIS BASIN – COAL RESERVES

The Basin contains a tremendous underground reserve base, which is about 5 times larger than the Pittsburgh 8 seam reserve base in Northern Appalachia. As the surface reserves deplete, and as demand increases, these reserves will likely be developed in the next ten years. Table 3 summarizes the economic reserves for Illinois Indiana and W.KY.

The table shows adequate reserves available to produce mid- and high-sulfur coals at current levels far beyond 2040. The basin is expected to develop to serve scrubbed utility plants along the river system and, potentially, in the southeast.

Table 3
Illinois Basin Coal Reserves (mmt) by Sulfur Content (lbs/mmBtu)

State	<1.2	1.21-2.49	2.5-4.49	>=4.5	Grand Total
IL		897	2,894	5,623	9,414
IN	352	189	242	964	1,746
KY	4	15	486	1,097	1,602
Grand Total	356	1,101	3,623	7,683	12,763

KEY ISSUES AND DRIVERS FOR ILLINOIS BASIN

- Tremendous coal reserves exist and significant expansion is possible in the ILB;
- The large mines are controlled by a few major producers (Peabody, Alliance, Freeman, Consol, etc.), but there are also a number of smaller mines in the region;
- Most mines have either CSX or NS rail service, but not both;
- Some mines have access to waterways, but at additional transportation cost to the docks;
- Production has declined in recent years (but as shown in our production forecasts, this production is expected to grow);
- The region will benefit when scrubbers are installed to meet air quality requirements; and
- ILB is a swing coal and is expected to be a blending partner for low sulfur PRB coal.

NORTHERN APPALACHIA

NORTHERN APPALACHIA OVERVIEW

The Northern Appalachian (NAPP) coal region is comprised of bituminous coal production principally from mines in northern West Virginia, western Pennsylvania and southeastern Ohio. NAPP is the third largest coal-producing region in the U.S., accounting for about 135 million tons of annual coal production in 2004. Total regional production (about 65%) is dominated by Pittsburgh seam coal, which is produced by a few major producers including Consol Energy, Foundation Coal Corp. and American Energy (Robert Murray). The three sub-regions of NAPP are described below:

- **Pennsylvania.** Historically, in southwestern Pennsylvania, the Pittsburgh 8 seam has had good coking properties resulting in steel companies tying up much of the reserve base for their own captive use. However, because of changing long-term resource requirements and the need for lower sulfur coals, steel companies have relinquished control of these reserves and mines. What was once a major metallurgical coal resource has now become a major steam

coal resource as utilities value the seam's characteristic high Btu (13,000) and relatively low sulfur (1.5-2.5%), low ash (6-10%), and low moisture content (6-8%).

Production from the Pittsburgh seam has historically come from Allegheny, Greene, Washington, Westmoreland, and Fayette counties. Because of good access to the coal crop and to navigable water, mines tended to be built along the Monongahela River. Thus, with a history of over 200 years of mining, most of the shallow, easily accessed coal along the river or along the coal outcrop in Allegheny and Fayette counties has been mined out; therefore, production has moved to deeper mines, further from the river. Virtually all production in this region now comes from Greene and Washington counties.

- **Northern West Virginia.** Production in Northern West Virginia historically serves two rivers. Mines in Monongalia, Marion, and Harrison counties typically serve or have access to the Monongahela River, while the mines in the West Virginia panhandle counties of Marshall, Ohio, and Brooke counties serve the Ohio River. The Northern West Virginia region is defined by those mines that are best served by the Monongahela River. The West Virginia mines on the Ohio River are present in the Ohio Valley region.

  In northern West Virginia, large blocks of higher sulfur Pittsburgh coal have been developed by CONSOL and Eastern Associated (Peabody) to supply coal to local power plants built along the Monongahela River. The Btu content of coal produced in this region varies from 12,500 to 13,300, sulfur values range from 2.5% to 3.5 %, and ash ranges from 7 to 12%. With 74% of the production tied up, CONSOL is the dominant producer and coal controller in this region. Peabody has 25%. The remainder is minor production from small producers operating in outliers of the Pittsburgh seam.

- **Ohio Valley Region.** West of the Pennsylvania/West Virginia state line, the Pittsburgh seam rapidly deteriorates in quality. Ash and sulfur content increase, and the Btu content drops from 13,000 Btu/lb. to around 12,000 Btu/lb in the Ohio Valley region. Because of its proximity to the river and the large utility and industrial markets, large amounts of Pittsburgh seam production have occurred in Ohio along the banks of the Ohio River. Most of the reserve in Ohio has been mined out and what remains is mainly controlled by CONSOL and Bob Murray. Substantial reserves remain in Northern West Virginia, and most of these reserves are controlled by CONSOL. Like the other areas, mining has moved away from the river over time. Many of the remaining mines transport raw coal production 5 to 15 miles underground to access the portal.

  Currently, CONSOL controls 54% of the production and Bob Murray controls about 46% of the production. With CONSOL's planned expansion of the McElroy, CONSOL will probably expand its control to 63% in 2005, while Murray drops to 37%. Alliance controls a major reserve block in West Virginia and hopes to open a mine in the next ten years.

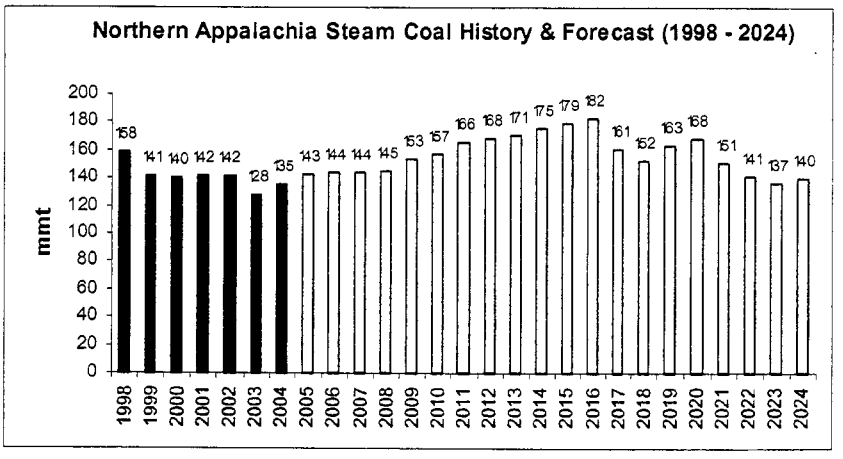
The coal is shipped to markets within the U.S. by rail, or rail-to-water, with some local deliveries by truck. As with CAPP, two major railroads, the NS and CSX, originate a great deal of the NAPP shipments, and then deliver the coal directly to power plants or to rail-to-barge docks for water delivery to other plants.

NORTHERN APPALACHIA - PRODUCTION

The Pittsburgh seam is the primary seam in NAPP, although other seams are produced, such as the Upper and Lower Freeport seams and the Bakerstown seam. The Freeport seams have metallurgical properties and both Freeport and Bakerstown seams can contain relatively high sulfur content. We focus on Pittsburgh seam coal in this report because of its dominance and because the transportation efficiencies that are available from large-scale loading facilities, which are unit train capable. Also, there are abundant reserves of mid- and high-sulfur coal available for underground mining. Consol Energy is the largest Pittsburgh seam producer. Pittsburgh seam coal is generally high in BTU value, ranging from 12,000 – 13,300 BTU, and is mid-to-high in sulfur content, ranging from about 2.2 % - 5.0 %.

Production from this region has taken place for over 200 years and will continue for years to come. Remaining Pittsburgh seam reserves would support production at existing levels for over 36 years. Our modeling shows that coal production in Northern Appalachia will reach a peak in about 10 years, as reserves in the important Pittsburgh Seam begin to deplete, and the remaining reserve base is unable to compensate for the loss of Pittsburgh Seam production. As seen in Figure 10, production from NAPP for 2005 is estimated to reach 143 million tons, which is 8 million tons up from 2004.

Figure 10



The Pittsburgh seam ranges from 5 to 8 feet thick and it is laterally extensive. As such, the seam is conducive to large scale, longwall mining methods. Almost 97% of Pittsburgh seam production comes from longwall operations, which provides for highly mechanized, very high productivity and very low cost coal mining. This has enabled the

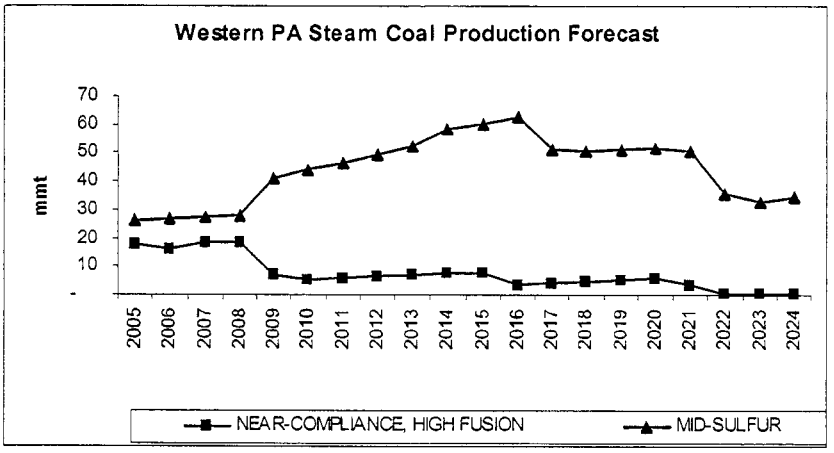
market prices for Pittsburgh seam coals to remain very low over the years and maintain a highly competitive presence in both U.S. and export coal markets.

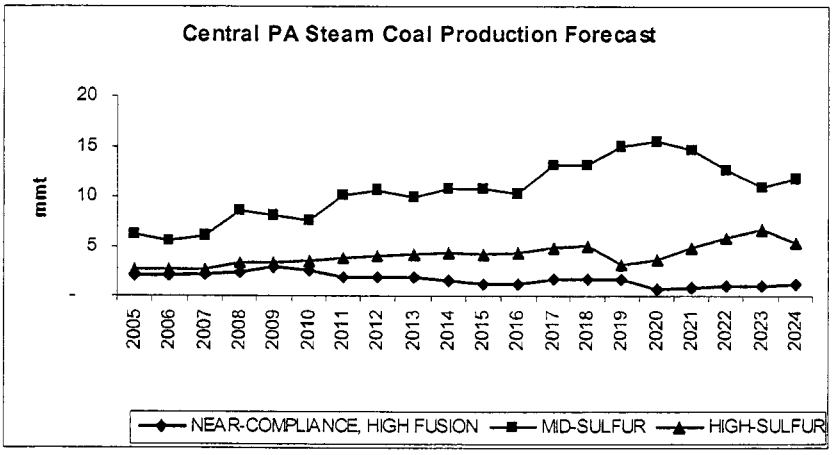
Assuming the market conditions maintain, several new greenfield mines could open up in the 2005-2011 timeframe. If so, Pittsburgh seam production could expand to 150 million tons per year by 2011. All proposed greenfield operations will be in mid- to high-sulfur coals.

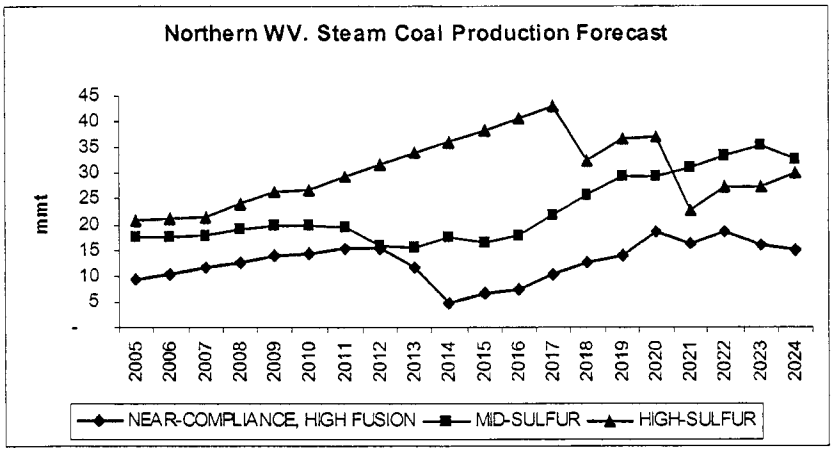
The following graphs illustrate our forecast for WPA, Central PA, NWV and Ohio NAPP coals by sub-region and coal quality type.

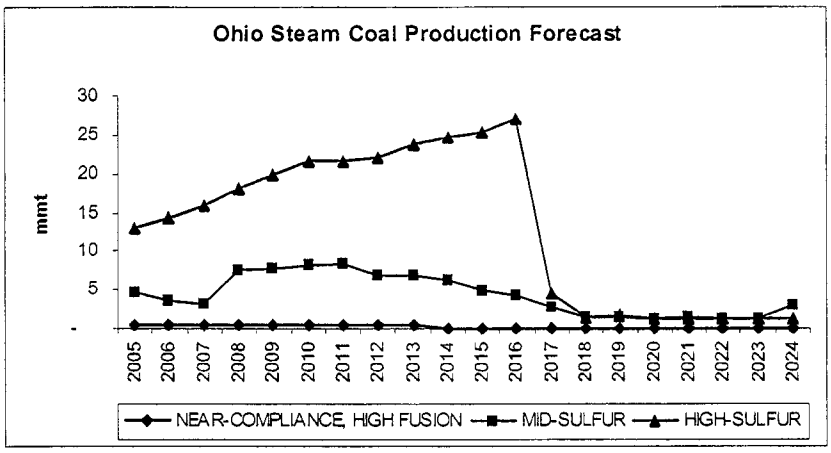
Figure 11

Northern Appalachia Production Forecast to 2024 by Sub-region and Coal Quality









The graphs displayed above show that H&A anticipates production of Pittsburgh seam coal to peak out in the 2016-2017 time period and decline from that point forward. Other coal types in the basin are, relatively, much lower in productive capacity and are generally represented by numerous smaller producers. The decline will extend past 2040 and overall NAPP production could decline to a level of +/-100 mmt by 2040. This production level is still adequate to consider as a long-term fuel alternative for a new generating plant.

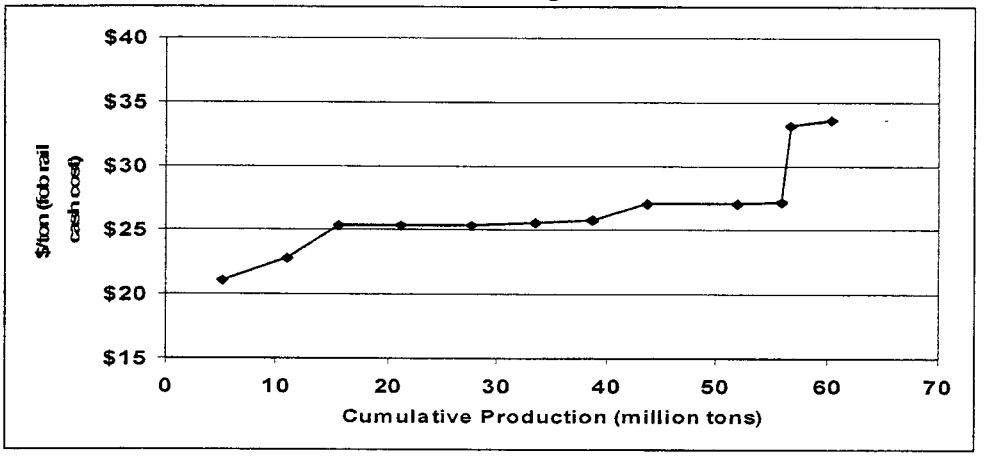
Since 1994, numerous mines producing coal from the Pittsburgh seam have closed due to reserve depletion or high costs. About 30 million tons of annual production has been lost due to depletion and another 22 million tons are anticipated to be lost by 2010. The lost production was offset by new mine openings or by expansions at other mines.

The SO_2 credit bank will be depleted around 2007, thus with a depleted credit bank and tighter SO_2 limits under the Clean Air Interstate Rules (CAIR), power plants will likely add scrubbers. Because of the Pittsburgh Seam's strong reserve base (although much smaller than ILB or CAPP) and relatively low costs (as compared to

other producing regions), Pittsburgh Seam mid- and high-sulfur coal will likely be the beneficiaries of this new demand.

The 2004 NAPP supply curve for Pittsburgh Seam mines shows the low-cash mining costs for the region, ranging from around $21.00 to $33.56 per ton, as shown in Figure 12. Most of the mines have cash costs ranging from $25.30 to $27.20.

Figure 12
Coal Supply Curve for Pittsburgh Seam Mines -- 2004



According to our long-range forecasts, we project that mining costs in this region may decrease by $3 to $6 per ton by 2011, based upon improvements in productivity and the replacement of old longwall mining equipment with newer and more efficient ones. There is a possibility that our productivity improvement projections may not materialize because the coal seams are getting thinner and underground coal haulage will be longer. However, we anticipate that overall productivity in the region will increase over the next 8 – 10 years.

As tighter limits on SO_2 emissions take effect the SO_2 credit market will tighten and more plants will be installing scrubbers. New scrubber construction will cause an increase in demand for mid- to high-sulfur coals. The Illinois Basin and Northern Appalachia regions will compete fiercely for the new scrubber market that will be developing over the next decade.

Northern Appalachia has an inferior reserve base to the Illinois Basin. Although, current mining costs are comparable, the Illinois Basin has the edge over Northern Appalachia; but Northern Appalachia has higher Btu coal than the Illinois Basin, which makes it more attractive. In the near term, however, it appears that the Illinois Basin can expand more rapidly.

NORTHERN APPALACHIA - RESERVES

Table 4

NAPP Total Steam Coal Reserves by Lbs SO_2/mmBtu and Total Pittsburgh Seam Reserves

Region/SO2 Content	=<1.2	1.21-2.49	2.5-4.49	>=4.50	Totals
Maryland	20	25	85	0	**130**
Ohio	200	400	2,900	2,000	**5,500**
Central PA	30	45	165	40	**280**
Western PA	10	10	800	30	**850**
N.WV	10	12	850	450	**1,322**
Totals	**270**	**492**	**4,800**	**2,520**	**8,082**
Pittsburgh seam total	n/a	131	1,427	1,471	3,029

The table indicates that reserves will sustain production at current levels well beyond 2040 before depleting. This assessment also assumes that several new greenfield longwall mines are developed in the Pittsburgh seam including Consol's Berkshire and Green Hill properties and Foundation's Green Manor reserves.

KEY ISSUES AND DRIVERS FOR NORTHERN APPALACHIA

- There are significant coal reserves and potential for expansion;
- Mining productivity is high and production costs are low at many mines due to long-wall mining;
- Most of the large mines are controlled by a few major coal producers (Consol, Foundation, etc.);
- There are many smaller mines, but they principally serve local industrial and utility plants;
- There is significant production capacity that has access to both CSX and NS rail service (e.g. Consol's Mine 85, Bailey and Enlow Fork complexes);
- A limited number of mines have access to waterways at additional cost of transportation to get to the docks; and
- Rail service to utilities in Florida is expected to carry a high rail rate.

COLOMBIAN COAL

COLOMBIA OVERVIEW

The Colombian coal industry is comprised of bituminous coal production principally from the following coalfields: **Cerrejón, La Loma,** and **La Jagua**. The coal is mid-to-high BTU, ranging from 11,400 – 12,200 BTU, and is very low in sulfur content, ranging from 0.6% to 0.8%. Colombia produces and exports about 64 – 69.5

million tons of coal annually to various markets in the U.S. and to other countries. We project that Colombian production and exports will grow to as much as 83 - 87 million tons by 2010. Figure 13 shows the major export mines in Colombia.

The country is a primary exporter of coal, and it has enormous amounts of coal equivalent to almost 7.7 billion tons of measured reserves. About 90%, or 6.90 billion tons, of the country's coal reserves are for steam coal use.

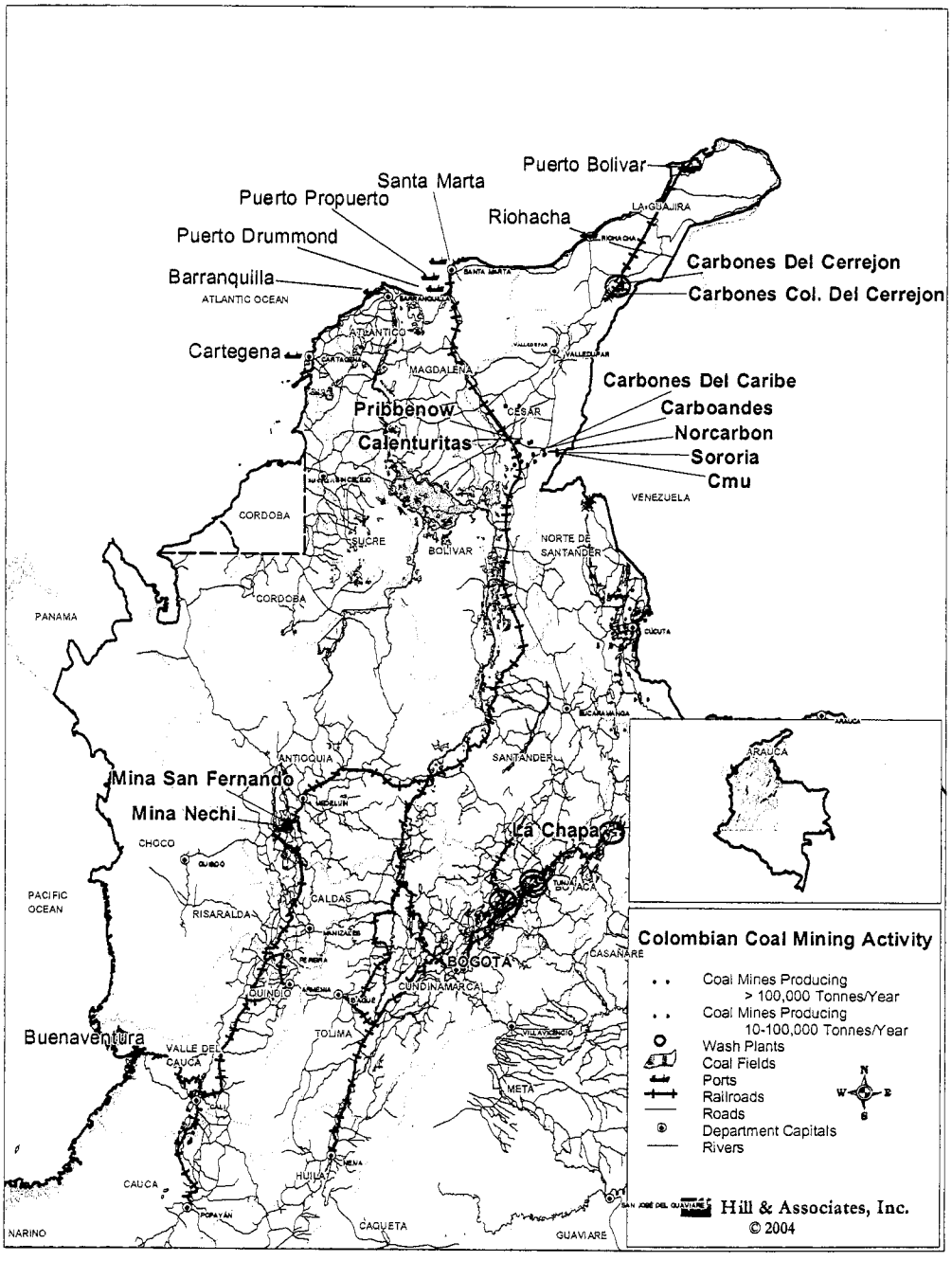
The vast majority of export tonnage comes from the Cerrejón, La Loma, and La Jagua regions. These three regions contain the bulk of the defined coal resources and offer relatively easy access to the coast. The mines in these regions share similar characteristics:

- Almost all production comes from surface operations;
- All are mining multiple seams at stripping ratios of approximately 6.5:1;
- In most, the seams are steeply pitched and lend themselves to truck and shovel methods;
- All have high quality coal with low-sulfur and ash, and medium- to high-BTU values; and
- Each region now has one large mine, and one or more smaller operations.

Most of the production is controlled by a small number of producers with the mine ownership in the hands of about 3 major supplies: Cerrejón Coal Company (BHP-Billiton, Anglo American and Glencore); La Loma (Drummond); and Carbones del Caribe. A number of smaller mines are owned by a mix of domestic and foreign companies.

Most of the mines in Colombia move their coal by truck to ports on the coast. A few mines have access to rail. A few other producers use barges on the Magdelena River to get coal into vessels. The expansion of rail service to additional mines will probably come in due time, but this has been slow to develop.

Figure 13
Major Coal Activity in Colombia



COLOMBIA - PRODUCTION

In the late 1970s, Colombian coal production was used to supply internal consumption, with the exception of small volumes of metallurgical coal for exports. In the 1980s, when the Cerrejón North Zone Project was developed, the country doubled coal production, going from 4.7 mmt to 9.8 mmt from 1980-1985.

During 1997, total production reached 36.0 mmt, increasing by 9.7% with respect to 1996's production of 32.5 mmt. In 1997, 84.2% of production (30.4 mmt) was exported to the international market and 15.7% (approximately 5.6 mmt) was for internal consumption.

During 1998, total production increased 3.17% with respect to 1997, reaching a total value of 37.2 mmt. Coal exports increased 2.49 mmt, totaling 33.0 mmt, while internal consumption was reduced to 4.2 mmt.

Total production fell to only 35.1 mmt in 1999, of which 32.9 mmt were shipped to the foreign markets and only 2.2 mmt were used for internal consumption. The slightly lower shipment levels in 1999 were the result of low international prices and the domestic economy's recession.

Contrary to the previous year, Colombian production in 2000 grew 16.54%, reaching 40.9 mmt which represents an increase of 5.8 mmt. On the shipment side, the growth was 16.26%, representing an increase in the exported volume of 5.4 mmt with respect to 1999 figures. The Colombian shipments totaled 41.6 mmt in 2000.

This growth during 2000 was supported mainly by a firm international market price and production increments of 2.07 mmt at Drummond's Pribbenow mine and 1.74 mmt at Carbones del Cerrejón, which returned to its normal production level after securing access to the railroad and Puerto Bolivar infrastructure. Cerrejón North Zone operations increased by a modest 0.97 mmt, and Carbones del Caribe also contributed with an additional 0.93 mmt.

During 2001, the country's total production reached 46.9 mmt, an increase of 6.0 mmt, which represents a production growth of 14.65% with respect to 2000 figures. Shipments totaled 41.83 mmt, a figure 9.28% above the 2000 shipments, representing an increase of 3.55 mmt.

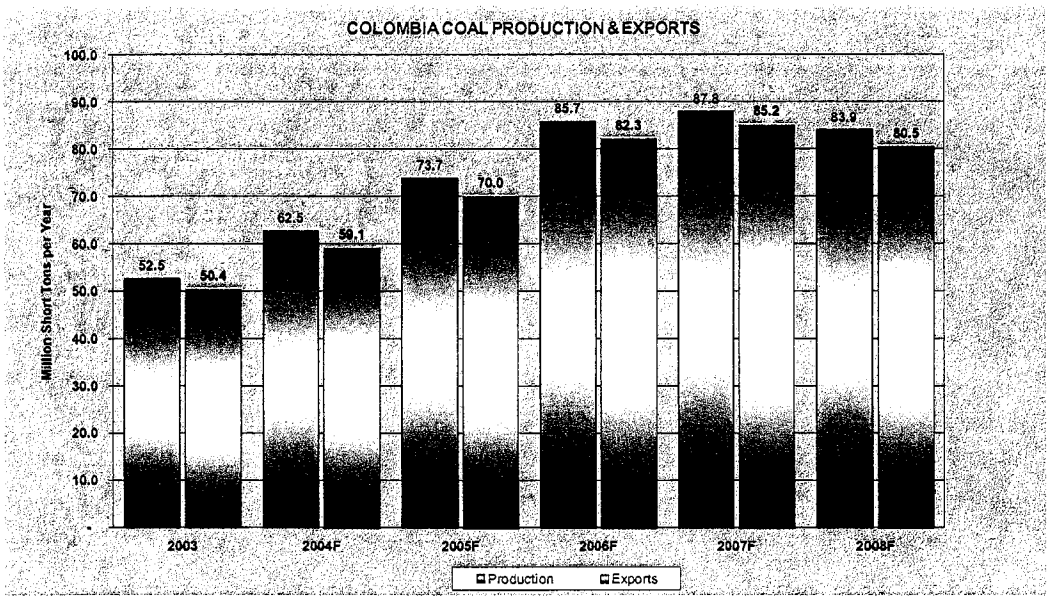
In 2002, Colombian production was 42.65 mmt, representing a reduction of 4.25 mmt in comparison with 2001 figures. This coal production reduction was due to the high mine inventory levels at the beginning of the year, the production cut announced by Cerrejón Coal Company, and the downward trend in the international coal prices.

Export shipments in 2002 were 40.22 mmt, a decrease of 1.6 mmt in comparison with 2001 shipments. This 3.83% reduction is due to the above-mentioned high inventory levels at the beginning of the year and the production cut of Cerrejón Coal.

Coal production during 2003 rebounded to 52.49 mmt (Figure 20), increasing 9.84 mmt or 23.08% when compared with 2002 figures. This increase was supported by production increases in Cerrejón, Drummond, and Carbones del Caribe. Following the production trend, the coal exports from Colombia reached 50.35 mmt, an increase of 10.12 mmt or 25.17%, returning coal inventories to normal levels.

In 2004, Colombia exported 59.08 mmt, which is 8.7 mmt above 2003, or 17% higher (Figure 14).

Figure 14



Cerrejon Coal. After the early 1999 access agreement signed between Cerrejón North Zone and Carbones del Cerrejón, modifications to the Cerrejón North Zone coal handling infrastructure were introduced, allowing these companies to increase the yearly capacity of the preparation plant, railroad, and Puerto Bolivar's coal handling infrastructure. The current capacity of the Cerrejón Coal infrastructure is approximately 32 mmt per year. Cerrejón Coal reaches this capacity by using short trains that allows for sending convoys more frequently, thus increasing the railing capacity.

After the consolidation of the above two companies, the existing plans to expand the coal handling infrastructure above 32 mmt per year are being reevaluated by the new owners of the Cerrejón Coal complex. Any production increment will be evaluated carefully in light of international coal demand. Any expansions will also have to be in

accordance with the corporate plans of the three big companies forming the consortium (BHP Billiton, Anglo American, and Glencore).

Consolidation of mines in Colombia will bring more discipline to the supply side of the coal market. New Cerrejón owners have a different market strategy. Cerrejón Coal Company is now a "swing producer" and its output level will depend on the coal prices in South Africa and North America. If South African coal prices lower due to an excess of coal supply in the international market, Cerrejón Coal Company will continue withholding production increases. If necessary, Cerrejón Coal will reduce production as it was forced to do in 2002. Cerrejón's production forecast for 2005 is currently 30.3 mmt. Recently Cerrejón has adjusted its market strategy to avoid production tonnage and price reduction in the European markets. Most of the additional coal that will come from Cerrejón will be offered in the USA.

Drummond Coal. In the Cesar Department, Drummond has been continuing with the expansion of its Pribbenow mine and its port in Cienaga. Drummond had announced plans to increase production to 33 mmt in 2008. Early in 2004, Drummond announced that the company will produce 24.3 mmt, increasing its exports by about 6.15 mmt. We have not included this number in our yearly forecast; however, because rail constraints currently allow only a maximum export level of 23 mmt.

The future increase of production from Drummond will come from its new coal resources in El Descanso. This area will initiate production in 2005 and will reach a production of 11 mmt in 2008.

Other Producers. The other coal producers from El Cesar will increase production modestly. It is estimated that ***Carbones del Caribe*** will produce nearly 4.4 mmt in its operations of La Lagua and La Victoria mine. Another producer is ***Prodeco*** with its project Calenturitas. After several restart attempts to, Calenturitas mine was restarted and produces 0.55 mmt per year. Prodeco's Calenturitas plan was to gradually increase production to reach 2.2 mmt per year in 2008. ***Carbones del Cesar's*** El Paso mine started production in 2004 with 110,000 tons and should be at 660,000 tons by 2008.

As shown in Figure 15, the Colombian coal supply curve shows about 50 mmt per year of export capacity available at an FOBT cash cost of less than US$19 per ton. This tonnage is available from the two largest producers; Drummond and Cerrejon Coal. In addition, there will be another 8 mmt available at progressively higher costs.

Figure 15

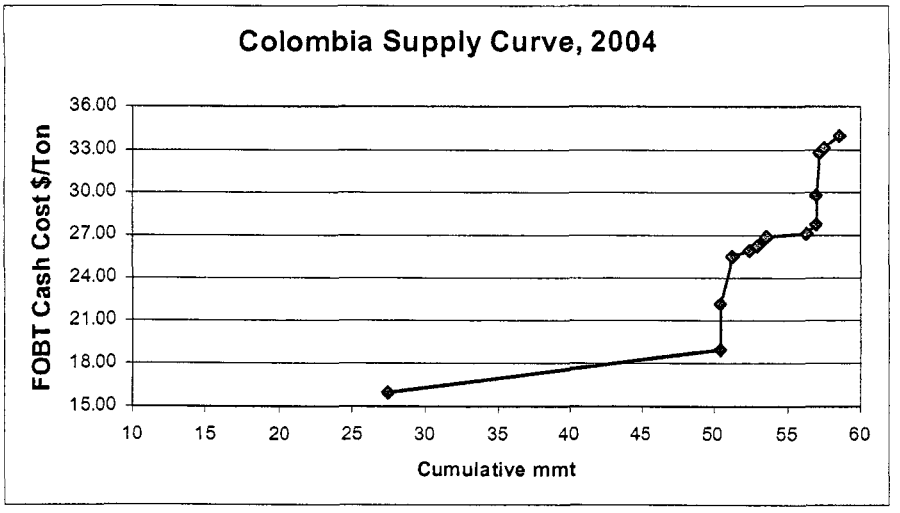


Table 5 shows the average ROM coal quality on an as-received basis for each coalfield. The Colombian coal is generally recognized for having a low-ash, high-volatile matter, low-sulfur content, and a high calorific value. The younger coals of the Cordoba Department in the San Jorge area are an exception to the rule; they exhibit a calorific value of 8,180 Btu/lb. with ash content of 17% and sulfur content of 1.50%. Other coals that exhibit high ash content are in Valle del Cauca and Santander where ash content ranges from 22 to 26%.

Table 5
Coal Qualities of the Colombian Coalfields

Zone	Moisture (%)	Ash (%)	Volatile Matter (%)	Sulfur (%)	Cal.Val (Btu/lb)
ANTIOQUIA	10.1	9.5	37.9	0.63	10,769
BOYACA					
• Sogamoso-Jericó	5.2	11.6	35.4	1.4	12,401
• Samacá-Ráquira	3.6	10.4	25.7	0.86	13,356
• Paipa-Tunja	9.9	11	40	1.74	11,340
CESAR					
• El Descanso	13.6	10.6	32.3	0.57	10,374
• La Jagua	7.1	5.3	35.7	0.62	12,606
• La Loma	10.3	5.6	36.8	0.59	11,616
CORDOBA					
• San Jorge	17	17	33.7	1.5	8,180
CUNDINAMARCA					
• Cogua Lenguazaque	3.8	10.2	28.1	0.92	13,185
GUAJIRA					
• Cerrejon North	11	8.9	33.4	0.75	11,550

Zone	Moisture (%)	Ash (%)	Volatile Matter (%)	Sulfur (%)	Cal.Val (Btu/lb)
• Central Cerrejon	9.5	8.0	33.9	0.66	11,900
NORTE DE SANTANDER					
• Tasajero	2.6	7.7	33.7	0.85	13,925
• Zulia Sur	3.4	11.9	35.3	1.27	12,967
• Zulia Norte	3.7	9.2	37.6	0.95	12,602
SANTANDER					
• San Luis	2.7	25.9	28.1	1.76	10,913
VALLE DEL CAUCA	2.7	22.4	28.1	2.85	11,088

COLOMBIA - COAL RESERVES

Colombian coal resources are distributed in the three main mountain ranges (Oriental, Central, and Occidental), mainly on the north coast and in the interior part of the country. The Colombian government has calculated measured plus indicated coal resources of 12.5 billion short tons, of which 7.7 billion tons are classified as measured resources and 4.8 billion tons as indicated. This represents 88 years of production at a level of 89 mmt per year. Colombia can adequately supply well beyond 2040.

Of the reserve total, approximately 90% is located in the North Coast area. The thermal coals are located mainly in the departments of Guajira, Cesar, Cordoba, Antioquia, Caldas, Valle del Cauca, and Cauca. Metallurgical coals are located in the central and eastern parts of the country in the departments of Cundinamarca, Boyacá, Santander, and Norte de Santander. Also, there are some anthracitic coal resources in these departments.

Table 6 shows the Colombian coal reserves by region.

Table 6

Resources and Reserves							
		Reserves			Hypothetical		Type of
Zone	Area	Measured	Indicated	Inferred	Resources	Total Resources	coal
La Guajira	Cerrejón North	3,306.93	-	-	-	3,306.93	S
	Cerrejón Central	738.55	-	-	-	738.55	S
	Cerrejón South	290.24	494.72	140.54	29.87	955.37	S
	Total	4,335.72	494.72	140.54	29.87	5,000.85	S
Cesar	La Loma	1,969.65	1,790.51	2,270.99	1,095.18	7,126.33	S
	La Jagua de Ibirico	284.73	-	-	-	284.73	S
	Total	2,254.38	1,790.51	2,270.99	1,095.18	7,411.06	S
Córdoba-Norte de Antioquia	Alto San Jorge	419.98	375.89	-	-	795.87	S
	Totales	419.98	375.89	-	-	795.87	S
Antioquia-Antiguo Caldas	Venecia-Fredonia	9.85	44.25	18.60	-	72.70	S
	Amagá-Angelópolis	13.05	70.15	101.78	27.98	212.96	S
	Venecia-Bolombolo	63.88	93.48	20.67	-	178.02	S
	Titiribí	12.49	41.06	4.91	1.18	59.64	S
	Totals	99.27	248.93	145.95	29.16	523.31	S
Valle del Cauca - Cauca	Yumbo-Asnazú	33.84	62.19	52.35	12.10	160.49	S
	Río Dinde-Quebrada Honda	4.82	18.36	21.70	-	44.89	S
	Mosquera-El Hoyo	7.03	21.01	33.86	-	61.91	S
	Total	45.69	101.57	107.92	12.10	267.28	S
Cundinamarca	Jerusalén-Guataquí	2.00	6.32	5.82	3.56	17.69	S
	Guaduas-Caparrapí	5.08	28.60	21.76	1.00	56.45	M
	San Francisco-Subachoque-La Pradera	12.51	53.13	67.12	7.12	139.88	M. S
	Guatavita-Sesquilé-Chocontá	24.14	70.89	117.81	11.18	224.02	M. S
	Tabio-Río Frío-Carmen de Carupa	21.42	61.53	60.45	27.32	170.71	M.S
	Checua-Lenguazaque	154.79	380.78	232.21	17.91	785.69	M.S
	Suesca-Albarracín	36.29	96.68	75.95	-	208.92	S
	Zipaquirá-Neusa	1.81	5.47	11.48	-	18.75	M.S.A
	Total	258.03	703.41	592.60	68.09	1,622.13	
Boyacá	Checua-Lenguazaque	39.34	143.16	127.69	-	310.19	M.S
	Suesca-Albarracín	8.61	47.72	117.13	-	173.46	S
	Tunja-Paipa-Duitama	26.49	107.16	188.95	-	322.59	S.M
	Sogamoso-Jericó	113.36	454.43	522.18	-	1,089.97	M.S
	Total	187.80	752.46	955.95	-	1,896.21	
Santander	San Luis	61.82	119.76	136.07	-	317.64	M. S
	Capitanejo-San Miguel	-	19.84	1.58	-	21.42	A.S
	Miranda	-	6.05	-	-	6.05	A.S
	Molagavita	-	8.76	-	-	8.76	A.S
	Páramo del Almorzadero	-	130.34	26.86	-	157.20	A.S
	Total	61.82	284.75	164.51	-	511.08	
Norte de Santander	Chitagá	0.73	2.18	8.16	-	11.07	A. M
	Mutiscua-Cácota	1.72	0.73	0.18	-	2.62	S. M
	Pamplona-Pamplonita	3.08	6.89	5.32	-	15.29	S. M
	Herrán-Toledo	5.27	16.13	10.11	-	31.50	S. M
	Salazar	8.50	17.09	6.39	-	31.98	S. M
	Tasajero	15.63	35.84	61.98	-	113.45	S. M
	Zulia-Chinácota	44.15	136.85	113.76	-	294.76	M
	Catatumbo	56.57	140.40	217.09	-	414.06	S
	Total	135.64	356.10	422.99	-	914.73	
Grand Total		7,736.51	4,823.58	4,636.94	1,234.40	18,431.43	

KEY ISSUES AND DRIVERS FOR COLOMBIAN COAL

- Colombia has enormous reserves so mining at high levels can sustain well past year 2040;
- Coal production is controlled by a small number of major coal producers
- Coal production costs are low;
- Large coal loading ports have been built for exports;
- Imports are making in-roads into the U.S.;
- Prices can be competitive with U.S. coal supplies, but they are subject to global competition for the coals and ocean freight rate variation;
- A medium degree of political and civil instability exists in Colombia;
- High ocean freight rates exist at the present time – likely to ease but slowly; and
- U.S. railroads have been reluctant to provide cost-competitive rail rates for imported coals destined for inland plants in the U.S.

VENEZUELAN COAL

VENEZUELA - OVERVIEW

The Venezuelan coal industry is comprised of bituminous coal production principally from the Guasare coalfield where over 95% of Venezuelan coal is produced. The coal is high BTU, ranging from 12,200 – 13,000 BTU, and is low in sulfur content, ranging from 0.7% to 0.83%. Venezuela produces and exports about 8.7 million ton of coal annually not including 1.3 mmt of coal from Colombia that is shipped via Maracaibo lake ports to various markets in the U.S. and to other countries.

We project that Venezuelan production and exports will grow to as much as 27.5-28.7 million tons by 2014. This growth takes into account the development of projects like Socuy, Las Carmelitas (Cosila), Cachiry and Casigua.

The country has an enormous amount of coal, equivalent to almost 770 million ton of measured reserves. About 70%, or 540 million ton, of the country's coal reserves are for steam coal use.

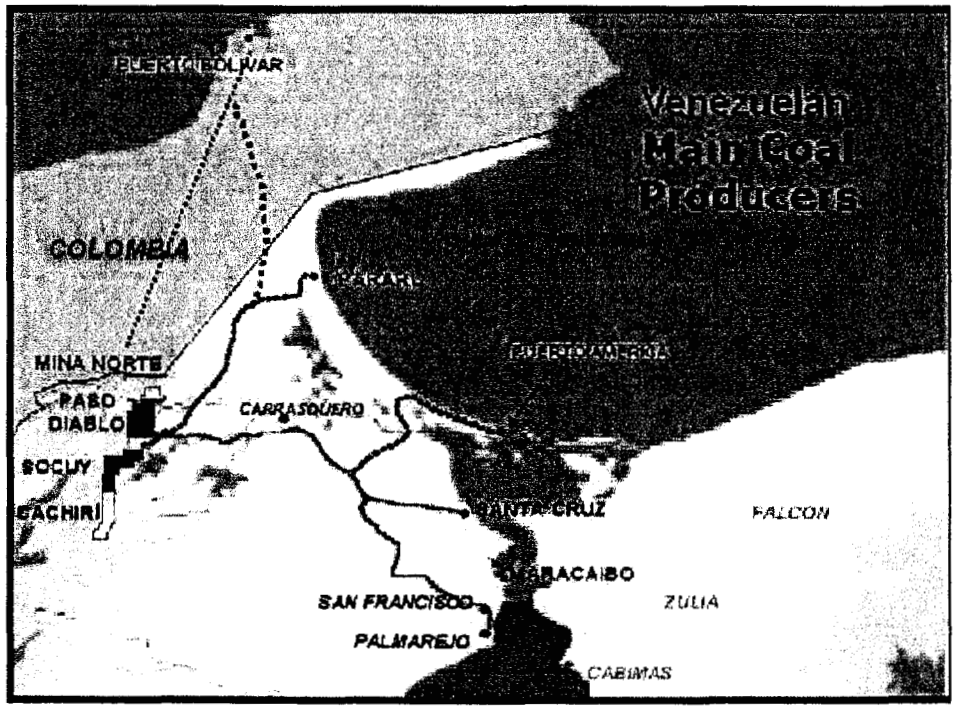
The vast majority of export tonnage comes from the Guasare basin and Tachira with a small amount from Fila Maestra in the eastern part of Venezuela. Paso Diablo and Mina Norte are the primary mines but there are also small mines in Tachira state with a marginal production of 0.2 mmt. Maracaibo lake ports also serve the coal produced in the Cucuta area in the Norte de Santander department. These regions contain the bulk of the defined coal resources and offer relatively easy access to the coast. The mines in these regions share similar characteristics:

- Almost all production comes from surface operations;
- All are mining multiple seams at stripping ratios of approximately 7.2:1;
- In most, the seams are steeply pitched and lend themselves to truck and shovel methods; and
- All have high quality coal with low-sulfur and ash and high-BTU values.

Venezuela coal transport infrastructure is limited, and inefficient. With the current infrastructure, and with some efficiencies gain, Venezuela export capacity will probably reach 11 -12 mmt. However, Carbozulia is currently negotiating a deal with a Brazilian company to develop the Socuy mine project, transport, and port infrastructure that will allow Venezuelan coal supply to reach about 28.7 mmt by 2014.

Figure 16, shows the location of producing coal mines and projects in Venezuela. As can be seen these are all located close to the northern shore of Venezuela and access export markets through ports on Lake Maracaibo or along the Gulf of Venezuela.

Figure 16
Venezuelan Coal Activity Map



VENEZUELA - PRODUCTION

Venezuela is the third largest producer of coal in Latin America after Colombia and Brazil. The Venezuelan coal industry marginally increased coal production during

2004, to 8.7 mmt, mainly through a production increase at Paso Diablo Mine, which was partially offset by a reduction of Mina Norte production. Mina Norte Production was affected by the rainy season that caused the destruction of the main bridge on the road connecting the mine with the ports.

Over 95% of Venezuelan coal production originates from the Guasare coalfield where the Paso Diablo and Mina Norte Mines are operated by Carbones del Guasare and Carbones de la Guajira, respectively. Carbozulia is a wholly-owned subsidiary of Corpozulia, a government entity in charge of the economic development of Zulia State.

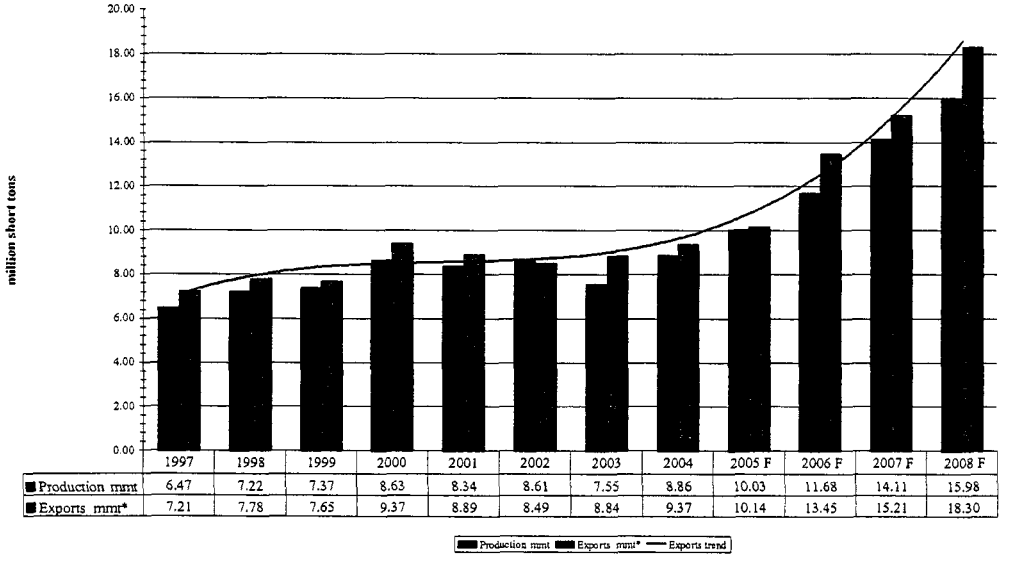
The Guasare coalfield is the most important of the coalfields, and Venezuela relies on this coalfield for future expansion of coal production. Expansion of production capacity at this field depends on the improvement of transport and port systems.

In 2000, coal production totaled 8.63 mmt and during 2001, coal production decreased to 8.34 mmt. In 2001, Venezuelan coal production was reduced by 3.4 % mainly because of the production problems encountered by Mina Norte, which produced approximately 772,000 tons, 330,000 tons lower than its normal level.

In 2002, coal production reached 8.61 mmt despite a civil strike that paralyzed the country from December 2002 to January 2003. The consequences of the civil strike on the economy and the severe foreign exchange currency restrictions imposed by the government also affected Venezuelan coal production in 2003, which reached 7.55 mmt, a decrease of 12.3%. Venezuelan coal production recovered again during 2004, reaching a production level of 8.86 mmt. It is estimated that Mina Norte will continue expanding its production, and new developments like Cosila in el Guasare basin and Fila Maestra in the east will come online, increasing the total production of Venezuela to 16 mmt in 2008. Figure 17 shows the export trends from 1997 to 2008.

Figure 17

Venezuela Coal Production and Export History



	1997	1998	1999	2000	2001	2002	2003	2004	2005 F	2006 F	2007 F	2008 F
Production mmt	6.47	7.22	7.37	8.63	8.34	8.61	7.55	8.86	10.03	11.68	14.11	15.98
Exports mmt*	7.21	7.78	7.65	9.37	8.89	8.49	8.84	9.37	10.14	13.45	15.21	18.30

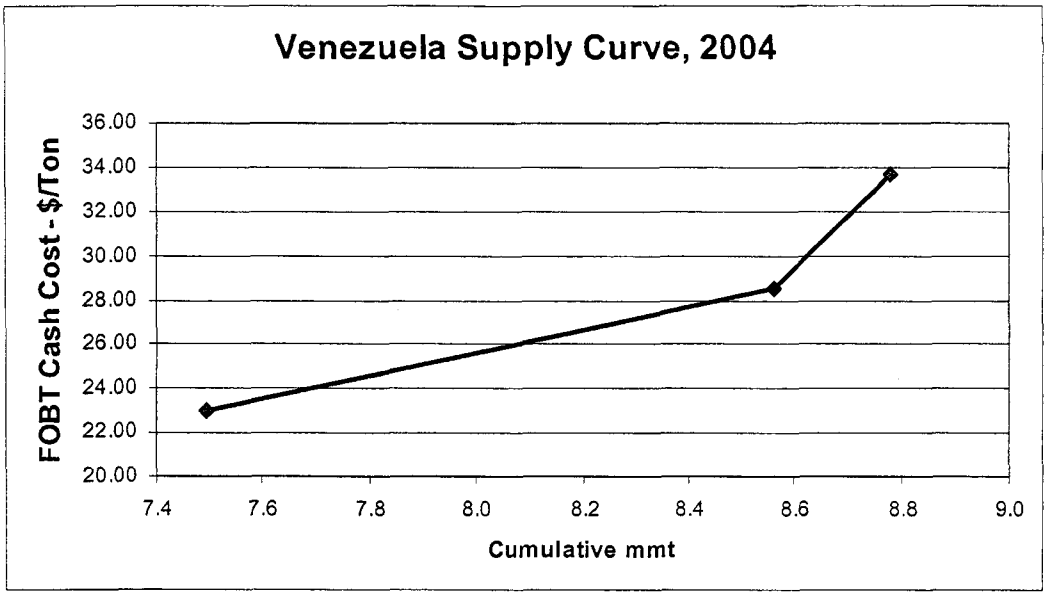
Venezuela's opportunities for increasing production in the future will be dependent on Carbones de Guasare's expansion projects in Paso Diablo and the development of the Socuy project mentioned above, as well as Carbones de la Guajira's Mina Norte and Cachiri projects.

Future Venezuelan coal industry growth will depend on the development of an effective transportation and port system, also mentioned above, that allows Guasare Basin producers to reduce FOBT cash costs and increase throughput capacity.

Due to infrastructure constraints, Venezuelan coal exports are currently limited to a maximum of about 12 mmt per year. Above this tonnage level, Venezuela will require a coal railroad transportation system and the development of one of several options for a modern port capable of handling capesize vessels. The port options include Puerto América and Pararu.

The FOBT cash cost curve for Venezuelan coal mines is shown in Figure 18. The chart shows that cash cost for the three operations range from $23.00 to $33.66. A total of 8.8 mmt cumulative capacity is available at cash costs below $34.00. New projects are expected to come in below the lower end of this curve, around $19-20 per ton FOBT. The lower costs will be attributable to efficiencies of a new rail and port infrastructure.

Figure 18



The typical coal qualities of the main Venezuelan coalfields are shown in Table 7. Venezuelan coals have an advantage over most Colombian coals in terms of higher heating value. Of course, a premium price is paid for this in comparison to the prices for Colombian products. The Venezuelan coals are generally lower in sulfur content than CAPP coals and, thus, compete very well against CAPP coals in coastal plants in the northeast of the U.S.

Table 7
Venezuelan Typical Coal Quality (GAR Basis)

	INHERENT MOISTURE (%)	ASH (%)	SULFUR (%)	(BTU/LB)
Paso Diablo	4 – 7	6 - 8	0.55 - 0.70	12,200 - 12,750
Naricual	4 – 6	6 - 7	0.80 - 1.1	12,800 - 13,100
Lobatera	NA	16 - 19.2	0.90 - 1.0	11,300 - 11,500

VENEZUELA - COAL RESERVES

The main coal reserves of Venezuela are distributed in four different areas -- Zulia, Táchira, Falcón, and Anzoátegui -- comprising a total estimated coal resource of 9,412 mmt. These coalfields are mainly located on the north coast. As Table 8 shows, the Venezuelan coal resources of the Zulia area are the most important.

Table 8
Venezuela Coal Reserves (mmt)

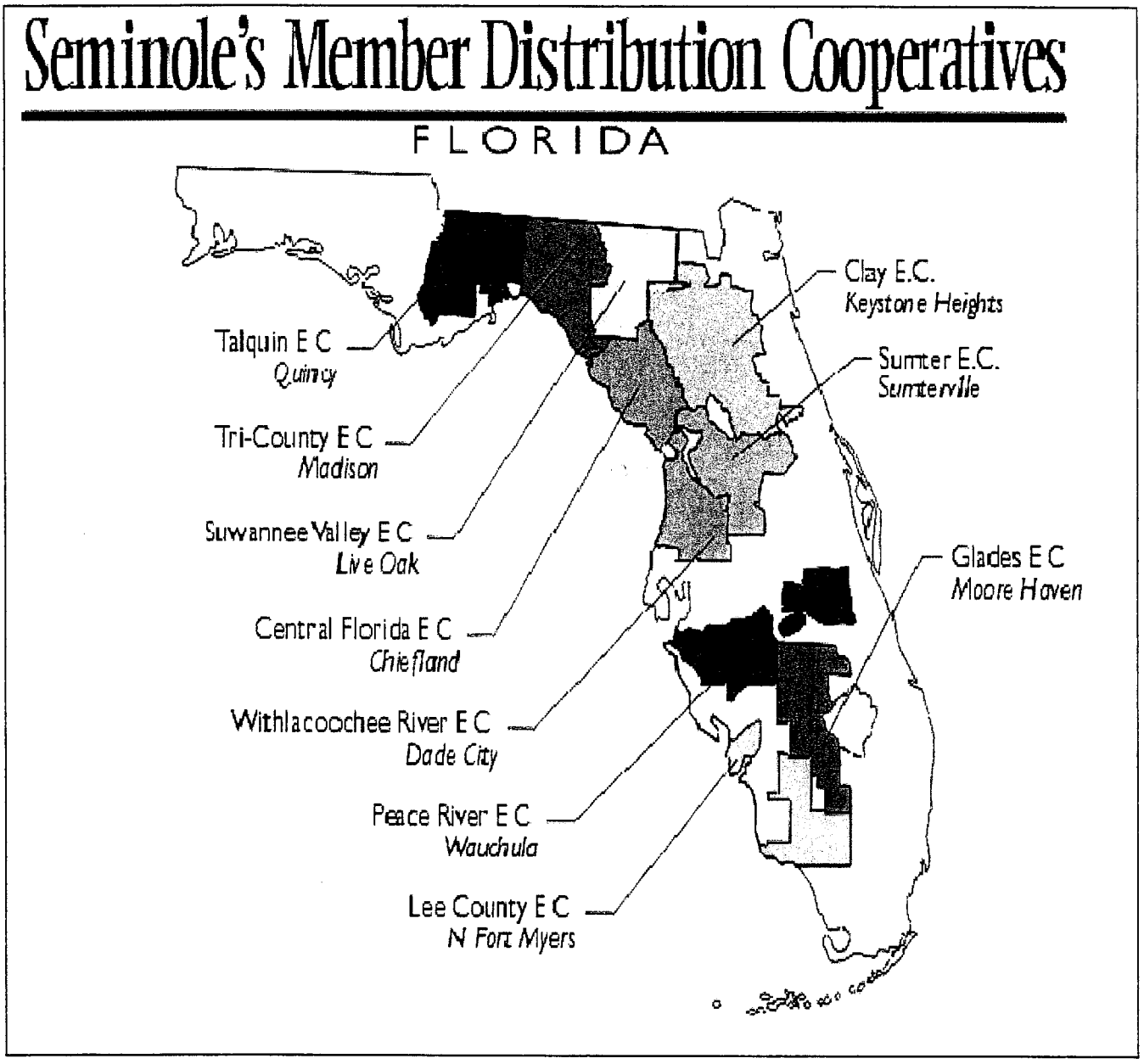
State	Reserves			Total Resources
	Measured mmt	Indicated mmt	Inferred mmt	mmt
Zulia	1,204	2,468	4,050	7,722
Táchira	163	263	732	1,159
Anzoátegui	134	98	31	263
Falcón	18	30	122	170
Merida	NA	NA	10	10
Guarico	NA	NA	55	55
Aragua	NA	NA	33	33
Total	**1,519**	**2,859**	**5,033**	**9,412**

The table indicates that, considering only measured and indicated reserves, Venezuela has the potential to support coal production at levels above 22 mmt per year for over 100 years. Reserves will not be the constraint in our view, it will be the development of those reserves that limits access to Venezuelan coals in the future.

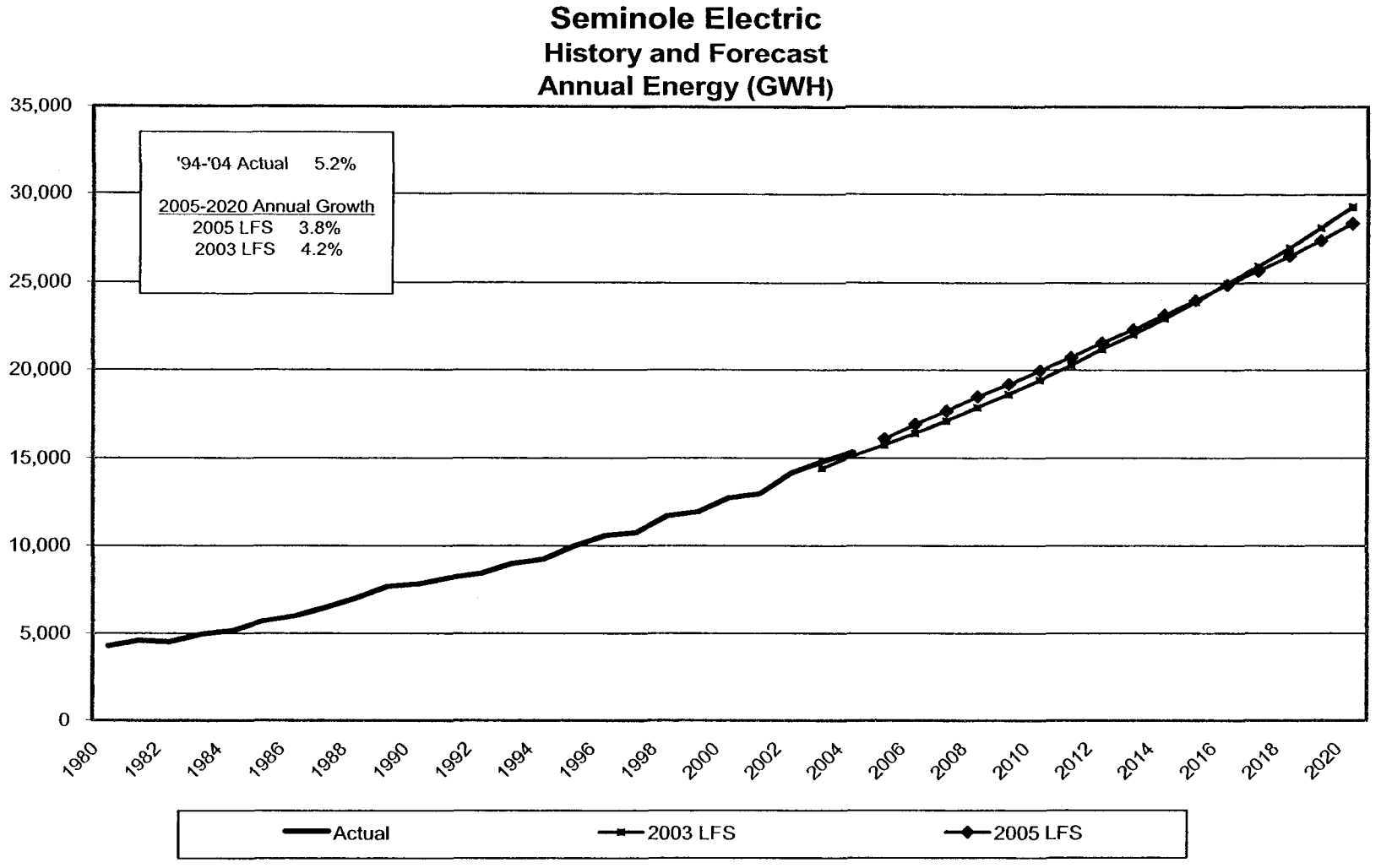
KEY ISSUES AND DRIVERS FOR VENEZUELAN COAL

- Venezuela has adequate reserves to sustain existing & planned mines;
- Coal production is controlled by a small number of major coal producers;
- Coal production costs are low;
- Deepwater port infrastructure is lacking and necessary to expand exports;
- Imports are making in-roads into the U.S., particularly in the Northeast;
- Prices are can be competitive with U.S. coal supplies, but they are subject to global competition for the coals and ocean freight rate variation;
- A higher degree of political and civil instability exists in Venezuela versus Colombia;
- High ocean freight rates exist at the present time – likely to ease but slowly; and
- U.S. railroads have been reluctant to provide cost-competitive rail rates for imported coals destined for inland plants in the U.S.

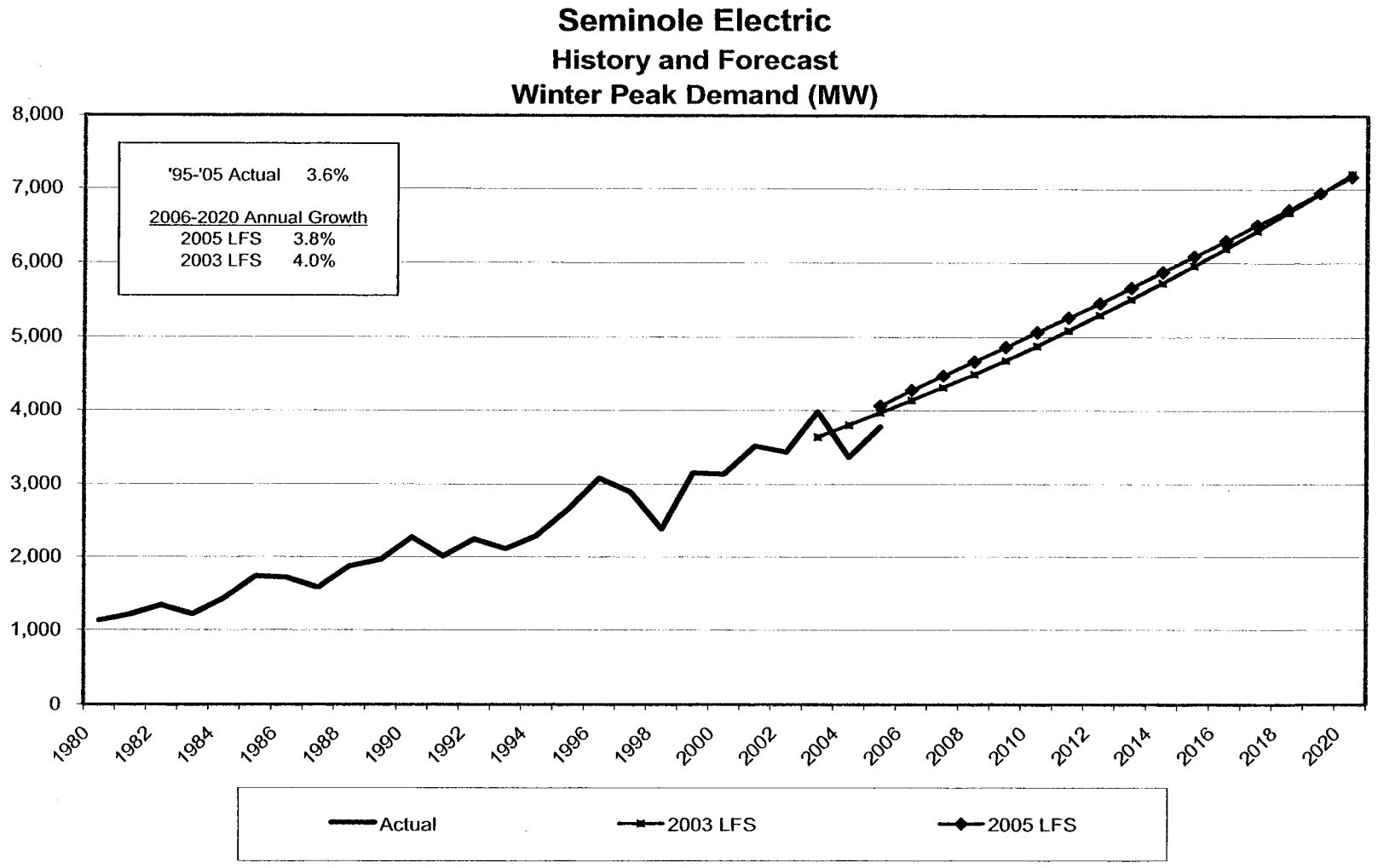
Seminole's Member Distribution Cooperatives



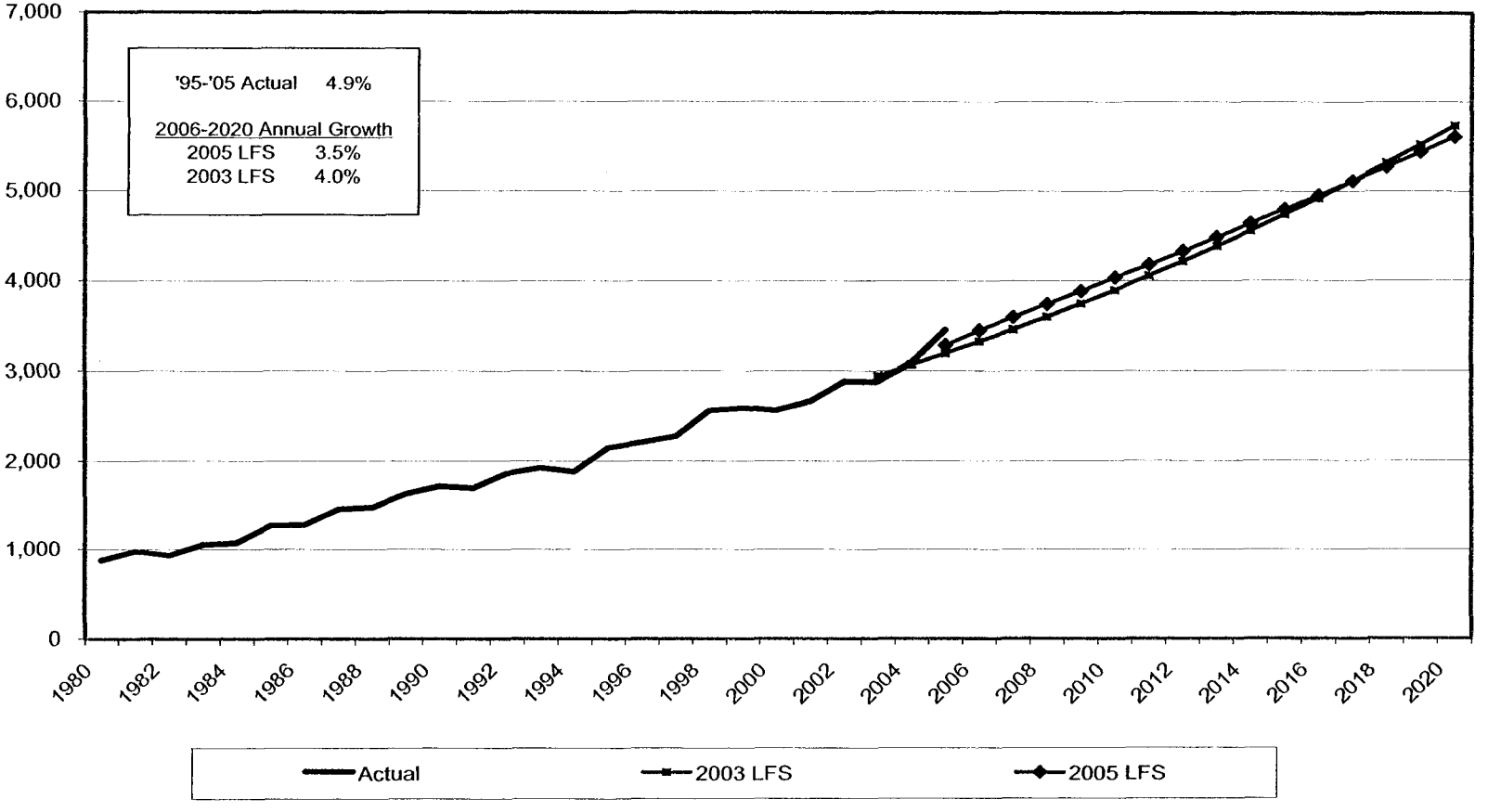
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Company/ SEC
Witness: William (Bill) Lawton (WTL-1)
Date: 06-07-06



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NO. 060220-EC Exhibit No. 28
Company/ SEC
Witness: William (Bill) Lawton (WTL-2)
Date: 06-07-06


Seminole Electric
History and Forecast
Winter Peak Demand (MW)
'95-'05 Actual 3.6%
2006-2020 Annual Growth
2005 LFS 3.8%
2003 LFS 4.0%
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
Actual
2003 LFS
2005 LFS

Seminole Electric Cooperative
History and Forecast
Summer Peak Demand (MW)



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Witness: Trudy Novak (TSN-1)
Date: 06-07-06

Seminole Electric Cooperative, Inc.
History of Seminole's Formal Request for Proposals

Date Issued	RFP	Award	Term	Final Award	Source	Number of Bidders	Number of Proposals
2/22/1988	Bid No. 88-19 Reserve Capacity	Hardee Power Partners Limited	Jan. 1993 thru Dec. 2012 (Hardee Power Station) Jan. 1993 thru Dec. 2002 (Big Bend #4)	356 MW * 145 MW *	1 CT and 1 CC Existing Unit	8	9
7/30/1990	Reserves and Displace FPC PR	Turnkey Facility: Black & Veatch/ Westinghouse	HPS #3 Project - to be in-svc. Jan. 1999 (project delayed in 1995 after unsolicited offer from FPC)			8	10
7/15/1996	RFP No. PP2000-02 Firm Capacity: 150 MW in 2000, additional 350 MW in 2001, additional 500 MW in 2002	FPC (Progress Energy) FPC (Progress Energy)	2000-2002 2001-2002 (additional MW)	150 MW 150 MW	System Purchase System Purchase	19	52
		Turnkey Facility: Black & Veatch/ Westinghouse	HPS #3 Project - in-svc. Jan. 2002 (confirmed still cost-effective during RFP; re-named Payne Creek Generating Station)	572 MW *	Combined Cycle		
3/2/1999	RFP No. SP 2002-03 Firm Peaking Capacity: 300 MW beg. Dec. 2001, add'l 600 MW beg. Dec. 2002 (up to 7 years; 2002-2008)	Reliant Energy Florida, LLC	Dec. 2001 thru Dec. 2006	364 MW *	2 CTs	11	12
		Oleander Power Project, Limited Partnership	Dec. 2002 thru May 2003 (364 MW/ 2 units), increasing to 546 MW (3 units) in June 2003 thru Dec. 2009	546 MW*	2 CTs; then 3 CTs		
7/6/2000	RFP No. IP 2004 Firm Year-round Intermediate and Peaking Capacity	Calpine Construction Finance Company, L.P.	June 2004 thru May 2020, with price re-openers/ early termination option every 5 years	360 MW *	Combined Cycle	9	14
3/4/2002	RFP 2006 50% Base/Intermediate 50% Peaking (between 375 - 525 MW)	Progress Energy	Dec. 2006 thru 2013	150 MW	System Purchase	17	24
		Self-Build: Aero-derivatives	In-svc. Dec. 2006 at Payne Creek site	310 MW *	5 Peaking Units		
3/31/2003	RFP No. FRS 2010 Full Requirements (Specified Delivery Points)	Progress Energy	Jan. 1, 2010 thru July 30, 2020 (Load Following PPA)	150 MW	System Purchase	6	16
4/19/2004	RFP No. BL 2012 Base Load Capacity (up to 600 MW)	Self-Build: Coal (Unit 3)	In-svc. May 2012 at SGS site	750 MW *	Coal Unit	5	14

* denotes winter rating of unit

Seminole Electric Cooperative, Inc.
April 2004 Request for Proposals
Direct Contact List

ACES Power Marketing
Alabama Electric Cooperative
Calpine
Central Power & Lime
Cinergy Services
Cogentrix/Goldman Sachs
Competitive Power Ventures, LLP
Constellation Power Development
Decker International
Dominion Generation
Duke Power Company
Eagle Energy Partners
Entergy
Entergy-Koch Trading, LP
Florida Municipal Power Assoc.
Florida Power & Light
City of Gainesville
Georgia Energy Cooperatives
Invenergy
JEA
Kissimmee Utility Authority
Lakeland Electric
Louisville Energy Marketing
Mirant
Municipal Electric Authority of Georgia
Morgan Stanley (Atlanta)
North Carolina EMC
New Hope Power Partnership
New Smyrna Beach
Nordic Energy
Oglethorpe
Orlando Utilities
Peabody Energy
Progress Energy
Progress Ventures
Reedy Creek
Reliant Energy
Southern Company Gen & Marketing
Tallahassee
Tampa Electric
Tenaska Power Services Co.
The Energy Authority
Tractebel USA

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Witness: Trudy Novak (TSN-2)
Date: 06-07-06

Seminole Electric Cooperative, Inc.
April 2004 Request for Proposals
Summary of Pulverized Coal Capacity Responses

Name	Capacity Amount MW	Term/Yrs
Invenergy, LLC	650	30
Longleaf Energy Associates, LLC	400-600	20 or 30
Peabody Generating Co., LLC	100-750	10 – 40

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Witness: Trudy Novak (TSN-3)
Date: 06-07-06

Seminole Electric Cooperative, Inc.
April 2004 Request for Proposals
Summary of Gas Combined Cycle Capacity Responses

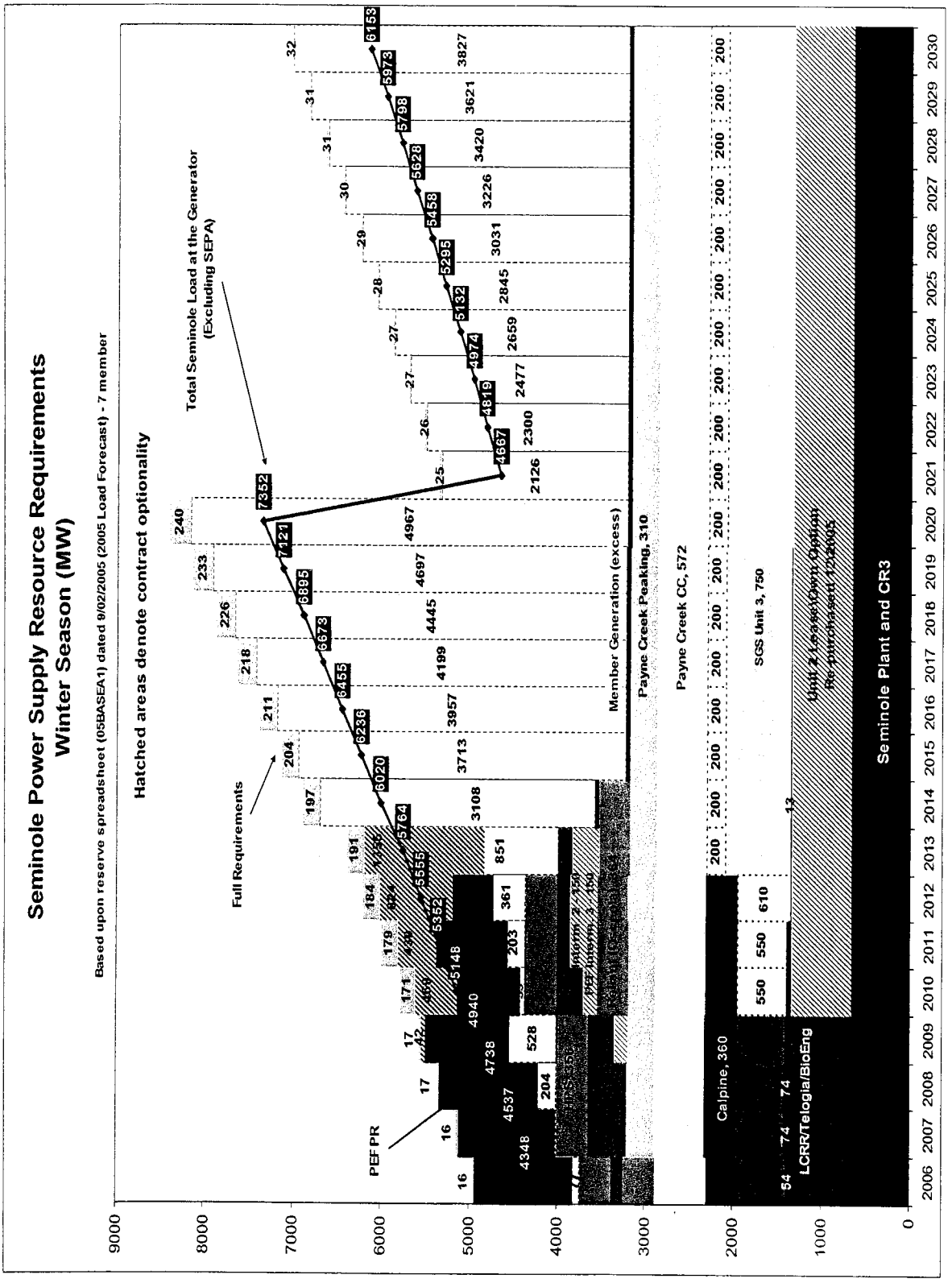
Name	Capacity Amount MW	Term/Yrs
Invenergy, LLC	520-550	20
Pasco Cogen, LTD	104	20
Pasco Cogen, LTD	115	20
Southern Power Company***	493	20
Southern Power Company***	635	20

*** Southern Power Company offered a total of eight offers (two capacity amounts at two different sites with two pricing proposals for each capacity amount at each site)

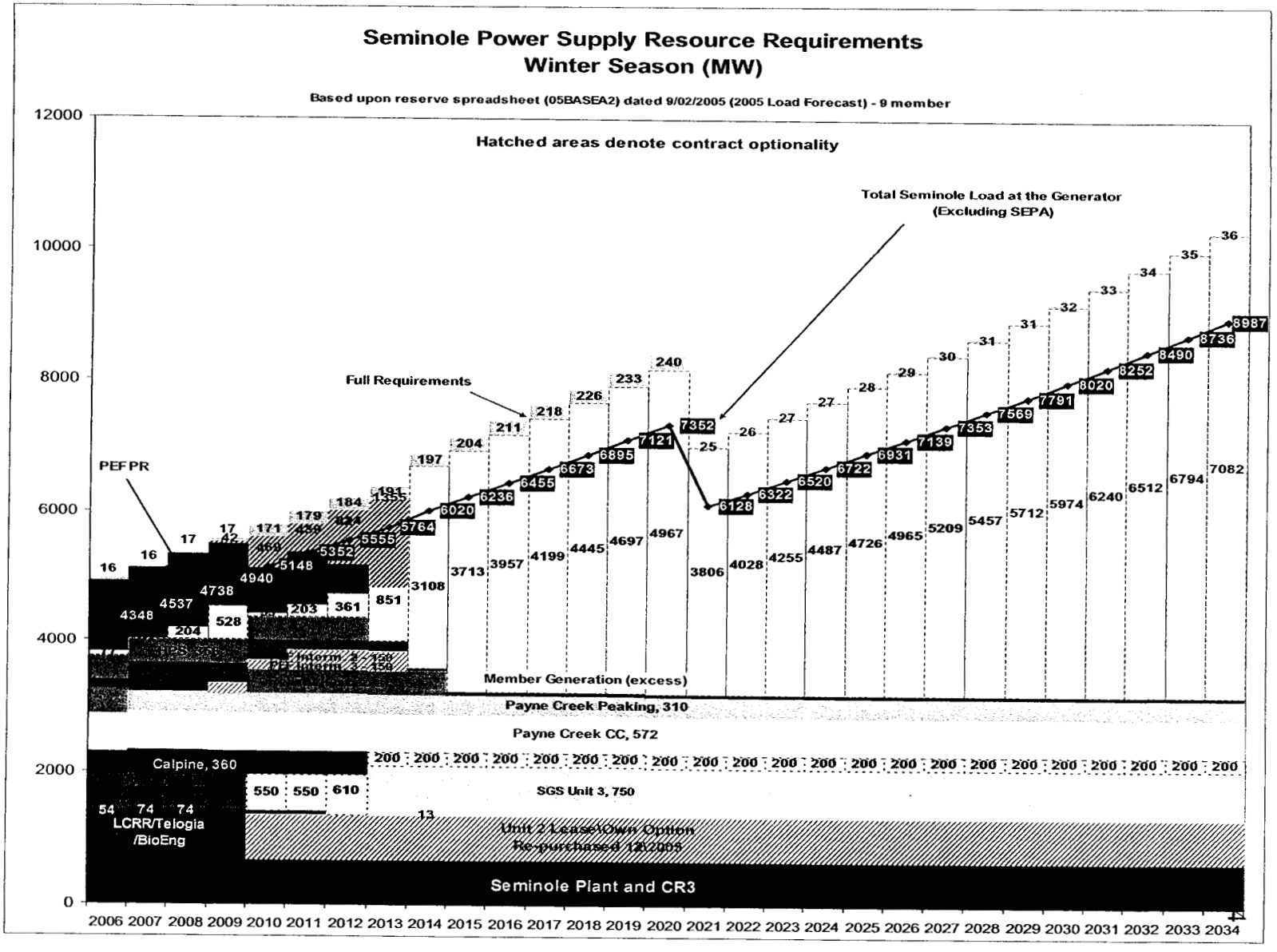
Seminole's Capacity Need
Without SGS Unit 3

Year	Winter MW	Summer MW
2012	971	1261
2013	1801	1702
2014	4058	3440
2015	4663	3620
2016	4907	3794
2017	5149	3977
2018	5395	4160
2019	5647	4346
2020	5917	4432
2021	3076	2255
2022	3250	2377

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Witness: Lane Mahaffey (LTM-1)
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Company/ SEC
Witness: Lane Mahaffey (LTM-2)
Date: 06-07-06


Seminole Power Supply Resource Requirements
Winter Season (MW)
Based upon reserve spreadsheet (05BASEA2) dated 9/02/2005 (2005 Load Forecast) - 9 member
Hatched areas denote contract optionality
Total Seminole Load at the Generator
(Excluding SEPA)
Full Requirements
PEF PR
Member Generation (excess)
Payne Creek Peaking, 310
Payne Creek CC, 572
Calpine, 360
SGS Unit 3, 750
Unit 2 Lease\Own Option
Re-purchased 12\2005
LCRR/Telogia
/BioEng
Seminole Plant and CR3
12000
10000
8000
6000
4000
2000
0
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034

Summary of Bus Bar Costs

Levelized Costs for 2012 – 2031

		90% Capacity Factor		80% Capacity Factor		70% Capacity Factor	
Coal Alternatives	**MW**	**Nominal $/MWh**	**PW 2012 $/MWh**	**Nominal $/MWh**	**PW 2012 $/MWh**	**Nominal $/MWh**	**PW 2012 $/MWh**
Self Build	600	$51.29	$30.73	$54.10	$32.47	$57.71	$34.70
FMPA Joint Project	150	$52.84	$31.74	$56.28	$33.83	$63.70	$38.54
Invenergy	650	$58.41	$34.55	$62.23	$36.83	$70.70	$41.43
Longleaf/LS Power	400	$62.19	$36.95	$66.74	$39.68	$72.57	$43.18
Peabody	400	$62.85	$37.01	$69.08	$40.69	$77.10	$45.41
Gas Alternatives	**MW**	**Nominal $/MWh**	**PW 2012 $/MWh**	**Nominal $/MWh**	**PW 2012 $/MWh**	**Nominal $/MWh**	**PW 2012 $/MWh**
Self Build	500	$66.52	$38.50	$68.09	$39.47	$70.11	$40.73
Invenergy	516	$69.23	$39.68	$71.20	$40.84	$73.73	$42.33
Southern Co., Orange Cty	533	$72.32	$41.68	$74.30	$42.88	$77.33	$44.72
Southern Co., Orange Cty	553	$72.53	$41.60	$75.43	$43.23	$78.41	$44.98
Southern Co., Orange Cty	645	$71.83	$41.31	$73.56	$42.37	$75.93	$43.81
Southern Co., Orange Cty	645	$72.90	$41.69	$74.88	$42.86	$77.47	$44.39
Southern Co., St. Lucie Cty	533	$72.99	$42.13	$75.20	$43.48	$78.20	$45.30
Southern Co., St. Lucie Cty	533	$74.08	$42.52	$77.34	$44.35	$80.64	$46.30
Southern Co., St. Lucie Cty	645	$72.71	$41.85	$74.58	$43.00	$77.13	$44.55
Southern Co., St. Lucie Cty	645	$73.61	$42.18	$76.35	$43.72	$79.14	$45.37
Pasco Cogen	106	$83.14	$47.70	$85.41	$49.05	$88.59	$50.83

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Company/ SEC
Witness: Lane Mahaffey (LTM-3)
Date: 06-07-06

Present Worth Revenue Requirements (PWRR) Results

Updated Economic Analyses Based on 7/2005 Base Case Present Worth Revenue Requirements (PWRR) in 2005 $000 for 2006 – 2030			
Study Description by Base Load Unit	**Average Annual PWRR**	**Average Annual PWRR Cost/ (Savings)**	**Cumulative PWRR Cost/ (Savings)**
500 MW Self-build Gas-Fired Combined Cycle Unit	770,653	19,903	497,568
750 MW Self-build Coal Unit	750,751	--	--

Initial Economic Analyses Based on 12/2004 Base Case Present Worth Revenue Requirements (PWRR) in 2005 $000 for 2006 – 2030			
Study Description by Base Load Unit	**Average Annual PWRR**	**Average Annual PWRR Cost/ (Savings)**	**Cumulative PWRR Cost/ (Savings)**
600 MW Self-build Coal Unit and 150 MW FMPA Coal Unit	682,903	4,940	123,493
All Gas Self-build Scenario	701,952	23,988	599,705
600 MW Purchased Power Coal Unit and 150 MW FMPA Coal Unit	705,321	27,357	683,923
750 MW Self-build Coal Unit	677,964	--	--

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 35
Company/ SEC
Witness: Lane Mahaffey (LTM-4)
Date: 06-07-06

Cumulative and Annual PWRR Results

Case Description:

Comparison of Coal versus Gas Scenarios

Cumulative PWRR Savings = $497,568,000
Average Annual PWRR Savings = $19,903,000
Average Annual Nominal PR Savings = $49,878,000

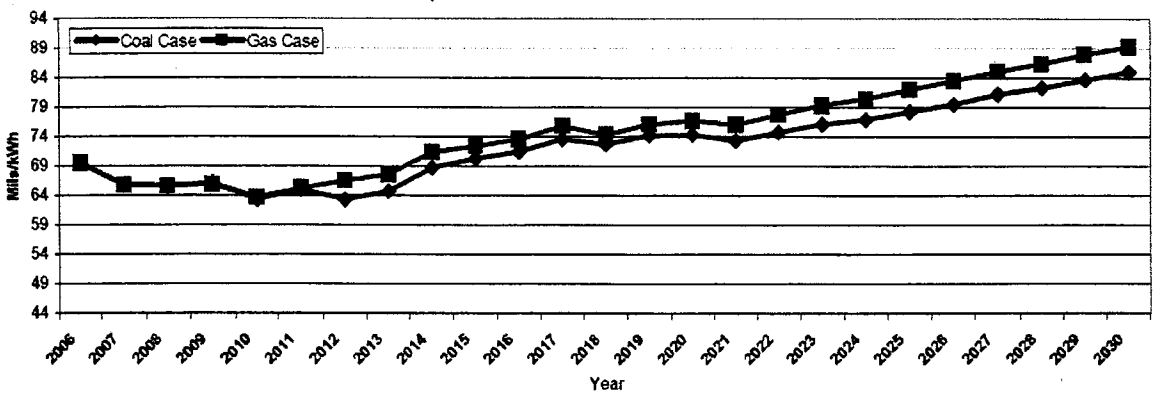
Assumptions:

- 2005 Load Forecast
- Annual 2005 Fuel Price Forecast
- 7 Member Load Commitment after July 2020
- Reliant Peaking Extension
- Calpine CC Extension
- Term: 2006-2030

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 36
Company/ SEC
Witness: Lane Mahaffey (LTM-5)
Date: 06-07-06

Seminole Electric Cooperative, Inc.

Revenue Requirements Projection
Comparison of Coal & Gas Scenarios



Year	Coal Case (05BASEA1)	Gas Case (05SBCCA1)	Difference	Coal Case (05BASEA1)	Gas Case (05SBCCA1)	Difference	PW Difference
2006	$69.50	$69.50	$0.00	$1,168,257,000	$1,168,321,000	$64,000	$60,377
2007	$65.80	$65.80	($0.00)	$1,155,427,000	$1,155,402,000	($25,000)	($22,250)
2008	$65.69	$65.64	($0.05)	$1,206,180,000	$1,205,245,000	($935,000)	($785,044)
2009	$66.16	$65.96	($0.20)	$1,262,822,000	$1,259,011,000	($3,811,000)	($3,018,669)
2010	$63.32	$63.73	$0.40	$1,258,799,000	$1,266,806,000	$8,007,000	$5,983,296
2011	$64.96	$65.26	$0.30	$1,340,497,000	$1,346,766,000	$6,269,000	$4,419,398
2012	$63.27	$66.56	$3.29	$1,358,947,000	$1,429,567,000	$70,620,000	$46,966,334
2013	$64.73	$67.60	$2.87	$1,439,463,000	$1,503,175,000	$63,712,000	$39,973,697
2014	$68.68	$71.42	$2.74	$1,584,450,000	$1,647,625,000	$63,175,000	$37,393,186
2015	$70.24	$72.46	$2.21	$1,679,262,000	$1,732,181,000	$52,919,000	$29,549,694
2016	$71.41	$73.54	$2.12	$1,770,919,000	$1,823,609,000	$52,690,000	$27,756,435
2017	$73.55	$75.85	$2.30	$1,881,348,000	$1,940,225,000	$58,877,000	$29,260,066
2018	$72.75	$74.33	$1.58	$1,923,229,000	$1,964,897,000	$41,668,000	$19,535,585
2019	$74.26	$76.09	$1.83	$2,028,180,000	$2,078,085,000	$49,905,000	$22,073,030
2020	$74.34	$76.70	$2.35	$1,730,659,000	$1,785,456,000	$54,797,000	$22,864,874
2021	$73.33	$76.05	$2.72	$1,239,041,000	$1,285,007,000	$45,966,000	$18,094,345
2022	$74.76	$77.77	$3.01	$1,304,996,000	$1,357,540,000	$52,544,000	$19,512,972
2023	$76.15	$79.32	$3.17	$1,372,889,000	$1,430,101,000	$57,212,000	$20,043,869
2024	$76.84	$80.41	$3.58	$1,433,886,000	$1,500,609,000	$66,723,000	$22,052,820
2025	$78.23	$82.01	$3.78	$1,503,487,000	$1,576,171,000	$72,684,000	$22,663,215
2026	$79.53	$83.51	$3.98	$1,576,782,000	$1,655,705,000	$78,923,000	$23,215,627
2027	$81.20	$85.07	$3.87	$1,660,251,000	$1,739,403,000	$79,152,000	$21,965,084
2028	$82.34	$86.35	$4.01	$1,740,119,000	$1,824,925,000	$84,806,000	$22,201,979
2029	$83.64	$87.94	$4.30	$1,817,863,000	$1,911,268,000	$93,405,000	$23,069,033
2030	$84.94	$89.30	$4.36	$1,902,617,000	$2,000,210,000	$97,593,000	$22,739,036
						$1,246,940,000	$497,567,990

Note: Discount rate is 6%

ORIGINAL

060220-EC

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 103

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Integrated Resource Planning in North Carolina -2005	) PUBLIC COMMENTS AND) STATEMENT OF POSITION OF) THE ALLIANCE TO SAVE) ENERGY AS AN INTERESTED) PARTY FOR THE JUNE 27) EVIDENTIARY HEARING IN) RALEIGH, NC

BY THE ALLIANCE TO SAVE ENERGY: The Alliance to Save Energy, located in Washington, DC, offers these comments and statement of position to the North Carolina Utilities Commission (Commission) as part of its proceeding to examine the role of utility demand-side management (DSM) and energy efficiency programs in the current integrated resource (IRP) planning docket.

The Alliance to Save Energy (Alliance) is a nonprofit 501-c-3 organization with the mission of promoting energy efficiency worldwide to achieve a healthier economy, a cleaner environment and energy security. The Alliance was founded in 1977 to carry out this mission. The full scope of our energy efficiency policy and program activities is described on our web site at: www.ase.org.

Introduction

Our comments today concern our recent experience advocating for increased utility DSM and energy efficiency program activity in the State of Georgia as part of a similar IRP proceeding before the Georgia Public Service Commission (GA PSC). The Alliance was an intervener in that proceeding and a key participant in the DSM Working Group established by the GA PSC to provide it with recommendations on future DSM and IRP activities. We feel that that this experience may be useful to the Commission to chart the future course of considering the proper and effective role of DSM in North Carolina. Attached to these comments, we provide the following relevant documents from the Georgia IRP proceeding which may be useful to include in the record for this current proceeding:

- Georgia PSC Order in 17687-U, July 9, 2004
- Georgia Demand-Side Management Working Group Report, February 15, 2005
- Georgia PSC Order in 17687-U, May 25, 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060220-EC Exhibit No. 37
Company/Witness: Alliance to Save Energy/N.C. Utilities Robert W. Brinkman
Date: 06-07-06

DOCUMENT NUMBER-DATE
04877 JUN-7 06
FPSC-COMMISSION CLERK

Alliance Intervention Experience

The Alliance to Save Energy intervened in the 2004 Georgia Power Company and Savannah Electric Company (Companies) IRP proceedings and submitted testimony (assisted by GDS Associates, a leading DSM consulting firm in Georgia) to the Commission addressing seven points:

1. Demonstrate that the implementation of cost effective energy efficiency program in the service areas of the Companies could save ratepayers hundreds of millions of dollars (over $1.4 billion in net present value saving to ratepayers of Georgia Power Company alone);
2. Show that the TRC test is the correct cost effectiveness test for DSM programs in Georgia;
3. Explain the recommendations of the Alliance to Save Energy relating to DSM programs and the need for a DSM Working Group;
4. Present up-to-date information of successful DSM programs and savings in other states;
5. Identify fundamental shortcomings in the DSM measure screening process used by the Georgia Power Company and the Savannah Electric and Power Company;
6. Demonstrate that the IRP plans filed by the Georgia Power Company and the Savannah Electric and Power Company were not integrated IRP plans as per the Georgia IRP statute and Commission rules; and
7. Provide Alliance to Save Energy recommendations for DSM cost recovery and shareholder incentive mechanisms.

The testimony provided the Commission with current mainstream thinking on the benefits of DSM and the best use of cost effectiveness tests to identify and screen potential energy efficiency programs. However, the Alliance testimony was significantly different from the Companies' testimony and left the Commission with an "all-or-nothing" message. Rather than return to the hearing process to further develop the record, a motion was unanimously passed by the Commission to have the opposing parties work out an acceptable solution.

Formation of Georgia DSM Working Group

As noted by the Commission, the positions of the parties on DSM programs were very far apart and they were unable to find a balance between economic efficiency (i.e. Total Resource Cost test benefits) and fairness and equity (i.e. Rate Impact Measure test results.) A motion was passed in July 2004 which ordered the creation of a DSM Working Group (Working Group) to develop reasonable and credible DSM initiatives. Comprised of the parties in the IRP cases, the Working Group's task was to propose a DSM Plan to the Commission that would be a comprehensive proposal consisting of:

1. A mix of DSM initiatives to be recommended to the Commission for approval, including how they would be implemented;
2. A recommendation of a process for the selection of future DSM initiatives; and

3. Recommendations for changes to the Commission's IRP rules regarding DSM or for proposed legislation (Georgia 2004).

It was further ordered by the Commission that the mix of DSM initiatives to be recommended be selected according to the following criteria:

1. The proposed DSM Plan should minimize upward pressure on rates and maximize economic efficiency;
2. The cost/benefit analysis result of each initiative using all three tests (RIM, Total Resource Cost, and Participants) shall be considered by the Working Group and shall balance between economic efficiency and fairness and equity;
3. An examination of where growth is occurring on the system shall be performed by the Working Group, which shall attempt to concentrate its recommended initiatives there. Consideration shall also be given to initiatives that encourage participation by low-income customers;
4. In addition to traditional DSM programs, the Working Group shall consider rate design initiatives. In considering such initiatives, the Working group should consider the cost/benefit analysis of such initiatives and the time periods that such initiatives would be available to a customer;
5. Every effort should be made by the parties to develop innovative programs and market approaches that will prevent upward pressure on rates and subsidies between participants and non-participants; and
6. Where appropriate, the Working Group should consider the development of pilot initiatives (limited enrollment, limited terms) as a tool to gauge initiatives.

A final order was issued by the Commission in August 2004 with a directive to the Working Group to deliver its recommendations to the Commission by February15, 2005.

DSM Working Group Final Report

The Working Group presented its Final Report to the Commission on February 16, 2005. In the report, four pilot DSM programs and an evaluation process for selecting future DSM initiatives were offered to the Commission for adoption. The four pilot programs were:

1. An ENERGY STAR® Home Program for new construction;
2. ENERGY STAR Appliance Program;
3. Duct Sealing and Infiltration Control Program; and
4. Home Inspector Program.

The report also made a recommendation for future DSM evaluations. The Working Group proposed a new procedure to screen and analyze proposed DSM programs for future IRP proceedings. First, the procedure would set an "analytical cap" for DSM expenditures – a proposed limit on the total amount of projected rate impact over the life of a program (3 years in Georgia). The analytical caps proposed in the report covered a range between $10 million/year to 1.5 percent of the revenue derived from residential and commercial sector electricity sales (~$40-50 million/year.) Second, DSM programs would be evaluated using both the RIM and TRC tests, showing program costs, program savings and potential impacts on rates up to the analytical cap amount. Therefore, this approach would not prevent the Commission from considering a

program because it failed the RIM test. Finally, the procedure recommended a new stakeholder participation process that involves interested parties during different stages of the IRP process – 18 months, 12 months, and six months before the IRP is filed with the Commission. This new procedure would therefore provide the Commission with additional options in selecting appropriate DSM programs.

The Commission had also requested from the Working Group recommendations on legislative proposals that could increase energy efficiency levels in Georgia. In response, the Working Group proposed measures that would facilitate the adoption of energy efficient appliances and equipment through traditional tax incentives, regulations tested in other states, and improved energy efficiency in state government facilities for the benefit of state taxpayers. The proposed legislative changes included:

1. Sales tax "holiday" for energy efficient appliances;
2. State appliance standards;
3. Development of a Georgia state energy policy; and
4. State facilities energy conservation goals.

Additional comments and recommendations were provided in the Final Report for the Commission to consider, such as pursuing fuel neutral participation in DSM programs from other utilities (i.e. gas companies and electric membership cooperatives).

2005 Commission's Final Order

On May 17, 2005, after almost a year of Working Group deliberations, the Commission voted 5 to 0 to unanimously accept the recommendations of the Working Group. In the Final Order, the Georgia Power Company agreed to implement each of the four pilot programs included in the report and the Savannah Electric and Power Company agreed to participate in the ENERGY STAR Home Program. It was further ordered by the Commission that the two utilities implement the evaluation process recommended in the report for selecting future DSM programs.

Recently, the Georgia Power and Savannah Electric and Power Companies (Companies) released documentation describing each of the energy efficiency initiatives they agreed to implement, which include:

ENERGY STAR Home Program.
This program seeks to increase the awareness level about the benefits of new ENERGY STAR homes sold in Georgia and provide incentives to cover the cost of home ratings. The Companies will also work with other utilities of the state to increase the awareness to all state residents.

ENERGY STAR Appliance Program.
The main objective of this program is to increase consumer awareness and understanding of the benefits of ENERGY STAR appliances. Working with ENERGY STAR, the Companies will educate retailers, consumers, and others to promote the energy efficiency benefits of ENERGY STAR appliances.

Home Inspector Program.
The Companies will train home inspectors about the benefits of energy efficiency and inspectors will make recommendations to potential home buyers at the point of sale.

Duct Sealing and Infiltration Control Affinity Marketing.
Working with Georgia Interfaith Power and Light (GIPL), Georgia Power will pay a fee to GIPL for each one of its members that is a Georgia Power customer that makes a duct sealing or a duct sealing/infiltration control improvement. Homes that are 10 years old or older with central heating and/or cooling will be targeted and qualify.

The 2007 IRP Process

Because of the new rules for IRP planning set by the Commission in adopting the Working Group report, the 2007 IRP process has been started and stakeholder meetings have been held. The stakeholder meetings have provided a forum for all parties in the IRP process to propose ideas for future DSM programs in Georgia to be considered by the Commission. The energy efficiency advocates in the stakeholder group have proposed that the Georgia Environmental Facilities Authority's (GEFA) Technical and Economic Potential for Energy Efficiency study ("TEPOT") provide a framework for considering DSM programs for the 2007 IRP.

Conducted by ICF Consulting, the TEPOT study provided detailed estimates of energy savings and peak demand reductions by sector and end use. For energy savings (kWh), about one-half of the energy savings potential was found to be concentrated in residential and commercial air-conditioning and in residential, commercial and industrial lighting. For peak demand savings (kW), about two-thirds of the savings potential was concentrated in these same end-uses. Thus, the energy efficiency advocates recommended that the future DSM programs in Georgia focus on lighting and air-conditioning in the residential and commercial sectors because this is where the major energy efficiency potential lies.

The Georgia utilities have been urged to develop programs that address these priority end-uses. At a minimum, all of the measures and programs that were found to pass the TRC test in the recent GEFA TEPOT study need to be included in measure screening and program screening, according to the energy efficiency advocates. The new DSM programs recommended by energy efficiency advocates for the 2007 IRP include the following:

- New commercial energy efficient construction program;
- New residential energy efficient construction program (expanded Energy Star Homes and advanced residential new construction);
- Existing residential air-conditioning replacement/upgrade program;
- Existing residential lighting efficiency program;
- Existing commercial air-conditioning replacement/upgrade program; and
- Existing commercial lighting efficiency program.

In addition to addressing high impact areas for energy efficiency, these programs also lend themselves to tie-ins with the newly-enacted energy efficiency tax incentives included in the Energy Policy Act of 2005. This legislation includes incentives for:

- Energy efficient new residential construction;
- Energy efficient new commercial construction;
- Energy efficiency retrofits of existing residential buildings; and
- Energy efficiency retrofits of existing commercial buildings.

We have found that the new IRP process with its emphasis on stakeholder input is providing all parties with the opportunity to debate and discuss the merits of different approaches to DSM and utility energy efficiency programs. This has been a major improvement over the previous adversarial process.

Other Resources Available to the Commission

The Commission should also examine current efforts to address many of the issues that arise in state IRP discussions. We believe that three very useful resources are as follows:

1. EPA/DOE National Energy Efficiency Action Plan. The U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA), together with leading electric and gas utilities, the National Association of State Regulatory Utility Commissioners (NARUC), leading state public utility commissions, and the National Association of State Energy Officials (NASEO), have initiated a major undertaking: a National Action Plan for Energy Efficiency. It was announced in October 2005, and has held numerous meetings and produced work products since then. The goal of the plan is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities.

This effort is engaging energy market leaders—including electric and gas utilities, state agencies, energy consumers, energy service providers, and environmental/energy efficiency advocates—in the development of the Energy Efficiency Action Plan. Through this Action Plan, leaders will identify key barriers limiting greater investment in energy efficiency and develop and document sound business practices for removing these barriers and improving the acceptance and use of energy efficiency relative to energy supply options. Upon completion of the Action Plan, leaders will pursue these business practices through their business channels, as appropriate, and will assist in the dissemination of these business practices to key audiences

The Energy Efficiency Action Plan will be a well-documented set of business cases, best practices, and recommendations that are designed to spur greater investment in energy efficiency by utilities and energy end-users within the next five years. Key anticipated products include:

- A report documenting best practices for overcoming barriers limiting utility investment in energy efficiency;
- A resource library of "best practice" model energy efficiency programs in a variety of end-use sectors;
- A communications strategy, including a series of regional/state workshops to share business cases and create additional leadership opportunities; and,
- A network of experts and resource materials on energy efficiency practices

The Commission and its Work Group should investigate the applicability of the Action Plan's work products to this current IRP proceeding. More details are available at: http://www.epa.gov/cleanenergy/eeactionplan.htm

2. EPA's Clean Energy-Environment State Partnership Program. Under the Partnership Program, states work across their relevant agencies to develop and implement a comprehensive strategy for using existing and new energy policies and programs to promote energy efficiency, clean distributed generation, renewable energy, and other clean energy sources that can provide air quality and other benefits. States are establishing and working toward achieving one or more specific and robust clean energy-air quality goals, including state goals for cost-effective clean energy.

EPA provides access to a comprehensive package of planning, policy, technical, analytical, and information resources to help State Partners establish and implement sound Clean Energy-Environment State Action Plans. EPA's Clean Energy-Environment Guide to Action describes 16 clean energy policies and strategies that states have used to achieve cost-effective clean energy. EPA also documents and disseminates successful state clean energy policies and provides opportunities for training and peer exchange.

North Carolina is a partner with EPA on this project through the North Carolina Energy Office and the North Carolina State Energy Office and the North Carolina Department of Environment and Natural Resources, Division of Air Quality. The Commission and its Work Group should contact these agencies and investigate the applicability of the Action Plan's work products to this current IRP proceeding. More details are available at: http://www.epa.gov/cleanenergy/stateandlocal/partnership.htm

3. Western Governors' Association. The Western Governors' Association's Clean and Diversified Energy Advisory Committee (CDEAC) has evaluated an array of options for bringing on-line 30,000 Megawatts of clean energy by 2015, increasing energy efficiency 20 percent by 2020 and providing adequate transmission for the region. A comprehensive series of documents has been made available and would be of significant value to the Commission and the Work Group. More information on these resources are available at: http://www.westgov.org/wga/initiatives/cdeac/index.htm

Recommendations and Statement of Positions

In conclusion, the Alliance to Save Energy offers the following recommendations to the Commission:

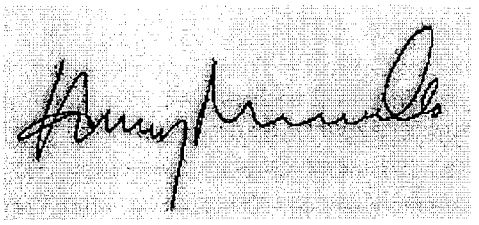
- The Commission should move ahead with its plans to set up a Work Group to insure that all parties and stakeholders have an opportunity to provide their input to defining cost-effective utility-operated energy efficient programs. The Work Group will be of significant value if the parties in the IRP proceeding have widely differing opinions on cost-effective DSM potential and other related issues. The Work Group will provide the proper venue to find common ground. We also believe that the Commission should provide the Work Group with a budget to engage any specialized outside consulting

assistance it may need. Some parties will have resources to attend the Work Group meetings, but it will be unlikely that parties other than utilities will be able to fund any needed research.

- The Commission should provide some guidance to the Work Group on the cost range it is willing to accept in order to field DSM programs. This can be expressed as a percentage of utility revenue or in absolute dollars. National experience shows that effective DSM programs require expenditures in the range of 0.50% to 1.5% of utility revenues.
- The Commission should require that the Work Group focus its efforts to sectors and end-uses that have the highest growth and greatest impact on forcing new supply resources. We believe that North Carolina's situation may be similar to Georgia's in that the impact of new residential and commercial construction is significant in driving load growth.
- The Commission should make a clear statement on the potential for cost-effective energy efficiency in North Carolina in any orders resulting from the upcoming evidentiary hearings. This will be of significant value to the Work Group as it prioritizes state needs to correctly target DSM and efficiency programs. Cost effective energy efficiency potential should be evaluated with the Total Resource Cost Test.

The Alliance, though not a party to the proceeding, is willing to assist the Commission and the Work Group in any way we can. We ask that these comments be made part of the record in this docket so that the Commission and the Work Group can make use of the recent Georgia IRP experience described above and use the other resources we have identified.

Respectfully submitted by:



Harry Misuriello
Director of Buildings and Utility Programs
Alliance to Save Energy
1200 18th Street, NW, Suite 900
Washington, DC 20036
Tel: 202 530 2214
Fax: 202 331 9588
Email: Misuriello@ase.org
Web: www.ase.org

Attachments:

1. Georgia PSC Order in 17687-U, July 9, 2004
2. Georgia Demand-Side Management Working Group Report, February 15, 2005
3. Georgia PSC Order in 17687-U, May 25, 2005

IN RE: **DOCKET NO. 17687-U: GEORGIA POWER COMPANY'S 2004 APPLICATION FOR AN INTEGRATED RESOURCE PLAN**

DOCKET NO. 17688-U: SAVANNAH ELECTRIC AND POWER COMPANY'S 2004 APPLICATION FOR AN INTEGRATED RESOURCE PLAN

FINAL ORDER

Date Submitted: July 2, 2004 Date Decided: July 9, 2004

APPEARANCES

For Georgia Power Company: Kevin C. Greene, Esq., Melissa L. Pignatelli, Esq., Troutman Sanders; **For Savannah Electric and Power Company**: Leamon R. Holliday, III, Esq., Bouhan, Williams and Levy; **For the Commission Staff**: Jeffrey C. Stair, Esq. Administrative Procedures Attorney, and Helen O'Leary, Administrative Procedures Attorney; **For the Consumers' Utility Counsel Division**: John Z. Wu, Staff Attorney; **For the Georgia Industrial Group**: Randall Quintrell, Esq.; **For the Georgia Textile Manufacturer's Association**: Peyton S. Hawes, Esq.; **For Calpine Corporation:** Michael S. Bradley, Esq., and Charles B. Jones, III, Esq., Sutherland, Asbill & Brennan; **For Southern Alliance for Clean Energy, Inc.:** James J. Presswood, Jr., Esq., Staff Attorney; For **Alliance to Save Energy:** Mr. Harry Misuriello; For **Georgia Environmental Facilities Authority**: Erin Kelley, Esq.; **For Homeowners Opposing Powerline Encroachment**: Richard N. Hubert, Esq., Chamberlain, Hrdlicka, White, Williams & Martin; **For Resource Supply Management**: Mr. Jim Clarkson; **For Georgia Interfaith Power and Light**: J. Renee' Kastanakis, Esq.; Reverend Woody Bartlett; and **For Live Oaks Company, LLC**: Mr. John S. Ellis.

BY THE COMMISSION:

I. STATEMENT OF PROCEEDINGS

On January 30, 2004, Georgia Power Company ("Georgia Power" or "GPC") and Savannah Electric and Power Company ("Savannah Electric") (collectively referred to herein as "Companies") separately submitted to the Commission applications for Integrated Resource Plans ("IRPs" or "Plans") for approval pursuant to O.C.G.A. § 46-3A-1 *et seq.* ("IRP Act" or "Act"). The Georgia Public Service Commission ("Commission") issued a Procedural and Scheduling Order on March 5, 2004, finding it appropriate and administratively convenient to hold concurrent and consolidated hearings in these dockets. No party entered an objection to the consolidation of the cases. These proceedings were declared to be contested cases as the term is defined in O.C.G.A. § 50-13-13 and were also held to encompass complex litigation pursuant to O.C.G.A. § 9-11-33(a).

The Procedural and Scheduling Order directed the Companies, at a minimum, to address those issues that are required by the IRP Act and Commission Rule 515-3-4 ("IRP Rules"), as well as any directives issued for the Companies to follow in the 2001 IRP cases.[1] In addition to the issues that traditionally are included in an IRP case, the Commission sought input from interested parties whether existing Utility Rule 515-3-4-.04(3), Request for Proposals Procedure for Long-Term New Supply–Side Options, should be modified to provide in greater detail the manner in which new supply side resources are to be requested, evaluated and presented to the Commission for certification.

In accordance with O.C.G.A. § 46-3A-5(c), the Commission established fees for review of the IRPs within sixty days of the filing of the applications. The Commission concluded that $143,060.00 was the appropriate fee for Georgia Power Company,[2] and $61,311.00 for Savannah Electric.[3] On March 16, 2004, Georgia Power and Savannah Electric remitted the established fee amount, thereby making the statutory deadline for this proceeding to be July 14, 2004.

Pursuant to statute, the Commission Staff ("Staff") and the Consumer Utility Counsel Division ("CUCD") of the Governor's Office of Consumer Affairs were parties to these dockets. Applications for Intervention were filed as follows:

> Docket No. 17687–U: Resource Supply Management ("RSM") intervened on February 18, 2004; Georgia Industrial Group ("GIG") intervened on February 19, 2004; Georgia Textile Manufacturers Association ("GTMA") intervened on February 20, 2004; Calpine Corporation ("Calpine") intervened on February 25, 2004; Georgia

1 See *Final Order*, Docket Nos. 12499-U, 13305-U and 13306-U, filed on July 17, 2001.
2 Docket No. 17687-U, *Order Establishing Fee for Georgia Power Company's Application for Approval of the 2004 Integrated Resource Plan*, filed on March 22, 2004.
3 Docket No. 17688-U, *Order Establishing Fee for Savannah Electric and Power Company's Application for Approval of the 2004 Integrated Resource Plan*, filed on March 22, 2004.

Environmental Facilities Authority ("GEFA") intervened on February 25, 2004; Southern Alliance for Clean Energy ("SACE") intervened on March 5, 2004;[4] Live Oaks Company, LLC intervened on March 26, 2004; Alliance to Save Energy ("ASE") intervened on April 16, 2004; Georgia Interfaith Power and Light ("GIPL") intervened on April 16, 2004; and Homeowners Opposing Powerline Encroachment, Inc. ("HOPE") intervened on April 19, 2004.

Docket No. 17688-U: Calpine intervened on February 25, 2004; SACE intervened on March 5, 2004;[5] Live Oaks Company, LLC intervened on March 26, 2004; and ASE intervened on April 16, 2004.

No party was denied intervention during the proceedings. [6]

On March 5, 2004, and again on May 25, 2004, the Commission filed amendments to its Procedural and Scheduling Order. Both sets of amendments were not substantive in nature, but, rather, were the result of the Commission's need to modify the dates on which the hearings were to be held and filings were to be made.

The Commission conducted the hearings in three phases in this matter. During the first phase of the hearings, the Companies presented their direct cases on April 19, 2004, and April 20, 2004, through one panel of witnesses comprised of Mr. Richard A. White. Mr. Larry R. White, Mr. Jeffrey A. Burleson, and Mr. Garey C. Rozier.[7]

On May 25, 2004, the Commission Staff presented a panel of witnesses setting forth its positions in these dockets. This panel consisted of Mr. Mark W. Crisp, Mr. Jerry W. Smith, Mr. Evan D. Evans, Ms. Kathleen F. Best, Mr. Daniel R. Cearfoss, Jr. and Mr. Phil M. Hayet. GIG and GTMA co-sponsored two witnesses, Mr. Jeffry Pollock and Mr. John A. Mallinckrodt, who testified on this same date, with Mr. Timothy Eves testifying on behalf of Calpine in between the presentations of the two GIG/GNG witnesses.

A witness panel comprised of Mr. Richard F. Spellman and Mr. Harry Misuriello also testified on behalf of ASE on May 25, 2004, and on May 26, 2004, as well, followed by a panel of three witnesses for SACE that consisted of Mr. James Presswood[8], Ms. Rita

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[4] In the Georgia Power IRP docket, an Amended Application for Leave to Intervene was filed by SACE on May 20, 2004.

[5] Also on May 20, 2004, an Amended Application for Leave to Intervene was filed by SACE in the Savannah Electric IRP docket.

[6] Although Mr. John S. Ellis intervened on behalf of Live Oaks Company, LLC, no appearance at the hearings was made by Mr. Ellis on behalf of this party.

[7] Both Mr. Burleson and Mr. Larry R. White are employed directly by Georgia Power. Mr. Richard A. White is employed by Savannah Electric. Mr. Rozier is employed by Southern Company Services. See Pre-filed direct testimony of the Companies' panel of witnesses, page 1.

[8] Mr. Presswood testified as a subject matter expert during the hearings and also served as SACE's counsel in this proceeding.

Kilpatrick, Mr. William Prindle.[9] This second phase of the hearings concluded after the testimony on behalf of a witness sponsored by GIPL, Ms. Melissa Heath, was provided.

Thereafter, during the third and final phase of the hearing that was held on June 28, 2004, the Companies presented rebuttal testimony through the same panel of witnesses that previously testified to support their direct cases.

At the conclusion of the hearings in these dockets, closing arguments and/or proposed final orders were filed by the Companies, ASE, Calpine, RSM, Staff, and the CUCD on July 1, 2004, or on July 2, 2004, as permitted by the Commission.

On July 9, 2004, at a Special Administrative Session, the Commission considered the positions of the various parties and rendered decisions on the Companies' respective IRPs.

In conjunction with doing so, the Commission hereby adopts in this Final Order, with modifications and further directives, the IRPs filed by Georgia Power and Savannah Electric. In doing so, the Commission sets forth in this Order further direction to Georgia Power and Savannah Electric for further reporting and analysis to be performed and provided to the Commission prior to or in conjunction with their next IRP filings, amendments or applications for de-certification. Finally, this Order issues directives by the Commission that are to be followed by its Staff in order to facilitate a Demand Side Management Working Group and initiate the process required for amending the agency's existing Utility Rule 515-3-4-.04(3), Request for Proposals Procedure for Long-Term New Supply–Side Options.

II. JURISDICTION AND AUTHORITY

Georgia Power and Savannah Electric are public electric utilities serving retail customers within the State of Georgia. Georgia Power and Savannah Electric are two of the five retail operating companies of which the Southern Company system is comprised. This Commission has jurisdiction over Georgia Power's and Savannah Electric's IRPs pursuant to O.C.G.A. § 46-2-1 et seq., generally, and the IRP Act in particular.

The IRP Act requires the Companies to file Integrated Resource Plans at least every three years.[10] The Companies' obligations with respect to the information that is filed is set forth pursuant to criteria identified in the Commission's IRP Rules. A "plan" is defined in the Act as an Integrated Resource Plan that contains the utility's: electric demand and energy forecast for at least a 20-year period; program for meeting the requirements shown in its forecast in an economical and reliable manner; the analysis of all capacity resource

[9] Although Ms. Sara Barczak was identified on the pre-filed direct testimony as a witness who would be testifying on behalf of SACE, she was unavailable to appear at the hearing to answer questions about the panel testimony. As such, the panel was permitted to proceed with its testimony in her absence.
[10] O.C.G.A. § 46-3A-2.

options, including both demand-side and supply-side options; and the assumptions used and the conclusions reached with respect to the effect of each capacity resource option on the future cost and reliability of electric service. The Plan also must:

(A) Contain the size and type of facilities which are expected to be owned or operated in whole or in part by such utility and the construction of which is expected to commence during the ensuing ten years or such longer period as the Commission deems necessary and shall identify all existing facilities intended to be removed from service during such period or upon completion of such construction;

(B) Contain practical alternatives to the fuel type and method of generation of the proposed electric generating facilities and set forth in detail the reasons for selecting the fuel type and method of generation;

(C) Contain a statement of the estimated impact of proposed and alternative generating plants on the environment and the means by which potential adverse impacts will be avoided or minimized;

(D) Indicate, in detail, the projected demand for electric energy for a 20-year period and the basis for determining the projected demand;

(E) Describe the utility's relationship to other utilities in regional associations, power pools, and networks;

(F) Identify and describe all major research projects and programs which will continue or commence in the succeeding three years and set forth the reasons for selecting specific areas of research;

(G) Identify and describe existing and planned programs and policies to discourage inefficient and excessive power use; and

(H) Provide any other information as may be required by the Commission.[11]

The Commission is required under O.C.G.A. § 46-3A-2 to make determinations as to the adequacy of the IRPs and to ensure that the utilities' Plans have appropriately addressed numerous matters. There must be a determination that the forecast requirements contained in the Plan are based on substantially accurate data and an adequate method of forecasting.[12] The Commission must also find that the Plans identify and take into account any present and projected reductions in the demand for energy that may result

[11] O.C.G.A. § 46-3A-1(7).
[12] O.C.G.A. § 46-3A-2(b)(1).

from measures to improve energy efficiency in the industrial, commercial, residential, and energy-producing sectors of the state.[13]

Further, the Commission must determine whether the Plans adequately demonstrate the economic, environmental, and other benefits to the state and to customers of the utilities, associated with the following possible measures and sources of supply:

(A) Improvements in energy efficiency;
(B) Pooling of power;
(C) Purchases of power from neighboring states;
(D) Facilities that operate on alternative sources of energy;
(E) Facilities that operate on the principle of cogeneration or hydro-generation; and
(F) Other generation facilities and demand-side options.[14]

After hearings have been conducted on a Plan, the Commission may approve the IRP; approve it subject to stated conditions; approve it with modifications; approve it in part and reject it in part; reject the plan as filed; or provide an alternate plan, upon determining that this is in the public interest.[15]

With regard to its rule-making authority to enact or modify regulations regarding the manner in which new supply-side resources are to be attained for the Companies' retail customers, the Georgia Legislature conferred upon the Commission a general blanket of authority under which it may enact those rules necessary to execute the functions that it has been delegated.[16] Along this avenue of authority, the Commission included in the Procedural and Scheduling Order a request for information from parties in order to determine whether its existing Utility Rule 515-3-4-.04(3), Request for Proposals Procedure for Long-Term New Supply–Side Options, should be enhanced and, if so, in what manner. In furtherance of this purpose, the agency's stated areas of interest included:

(a) The procedures for the issuance of any Request for Proposals (RFP)
(b) The contents of the RFP
(c) The need for and role of an Independent Evaluator to oversee the RFP process
(d) Evaluation Criteria and Procedures including selection process for a competitive tier and/or short list of bidders
(e) Codes of conduct for participation in an RFP
(f) The manner in which Information will be made available to bidders
(g) Exceptions, if any, to the RFP procedures

[13] O.C.G.A. § 46-3A-2(b)(2).
[14] O.C.G.A. § 46-3A-2 (b)(3).
[15] GPSC Utility Rule 515-3-4-.01(2).
[16] O.C.G.A. § 46-2-30.

(h) The inclusion of a "Self-build" option by a Georgia-regulated utility, in the RFP process; and

(i) A description of, and the use that is to be made of, a "Target Price" in the RFP evaluation process.[17]

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

To ensure that the competing interests of all parties were properly considered, the Commission has carefully analyzed all evidence of record including the testimony given and the various exhibits entered by all the parties. As set forth hereinafter, the Commission makes findings of fact and conclusions of law[18] based on the evidentiary record created, taking into consideration any joint proposals for a resolution to an issue raised by this agency.

A) REVIEW AND EVALUATION OF THE INTEGRATED RESOURCE PLANS FILED BY GEORGIA POWER COMPANY AND SAVANNAH ELECTRIC AND POWER COMPANY[19]

1) LOAD FORECAST

In Volume 1A, Table 4.2, on page 9 of the Technical Appendix[20] to Georgia Power Company's 2004 IRP filing, the load forecast for the years 2004 through 2023 is set forth as it pertains to the Companies' service areas as well as the Southern System as a whole. With regard to the demand and energy forecasts that are used to project load for the Companies, the Staff panel of witnesses was the only one to comment on each of them. A review of the testimony provided by Staff regarding the adequacy of the forecasts filed by Georgia Power and Savannah Electric is relevant to this Commission making at determination whether they should be approved as filed.

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[17] *Procedural and Scheduling Order*, March 5, 2004, p. 6.

[18] The areas of discussion included in the body of the Order in terms of Findings of Fact and Conclusions of Law speaks only to the areas of the Plans filed that were contested. Matters that were not disputed or previously were decided by the Commission in these dockets are referenced in the ordering paragraphs only.

[19] Due to the way the transcripts of the three phases of the hearing were prepared in these dockets, there is no way to identify specific pages in the transcripts when pre-filed testimony of any witness(es) is(are) referenced. As a consequence, all statements referenced as an authority in this Final Order will be cited from a party's pre-filed testimony, which, at the hearing, was accepted into the record as evidence.

[20] This information is contained in the Trade Secret version of the Georgia Power's filing.

a) Sufficiency of Load Forecasts

Georgia Power Company

In conducting its analysis, Staff noted that Georgia Power used econometric models developed in-house for the short-term forecasts (2004–2006), and a set of EPRI end-use models (REEPS, COMMEND and INFORM) for the longer-term forecasts (2007-2023). Georgia Power also used the EPRI model, HELM, to produce the demand forecast. The long-term models used are well accepted industry-wide, and Georgia Power performed an appropriate analysis of data input and calibration for each of these load forecast models. Staff acknowledged that some judgment was necessary in the selection of variables for all models, and that Georgia Power appeared to have made reasonable decisions for the Budget 2004 forecast, which was prepared during the spring of 2003.[21] The energy forecast is dependent on the input variables provided by Economy.com.

In its analysis of load, Georgia Power provided data that indicated a recent tendency for this company to over-forecast total company demand, with the errors ranging from approximately 1% to 7% on a weather adjusted basis[22]. However, the more recent interim forecasts appeared to have improved and were in the range of 1% to 4% error. Staff determined that these percentages of errors are in the range of what is acceptable.

A similar review of the weather adjusted comparisons for total company energy[23] revealed that on a total company basis, Georgia Power systematically also has over-forecasted energy usage. However, the forecast errors are within acceptable ranges of 3% to 5%, with more recent forecasts indicating improved accuracy with variances of approximately 1% to 3%.

Staff evaluated the weather adjusted energy forecasts by customer class[24] and concluded that forecast accuracy is within acceptable limits, with the potential exception of the industrial class. (Pre-filed Panel Testimony of Staff, p. 49). The industrial class energy forecast errors from the Budget 1999 through the Budget 2001 forecasts are in the range of 15% over-forecasted. The Budget 2002 forecast improved accuracy considerably to the 3% to 7% range. Georgia Power lost industrial customers from 1990 through 2003. Over the period, the number of industrial customers declined at the average annual rate of 2.9%. Georgia Power forecasted an average annual rate of decline for industrial customers of 1.6% for the period of 2004 through 2023. The industrial class represented approximately 24% of the total Georgia Power demand in 2003. A ratio has been projected by the Company to decline to about 20% in 2023. On

[21] Georgia Power performed weather-normalization for both energy and demand data in order to provide historically appropriate comparisons of forecasts to actual energy and demand.
[22] *Georgia Power's 2004 IRP Filing* Technical Appendix Volume 2, Section 9, pages 189- 190.
[23] *Georgia Power's 2004 IRP Filing* Technical Appendix Volume 2, Section 9, page 185.
[24] *Georgia Power's 2004 IRP Filing* Technical Appendix Volume 2, Section 9, pages 185-188.

an energy basis, the industrial class represented about 35% in 2003, a ratio is projected to decline to 30% in 2023.[25]

Staff observed that Georgia Power estimated and adjusted the industrial class to account for a trade secret concern that has the potential to be realized in the upcoming years. Id. at 50. Minor adjustments start in 2007 and major adjustments occur in 2008 and beyond. It is likely these estimates will change when trade secret concerns had by the Company are decided one way or another. Secondary economic effects of these trade secret concerns were included in the residential and commercial classes also.

In looking at Georgia Power's forecast, which was prepared in the spring of 2003, Staff concluded that there have been potential signs of some economic recovery in the southeastern United States, which make it prudent to examine a case where some growth in the industrial class resumes before 2008. In order to examine this scenario, Staff recommended a sensitivity case to be performed, that in addition to other data changes, increased the total system load and demand by 1% over the Georgia Power Budget 2004 forecasts. Id. at 51. This case represents the possibility that some economic recovery is now in progress but had not yet been picked up in the Georgia Power forecasting models.

Necessity for Update to Georgia Power's Existing Load Forecast

When doing cross-examination of the Companies' direct testimony, Staff inquired as to whether there would be an updated load forecast filed with the Commission by Georgia Power for use in the upcoming 2004 rate cases. (Transcript (Tr.) 47.) Witness Jeffrey Burleson indicated that one had not been prepared and there was no intention to file one. (Tr.48.) During the rebuttal phase of the hearing, Staff made additional inquiries during cross-examination through which the genuine need for the Commission to obtain a new or updated load forecast from Georgia Power was explored. (Tr.984-997.) Among the points made by Staff that would support a more current load forecast being filed by Georgia Power included the fact that some of the data underlying the one in the IRP was from at least January 2003, maybe earlier (Tr.991-992); the growth predicted in the forecast for the various retail customer sectors may have far exceeded actual growth as per recent Company pronouncements (Tr.986-991); and the significant role that a load forecast plays in a rate case, which Georgia Power filed on July 1, 2004, seeking increased rates. (Tr.990-994.)

Through its responses, Georgia Power witness Burleson disputed any need for an updated load forecast to be filed. He indicated that, as per the Final Order in the last IRP case (Docket No. 13305-U), Georgia Power only had to notify the Commission if a new load forecast was developed by the Company. (Tr.980.) Mr. Burleson indicated that information tracking any variances in the load forecast is routinely made available to management of the Company in the form of reports. (Tr.982.)

[25] Georgia Power Company's Technical Appendix, Vol. 2, Section 2, page 22.

In furthering his opposition to preparing an updated forecast based on actual data becoming available since it was prepared in early 2003, this witness contended that the actual data, once weather normalized, would result in the forecast being lower than what it is presently. (Tr.994-995.) While there may be actual data that shows higher sales for a customer class, Mr. Burleson seemed to infer that such increases were somehow offset by lower than predicted sales in the forecast for another class. (Tr.986-988)

When asked about the importance of its load forecast in terms of its upcoming rate case, Mr. Burleson did concede that there would be overearnings by a utility if its revenue requirements were to be spread across a customer base that was lower than what was forecasted. (Tr.992-994.) In light of this and other inquiries made by Staff, Mr. Burleson stood firm in his position that a load update was not necessary.

While the Commission understands the position of Georgia Power in this regard, it shares Staff's concern about Georgia Power's decision that a more current load forecast will not be made available for the rate case that is to be decided later this year. While Mr. Burleson possesses a great deal of credibility as a witness, the Commission would be derelict in its duty if it were merely to rely on his representations as to the impact that the availability that actual data has had on the forecast, and not to direct that this updated information be filled with this agency. Since the information necessary to update the existing forecast appears to be readily available to representatives of the Company, it should not be any hardship for the Company to do an update to its load forecast.

It also must be noted that the need for an updated load forecast is compounded by the fact that a cost of service study has been done by rate schedule for the first time in the 2004 rate case. If actual sales data deviates from that which is embedded in the existing load forecast, it could result that certain customer classes will have rates set for them that subsidize rates that will be set for consumers that take service under another class's rates. To eliminate any far-reaching ramifications from this occurring, it is imperative that by no later than August 15, 2004, Georgia Power must file an updated load forecast and budget comparison information with the most up-to-date information as of March 31, 2004.

Savannah Electric and Power Company

Staff noted that Savannah Electric prepared short-term (2004–2006) econometric models for most classes. (Pre-filed Panel Testimony of Staff, p. 53). For its industrial class, the company tabulated individual customer forecasts to obtain the forecast of the entire class. Savannah Electric used a set of EPRI end-use models (REEPS, COMMEND and INFORM) for the longer-term forecasts (2007-2023). The company also used the EPRI model, HELM, to produce the demand forecast. The long-term models are well accepted industry-wide and Savannah Electric has performed the appropriate analysis of data input and calibration for each of these models.

Like its sister company, Georgia Power, Savannah Electric performed weather-normalization for both energy and demand data in order to provide historically accurate comparison of forecasts to actual energy and demand. It provided data indicating forecast errors that are in the range of approximately 1% to 5% on a weather adjusted basis, with the exception of the industrial energy.[26] However, a more recent interim Budget 2003 forecast resulted in errors of 1% to 3%. As with Georgia Power, this range of errors is acceptable, and the company's demand forecast is also within standard tolerances. Id.

For the industrial energy forecast comparisons on a weather adjusted basis, Savannah Electric over-projected energy sales by as much as 15% in the most recent forecast. [27] Staff noted that it was advisable to attempt additional econometric or other modeling for the short-term industrial energy sector to see whether any improvement could be achieved since this class represented approximately 20% of the total sales in 2003. Id.

Staff ultimately concluded that Savannah Electric's short-term models fit the historical data and appear to be reasonable and consistent with trends, with the possible exception of the industrial sales forecast, and that the company's demand projections were reasonable. Id. at 54.

Necessity for Update to Savannah Electric's Existing Load Forecast

While Savannah Electric witness Richard White was not asked the same questions about the load forecast as Georgia Power witness Jeffrey Burleson, similar concerns are present about the age of the existing load forecast exist since Savannah Electric also will be filing a rate case later this year. Irrespective of the concern that this utility does not share its sister company's situation in terms of doing a cost of service by individual rate, Savannah Electric likewise is directed to update its load forecast and budget for filing with the Commission based on the relevancy of such information to the rates that will be set next year as a result of its 2004 rate case filing.

b) Recommendations Regarding the Companies' Load Forecast

Based upon the evidence in the record, the Commission finds and concludes that it is appropriate to approve the demand and energy forecasts as filed by Georgia Power and Savannah Electric without modification to any projections to any customer class. In doing so, however, the Commission does find the concerns about the vintage of the forecast information, which is old and can easily be updated by actual data. Providing this more current information is essential because this information will play a critical role in the Company's upcoming rate case. As such, the Commission further finds and concludes that Georgia Power and Savannah Electric shall each update its forecasts utilizing actual data through March 31, 2004. Once updated, these forecasts shall be filed by the Companies on or before August 16, 2004.

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[26] *Savannah Electric's 2004 IRP Filing,* Technical Appendix, Section 1, pages 46-47.
[27] Id. at 46.

2) RELIABILITY—AUTHORIZED TARGET RESERVE MARGIN

In an effort to plan for a reliable system, allowances for capacity resources in excess of a utility's projected peak demand requirement are made for the purpose of recognizing that generating units can fail randomly, and load projections typically have some measure of forecast error. This commitment to have excess capacity provides a reasonable assurance that the utility will always have resources available to serve its load. A system with too large of a reserve margin will tend to have high revenue requirements because it will overbuild capacity on its system. A system with too small of a reserve margin will have to depend on purchases from the wholesale market that can be quite high at times of peak demand, once again resulting in high revenue requirements. The goal of a reserve margin study is to determine the level at which revenue requirements are the lowest for a given level of reserve margin. This results in a well-planned, reliable, and cost-effective utility system.

In the 2004 IRP, the Companies have proposed that the ultimate system reserve margin should be set at 13.5% for the first 3 years, and then 15% for the years after that. As support underlying this recommendation, Southern Company Services conducted a reserve margin study[28] that updated the one that was previously done in 1999. The conclusion reached in both studies was that 15% is the appropriate level of reserve margin for the Southern Company System. In the 2001 IRP, Georgia Power cited to the 1999 study as its basis for relying on 15% as its target reserve margin level for the Southern Company System.[29] Also, in the 2001 IRP, Georgia Power proposed a lower System reserve margin level for the short-term, arguing that it was an acceptable level for the first three years of the IRP study period. Ultimately, the Commission accepted these target reserve margin levels for the 2001 IRP.

For purposes of its 2004 IRP reserve margin study, Southern Company Services relied on its Monte Carlo Frequency and Duration Model "MCFRED," to develop the relationship between system revenue requirement and reliability based on Expected Unserved Energy (EUE). The cost of EUE is the payment which one customer is willing to make to avoid an hour of sudden, unexpected, firm load curtailment on a hot, summer afternoon. The goal of the reserve margin study is to determine the appropriate level of reserve margin such that total system revenue requirement is minimized, considering the cost of generating to serve load, the cost to build new capacity and the cost of expected unserved energy that might result from not having built quite enough capacity to serve load. In the 2004 filing, the reserve margin study explains that several changes were made in the modeling methodology to more closely represent the operational characteristics of the system.

Base on the results of the reserve margin study and the resulting analysis done by Staff, the Commission believes that the Companies' proposed system reserve margin

[28] See Technical Appendix Volume 1B of Georgia Power's filing.
[29] *Staff Panel Testimony* filed May 11, 2001, Docket Nos. 13305 and 13306, page 18 at line 5.

recommendation, which includes a risk adjustment,[30] should be approved in this IRP. Their recommendation appears to be quite reasonable based on a number of facts. These include an acknowledgement that a 15% reserve margin is consistent with what other utilities typically use, that presently there is considerable excess merchant capacity in the southeast region and that Southern Company as a whole is itself in an over-capacity situation.

As such, the Commission finds and concludes that the Companies' proposed 13.5% target reserve margin for the 2004 – 2006 time frame shall be set at 13.5%, with 15% to be used for the remainder of the study period. It is further directed that, in future reserve margin studies, as with all evaluations that are conducted as part of an IRP, consistent modeling data should be used to the greatest extent possible.

3) SUPPLY-SIDE MANAGEMENT

a) Generation Expansion Plan

Georgia Power Company's Resource Planning Process

Georgia Power's base case supply-side Resource Plan, which covers the 20-year period from 2004 through 2023, identifies the need for new resources to begin in 2009 and continue every year thereafter through 2023. In each of those years, Georgia Power proposes to add various combinations of gas-fired combustion turbine ("CT") and combined cycle ("CC") units. Between 2004 and 2008, the Companies' have already made commitments to satisfy their resource needs based on prior IRPs, through reduction in the peak demand forecast, and in accordance with Commission certification proceedings that took place in December 2000 and December 2002.

The December 2000 certification allowed Georgia Power to proceed with the following resources:[31]

- 1,800 MW of purchased power coming online in the 2003 and 2004 time period based on purchases from Southern Power Company. (The Franklin and Harris Power Purchase Agreements (PPAs).
- 12 MW upgrades to the Goat Rock Hydro units

[30]On page 48 of the Risk Margin study, Southern Company Services reported that the optimal reserve margin for the system is actually lower than the 15% reserve margin that the Companies have recommended. However, through a series of additional analyses, risk factors were derived and added to the lower reserve margin result. The net result of these risk factors is that additional capacity has to be planned for the system to satisfy the higher reserve margin targets. It should be noted that the use of risk adjustments is not unusual when they are applied in such a way that the utility may meet other goals in addition to those required by the basic methodology. Staff determined that planning for a reliable system in an uncertain environment was an adequate reason in these filings to use a risk adjustment.

[31] *Georgia Power Company's 2004 IRP* Main Document, pages 1-7.

The December 2002 certification included:

- 1,660 MW of purchased power coming online in 2005 based on purchases from Duke Energy Southeast Marketing, LLC and Southern Power Company.[32]

Savannah Electric's Resource Planning Process

Savannah Electric's base case supply-side resource plan also covers the same 20-year time frame and has identified the need for new resources to begin in 2009. Just as in the case of Georgia Power, after 2009, and through the remainder of the planning period, Savannah Electric's resource plan calls for the addition of CT and CC units. Based on decisions made in prior IRPs and approved in Commission certification proceedings (one in March 2000, and another in December 2002), Savannah Electric has already made commitments to satisfy its resource needs covering the period of 2004–2008.

In March 2000, the Commission certification allowed Savannah Electric to proceed with the following resources:[33]

- 200 MW of purchased power coming online in June 2002 based on purchases from Southern Power Company, from its Wansley Combined Cycle Plant. This is a 7.5 year PPA covering the period of June 2002 through December 2009.

The December 2002 certification provided approval for:

- 200 MW of purchased power coming online in June 2005 based on purchases from Southern Power Company, from its McIntosh Combined Cycle Plant.[34]

- The retirement of approximately 100 MW at Plant Riverside on May 31, 2005, based on the purchase of McIntosh unit.

Based upon the information filed by the Companies in their IRPs, the Commission finds and concludes that the Companies' respective Generation Expansion Plans appear to be adequate.

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[32] Since both Companies filed their IRPs on January 30, 2004, a joint application was made to the Commission on May 7, 2004, requesting direction to buy the two units, McIntosh 10 and 11, which were the subject of the purchase power agreements that they previously entered with Southern Power Company, and which the Commission certified in December 2002. The Commission issued this directive in an order filed on May 19, 2004, in Dockets 15392-U and 15393-U and will be considering the valuation of them as part of a rate case later this year.

[33] *Savannah Electric and Power Company's 2004 IRP* Main Document, pages 1-8.

[34] See Footnote Number 17.

b) Unit Retirement Study

In conjunction with its 2004 IRP filings, the Companies have considered whether it is prudent to consider for retirement any of their electric plants or the individual units located within them. In doing so, Georgia Power has requested that the Commission de-certify the Plant Atkinson CTs 5A and 5B, which total 80 MW of capacity, and which were retired from service on December 31, 2003. (Pre-filed Panel Direct of the Companies, page 7.) Upon examining whether Georgia's plans for the retirement of these two units are reasonable, Staff testified that they were. (Tr.485.) No other party addressed this issue with Georgia Power at the hearing.

A decision to extend the life of a unit at Plant Kraft has been made by Savannah Electric in its IRP filing. This utility previously had been planning for the retirement of the Kraft CT unit, which is a 17 MW combustion turbine that is capable of providing black start service. However, Savannah Electric since has performed further retirement evaluations (Pre-filed Panel Direct of the Companies, page 14) and is now recommending that the life of Kraft CT 17 MW be extended. Neither Staff (Pre-filed Staff Panel Direct Testimony, pages 43-44) nor any other party has opposed Savannah Electric's doing so.

Based on these considerations, the Commission finds and concludes that it is reasonable for Plant Atkinson CT's 5 A and 5B to be de-certified by Georgia Power Company. The Commission further finds and concludes that it is prudent for Savannah Electric to extend the planned life of the 17 MW Kraft CT unit that is capable of providing black starts and to remove it from further consideration for retirement.

c) Fuel Forecast

Staff expressed concern in its direct testimony that natural gas prices have risen sharply in the past year or two and seem to be forecasted to gradually trend lower from the currently high levels for a few years before returning to an upwardly trending pattern over the long term. (Pre-filed Staff Panel Direct Testimony, p. 16.) Unlike past history, as the natural gas prices decline in the next few years, none of the industry experts appear to expect prices to drop back to around $3.00/mmbtu again over the next 20 years. Id. For purposes of making a proper analysis of the IRP filings, Staff compared the Companies' base and high gas forecast to other forecasts including NYMEX and the Energy Information Administration's ("EIA") forecast. Based on its comparison, Staff concluded that the Companies' reference case forecast may be a little low. Id.

The Staff pointed out that price forecasts currently exhibited large fluctuations associated with many uncertainties in the markets. Id. at 15. The EIA 2003 Energy Outlook forecast of the fuel prices may be low given the more recent developments in the natural gas markets. The EIA revised these price forecasts upward in the EIA 2004 Energy Outlook published in December 2003. The gas price for electric generators for the Middle Atlantic region, as reported in the 2004 EIA Energy Outlook, was revised

upward by an average of 10.6% for the period 2004 to 2025. Id. at 54-55. For the short-term period 2004 to 2008, the average increase in the gas price forecast for the electric generators is 18.4%. Id. For the period of 2009 to 2025, the average annual price upward revision is about 8.4%. At the retail level, the EIA forecast for residential gas prices in the Middle Atlantic Region was revised upward by an average of 8.8% for the period of 2004 to 2008, and an average of 3.7% for the period of 2009 to 2023. Id. For commercial customers and industrial customers, the price forecast revisions are higher: commercial users: 2004-2008, 19.3%; 2009-2023, 10.3%; and industrial users: 2004-2008, 13.9%; 2009-2023, 9.8%. Id. Even though there is not full agreement with all of the Companies' data assumptions, none were determined by Staff to be completely unreasonable. (Pre-filed Staff Panel Direct Testimony, p. 15.)

Within the testimony of John Mallinckrodt, the Georgia Industrial Group and Georgia Textile Manufacturers Association expressed concern that GPC is planning to rely totally on natural gas for future resource additions. (Pre-filed Testimony of John Mallinckrodt, p. 2.) A primary basis for GPC's reliance on natural gas is an assumption that natural gas prices will drop due to increased imports of liquid natural gas ("LNG"). Id. Mr. Mallinckrodt pointed out that domestic supply is declining, as are imports from Canada, and that even assuming that all LNG that is projected to be imported through both existing, expanded and new terminals, LNG will still not significantly increase domestic gas supply. Id. at 5. GIG/GTMA argued that contrary to GPC's projection of declining natural gas prices in 2004 to 2009 timeframe, natural gas prices are not likely to change significantly relative to current high levels. Id. at 7.

The fuel forecasts of Georgia Power and Savannah Electric utilized in various parts of the IRP originated over a range of dates. For example, fuel prices used in some of the forecast models were based on the EIA 2003 Energy Outlook published in December 2002 (*Georgia Power's 2004 IRP Filing* Main Document, page 3-3; *Savannah Electric's 2004 IRP Filing* Technical Appendix, Section 1, page 76), and it appears that other fuel forecasts were derived for other analyses such as the Optimal Resource Mix Study.

Staff recommended that the Companies update and file prospectively their fuel forecasts on June 30th of each year. (Pre-filed Staff Panel Direct Testimony, p. 87.) As per Staff, the updates should include an assessment of how the conclusions and recommendations reached by the Commission in the most recent IRP order may need to be modified as a result of the updated forecasts. These updates should also include a comparison of the forecasts used in the previous IRP with the actual data for the current year. The Staff also recommended that the Commission consider continuing its previous order requiring Georgia Power and Savannah Electric to file load and fuel forecasts, together with detailed supporting information and analyses each year, rather than at the three year IRP intervals, in order to capture significant changes in the region. Id.

With regard to three of Staff's recommendations, the Companies argued that, pursuant to Commission Rule 515-3-4-.06(5), they already are already required to notify the Commission of any major changes in any condition that would impact resource

planning. (Pre-filed Panel Rebuttal of the Companies, page 41.) Georgia Power and Savannah Electric also are currently under the obligation to file with the Commission a copy of each load forecast update prepared by the Companies as soon as such update becomes available. Id. Similarly, since the Companies already currently file a copy of the Environmental Compliance Strategy each year, as well as filing a status report of their certified DSM programs, the obligation to make a further in this area would be burdensome and unnecessary, In sum, the Companies argued that Commission already has in place several mechanisms through which it can stay abreast of their resource planning process in between filed IRPs and additional filings to report on same would be redundant. Id.

The Commission is concerned about the volatility in the price of natural gas, the increasing cost of fuel, and the IRPs' long term reliance on natural gas. In order for this agency to adequately monitor the issues surrounding fuel that have developed in recent years and are expected to continue, the Commission finds and concludes that both Companies shall promptly notify the Commission of any changes in fuel price conditions, including external forecasts that may warrant development of a new utility price forecast. In imparting this information, Georgia Power and Savannah electric also shall advise the Commission of the impacts these changes may have on the long range IRP.

The Commission further finds and concludes that the Companies shall make available any fuel forecast update as soon as it is available. This information shall be provided as appropriate within each 6 month Progress Report to the Commission as required by Utility Rule 515-3-4-.05.

4) DEMAND SIDE MANAGEMENT

a) Demand Side Management Issues Raised by The Companies Proposals

Neither the IRP filing for Georgia Power nor the filing made by Savannah Electric contained any new Demand Side Management ("DSM") programs because, the Companies contended, none were found to be cost-effective by applying the screening tests specified in the Commission's rules and prior orders. (Pre-filed Panel Direct of the Companies, page 41.) Georgia Power and Savannah Electric have indicated that it remains appropriate for this Commission to use the Rate Impact Measure ("RIM") test as the final screening tool to determine whether a DSM measure should be implemented. Id. at 10 and 16. Both Companies also stated their intent to continue the Power Credit program, which was reauthorized by the Commission in its 2001 IRP order. Id. at 9 and 16.

Georgia Power also proposed to maintain its Low Income Weatherization Assistance Program and to continue existing energy information programs that provide customers

with cost-effective energy saving options. Id. at 10. Similarly, Savannah Electric has made the same proposal. Id. at 16.

1) Implementation of Additional Measures to Foster Energy Efficiency

a) Partnership with Energy Star®

Georgia Power and Savannah Electric indicated that in April 2004, they entered into a partnership with Energy Star®, through which appliances acknowledged as having a certain level of energy efficiency would be promoted by the Companies in ways such as providing consumers with manufacturers' coupons for energy efficient appliances with their bills. (Tr.1029.)

The Commission finds and concludes that both GPC and Savannah Electric shall continue to develop the partnership that it has entered into with Energy Star® through which appliances acknowledged as having a certain level of energy efficiencies would be promoted by the Companies in ways such as providing consumers with manufacturers' coupons for energy efficient appliances with their bills.

b) Desire for Greater Levels of Customer Education

It was apparent to the Commission through comments made by public witnesses that most of them supported additional education regarding efficient use of electricity. Public witness Ms. Peggy Bartlett stated in relevant part that "[w]here I expected some folks to be quite resistant to suggestions that they change their personal habits with regard to lights, computers, small appliance, copy machines, . . . we have found extremely positive response. People want to know what to do. They are grateful for educational specifics of what they should do." (Tr.428.) Another citizen who made public comments, Ms. Elizabeth Mojica, stated that she was "disappointed in Georgia's lack of renewable energy sources and the poor education of consumers on energy conservation issues." (Tr.446.) Mr. John Heavener, also a public witness who gave up his personal time to come to the hearing, commented that "[a] part of that strategy could be encouraging commercial and residential consumers to utilize Energy Star® appliances and building products as well as instituting education campaigns on how to reduce the demand for energy." (Tr.458.)

The interest among consumers in making efficient use of electric energy also was addressed by Staff witness Evan Evans, who testified that helping people understand how to set programmable thermostats already located in their homes could itself be a program design, and that education along those lines incorporated into the informational program that Georgia Power already has in place would produce benefits. (Tr.521.) In terms of understanding how to exact energy efficiencies from current electric usage, ASE's witness, Dick Spellman, noted that the existence of market barriers resulted in most people lacking awareness of energy efficient technologies, which is why

educational programs like the one provided by Georgia Power through brochure information are greatly needed to educate the public. (Tr.849-850.)

Georgia Power and Savannah Electric stated on rebuttal that "[a]lthough [they] work with customers daily on how to use energy efficiently, the Companies are also willing to engage in additional customer education regarding DSM." (Company Panel Rebuttal testimony, page 7.) As support for this representation, the Companies noted a number of ways that they proposed to do so. The Companies further stated their willingness to more aggressively promote their willingness to conduct energy audits for customers upon request in an effort to raise customer awareness of the availability of this service. (Tr. 1027-1037.)

Based upon the foregoing, the Commission finds and concludes that the Companies shall initiate customer education programs through which they each will disseminate information to consumers about the efficient use of electricity. Georgia Power and Savannah Electric also shall more aggressively promote the availability of energy audits for interested customers.

c) Funding for Educational Initiatives

In order for Georgia Power and Savannah Electric to properly implement the customer education programs that they have been charged with initiating, the Commission finds and concludes that Georgia Power shall fund with no more than $2,000,000 annually an energy efficiency campaign that it shall implement to promote consumer awareness of those energy efficiency measures and practices that produce the greatest economic efficiency and benefit to a participant. Savannah Electric shall support a similar initiative with no more than $200,000 annually in funding to do so.

All of the funding authorized for these programs shall be directed to promoting education regarding those energy efficiency measures and practices that produce the greatest economic efficiency and benefit for the participant. In terms of outreach to achieve this goal, the Companies may use any recognized medium through which their customers could reasonably be expected to be reached with energy efficiency information, including, but not limited to, television advertisements, radio spots and advertisements in local newspapers and periodicals.

All such advertisements made through these mediums shall be for the exclusive purpose of promoting education in the area of energy efficiency and shall not serve as a forum to promote the Southern brand (or that of its subsidiaries) in any way, or to further other initiatives of the Companies outside of those contemplated herein. Television, radio and/or print ads shall provide as much information about managing electric usage as possible in the time/space allotted. A general understanding of electric energy efficiency and conservation should be able to be derived by the average viewer after viewing/listening to any advertisements. The theme of all advertisements should be strictly education-based. Any advertisements that the Commission, in its sole discretion,

finds not to be adequate for its intended purpose shall not be financed with monies allocated in this order for consumer education.

Copies of television ads, radio scripts and print advertisements containing information that is to be disseminated to the public shall first be provided to the Commission's Consumer Affairs Office, the Commission's Public Information Office and the Commission's Electric Staff in advance of being published. Upon their receipt of same, Staff will immediately give other interested parties five (5) business days to review the content of what the Companies seek to publish in order to raise any objection as to the content of the ads. The Commission shall be the ultimate decision maker as to whether an advertisement shall be approved.

In order for Staff to monitor the spending that the Companies will be doing in providing energy efficiency education, the Companies shall filed quarterly reports with the Commission detailing with specificity the expenditures made through this education program. None of the funds allocated shall be used for any expenditure not expressly contemplated by this order.

d) DSM Working Group

The Integrated Resource Planning statute requires this Commission to consider both demand side and supply-side options. In doing so, this Commission must evaluate "the economic, environmental, and other benefits to the state and to consumers of the utility" associated with these various options. O.C.G.A. §§ 46-3A-1(7) and 46-3A-2(b)(3).

In the early 1990's, the Commission embraced numerous DSM programs that ultimately proved costly to non-participants and provided little system-wide benefit. The primary reason for this failure was that there was no real focus or targeted objectives in approving those DSM options. As a result of this failure, in its 1995 IRP Order the Commission adopted the RIM test, which virtually eliminated implementation of any DSM initiative. As it has turned out, the Commission went from one extreme to another.

Since 1995, much has changed in the electric industry that now may impact this Commission's opinion about the need for more DSM. Among other things, many states have found ways to improve and refine these DSM programs. The move towards retail electric deregulation has all but ended, and many regulators are once again considering the public service obligations of utilities that have been granted monopoly rights. These factors, coupled with a dramatic increase in fuel costs to generate energy over the past few years, make the issue of energy efficiency one that must be more closely examined to see whether the position that this agency supported in 1995 regarding the RIM test should be revisited.

In light of these factors, the Commission seeks to find a solution that will strike a balance between economic efficiency and fairness and equity when considering implementation of DSM programs. Regrettably, the record that was created in these

dockets has not been not adequately developed in this area for the Commission to be able to find that balance. The positions of the parties on DSM were very far apart and, for most of the hearing, the parties seemed to be talking past each other and not attempting to reach any middle ground.

As such, rather than returning to the hearing process at this time to further develop the record, the Commission believes that a more productive way to proceed would be to form a DSM Working Group that shall meet to develop a proposed DSM initiative for this Commission to consider. Instead of the all-or-nothing approaches that were presented at the hearing, it is the sincere desire of this agency that the Working Group will develop a reasonable and credible DSM initiative.

Based on the foregoing, the Commission finds and concludes that a Working Group of interested stakeholders to develop a proposed DSM Plan for residential and commercial customers for the Commission's consideration. The Commission Staff shall organize and act as the facilitator of the Working Group, which shall consist of the parties in the IRP cases. The Companies shall not be required to pay the cost of retaining a consultant as requested by ASE during the hearing

The Working Group shall convene for the first time no later than August 15, 2004, and meet as often as needed thereafter. Within 10 days after each of its meetings, the Working Group shall file reports with the Commission in these IRP dockets. These reports shall detail the minutes of the meeting and provide status information regarding the project, including milestones reached and a timetable for completion of remaining milestones. The Commission does not find it appropriate to require the Companies to provide $300,000 as requested by ASE to pay costs that may be incurred by the group in executing and fulfilling its mission.

The Companies will provide to the Working Group such data as may be reasonably necessary for the Working Group to perform its tasks and develop its proposed DSM Plan. To the extent that the Companies contend that any such information is proprietary, it shall be filed with the Commission and be made available to members of the group pursuant to the Commission's Trade Secret rules.

The proposed DSM Plan shall be a comprehensive proposal consisting of 1) a mix of DSM initiatives to be recommended to the Commission for approval, including detailed information regarding how each of the initiatives would be implemented; 2) a recommended process for the selection of DSM initiatives in the future; and 3) recommendations regarding the need for changes to the Commission's IRP rules regarding DSM or for proposed legislation.

The recommended mix of DSM initiatives in the DSM Plan shall be selected by the Working Group using the following criteria:

a. The proposed DSM Plan should minimize upward pressure on rates and maximize economic efficiency. This directive is extremely critical given Georgia Power Company's $328 million pending rate increase request and Savannah Electric and Power Company's scheduled rate filing.

b. The cost/benefit analysis results of each initiative using all 3 tests (RIM, Total Resource Cost test and Participants test) shall be considered by the Working Group and shall balance between economic efficiency and fairness and equity.

c. An examination of where growth is occurring on the system shall be performed by the Working Group, which shall attempt to concentrate its recommended initiatives there. Consideration shall also be given to initiatives that encourage participation by low-income customers.

d. In addition to traditional DSM programs, the Working Group shall consider rate design initiatives. In considering such initiatives, the Working Group should consider the cost/benefit analysis of such initiatives and the time periods that such initiatives would be available to a customer.

e. Every effort should be made by the parties to develop innovative programs and market approaches that will prevent upward pressure on rates and subsidies between participants and non-participants.

f. Where appropriate, the Working Group should consider the development of pilot initiatives (limited enrollment, limited terms) as a tool to gauge initiatives.

g. The Working Group shall also provide input to the utilities in the development of the energy efficiency educational efforts approved by the Commission.

By no later than February 15, 2005, the Working Group shall conclude its mission by submitting a proposed DSM Plan to the Commission.

After the Working Group has tendered its recommendation to the Commission, this agency will consider any further action to be taken regarding the appropriate mix of DSM initiatives to be adopted and the process for the selection of DSM initiatives in the future.

e) Increased Weatherization Program Funding

In their rebuttal testimony, the Companies acknowledged the Commission's concerns regarding low-income customers and expressed a continued commitment to the low-income weatherization assistance programs that have been established for these

customers. (Tr.1025-1026.) Under cross examination by the Staff during the rebuttal phase of the hearing, the Companies indicated that they were amenable to increasing the existing level of funding for their respective low-income weatherization programs. Id. Georgia Power proposed raising its funding level by $300,000 annually (Tr.1025), while Savannah Electric indicated that it believed a $30,000 per year funding increase of its program was appropriate. (Tr.1026.)

During the Special Administrative Session held on July 9, 2004, to issue a decision in this matter, the Commission Chairman read a letter (that also was made part of the record) from Georgia Power in which it was stated this utility, and not its ratepayers, would provide this extra funding. Savannah Electric, he noted, was working toward doing the same thing.[35]

As such, the Commission finds and concludes that the low-income weatherization program of Georgia Power Company shall be continued. Its level of funding, now set at $1,000,000, shall be increased by $300,000, thereby making $1,300,000 the total sum of money that shall be dedicated to the program annually for the next three years. Georgia Power Company has agreed that this additional $300,000 in annual funding shall not be recoverable from ratepayers.

Savannah Electric's low-income weatherization program also shall be continued. Its level of funding, now set at $100,000, shall be increased by $30,000, thereby making $130,000 the total sum of money that shall be dedicated to the program annually for the next three years. Savannah Electric shall work toward supplying the additional funding so that the $30,000 will not be paid by ratepayers. After doing so, Savannah Electric shall report back to the Commission with information as to whether this is possible.

In terms of executing their weatherization programs, both Companies shall offer programmable thermostats to customers with central heat and air who wish to have them installed. Education regarding the use of these thermostats also shall be provided to the participants in these programs.

f) Staff's Programmable Thermostat Recommendation

During its direct case, Staff recommended that Georgia Power and Savannah Electric should be required to develop and implement pilot programs that provide customers an incentive to install programmable thermostats (Energy Star®) in existing residences, and that pilot programs be initiated by both Companies. (Pre-filed Direct Testimony of Staff Panel, page 58.) Initially, it was proposed by Staff that Georgia Power's program should be limited to 25,000 participants, while Savannah Electric's program should have up to 2,000 participants Id.

In the rebuttal testimony of Georgia Power and Savannah Electric, the Companies expressed support for all of Staff's DSM recommendations except for this one. (Pre-filed

[35] Transcript of Special Administrative Session, July 9, 2004, pages 4-5.

Panel Rebuttal Testimony of Companies, page 19.) This lack of support stemmed from Georgia Power's further examination of this measure[36] in which programmable thermostats were represented as having passed the RIM test by only $1.00 before any rebate was considered. Id. After the $25 rebate recommended by Staff was added to the cost of the program, Georgia Power noted that the programmable thermostat program failed the RIM test by at least $24 per thermostat. (Tr. 545.) It also was represented that additional program costs would only serve to worsen this disparity, and that the specifics for Savannah Electric regarding this measure's implementation would be similar. Id.

In light of the Commission's decision to create a Working Group to further consider DSM initiatives, the Commission declines to adopt the Staff recommendation on the development of pilot programmable thermostat program at this time.

2) Continuation of Power Credit Program

As proposed by the Companies, the Commission finds and concludes that Power Credit program should be continued. However, as recommended by Staff (Pre-filed Panel Direct of the Staff, page 60), the program shall be further evaluated by the Georgia Power and Savannah Electric based upon the marginal costs that result from this filing and be included with the updated evaluation of other DSM measures within 3 months of the issuance of the Commission's final order in these dockets. Furthermore, until such time that the Companies project that they will begin activating the programs to reduce peak loads, these programs only should be evaluated as providing reliability benefits.

3) Request for Updated DSM Data Made By Staff

With regard to the "consistency of data" issue discussed elsewhere in this order, Georgia Power and Savannah Electric agreed during cross examination by Staff to file the demand side management evaluation, just as it has always done, with what would be the most current data available at the time of the filing. (Tr.1039.) The Companies did, however, indicate the need to come back with a supplemental filing, probably in the late March/early April time frame, which would show the results of the DSM evaluation using all of those new cost assumptions that were developed in the IRP process. Id. Georgia Power Company and Savannah Electric noted that it would be their intent to try and have that data available prior to the presentation of the Companies' direct cases for the next IRPs filed. As a consequence, Georgia Power and Savannah Electric would be providing updated evaluations for all of those measures with the exact same cost data used in the IRP process itself. (Tr.1037.)

To move towards consistency of data in all analysis performed, the Commission finds and concludes that it is appropriate for the utilities to update the DSM evaluation as described herein during the next IRP filing.

[36] This examination centers on use of such a thermostat in a home heated by natural gas.

5) Use Made of Real Time Pricing Tariffs

In reviewing the Companies' various pricing options, Staff pointed out a number of short-comings with Georgia Power's Real Time Pricing ("RTP") tariffs in terms of it being viewed as a load management tool. Staff argued that due to the way this tariff has been administered, RTP has not resulted in a sizable reduction of load during peak periods. (Pre-filed Direct Testimony of Staff Panel, page 60.) Rather, Staff contended that since it appears that RTP is being used to compete for new loads, the Company's claims of peak load reduction benefits to its system really do not exist. Id. Staff did not dispute that RTP can be a tool for economically adjusting the load shapes of participants in a manner that can benefit not only them but non-participants as well. It did take the position, however, that in order to be effective and beneficial, the hourly price signals must be adequate to encourage participants to change their hourly load shapes. Id. at 60-61. Prices charged of participants on these tariffs must be set to ensure that these customers are supporting the marginal costs incurred to serve them, plus provide a reasonable contribution toward fixed costs. Id. If they are not set to recover these costs, then non-participating customers would be subsidizing the customers on these rates.

The Staff also expressed a concern that the tariff does not contain sufficient requirements for establishing a firm Customer Baseline Load (CBL) below the actual projected load for new load. Id. at 61. The RTP tariff automatically permits an industrial customer to establish its CBL at 60% of the forecasted load for new load, without proof that it can actually operate at 60% of the forecasted load. In addition, the CBL for new loads can be further reduced by reducing load on a one-time basis for only two (2) consecutive hours, with a day-ahead notice. RTP customers have significant economic incentive to reduce their loads for these two hours, considering the fact that they can achieve significant potential savings on all additional load reductions.[37] Staff was concerned that, while RTP tariffs provide significant incentive for customers to temporarily reduce loads to obtain lower RTP prices, reductions may not materialize when the need for significant, sustained load to be shed in the future. Id. at 62. This concern is supported by the fact that estimated RTP reductions for 2003 were such a small fraction of the total RTP load above CBL on Georgia Power's system. If a customer's CBL is set artificially low, then that customer would not be making an appropriate contribution towards fixed costs and those costs would have to be shifted to the remaining non-participating customers.

Staff testified at the hearings that Georgia Power's RTP tariff, as presently administered, has not achieved an appreciable level of load reduction relative to total load above the CBL. Id. at 63. As such, it should be subject to revisions in the upcoming rate case to achieve this goal, if the Commission regards the purpose of RTP to be a load management tool. Id. In addition, the Staff recommended that in its next IRP filing,

[37] This information was derived from the Staff Report filed with the Commission in Docket No. 16896-U, Proceeding to Examine Alleged Discrimination in the Application of Georgia Power Company's Real Time Pricing Tariff, filed on November 14, 2003, p. 8-9.

Georgia Power provide an updated study of the peak load reduction benefits and costs of RTP. Id.

In rebuttal testimony Georgia Power argued that the Staff recommendations do not recognize the primary purposes of the RTP tariffs, which are to provide marginal cost based rates to customers in Georgia that represent market conditions while fully covering cost and making a contribution to fixed costs of customers. (Pre-filed Panel Rebuttal of the Companies, page 21-22.) Georgia Power further argued that its RTP tariffs helped it to compete in the customer-choice market, which results in downward pressure on rates to all of its customers. It was further noted that load management also was a benefit derived from RTP tariffs, through which customers could compare the value of electricity to their cost and make a decision whether or not to purchase energy. Id. Georgia Power testified that it has seen RTP load reduction of over 800 MW in previous years when constrained capacity resources forced the RTP price to extremely high levels. Id.

The Commission finds and concludes that the RTP tariffs shall be further evaluated during the Georgia Power 2004 rate case. If it is found to be appropriate in that case for modifications to the RTP tariffs to be made, the Commission will consider doing so in conjunction with issuing its final order in that docket. For purposes of this case, however, from a system reliability standpoint, it is extremely important to have the best information available to evaluate the load impact of RTP tariffs on the system. Therefore, the Commission finds and concludes that, in its next IRP filing, Georgia Power shall provide an updated study of the peak load reduction benefits from its RTP tariffs.

6) Green Power Programs

Georgia Power Company's 2004 IRP filing includes a stated intention to pursue Green Energy contracts that will provide renewable resources to meet customer requirements.[38] Savannah Electric stated in its IRP filing[39] that it will participate in the Green Power Program approved in Docket No. 16574-U. These programs will not provide capacity resources but will allow willing customers to purchase green energy at zero-cost to non-participants. Both are designed so that they are voluntary for the participants and will have no adverse impact on non-participants. The green portfolio as contemplated will likely include solar, wind, and landfill gas resources.

In the summer of 2003, the Commission approved for each company a Green Energy tariff that authorizes it to sell renewable energy under certain terms and conditions. Despite obtaining this approval, however, the Companies have represented that they are having difficulty in finding local viable sources for their Green Power Programs (Tr.89), which presently are not active. In its testimony, the Staff Panel recommended

[38] See pages 1-7.
[39] See page 9.

that the Companies increase their efforts to locate and contract for green energy resources. (Pre-filed testimony of Staff Witness Panel, p. 71.)

In conjunction with their doing so, Staff also recommended that a target date of one year be established for them to identify a source or sources of green energy, to secure these resources, to establish the availability of the option and to initiate subscriptions with their customers. Id. If, however, within the one year period from August 1, 2004, the Companies remain unable to establish a contractual relationship renewable energy despite employing their best efforts, they should be required to return to the Commission with an explanation and request that their Green Power Programs be re-evaluated. Id. The Companies indicated that they agreed with this recommendation in their rebuttal testimony. (Pre-filed testimony of Companies' Rebuttal Panel, pages 2-3.)

As a consequence of the foregoing, the Commission finds and concludes that the Companies shall increase their efforts to locate and contract for green energy resources. A target date of one year from the date of this final order shall be established at which time the Companies shall identify a green energy source or sources; contract to secure the resources; confirm the availability of the tariff with interested consumers, as well as commence their pre-planned advertising campaigns; and to initiate subscriptions with their customers. If, by August 1, 2005, the Companies remain unable to successfully execute these functions despite employing their best efforts, Georgia Power and Savannah Electric shall file notification of the underlying circumstances with the Commission by September 1, 2005, so that the agency can re-evaluate their Green Power Programs.

7) TRANSMISSION

The Staff Panel was the only set of witnesses that provided any type of examination of the Companies" transmission system planning, the results of which will be set forth generally hereinafter. In doing so, Staff found that the Companies made an assessment of the adequacy and reliability of their transmission system by using the Guidelines for Planning the Southern Company Transmission System (the "Southern Guidelines"), the Guidelines for Planning the Georgia Integrated Transmission System ("ITS Guidelines"), the North American Electric Reliability Council ("NERC") Planning Standards, and the Southeastern Electric Reliability Council ("SERC") Supplements to the NERC Planning Standards. The Companies used two basic criteria for determining its reliability of the transmission grid: (1) overloads on line conductors (based on their thermal limits), and (2) under-voltage on transmission busses.[40] (Pre-filed Panel Testimony of Staff, pages 66-67.)

Staff observed that these criteria were applied first to the "base case" where all generation and loading conditions are at levels that are expected to be "normal."

[40] There are other planning criteria such as transient stability but the criteria mentioned above are the main ones.

Subsequently, the criteria were applied to contingency cases (in particular to first-contingency failure situations), where a generation unit or a transmission line (or transformer) is removed from service. Id. at 67. Under these contingency conditions, the Companies would be able to determine where trouble spots are given likely operating conditions which would allow them to determine whether operating solutions exist to solve the problem, or whether new transmission facilities must be built to solve it. Insofar as their planning procedures are concerned, the Companies took a typical approach to identifying and proposing various solutions to problem areas on the transmission system, eliminating solutions that do not work, and selecting the most cost-effective solution for the long-term.

Staff's analysis resulted in a finding that three basic types of transmission projects existed: 1) projects related to general improvements to the transmission grid; 2) projects related to the addition of new generation to the transmission grid; and 3) projects related to the increase in interface transfer capacity (imports or exports) between the Southern Company (Georgia Power and Savannah Electric in particular) and adjacent utility systems. Although Staff's review was limited to only 12 projects, each of them appeared to be justifiable.[41] Id. at 68-69. The Companies were believed to have identified projects in the ten-year transmission plan that presently are or will be necessary to provide adequate and reliable electric service to their respective customers. Id. Of course, the Commission does not certify transmission projects in the IRP, and decisions on the inclusion of transmission costs in base rates is a decision that is made in rate cases.

In terms of recommendations, Staff had just one. In future IRP filings, Staff would like the Companies to provide the most inclusive and detailed data available for the first half of its 10-year plan. For the remaining half of its plan, the data provided could contain less in-depth information. Id. at 91. In considering Staff's request in this regard, the Companies have indicated in their rebuttal that they are not opposed to doing so. (Pre-filed Panel Rebuttal Testimony of the Companies, page 3.)

As such, the Commission finds and concludes that future IRP filings should provide specific, comprehensive, detailed data for the first 5 years of the 10-year transmission plan, and less detailed data for the remaining 5 years of the plan.

8) ENVIRONMENTAL COMPLIANCE STRATEGY

In analyzing the Companies' IRP filings, Staff reviewed the 2002/2003 Environmental Compliance Strategy Report contained in the Technical Appendix, Volume 1B of Georgia Power's IRP filing. In doing so, the Environmental Compliance Strategy Report was examined to determine if the many environmental issues impacting electric utility operations were adequately analyzed and properly incorporated into the IRPs. Staff also

[41] Despite making this statement, Staff noted that it could not be stated with certainty that every other project is absolutely necessary, nor could it be said definitively that there might not be other alternatives to some of the projects that the Companies are proposing.

evaluated the environmental issues and assumptions utilized in the Unit Retirement Study, which is also found in Technical Appendix, Volume 1B.

As a result of conducting its review, Staff made three recommendations to the Commission in which it sought additional information to what had been filed in the IRPs. Its first recommendation was that, within 60 days of a final order in these dockets, a comprehensive assessment be filed by the Companies detailing all of the possible impacts of all pending environmental regulations that may take effect in the next twelve months. This assessment should provide the Commission with an annual update of the impact of newly promulgated environmental regulations or proposed legislation that may modify the Companies' most recently completed IRP process. It also should include a high and low range of potential capital cost requirements if a particular regulation is promulgated or legislation is enacted, and state whether compliance with the enactment will materially change the recommendations made in the 2004 IRPs. Staff further proposed that the Companies be directed to provide the Commission with an annual update of their Environmental Compliance Strategy along with an analysis of how the updated strategy will impact the Companies' planning processes for the addition of generation and transmission. (Pre-filed Panel Testimony of Staff, pages 91-92.)

A second recommendation made by Staff was for the Companies to use in future IRP filings the same environmental scenarios from their Unit Retirement Study as they do in the Resource Planning Model (IRP Base Case). Id. at 92. This request was made based on a belief that in the 2004 filings, the Unit Retirement Study used included two additional cases recognizing the potential for increased levels of compliance, including Regional Particulate, Regional Haze, State NOx 8-hour Ozone SIPs, Mercury MACT, Clear Skies Act, Clean Power Act and Clean Air Planning Act. Id. The scenarios used in the Resource Planning Model Base Case, however, appeared to Staff to only include previous Acid Rain provisions, the 1-hour ozone requirements and the Regional NOx SIP Call for Georgia beginning in 2007. Using the same scenarios in both the IRP base case and the Unit Retirement Study was promoted by Staff as providing for greater homogeneity.

Staff's third recommendation was for Georgia Power to prepare and file an assessment of the potential impact of increased environmental costs due to hydropower re-licensing. Id. at 92-93. The assessment sought should include the potential impact of increased environmental costs due to hydropower relicensing, reflecting not only the costs of re-licensing but also the potential for lost capacity due to operational modifications to mitigate environmental concerns and the potential increased capacity as a result of unit rehabilitation. In addition thereto, Staff recommended that Georgia Power be directed to provide an assessment of the impact of lost hydropower generation on the existing IRP resource mix if, during relicensing, capacity loss occurs due to environmental mitigation.

With respect to its first recommendation, it should be noted that the Company filed on May 21, 2004, Southern Company's 2003/2004 Environmental Compliance Strategy Review, which is an annual filing that is made on behalf of Georgia Power and

Savannah Electric. This 2004 environmental filing, which was made one week after Staff's panel testimony was filed, contains much of the information that Staff recommended be filed, although perhaps not to the level of detail that was identified in the panel testimony. (Pre-filed Panel Rebuttal of the Companies, page 43.)

As it pertains to Staff's second recommendation, the Companies indicated that there was no objection with compliance but noted that it appeared to be the product of Staff's confusion that the environmental scenarios from the IRP base case were different from those used in the Unit Study when this was not the case. (Pre-filed Panel Rebuttal of the Companies, pages 49-50).

Regarding the third recommendation, however, Georgia Power has expressed concerns in its panel rebuttal testimony regarding Staff's request as it relates to the preparation and filing of an assessment of potential impacts of increased environmental costs due to Hydropower Re-licensing. In doing so, Georgia Power noted that such an analysis was done in compliance with the 2001 IRP order in which it was noted that cost and other issues related to facility upgrades were largely unknown some 5 years before the first facility was to be relicensed.[42] (Pre-filed Panel Rebuttal of the Companies, page 53.)

Based upon the foregoing, the Commission finds and concludes that the Companies shall continue to file their Environmental Compliance Strategy Review on an annual basis; provided, however, that the scope of this filing shall be supplemented to include: 1) a high and low range of potential capital cost requirements if a particular regulation is promulgated or legislation is enacted, and information whether compliance with the enactment will materially change the recommendations made in the 2004 IRPs; and 2) an analysis of how the updated strategy will impact the Companies' planning processes for the addition of generation and transmission.

The Commission further finds and concludes that it is appropriate for Georgia Power to keep this agency and its Staff abreast of any developments that will result in more concrete information becoming available regarding cost estimates and facility upgrades for the hydropower facilities that are to be relicensed. Information that should be provided to the Commission on this issue, when available, shall include the potential impact of increased environmental costs due to hydropower relicensing, reflecting not only the costs of re-licensing but also the potential for lost capacity due to operational modifications to mitigate environmental concerns and the potential increased capacity as a result of unit rehabilitation. In addition thereto, Georgia Power shall provide in its Environmental Compliance Strategy Review an assessment of the impact of lost Hydropower generation on the existing IRP resource mix if, during relicensing, capacity loss occurs due to environmental mitigation.

[42] The hydropower facilities to be relicensed within the next 20 years include Morgan Falls (2009), Bartletts Ferry (2014) and Wallace Dam (2020).

9) GENERAL RECOMMENDATIONS

a) Anticipated Impacts of Resource Plans on Rates

In its rebuttal testimony, the Companies opposed providing more detailed information regarding individual company rate impacts resulting from the underlying resource selections. (Companies' Pre-filed Rebuttal Panel Testimony, p. 48.) The panel indicated that more detailed information regarding rate impacts of resource selections was not the purpose of the IRP hearing, which was held to examine the development of resource plans and not project rates. (Tr. 1013-1014.) However, when pressed as to what type of hearing would take place at which the Commission would have the opportunity to examine the potential rate impacts, given that gas prices are high, environmental costs are growing and the company plans to do nothing but build gas-fired units, no forum could be identified. Id. It was also noted during rebuttal that what information had been provided about rate analyses in Exhibit A-1 to Georgia Power's Technical Appendix 1-A pertained to the Southern Company foot print as a whole, and not to each of the individual operating companies. (Tr. 1004-1005.)

Based upon the absence of company-specific details regarding rate-analyses for the resources identified in the plan, the Commission finds and concludes that the Companies must more fully communicate in future IRP filings information regarding the anticipated impacts their resource plans have on their forecasted rates. The nature of the Companies' resource mix clearly is changing. Operating companies' rates are vulnerable to such things as fuel spikes, environmental actions and technology advancements. As the resource mix changes from one that primarily uses coal and nuclear energy to one that more heavily relies on natural gas, the vulnerabilities and rate impacts that accompany such change must be clearly and accurately articulated within the IRP filings. Furthermore, at such time as the ultimate decision is to be made as to selecting one technology type over another, the knowledge of forecasted rate impacts should provide additional guidance in selecting the appropriate resource type. The IRP review, with its focus on a long-term evaluation of resource plans would be the ideal proceeding to also evaluate the resulting impacts on individual operating company customer rates.

b) Filing of Information in Integrated Resource Plans

In future IRP filings, the Companies are encouraged to use consistent data in evaluating all aspects of the IRP. Again, this includes transmission analyses, DSM modeling, retirement studies, as well as the load forecast, etc.

B) DIRECTIVES PERTAINING TO THE IRP RULES REGARDING THE PROCESS FOR ISSUING AND EVALUATING REQUESTS FOR PROPOSALS

As previously stated in this Order, the Commission invited interested parties to provide testimony during the hearings on various topics related to the manner in which bids for purchase power contracts are solicited and evaluated on behalf of the Companies. The purpose of seeking this information was to consider amending Utility Rule 515-3-4-.04(3), Request for Proposals Procedure for Long-Term New Supply–Side Options, to state with greater specificity the steps that were to be followed when a competitive solicitation was to be issued for purchase power to fill a designated supply-side need. Recommendations were made that pertain to the timing issues related to the bidding process to be considered in future solicitations.

a) Modifications Proposed to Existing Utility Rule 515-3-4-.04(3)

The Staff, Calpine, and GTMA/GIG pre-filed testimony[43] that responded to the issues identified by the Commission on this subject, all of which was supportive of having some form of an independent evaluator involved in the RFP process. Each of the witnesses testifying on this topic, however, had different ideas regarding the details that would need to be laid out regarding the manner in which the RFP was to be issued, how they were to be evaluated, and how the winning solicitations were to be selected and presented to the Commission for certification. The Companies, while not as adamant as the other responding parties as to the need to have an independent entity perform these functions, offered testimony as to what they believed would be a fair process through which an independent monitor could assist in the RFP.[44]

As the hearing progressed, representatives of Staff, Calpine, GTMA/GIG, the CUC and the Companies met to discuss this issue to see if a joint solution could be reached. During the rebuttal phase of the hearings, the Companies, on behalf of all of the aforementioned parties, entered into evidence as "Joint Parties Exhibit 1" a Stipulation endorsing the acceptance of measures to be applied in future supply-side solicitations over which a Commission-selected Independent Evaluator would preside. The structure proposed therein represents principles and procedures the sponsoring entities believe should be captured and embodied in a rulemaking by the Commission to modify existing Rule 515-3-4-.04(3) in order to adopt an Independent Evaluator ("IE") for use in all

[43] Staff's initial view on the RFP related issues can be found on pages 76 through 87 of its pre-filed panel testimony. Calpine's preliminary position on these issues was provided by Mr. Timothy Eves on pages 8 through 20 of his pre-filed testimony. GTMA/GIG's stance on this subject matter was provided by Mr. Jeffry Pollock on pages 5 through 10 of his pre-filed testimony.

[44] The positions taken by the Companies on the contemplated RFP process changed throughout the hearings and can be found on pages 17 through 27 of their pre-filed direct testimony, as well as later in their proposal modifying this initial position found on pages 22 to 40 of their rebuttal.

future RFPs. To make the changes called for by the Stipulation, it was further recommended that a rulemaking be commenced by the Commission.[45]

Based on the agency's review of the Joint Stipulation, which is attached and incorporated by reference herein, the Commission finds and concludes that it is appropriate to approve and accept its terms and provisions as part of the Final Order in these dockets. In order to properly further the enhancements that have been authorized, the Commission finds and concludes that a rulemaking proceeding shall be initiated before the end of August 2004, in which the Commission shall accept and incorporate the proposed amendments to the RFP Rule in accordance with the RFP/IE structure endorsed by the stipulation.

b) Detailed Code of Conduct To Be Prepared by the Companies

The Commission also finds and concludes that the Companies shall prepare and file for the agency's approval no later than August 31, 2004, a detailed code of ethics regarding affiliate communications, particularly as they relate to the preparation and evaluation of competitive solicitations. The depth and breadth of the code of conduct that is to be proposed by Georgia Power and Savannah Electric shall be extended to cover those individuals that are directly or indirectly in the employ of any of its affiliates or parent company and shall be executed in the manner contemplated by the Joint Stipulation.

c) Status Of The 70/30 Directive Regarding The Ownership Percentage Of And The Purchased Power Percentage Of Capacity Called For In the 2001 IRP Order

In his pre-filed testimony, Calpine witness Tim Eves argued that the directive calling for at least 70% ownership of capacity by the Companies and not more than 30% purchased power[46] should be regarded as a flexible Commission "guideline" and not a "hard cap."[47] (Pre-filed testimony of Calpine, p. 21-22.) However, the manner in which the limitations on the percentage of purchased power works is now governed by the terms of the Joint Stipulation. The only remaining question is whether the Commission, at this time, should modify those percentages. Having considered doing so, the Commission expressly declines to make any such modification at this time. In opting not to change the percentages, the Commission notes that the Companies are not and will not be in the next 3 years in a situation in which the issue the 30% cap will be reached. Consistent with the terms of the Joint Stipulation, the Commission will revisit the issue in the 2007 IRP.

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[45] On transcript pages 962-966, Companies' witness Garey C. Rozier provided a good summary of the contents of the Stipulation, which will not be recited again in this Order, but rather, will be made an attachment to and be incorporated by reference.

[46] This 70/30 directive is contained in the *Final Order* issued in IRP Docket Nos. 13305-U and 13306-U.

d) Directives Pertaining to the Contemplated Solicitation for 2009 Capacity Needs

1) Inclusion of Life of Unit Solicitations in Future IRPs

During the hearing, Staff made a recommendation that future capacity solicitations should include requests for consideration of proposals for "life-of-unit" proposals. (Pre-filed Direct Staff Panel Testimony, page 90.) As understood by the Commission, these bids effectively permit a merchant unit owner to sell the capacity and energy to the Companies for the same time period that the Companies themselves would operate a self-build option. On rebuttal, the Companies indicated that it was opposed to seeking life-of-unit proposals on the grounds that it would cause a loss in operating flexibility, was unnecessary since the existing 7 to 15 year solicitations have yielded good results, and would cause confusion as to what is actually meant in by the phrase "life-of-unit" in submitting and evaluating such a bid. (Tr. 1014-1016.)

The Commission disagrees with the Company in part, and would like to see such bids solicited in order to foster competitive bidding in Georgia. In seeking life-of-unit bids, however, the Commission does agree that there exists a potential for confusion as to what exactly is being sought in terms of a supply side resource.

Based on these concerns, the Commission finds and concludes that in the 2009 RFP, the Companies shall seek 30-year contracts for purchased power in addition to the 7- and 15-year contracts that it has been soliciting in recent time. In the event that this directive would conflict with the Commission's 30% limit on total supply-side purchased power resources, the life-of-unit purchases could then be structured as an actual sale of the unit(s) to the Companies.

2) Schedule of Actions for the Next RFP to be Issued

In furtherance of the objectives set forth in the Joint Stipulation regarding the competitive bidding process referenced above, the Commission finds and concludes that the a schedule of events for the release of an RPF shall be adhered to in conjunction with seeking the most economical supply-side capacity assets in the immediate future. On or before July 15, 2005, the Companies will file for approval with the Commission a proposed schedule of events for the release of RFPs for the time period 2009 through 2012. This filing shall also include target dates for submitting proposed IE's, RFP Service Dates, dates for notification of bid and evaluation team members, dates for filing of draft RFP's and standard purchase power agreements and capacity to be sought in each RFP.

Once approved by the Commission, any deviations, planned or unintended, from the established schedule must be authorized by this agency before they are made by the Companies.

IV. ORDERING PARAGRAPHS

WHEREFORE IT IS ORDERED that the Commission adopts the Integrated Resource Plans developed by Georgia Power and Savannah Electric with the augmentations and/or modifications set out below.

ORDERED FURTHER, that the demand and energy forecasts filed by Georgia Power and Savannah Electric be approved without modification to any projections to any customer class.

ORDERED FURTHER, that Georgia Power and Savannah Electric shall update their demand and energy forecasts and budget comparison information through March 31, 2004, in order to reflect actual usage that has occurred since these forecasts were finalized in the spring of 2003. Once updated through this time frame, these forecasts shall be filed with the Commission by no later than August 16, 2004.

ORDERED FURTHER, that in conducting future reserve margin studies, as with all evaluations that are conducted as part of an IRP, consistent modeling data should be used to the greatest extent possible.

ORDERED FURTHER, that the Companies' target reserve margin for the 2004–2006 timeframe shall be set at 13.5%, with 15% to be used for the remainder of the study period.

ORDERED FURTHER, that the Companies' Generation Expansion Plans shall be regarded as adequate based upon the information that has been made available to the Commission .

ORDERED FURTHER, that Plant Atkinson CT's 5 A and 5B shall be de-certified by Georgia Power Company.

ORDERED FURTHER, that Savannah Electric shall extend the planned life of the 17 MW Kraft CT unit capable of providing black starts and remove it from further consideration for retirement until such time when such action is shown to be warranted.

ORDERED FURTHER, that Georgia Power and Savannah Electric shall inform the Commission in a filing of any changes in fuel price conditions, including external forecasts that may warrant development of a new utility price forecast and advise the Commission on the impacts these changes may have on the long range IRP. The Companies also shall make available any fuel forecast update as soon as it is available within each 6 month Progress Report to the Commission called for by Utility Rule 515-3-4-.05.

ORDERED FURTHER, that both GPC and Savannah Electric shall further develop the partnership that it has entered into with Energy Star® through which appliances acknowledged as having a certain level of energy efficiencies would be promoted by the Companies in ways such as providing consumers with manufacturers' coupons for energy efficient appliances with their bills.

ORDERED FURTHER, that Georgia Power and Savannah Electric also shall more aggressively promote the availability of energy audits for interested customers.

ORDERED FURTHER, that the Companies shall offer as part of their low-income weatherization programs the option of having programmable thermostats installed to those customers with central heat and air that wish to have the thermostat installed. Education as to how to use the thermostat shall also be provided.

ORDERED FURTHER, that a Working Group be created of interested stakeholders to develop a proposed DSM Plan for residential and commercial customers for the Commission's consideration. The Commission Staff shall organize and act as the facilitator of the Working Group, which shall consist of the parties in the IRP cases.

ORDERED FURTHER, that the recommendation by ASE and supported by SACE and GIPL for the Companies to be required to fund a consultant for a working group is rejected in its entirety.

ORDERED FURTHER, that the Working Group shall convene for the first time no later than August 15, 2004, and meet as often as needed thereafter.

ORDERED FURTHER, that within 10 days after each of its meetings, the Working Group shall file reports with the Commission in these IRP dockets. These reports shall detail the minutes of the meeting and provide status information regarding the project, including milestones achieved and a timetable for completing those that remain.

ORDERED FURTHER, that the Companies will provide to the Working Group such data as may be reasonably necessary for the Working Group to perform its tasks and develop its proposed DSM Plan. To the extent that the Companies contend that any such information is proprietary, it shall be filed with the Commission and be made available to members of the group pursuant to the Commission's Trade Secret rule.

ORDERED FURTHER, that the proposed DSM Plan shall be a comprehensive proposal consisting of 1) a mix of DSM initiatives to be recommended to the Commission for approval, including detailed information regarding how each of the initiatives would be implemented; 2) a recommended process for the selection of DSM initiatives in the future; and 3) recommendations regarding the need for changes to the Commission's IRP rules regarding DSM or for proposed legislation.

ORDERED FURTHER, that the recommended mix of DSM initiatives in the DSM Plan shall be selected by the Working Group using the following criteria:

a. The proposed DSM Plan should minimize upward pressure on rates and maximize economic efficiency. This directive is extremely critical given Georgia Power Company's $328 million pending rate increase request and Savannah Electric and Power Company's scheduled rate filing.

b. The cost/benefit analysis results of each initiative using all 3 tests (RIM, Total resource Sot test and Participants test) shall be considered by the Working Group and shall balance between economic efficiency and fairness and equity.

c. An examination of where growth is occurring on the system shall be performed by the Working Group, which shall attempt to concentrate its recommended initiatives there. Consideration shall also be given to initiatives that encourage participation by low-income customers.

d. In addition to traditional DSM programs, the Working Group shall consider rate design initiatives. In considering such initiatives, the Working Group should consider the cost/benefit analysis of such initiatives and the time periods that such initiatives would be available to a customer.

e. Every effort should be made by the parties to develop innovative programs and market approaches that will prevent upward pressure on rates and subsidies between participants and non-participants.

f. Where appropriate, the Working Group should consider the development of Pilot Initiatives (limited enrollment, limited terms) as a tool to gauge initiatives.

g. The working group shall also provide input to the utilities in the development of the energy efficiency educational efforts approved by the Commission.

ORDERED FURTHER, that by no later than February 15, 2005, it shall conclude by submitting a proposed DSM Plan to the Commission.

ORDERED FURTHER, that the Commission does not find it appropriate to require the Companies to provide $300,000 as requested by ASE to pay costs that may be incurred by the group in executing and fulfilling its mission.

ORDERED FURTHER, that after the Working Group has tendered its recommendation to the Commission, this agency will consider any further action to be

taken regarding the appropriate mix of DSM initiatives to be adopted and the process for the selection of DSM initiatives in the future

ORDERED FURTHER, that given the Commission decision to create a Working Group to consider DSM programs, the Staff recommendation that the Companies develop a pilot programmable thermostat DSM program is not adopted by the Commission at this time.

ORDERED FURTHER, that the low income weatherization program of Georgia Power Company shall be continued. Its level of funding, now set at $1,000,000, shall be increased by $300,000, thereby making $1,300,000 the total sum of money that shall be dedicated to the program annually for the next three years. Georgia Power Company has agreed that this additional $300,000 in annual funding shall not be recoverable from ratepayers.

ORDERED FURTHER, that Savannah Electric's low-income weatherization program also shall be continued. Its level of funding, now set at $100,000, shall be increased by $30,000, thereby making $130,000 the total sum of money that shall be dedicated to the program annually for the next three years. Savannah Electric shall work toward supplying the additional funding so that the $30,000 will not be paid by ratepayers. After doing so, Savannah Electric shall report back to the Commission with information as to whether it can do so.

ORDERED FURTHER, that additional education on the efficient use of electricity shall be made available by the Companies.

ORDERED FURTHER, that Georgia Power shall fund with no more than $2,000,000 an energy efficiency campaign that it shall implement to promote consumer awareness of those energy efficiency measures and practices that produce the greatest economic efficiency and benefit to a participant.

ORDERED FURTHER, that Savannah Electric shall fund with no more than $200,000 an energy efficiency campaign that it shall implement to promote consumer awareness of those energy efficiency measures and practices that produce the greatest economic efficiency and benefit to a participant.

ORDERED FURTHER, that in order to further their respective energy efficiency educational campaigns, the Companies may use any recognized medium through which their customers could reasonably be expected to be exposed, including, but not limited to, television advertisements, radio spots and advertisements in local newspapers and periodicals.

ORDERED FURTHER, that all information disseminated through the media shall be for the exclusive purpose of promoting education in the area of energy efficiency and shall not serve as a forum to promote the Southern brand (or that of its subsidiaries) in any way, or to further other initiatives of the Companies outside of those contemplated

herein. Television, radio and/or print ads shall provide as much information about managing electric usage as possible in the time/space allotted. A general understanding of electric energy efficiency and conservation should be able to be derived by the average viewer after seeing/listening to any advertisements. The theme of all advertisements should be strictly education-based. Any advertisements that the Commission, in its sole discretion, finds not to be adequate for its intended purpose shall not be financed with monies allocated in this order for consumer education.

ORDERED FURTHER, that copies of television ads, radio scripts and print advertisements containing information that is to be disseminated to the public as part of the energy efficiency programs shall first be provided to the Commission's Consumer Affairs Office, the Commission's Public Information Office and the Commission's Electric Staff in advance of being published. Upon their receipt of same, Staff will immediately give other interested parties five (5) business days to review the content of what the Companies seek to publish in order to raise any objection thereto. The Commission shall be the ultimate decision maker as to whether an advertisement shall be approved.

ORDERED FURTHER that the Companies shall file quarterly reports at the Commission detailing with specificity the expenditures made through this education program. None of the funds allocated shall be used for any expenditure not expressly contemplated by this order.

ORDERED FURTHER, that to move towards consistency of data in all analyses performed, the Commission finds that it is appropriate for the utilities to update the DSM evaluation as described herein during the next IRP filing.

ORDERED FURTHER, that the Companies shall continue their implementation of the Power Credit Program;

ORDERED FURTHER, that the Power Credit program shall be further evaluated by the Companies based upon the marginal costs that result from this filing and be included with the updated evaluation of other DSM measures within 3 months of the issuance of the Commission's Final Order in these dockets.

ORDERED FURTHER, that with regard to the "consistency of data" issue discussed elsewhere in this order, as it relates to the DSM screening analysis, Georgia Power and Savannah Electric shall file the demand side management evaluation with what would be the most current data available at the time of the filing, but then come back with a supplemental filing, in the late March, early April time frame, that would show the results of the DSM evaluation using all of those new cost assumptions that were developed in the IRP process.

ORDERED FURTHER, the Companies shall update their DSM evaluation in the manner described in this order for use in their 2007 IRP filings.

ORDERED FURTHER, that the Commission shall evaluate the RTP tariffs during the Georgia Power 2004 rate case and make any appropriate tariff revisions at that time as it sees fit.

ORDERED FURTHER, that, in its next IRP filing, Georgia Power shall include an updated study of the peak load reduction benefits from RTP tariffs.

ORDERED FURTHER, that the Companies shall increase their efforts to locate and contract for green energy resources for their Green Energy Programs.

ORDERED FURTHER, that a target date of one year from the date of this Final Order shall be established during which the Companies shall identify a green energy source or sources; contract to secure the resources; confirm the availability of the tariff with interested consumers, as well commence their pre-planned advertising campaigns; and to initiate subscriptions with their customers.

ORDERED FURTHER, that if, by August 1, 2005, the Companies remain unable to successfully execute these functions relating to renewable resources despite employing their best efforts, Georgia Power and Savannah Electric shall file a notification of the underlying circumstances with the Commission by September 1, 2005, so that the agency can re-evaluate their Green Power Programs.

ORDERED FURTHER, that in future IRP filings, the Companies provide the most comprehensive, detailed data available for the first half of their 10-year transmission plan. For the remaining half of its plan, less detailed data may be filed

ORDERED FURTHER, that the Companies shall continue to file their Environmental Compliance Strategy Review on an annual basis; provided, however, that the scope of this filing shall be supplemented to include: 1) a high and low range of potential capital cost requirements if a particular regulation is promulgated or legislation is enacted, and information whether compliance with the enactment will materially change the recommendations made in the 2004 IRPs; and 2) an analysis of how the updated strategy will impact the Companies' planning processes for the addition of generation and transmission.

ORDERED FURTHER, that Georgia Power shall keep this agency and its Staff abreast of any developments that will result in more concrete information becoming available regarding cost estimates and facility upgrades for the hydropower facilities that are to be relicensed. Information that should be provided to the Commission on this issue, when available, shall include the potential impact of increased environmental costs due to hydropower relicensing, reflecting not only the costs of re-licensing but also the potential for lost capacity due to operational modifications to mitigate environmental concerns and the potential increased capacity as a result of unit rehabilitation.

ORDERED FURTHER, that Georgia Power shall provide in its Environmental Compliance Strategy Review an assessment of the impact of lost Hydropower

generation on the existing IRP resource mix if, during relicensing, capacity loss occurs due to environmental mitigation.

ORDERED FURTHER, that the Companies must more fully communicate to the Commission in future IRP filings information regarding the anticipated impacts their resource plans have on their forecasted rates. The vulnerabilities and rate impacts that accompany the resource mix change being planned for must be clearly and accurately articulated within the IRP filings.

ORDERED FURTHER, that in conducting IRP studies the Companies should to the greatest extent possible, set as an objective to use consistent data throughout all analyses conducted as part of the IRP.

ORDERED FURTHER, that the Joint Stipulation regarding the RFP/IE rule enhancements agreed to by interested parties in these dockets is approved as part of the Final Order in the dockets, a copy of which is attached and incorporated by reference herein.

ORDERED FURTHER, that a rulemaking proceeding shall be initiated by Staff before the end of August 2004, in which the Commission shall promulgate as rule amendments the RFP/IE structure endorsed by the Joint Stipulation.

ORDERED FURTHER, that the Companies shall prepare and file for the agency's approval no later than August 31, 2004, a detailed code of conduct regarding affiliate communications, particularly as they relate to the preparation and evaluation of competitive solicitations.

ORDERED FURTHER, that the depth and breadth of the code of conduct that is to be proposed by Georgia Power and Savannah Electric shall be extended to cover those individuals that are directly or indirectly in the employ of any of its affiliates or parent company and shall be executed in the manner contemplated by the Joint Stipulation.

ORDERED FURTHER, that consistent with the IRP Final Order issued July 5, 2001, the Commission shall limit the amount of supply-side capacity provided through purchased power contracts to 30 percent of total supply-side resources. A determination of whether this cap should be increased, decreased or eliminated in its entirety is an issue that this Commission will not have the need to contemplate until the 2007 IRP.

ORDERED FURTHER, that in the 2009 RFP, the Companies shall seek 30-year contracts for purchase power in addition to the 7- and 15-year contracts that it has been soliciting in recent time. In the event that this directive would conflict with the Commission's 30% limit on total supply-side purchase power resources, the life-of-unit purchases could then be structured as an actual sale of the unit(s) to the Companies.

ORDERED FURTHER, that on or before July 15, 2004, the Companies will file for approval with the Commission a proposed schedule of events for the release of RFPs for the time period 2009 through 2012. This filing also shall include target dates for submitting proposed IE's, RFP Service Dates, dates for notification of bid and evaluation team members, dates for filing of draft RFP's and standard purchase power agreements and capacity to be sought in each RFP.

ORDERED FURTHER, that once approved by the Commission, any deviations, planned or unintended, from the established schedule of events must be authorized by the agency before they are made by the Companies.

ORDERED FURTHER, that no determinations are made as to the need, effectiveness or reasonability of any rates, tariffs and pricing strategies filed in conjunction with the IRPs in this Order. The feasibility and determination of the appropriate level of these rates, tariffs and pricing strategies shall be made in the general rate cases that have been or will be filed by the Companies in 2004.

ORDERED FURTHER, that all findings of fact and conclusions of law contained within the preceding sections of this Order are hereby adopted as findings and conclusions of this Commission.

ORDERED FURTHER, that a motion for reconsideration, rehearing or oral argument or any other motion shall not stay the effective date of this Order, unless otherwise ordered by the Commission.

ORDERED FURTHER, that jurisdiction over this matter is expressly retained for the purpose of entering such further Order or Orders as this Commission may deem just and proper.

The above by action of the Commission during a Special Administrative Session held on July 9, 2004.

REECE MCALISTER	**H. DOUG EVERETT**
EXECUTIVE SECRETARY	**CHAIRMAN**
DATE	**DATE**

FINAL REPORT OF THE GEORGIA DSM WORKING GROUP

FEBRUARY 15, 2005

Prepared in Response to the Georgia Public Service Commission Orders in Integrated Resource Planning dockets 17687-U and 17688-U

I. Executive Summary

In July of 2004, the Georgia Public Service Commission unanimously passed a motion establishing the Demand-Side Management Working Group to address issues raised in Integrated Resource Planning dockets 17687-U and 17688-U. This motion was subsequently included in the ordering paragraphs of the Commission's final order in this docket, and directed the workgroup to accomplish three tasks:

- Bring the Commission a mix of DSM initiatives to be recommended to the Commission for approval, including detailed information regarding how each of the initiatives would be implemented;
- Recommend a process for the selection of DSM initiatives in the future;
- Recommendations for the need for changes to the commission's IRP rules regarding DSM or for proposed legislation.

The motion and subsequent order also established six criteria for proposing this mix of DSM programs to the Commission. These criteria are described later on in this report, but foremost among the criteria was the requirement that the proposed DSM Plan should minimize upward pressure on rates and maximize economic efficiency.

This report to the Commission provides an overview of the deliberations of the workgroup and its recommendations to the Commission in the following major areas:

- A proposed mix of DSM programs for the Commission to consider and approve for immediate implementation
- A recommended procedure for evaluation of future DSM programs
- Recommended Changes to IRP rules and Legislative recommendations

These are described in detail in the body of the report and in its appendices.

The Workgroup Process

The Demand Side Management (DSM) Working Group met officially eight times and informally several times to fulfill the order of the Commission dated July 14, 2004. The Commission directed that all interveners in Dockets 17687-U and 17688-U would be allowed to participate as members of the workgroup. The workgroup looked at the three tests run by Georgia Power Company (GPC) and Savannah Electric and Power Company (Savannah Electric) to evaluate potential DSM measures that have been adopted by the Commission. Those three tests, Total Resource Cost (TRC), Participant, and Rate Impact Measure (RIM), have provided the basis for Commission decisions on whether to implement DSM programs. All three tests involve the projection and estimation of many costs.

The Commission requested information to help it balance rate impacts with economic efficiency when considering DSM resources. As one way to accomplish this goal, the workgroup recommends an "analytical cap" that would provide the Commission adequate

information to review effective DSM measures while minimizing the IRP preparation responsibility burden on the Companies. The "analytical cap" is a proposed limit on the total amount of projected rate impacts over the life of the program before the Companies would stop evaluating additional programs for that integrated resource planning cycle, currently every three years. This cap, as described later on, is expressed both in absolute dollars and as a percentage of the companies' revenue requirements. Thus, the Commission would have before it DSM proposals that include program costs, energy savings, and quantifiable impacts on customer rates, if any. The companies would be required to design programs up to the analytical cap. Any party would be free to oppose the actual implementation of any program that did not pass RIM, but the Commission would not be prevented from considering a program just because it failed RIM but provided other TRC benefits of interest to the Commission. The companies would be required to quantify the rate impact in their evaluation so that the Commission would have the best information possible to make an informed decision. One other step in this process would be to allow the Commission to authorize a pilot program for any program, including those that did not pass RIM, in order to acquire additional information about the true cost, demand and energy savings of the program.

The workgroup understood the limited resources available and worked diligently to maximize the impact of its recommendations while placing as little burden as possible on the ratepayers. The discussions were very productive and led the workgroup to some very innovative suggestions that merit additional scrutiny.

II. Introduction

Neither the 2004 IRP filing for Georgia Power nor the filing made by Savannah Electric contained any new DSM programs because, the Companies contended, none were found to be cost-effective by applying the screening tests specified in the Commission's rules and prior orders, although other parties disagreed. Georgia Power and Savannah Electric indicated in that proceeding that it remained appropriate for this Commission to use the RIM test as the final screening tool to determine whether a DSM measure should be implemented.

The Integrated Resource Planning statute requires this Commission to consider both demand side and supply-side options. In doing so, this Commission must evaluate "the economic, environmental, and other benefits to the state and to customers of the utility" associated with these various options. This suggests that these other benefits be evaluated using the TRC test which is designed to quantify these important benefits.

In the early 1990's, the Commission approved numerous DSM programs that ultimately proved costly to non-participants and provided little system-wide benefit. In its final order in Dockets 17687-U and 17688-U the Commission found that the Primary reason for this failure was that there was no real focus or targeted objectives in approving those DSM options. Others assert that the reasons for failure were a heavy reliance on the TRC test without consideration for RIM, and unanticipated expenses associated with implementing programs without much use of preliminary pilot projects for evaluation

purposes. As a result of this failure, in its 1995 IRP Order the Commission adopted the RIM test, which virtually eliminated implementation of any DSM initiative. As the Commission noted in its July 2004 motion, the Commission went from one extreme to another. Thus, the Commission's motion and subsequent order charged the workgroup to provide recommendations that would assist the Commission in achieving a balance between rate impacts (e.g., RIM) and economic efficiency (e.g., TRC.)

Since 1995, much has changed in the electric industry that now may impact this Commission's opinion about the need for more DSM. Among other things, many states have found ways to improve and refine these DSM programs. This, along with a dramatic increase in fuel costs, makes the issue of energy efficiency one that should be more closely examined to see whether the policy that this agency supported in 1995 regarding DSM evaluation should be continued.

The Commission is seeking to find a solution that will strike a balance between economic efficiency and fairness and equity when considering implementation of DSM programs. The Commission felt that the record that was created during the hearings for these dockets has not been adequately developed in this area for the Commission to be able to find that balance.

The Commission therefore believed that a more productive way to proceed would be to form a DSM Working Group that would develop a proposed DSM initiative for the Commission to consider. Instead of the all-or-nothing approaches that were presented at the hearing, it was the sincere desire of the Commission that the Working Group develop a reasonable and credible DSM initiative.

a. Charge from the Commission

The Commission directed the workgroup to accomplish three tasks:

1. Bring the Commission a mix of DSM initiatives to be recommended to the Commission for approval, including detailed information regarding how each of the initiatives would be implemented;
2. Recommend a process for the selection of DSM initiatives in the future;
3. Recommendations for the need for changes to the commission's IRP rules regarding DSM or for proposed legislation.

The Commission further directed that the mix of DSM initiatives to be recommended shall be selected according the following criteria:

1. The proposed DSM Plan should minimize upward pressure on rates and maximize economic efficiency;
2. The cost/benefit analysis results of each initiative using all 3 tests (RIM, Total Resource Cost test and Participants test) shall be considered by the Working Group and shall balance between economic efficiency and fairness and equity;

3. An examination of where growth is occurring on the system shall be performed by the Working Group, which shall attempt to concentrate its recommended initiatives there. Consideration shall also be given to initiatives that encourage participation by low-income customers;
4. In addition to traditional DSM programs, the Working Group shall consider rate design initiatives. In considering such initiatives, the Working Group should consider the cost/benefit analysis of such initiatives and the time periods that such initiatives would be available to a customer;
5. Every effort should be made by the parties to develop innovative programs and market approaches that will prevent upward pressure on rates and subsidies between participants and non-participants; and
6. Where appropriate, the Working Group should consider the development of pilot initiatives (limited enrollment, limited terms) as a tool to gauge initiatives.

7. The workgroup believes that the recommendations in this report and the proposed mix of DSM programs meet the Commission's requirements as set forth above.

b. Members of the DSM Working Group

The Commission directed that all interveners in the IRP dockets 17687-U and 17688-U would be allowed to participate as members of the workgroup. Although not all interveners chose to participate, most did. Participating interveners along with the primary representatives were:

1. Georgia Power (GPC) - Jeff Burleson, Dean Harless
2. Savannah Electric – Dick White, Matt Gignilliat
3. Southern Alliance for Clean Energy (SACE) - Jim Presswood, Rita Kilpatrick
4. Alliance to Save Energy (ASE) – Harry Misuriello, Dick Spellman
5. Georgia Environmental Facilities Authority (GEFA)-Kevin Kelly, Julia Miller,
6. Consumers' Utility Counsel (CUC) Division of the Governor's Office of Consumer Affairs – Jeanette Mellinger, Christiane Sommer, Matthew Hardy
7. Georgia Interfaith Power and Light (GIPL) – Woody Bartlett
8. Georgia Industrial Group(GIG) – Randy Quintrell
9. Georgia Textile Manufacturer's Association (GTMA) – Peyton Hawes
10. Resource Supply Management (RSM) – Jim Clarkson
11. Georgia Public Service Commission (PSC) – Jim Bottone, Dan Cearfoss, Janey Chauvet

Non-interveners who regularly attended and participated in the Working Group discussions included Dennis Creech from the Southface Energy Institute, Tyler Newman from the Georgia Homebuilders Association, and Phil Weatherly from Georgia EMC.

III. DSM Initiatives

The Work Group settled on four programs to offer to the Commission for adoption at this time. Each program is discussed in detail in the appendices. These four programs are designed to accomplish the goals set out in the Commission's order:

a. The proposed statewide, "fuel neutral" **Energy Star Home Program** is directed at growth areas as it applies to new construction.
b. The **Energy Star Appliance Program** uses market forces and market techniques to encourage the purchase of more energy efficient appliances, while establishing partnerships across the manufacturing and retail sectors.
c. The **Duct Sealing and Infiltration Control Program** is the implementation of the only measures to pass all three screening tests and uses an innovative marketing strategy designed to minimize cost while maximizing effectiveness.
d. The **Home Inspector Program** is an innovative program that seeks to educate home inspectors to the benefits of DSM so that they can convey additional recommendations to potential homebuyers at the time of home purchase.

IV. Recommended Procedure for future DSM evaluation

The workgroup looked at the three screening tests run by the companies to evaluate potential DSM measures that have been adopted by the Commission. Those three tests, TRC, Participant, and RIM, have provided the basis for Commission decisions on whether to implement DSM programs since 1995. All three tests involve the projection and estimation of many costs. The Work Group is proposing a process where additional measures would be further developed for Commission consideration. To implement this process, the workgroup decided on an "analytical cap" that would apply to measures that did not pass RIM, but may offer substantial TRC benefits. It would also provide the Commission additional options in selecting appropriate DSM programs. As described earlier, the analytical cap would represent some degree of projected rate impact. The companies would be required to design DSM programs until the cumulative projected rate impact reaches the analytical cap. Any party would be free to oppose the actual implementation of any program that did not pass RIM, but the Commission would not be prevented from considering a program just because it failed RIM as is the case today. The companies would be required to quantify the rate impact in their evaluation so that the Commission would have the best information possible to make an informed decision. One other step in this process would be to allow the Commission to authorize a pilot program for any program, including those that did not pass RIM, in order to acquire additional information about the true cost of the program.

The listing of the proposed programs would rank them first by those that passed RIM, then by their TRC score. The objective was that if the Commission agreed to pursue the implementation of a program that did not pass RIM, that program should represent the least cost resources available for the system as a whole.

The Work Group did not decide where to recommend the Commission set the analytical cap. There were a range of proposed caps, from an absolute cap of 10 million dollars of rate impact to a cap of up to 1.5% of the revenues of the affected class. As of today, the 1.5% cap would equate to a rate impact of 40-50 million dollars for the commercial and residential classes. If the Commission decides to adopt the analytical cap process, the interested parties, including staff would offer their recommendation to the Commission at that time.

V. Recommended Changes to IRP rules and Legislative recommendations

Proposed legislative changes

In its order establishing the demand-side management working group, the Commission asked for recommendations on legislative proposals that could increase energy efficiency levels in Georgia. These proposals facilitate adoption of energy efficient appliances and equipment through traditional tax incentives and regulations tested in other states. Other proposals facilitate improved energy efficiency in state government facilities for the benefit of Georgia's taxpayers. The Commission should ask the workgroup to draft a letter for its signature to the Governor, House and Senate leaders and key committee chairmen to ask for their support in implementing these steps.

- **Sales tax "holiday" for energy efficient appliances**. This proposal establishes one or more time periods per year when energy efficient consumer products are exempt from the Georgia state sales tax. This type of tax exemption has been successfully used in other jurisdictions to assist the market for ENERGY STAR products develop. There are two periods during the year when these incentives can tie into other efforts to promote energy efficiency: October, when Energy Awareness Month campaigns are conducted; and in the spring for traditional home appliance retail promotions. This measure typically enjoys broad bi- partisan support in addition to support from the appliance retail industry and consumer groups.

- **State appliance standards**. States have authority to regulate the energy performance of appliances and equipment not covered by Federal standards. Cost-effective appliance and equipment standards have been responsible for reducing US energy consumption by 2.5 percent over the last 20 years and have provided significant consumer and environmental benefits. States have recently taken the lead in the coverage of new product categories not regulated by the Department of Energy, such as ice machines and certain cooling equipment. The states of California, Connecticut and Maryland currently set minimum cost effective efficiency requirements, soon to be joined by New Jersey. Legislation is pending in many other states with good prospects for passage. State legislation has been based on the model bill developed by the Appliance Standards Awareness Project which sets the technical requirements for 18 residential and commercial products. Many of the specifications are based on ENERGY STAR criteria.

- **Support a Georgia state energy policy**. The Commission has a legitimate interest in supporting and helping to formulate a state energy policy for Georgia. Such a policy could set measurable goals for the state to achieve in managing its beneficial use of energy over the long term. A comprehensive policy would address energy use in all sectors(buildings, transportation, and industry) and provide direction to Georgia's state agencies, local governments, institutions, businesses and industries. The Commission's primary interests are in managing current loads and future growth in the residential, commercial and industrial sectors. Beneficial demand side policies include effective building energy codes and their enforcement, upgrades of appliance and equipment efficiency, and support for voluntary market-based initiatives such as the ENERGY STAR program.

- **State facilities energy conservation goals**. The Federal government has set energy use reduction targets for government facilities through executive order. Federal facilities are required to achieve a 20 percent reduction in energy use over a reasonable period of time compared to a baseline year. A number of state governments have followed this example. Companion initiatives include purchasing and procurement policies to buy energy efficient ENERGY STAR products. A similar program in Georgia would assist the Commission in managing Georgia's energy demands.

VI. Rate Structure Recommendation

The Work Group had several discussions on possible rate design and how consumers could be given better information as to the costs to serve them during peak periods so that they could choose to lessen their demand on the system. The Work Group recognizes that rate design can itself be an important Demand Side Measure. Proper rates and the subsequent customer response can increase the efficiency of the utility system by discouraging use at the system peak and encouraging use during the off-peak periods.

GEFA supplied the Work Group with a study of energy efficiency residential rates. That study is attached as Appendix 6.

Customers should, to the extent possible and practical, receive prices that correspond to the utility's margin cost to produce and deliver power. Time sensitive rates such as TOU and RTP should be additional consideration.

While the Work Group is not advocating a specific rate design as part of this filing, the Commission should order the Companies to file possible rate structures that would enhance DSM goals as part of its IRP filing.

VII. Additional Comments and Recommendations

- The Commission should direct/encourage fuel neutral participation in DSM programs from gas companies, gas marketers, EMCs, and municipal energy suppliers.

- Some members of the DSM workgroup believe that the group should continue to meet periodically to be able to refine its procedures to bring the Commission the best, most up to date information possible and to continue to explore additional means to implement DSM in creative, market based ways that place the least burden on ratepayers as possible. Others believe the proposed new process already affords a collaborative approach since interested parties will be involved in each phase of the Companies DSM evaluation process.
- There were recommendations on revising the existing IRP rules related to information provided during program certifications, power line construction having to do with an evaluation of needs tied to DSM implementation, monetizing the value of reduced air emissions to use in the calculation of avoided costs, and others that some members of the workgroup believed fell outside the scope of the workgroup. The workgroup strived to keep a narrow focus on how best to design immediate DSM opportunities and how best to evaluate DSM in the future in order for the Commission to implement the strongest plan possible without undue cost shifting while providing for the maximum benefit to ratepayers.
- The fact that avoided costs in the Docket 4822-U order have a 5% adder for purposes of screening QFs was discussed among the group.
- The timing of the IRP filings in relation to the accounting order/rate cases was also discussed as an issue of concern to some members, however, no agreement was made on whether or how best to coordinate or adjust the timing for IRP and rate case schedules.

VIII. Appendices

1. Proposed DSM evaluation process
2. Energy Star Home Program
3. Energy Star Appliance Program
4. Duct Sealing and Infiltration Control Program
5. Home Inspector Program
6. Residential Rate Structure Study

Appendix 1

Proposed DSM Screening Process

Striving to fulfill the Commission's Final Order in the 2004 IRP Docket

In the Final Order for the 2004 IRP Docket (Docket 17687-U), the Georgia Public Service Commission lamented the current state of debate concerning demand-side management programs in Georgia and articulated an interest in reexamining the value of demand-side management programs for Georgia's ratepayers while overcoming the mistakes of the past that "proved costly to non-participants and provided little system-wide benefit."[1] The Commission expressed its desire to "find a solution that will strike a balance between economic efficiency and fairness and equity when considering implementation of DSM programs."[2]

The Commission Order created a Demand-Side Management Working Group and charged the group with creating a DSM Plan that minimizes upward pressure on rates while maximizing economic efficiency and encompasses, among other things, a "recommended process for the selection of DSM initiatives in the future..."[3]

The Demand-Side Management Working Group has worked hard to fulfill these goals and, here, presents to the Commission a collaborative process and a method for future evaluation of DSM initiatives.

Greater Pre-Filing Collaboration in the Future

The Georgia DSM Working Group proposes a change to the DSM plan development process in order to allow participation by interested stakeholders in the screening and ranking process for DSM measures and programs before the official filing of the IRP with the Georgia PSC. Here are the proposed changes:

1. Utilities filing IRPs will meet with interested stakeholders at least three times, as the DSM portion of the IRP is developed, to solicit input from these stakeholders, as follows:

2. Approximately 18 months before the official IRP filing date by the utilities, the Companies will gather input from interested stakeholders on DSM measures and programs that should be included in the DSM measure and program screening process and to gather input on costs, useful lives, energy savings, and maximum achievable market penetration of these measures and programs;

[1] "Final Order." Georgia Public Service Commission. July 9, 2004. Page 20.
[2] Ibid. Page 20.
[3] Ibid. Pages 36 & 37.

3. Approximately 12 months before the official IRP filing date, the Companies will meet with interested parties to review initial results of all cost effectiveness screening results for DSM measures. At this point in the process, the parties may agree to adjust the "analytic" cap, as proposed below (see note (3)(b)(iv) below); and

4. Approximately 6 months before the official IRP filing date, the Companies will meet with interested parties to review initial results of all cost effectiveness screening results for DSM programs (where cost effective measures have been bundled into programs).

DSM Screening Process for the Future

The DSM Working Group's proposed DSM Screening Process for the Future outlines a new process by which the Companies will evaluate DSM measures and programs and present the results of this evaluation to the Commission in their IRP filing. The DSM Screening Process for the Future consists of the following steps[4]:

1. **Review of Significant Events Since Previous IRP Filing:** The Companies will describe significant events that have taken place with DSM since the previous IRP filing.

2. **Demand-Side Resource Assessment and Initial Cost Screening:** The Companies will conduct a demand side resource assessment and initial cost screening, which will consist of several components.

    a. First, the Companies will present the results of their **comprehensive review** of available demand-side management technologies / measures. The Companies report how many residential and non-residential demand-side measures they have identified for consideration.
    b. Next, the Companies will conduct a **qualitative screening**, evaluating whether the identified DSM measures are commercially available in their service territory, whether the measures are appropriate for their customers, whether the technology is premature, etc. Based on this screening, the Companies will exclude all measures they consider unworthy of further analysis.
    c. Lastly, the Companies will conduct an **economic screening** of the remaining measures, calculating the energy consumption and energy savings potential for each individual DSM measure. This permits the Companies to calculate the costs and benefits for a single installation of each DSM measure. The Companies will then use these costs and benefits to score each measure according to the Participant Test, the Total Resource Cost (TRC) test, the Rate Measure (RIM) test and the Societal Cost Test, as required by PSC rule 515-3-4.04.

[4] Note: Steps 1 though 2(c) are the same as the current process.

3. **Demand-Side Program Development:**

   a. After the Companies have conducted the economic (cost – benefit) screening of DSM measures, they will rank both the list of residential and the list of non-residential measures with measures that pass both TRC and RIM at the top of the list followed immediately by a ranking of measures based on TRC benefits of the DSM measures.
   b. The Companies will then develop DSM program budgets starting with the first measure on the list, going sequentially down the list.
      i. The Company will diverge from a strict sequential approach in instances where the bundling of measures (that do not appear sequentially) makes programmatic and economic sense.
      ii. For each program, the Companies will list (1) the absolute dollar value of net present value from the TRC test for the program and (2) the absolute dollar value of net present value from the RIM test for the program (considering expected levels of participation for the program), and will indicate what the long-term percentage rate impact is for the program with respect to the Companies' commercial and residential retail revenues over the life of the DSM measures in the program. DSM Working Group members accept the premise that the "program eligible class" should cover the costs for any DSM programs. Since the Commission instructed the Working Group to address DSM initiatives for the commercial and residential classes, the Working Group proposes that cost recovery for the programs be limited to the commercial and residential classes.
      iii. The Companies will continue to conduct this sequential analysis, keeping a running total of the absolute dollar value of the net present value of TRC benefits and RIM impacts for all proposed DSM programs and the percentage that absolute dollar value of RIM impact represents with respect to the Companies' commercial and residential retail revenues. The "percent rate impact" figures will be calculated over the useful life of DSM measures in the program.
      iv. To limit the additional amount of work and analysis that is required to prepare the DSM portion of future IRPs, the Companies will stop its DSM program cost analysis once the running total of absolute dollar value of RIM impacts, for all proposed programs, hits a prescribed cap. DSM Working Group members differed in opinion about the appropriate level at which to set this "analytic" cap. Georgia Power proposes the cap be set at $10 million of upward rate impacts. Other parties proposed setting the cap at either 1% or 1.5% of total retail revenues for the commercial and residential classes. One percent of the retail revenues for the commercial and residential classes amounts to roughly $36 million, while 1.5% amounts to roughly $53 million.

c. The Commission should use the list of proposed DSM programs, listed with associated long-term rate impacts, to determine which programs it deems appropriate to recommend pursuing for certification or approval, based on its determination of a balance between supporting demand-side management measures and minimizing upward pressure on rates.

An example of this analysis is presented in the attached spreadsheet. All of the long-term TRC benefits and RIM impacts values listed are hypothetical figures for demonstration purposes only.

Appendix 2

2004 IRP – DSM Working Group
Energy Star Home Program
February 2005

General Discussion

The Energy Star Home program will be a statewide program with all electric utilities, including investor owned utilities, electric membership corporations ("EMC") and municipalities and gas utilities able to opt-in as the market develops. For purposes of this document, the entities listed above participating in the Energy Star Home program will be collectively referred to as "Utilities." The Georgia Public Service Commission ("Commission") should encourage, or direct, gas distribution companies to participate so that a "fuel neutral" program that leverages natural market forces evolves. A fuel neutral Energy Star Home customer awareness campaign would be supported by those Utilities either directed or wishing to participate. Support from non-regulated Utilities for the Energy Star Home customer awareness campaigns is voluntary. The main goals of this program are to:

1. Increase the number and penetration of ENERGY STAR Homes in Georgia;
2. Acquire cost effective electric and gas energy savings for Georgia;
3. Increase consumer demand for ENERGY STAR Homes through public education and ENERGY STAR Homes awareness activities; and
4. Increase realtors and lenders' understanding of the benefits of ENERGY STAR Homes.

Georgia Power Company ("Georgia Power") and Savannah Electric and Power Company ("Savannah Electric" – collectively, the "Companies") will take a leadership position with other Utilities and work to raise Energy Star customer awareness. The Companies will also work with builders, realtors and Energy Star inspectors to develop an Energy Star Home program concept which promotes Energy Star Home energy efficiencies for homes that have heat pumps and electric water heating. The Companies' programs will serve as a leadership example to other Utilities in the state, and the Companies will actively reach out to other Utilities and encourage them to participate and coordinate program offerings.

The development of the initial program design will consider features commonly found in other successful Energy Star Home programs currently operating in other states (including efficient home design, efficient space and water heating systems, energy efficient air conditioning, efficient appliances and efficient home lighting). The initial program implementation would seek to have 1,000 and 50 Energy Star homes (with heat pumps and electric water heating) completed in Georgia Power's and Savannah Electric's (respectively) territory in the first two years. The Companies will provide funding of $300 per single family home to the builder for assisting to have the heat pump/electric

water heater home certified as an Energy Star Home. This assistance with the cost of the Energy Star certification would be in addition to any standard heat pump incentives that are available. The ultimate owner of the Energy Star home will receive the bill savings associated with the energy usage reductions associated with an Energy Star home. A program evaluation will take place during the first two years. The evaluation results would then be used during and after the two-year period to assess the program and guide any needed changes.

In addition to raising customer awareness, as part of the Energy Star Home program the Companies will: 1) assist home builders in understanding the Energy Star Home energy efficiency requirements and Energy Star Home building practices; 2) assist realtors in understanding the Energy Star Home energy bill saving potential (for reinforcement to potential buyers of the home); and 3) train additional Energy Star Home inspectors to support the increase of Energy Star homes in Georgia. Overall, the program will assist home builders and buyers in designing and constructing homes that use at least 15% less energy than homes built to the current Georgia energy code standards.

Savannah Electric will also sponsor an Energy Star demonstration home during the Parade of Homes in 2005 and will continue this participation in encouraging the benefits of Energy Star to builders throughout the year through such events as the Home Builders Show.

The statewide program should also make provisions to accommodate existing local programs such as the Southface Earth Craft Home program. Earth Craft Homes typically perform at ENERGY STAR Home levels, but also include other "green" and environment-friendly features that appeal to certain customer groups. Therefore, the Energy Star Home program should augment the Earth Craft home and the market momentum it has already created.

Qualifying Homes

Homes can qualify as Energy Star through a:

- Home Energy Rating System ("HERS") Rating, or
- Builder Option Packages ("BOP") Rating

HERS Rating – the HERS rating is an evaluation of the energy efficiency of a home, compared to a computer-simulated reference house (of identical size and shape as the rated home) that meets minimum requirements of the Model Energy Code ("MEC"). The HERS rating results in a score between 0 and 100; with the reference house assigned a score of 80. From this point, each 5 percent reduction in energy usage (compared to the reference house) results in a 1 point increase in the HERS score. Thus, an Energy Star qualified new home, required to be at least 30% more energy-efficient than the reference house, must achieve a HERS score of at least 86. HERS ratings are conducted by third-party HERS raters.

HERS ratings involve the analysis of a home's construction plans, and at least one on-site inspection of the home. The plan review allows the HERS rater to attain technical information such as orientation, shading area, proposed Seasonal Energy Efficiency Ratio ("SEER") rating, insulation levels, etc. The on-site inspection includes a blower door test (to test the leakiness of the house) and a duct test (to test the leakiness of the ducts). Results of these tests, along with inputs derived from the plan review, are entered into a computer simulation program to generate the HERS score and the home's estimated annual energy costs.

BOP Rating – a BOP represents a set of construction specifications for a specific climate zone. BOPs specify performance levels for the thermal envelope, insulation, windows, orientation, heating, ventilating and air conditioning ("HVAC") system and water heating efficiency for a specific climate zone that meet the Energy Star standard (for the purposes of using BOPs, the U.S. has been divided into 19 separate climate zones).

Though constructing a home to BOP specifications negates the need for a full customer HERS rating, third-party verification that BOP requirements have been met is still necessary. Similar to HERS ratings, BOP ratings typically entail at least one on-site inspection of the home to test the leakiness of the envelope and ducts. However, unlike the HERS rating, the score derived from these tests is compared with the pre-determined specifications of the BOP to either pass or fail the house as an Energy Star qualified new home.

Education and Training

Education and training activities will be a critical component of the ENERGY STAR Homes program. Significant cost savings can be obtained by providing the workshops, seminars and other trainings on a statewide scale, across utility service areas. Allies include homebuilders, mortgage lenders, realtors, building inspectors, insulation contractors, HVAC contractors and distributors, and building supply retailers. The overall marketing message is that ENERGY STAR Homes are energy efficient, high performance homes that are nationally recognized by the Environmental Protection Agency for greater value, lower operating costs, superior durability, comfort, and safety.

Strategies for reaching the homebuilder and building subcontractor audience could include:

- Establish partnerships with builder associations in Georgia (e.g. Greater Atlanta Home Builder's Association and the Georgia HBA) to achieve early buy-in and ongoing coordination of marketing and education and training activities;
- Provide onsite instruction/training for builders and their subcontractors;
- Conduct workshops and seminars including comprehensive ENERGY STAR Builder workshops as well as focused trainings on insulation, ventilation, HVAC, and marketing techniques; and
- Provide case studies and articles for builder association newsletters /magazines as well as for local and statewide press releases.

Strategies for reaching new home purchasers, real estate and possibly mortgage lender professionals could include:

- Public awareness campaign focusing on home and trade show exhibits, open-house tours, radio and print ads, trade journal ads, and consumer brochures;
- Coordination with realtor multiple listing service (MLS) to denote "ENERGY STAR Home" and/or HERS ratings;
- Conduct workshops and seminars that focus on such topics as technical overview of ENERGY STAR Homes and marketing techniques for selling ENERGY STAR Homes; and
- Promote program at "First Time Buyers Seminars" sponsored by local banks and possibly include local builders and contractors.

Marketing Plan

Program marketing could include direct builder outreach, targeted mailings (postal system and e-mail), public relations activities, home and trade show exhibits, billboards, radio and print ads, trade journal ads, information on utility web sites, open-house tours, builder and homebuyer seminars, bill stuffers, and consumer brochures. The program will be co-branded with the national ENERGY STAR Homes effort.

Staffing

The participating utility companies will decide how best to staff this program and deliver services. However, sufficient resources will be allocated to meet the program objectives. The use of contractors is anticipated for technical training.

Evaluation Plan

An evaluation plan for the ENERGY STAR Homes program will be developed and will include some or all of the following components:

- Impact Evaluation;
- Process Evaluation;
- Market Assessment and Evaluation (including an analysis of the current penetration of ENERGY STAR Homes in Georgia by participating utility service area);
- Builder and subcontractor focus groups;
- Home buyer survey and/or focus groups;
- Review of Penetration Curves;
- Development of Incremental Cost Information; and
- Development of a cost-effectiveness analysis (Participants Test, Rate Impact Measure test and Total Resource Cost test).

Program Budget

The expected program budget for the first two years will be capped at $1,500,000 for Georgia Power with the actual expensed amounts depending on the successfulness of the marketing campaign and the program evaluation costs. Program budget dollars can be shifted to accommodate additional Energy Star certification fee payments to builders if the program is more successful than expected. Also, if the program exceeds expected levels of penetration early in the two year pilot phase, the Companies can seek additional funding from the Commission.

Expected annual energy cost savings for a customer with an Energy Star home is about $150.00.

Program Schedule

The program implementation will begin once the Commission approves the program plan. The following table provides an expected schedule for the major program activities.

Program Activities	Expected Schedule
Develop Program Materials	March – June 2005
Work with Other Utilities	May 2005
General Awareness Campaign	June 2005
Work Shop for Realtors	July 2005
Work Shop for Builders	July 2005
Training for Energy Star Certifiers	March 2005 – December 2007
Program Evaluation (1)	May 2006 – December 2007
Program Results Filing (2)	April 2008

Notes:

(1) The program impact evaluation should start when there is a large enough sample (probably when there are 50 to 100 Energy Star homes). The process evaluation can be ongoing from the beginning of the implementation of the program.

(2) After the program evaluations have been completed, the results of the evaluation along with suggested program modifications should be filed with the Commission

Cost Effective Analysis

The Energy Star Home Program is expected to pass the Participants Test, the Rate Impact Measure test and the Total Resource Cost test, however, the program evaluation at the end of the two years will determine the cost effectiveness of the program.

Appendix 3

2004 IRP – DSM Working Group
Energy Star Appliance Program
February 2005

General Discussion

Georgia Power Company ("Georgia Power") and Savannah Electric and Power Company ("Savannah Electric") will work with ENERGY STAR® Appliance program managers at the Department of Energy ("DOE") and the Environmental Protection Agency ("EPA") to educate retailers, consumers and others (as identified) on the energy bill savings associated with ENERGY STAR appliances. Additionally, Georgia Power will actively reach out to ENERGY STAR appliance manufacturers and retailers to increase awareness of their customers on any manufacturer rebates or coupons they may have available for ENERGY STAR appliances. This would be accomplished through means such as bill stuffers and possibly through brochures and material supplied to retailers for dissemination to their customers. Georgia Power will take a leadership position on ENERGY STAR promotion in Georgia as part of the Southern Company's system-wide partnership agreement with EPA and DOE. The main goal of this program will be to increase the market penetration of ENERGY STAR appliances in Georgia, particularly for those appliances where the ENERGY STAR penetration is currently below 50 percent.

The ENERGY STAR Appliance program will be a statewide program throughout Georgia with electric utilities (investor owned utilities ("IOUs"), electric membership corporations ("EMCs") and municipals ("MUNIs")) and gas utilities able to opt-in as the market develops. The Georgia Public Service Commission ("Commission") should encourage, or direct, gas distribution companies to participate so that a "fuel neutral" program that leverages natural market forces evolves. It is important that both regulated electric and natural gas companies will offer the same program statewide to avoid market confusion that will affect manufacturer, retailer, and customer participation. There will also be economies of scale in the public awareness campaign and potential training of retailer sales staff. For example, the electric and gas utilities can pool resources to defray costs while ensuring that all retailers and consumers receive the same information and marketing materials.

A fuel neutral ENERGY STAR Appliance public awareness campaign would be supported by those utilities who participate. Support from non-regulated electric and natural gas utilities for the ENERGY STAR Appliance public awareness campaign is voluntary, and utilities may choose to participate only in the public awareness campaigns. The main goals of this program are to:

1. Increase the penetration of ENERGY STAR appliances sold in Georgia;
2. Acquire cost effective electric and gas energy savings and at least in the case of the Energy Star clothes washer and dishwasher, some water savings for Georgia; and

3. Increase consumer demand for ENERGY STAR appliances through public education and ENERGY STAR awareness activities.

Introduction

The overarching goal of the ENERGY STAR Appliance program is to develop the manufacturer and retailer infrastructure and consumer demand to increase the availability and awareness and sales of ENERGY STAR appliances. In support of this overarching goal, the following specific goals have been identified:

- Increase consumer demand and purchase of ENERGY STAR appliances;
- Maintain strong sales of ENERGY STAR appliances to provide impetus for improved federal appliance standards; and
- Increase retailer and manufacturer promotion of ENERGY STAR appliances.

The ENERGY STAR Appliance program's initial two year phase will be designed to support the development, introduction, sale and use of energy efficient refrigerators, freezers, room air conditioners, dishwashers, clothes washers, dehumidifiers, and consumer electronics (e.g., computers, TVs, VCRs, DVD players). The overall goal is to create and sustain positive change in the residential appliance market, increasing availability, consumer acceptance, market penetration, and use of energy efficient appliances that have the ENERGY STAR label.

The major barriers to be addressed by the ENERGY STAR Appliance program can be summarized as follows:

- First cost premium;
- Lack of consumer awareness of ENERGY STAR appliances; and
- Lack of retailer/supplier interest in and support for ENERGY STAR appliances.

The ENERGY STAR Appliance program's intervention strategies will have elements designed to overcome many of these barriers by:

Addressing first cost premium through:

- Providing communication to customers in support of manufacturers' product rebates and other sales incentives; and
- Demonstration and promotion of ENERGY STAR appliances' economic benefits by featuring life-cycle costing.

Addressing lack of consumer awareness through:

- Comprehensive marketing/consumer education campaign;
- Point-of-sale displays and materials; and
- Encouragement of manufacturer labeling of products.

Addressing lack of retailer/supplier interest through:

- Product and program training; and
- Point-of-sale displays, materials and demonstrations.

Table 1.1 presents 2001 saturation rates for major appliances as reported in the Energy Information Administration's ("EIA") 2001 Residential Energy Consumption Survey ("RECs") for the South Atlantic Region. In addition, market share of ENERGY STAR appliances in Georgia is shown for the first three quarters of 2004.

Table 1.1 Appliance Saturation and ENERGY STAR Market Penetration in Georgia

Appliance	Current Appliance Saturation in South Atlantic Region[1]	2004 ENERGY STAR Market Penetration[2]
Clothes Washers	85%	20.5%
Refrigerators	84%	29.0%
Freezers	33%	n/a
Dishwashers	58%	81.8%
Room A/C	14%	25.1%
Dehumidifier	6%	n/a

Sources: 1) 2001 EIA Residential Energy Consumption Survey
2) 2004 Energy Star Sales Data (Combined first three quarters of 2004)

Successful implementation of this program is expected to result in an increase in the penetration of energy efficient residential appliances.

The Georgia ENERGY STAR Appliance program will be administered by electric and gas utilities within their respective service territories. This program will be implemented first in the service area of Georgia Power.

The statewide program should also make provisions to leverage national and regional ENERGY STAR public awareness campaigns as well as any local initiatives that may target energy efficient appliances. The ENERGY STAR national appliance program includes an annual promotion campaign beginning April 15 and going through July 15 with the ENERGY STAR appliance manufacturer partners possibly providing:

- local promotions;
- national media campaigns;
- in-store events;
- product buy-downs or discounts;
- product rebates;
- sales promotion support;
- retail training; and
- incentives to retailers.

Georgia's regulated and non-regulated utilities can work with the ENERGY STAR manufacturers by providing assistance in promoting customer and retailer awareness on ENERGY STAR appliances and the timing of ENERGY STAR manufacturers' promotional campaigns.

Target Market

The target market includes Georgia consumers and residential appliance manufacturers, distributors, retailers.

Targeted End Uses and Recommended Technologies

The ENERGY STAR Appliance program seeks to reduce the amount of water, electricity and gas used in homes for washing clothes, refrigeration, automatic dishwashing, consumer electronics, dehumidification, air conditioning and heating. The technologies are ENERGY STAR clothes washers, refrigerators, freezers, dishwashers, consumer electronics, dehumidifiers, and room air conditioners/heat pumps. Georgia Power, in cooperation with other participating gas and electric utilities, will pursue cooperative promotions with retailers and manufacturers of ENERGY STAR appliances.

Education and Training

Education and training activities will be an important component of the ENERGY STAR Appliance program. Significant cost savings can be obtained by providing the consumer education and retailer trainings on a statewide scale, across utility service areas. Approaches from successful regional programs in other areas will be considered when developing initial consumer education and retail sales staff training. A combination of sales videos, on-line educational material, and in-store training will be considered. The overall marketing message, as stated on the EPA website, is:

> ENERGY STAR qualified appliances incorporate advanced technologies that use 10-50% less energy and water than standard models. The money you save on your utility bills can more than make up for the cost of a more expensive but more efficient ENERGY STAR model.

Strategies for reaching the manufacturers, distributors and retailers could include:

- Leverage EPA's marketing and public awareness resources in order to immediately offer a known "brand" to manufacturers and retailers;
- Establish partnerships with manufacturers and retailers who have experience with ENERGY STAR appliance campaigns in other regions of the country to achieve early buy-in and recruitment of industry "champions" in Georgia market; and
- Provide onsite training for retail sales staff.

Strategies for reaching consumers could include:

- Public awareness campaign focusing on radio and print ads, bill stuffers, point-of-purchase displays, and consumer brochures;
- Coordinate with Georgia public service campaigns and associated announcements that relate to environmental issues and energy conservation;

- In conjunction with the ENERGY STAR Homes program, promote ENERGY STAR appliances at "First Time Buyers Seminars" sponsored by local banks and retail partners; and
- In conjunction with the Home Inspectors Program, promote ENERGY STAR appliances to new home buyers who may be in the market to replace or purchase new appliances.

Marketing Plan

Marketing activities for the ENERGY STAR Appliance program in Georgia will involve a multi-utility marketing effort that may include:

- A comprehensive public relations and advertising campaign that features television advertising; local newspaper and regional magazine print advertising; point-of-sale materials that are coordinated with the other advertising; and a variety of public relations activities;
- Coordination with the federal ENERGY STAR annual campaign; and
- Support to appliance retailers which could include recruitment into the program; sales representative training; regularly scheduled maintenance visits to retailers; distribution of point-of-sale materials directed to consumers; and support for special promotional events.

Staffing Plan

The participating electric and gas companies will decide how best to staff this program and deliver services. However, sufficient resources will be allocated to meet the program penetration targets. The use of contractors is anticipated for technical training.

Evaluation Plan

The focus of an evaluation plan will be on the development of statewide market progress reports to provide timely feedback on the status of the market and the progress made toward meeting the program's goals and objectives. Rather than comprehensive market assessments conducted every few years, these progress reports should be more brief and conducted frequently (i.e., semi-annually). Each report will address the current status of program activity plus selected program aspects such as information on the tracking of market indicators; customer awareness and understanding of ENERGY STAR brand and labeling; surveys and research to support performance targets established by the participating utilities; or feedback on the effect of changes in program design on market response, such as changes in marketing materials and approaches or promotional rebate levels.

An evaluation plan for the ENERGY STAR Appliance program will be developed and will include some or all of the following components:

- Market Assessment and Evaluation (including an analysis of the current penetration of ENERGY STAR appliances in Georgia);
- Ongoing estimates of market share for ENERGY STAR appliances;

- Consumer awareness and knowledge survey;
- Retailer survey;
- Review of penetration curves;
- Annual reporting; and
- Development of Incremental Cost Information.

Market Indicators

To assess the initiative's progress, the following market indicators should be considered for potential monitoring:

- Market share - percent of market share of ENERGY STAR appliances;
- Price changes - average incremental prices of ENERGY STAR appliances;
- New products - additional number of manufacturers/products joining the program;
- Awareness/attitudes - the percentage of consumers aware of Energy Star appliances;
- Common practice - percent of new homes with Energy Star appliances; number of large residential users that specify Energy Star appliances;
- Leverage of investment - regional marketing support provided by manufacturers; and
- Adoption of labels, codes or standards - upgrading of federal appliance efficiency standards and simultaneous upgrade of Energy Star specifications.

Program Budget

Georgia Power's budget for the initial two year plan will be $400,000.

Proposed Schedule

The program implementation will begin as soon as it is approved by the Commission. The following table shows the schedule for the major program activities:

Program Activities	Expected Schedule
Develop Program Materials	March – June 2005
Work with manufacturers and retailers	April - July 2005
Set Up Reporting Requirements	July 2005
Program Evaluation	April 2005 – December 2006
Program Evaluation Report Filing	April 2007

Cost Effective Analysis

The ENERGY STAR Appliance program is expected to pass the Participants Test and Total Resource Cost test but fail the Rate Impact Measure test. However, Georgia Power considers it important customer service to increase customer awareness on energy efficiency and ENERGY STAR. Therefore, Georgia Power is providing annual funding of $200,000 to assist in increasing customer awareness specific to ENERGY STAR appliances.

Appendix 4

2004 IRP – DSM Working Group
Duct Sealing and Infiltration Control Program
February 2005

General Discussion

The only two measures that passed all three economic tests (Participant Test, Rate Impact Measure ("RIM") test and Total Resource Cost test) from the Georgia Power Company's ("Georgia Power") updated analysis[5] were Duct Sealing ($40 in RIM net benefits) and Infiltration Control ($21 in RIM net benefits) on gas heated homes. These two measures are currently contained in Georgia Power's energy efficiency informational programs, and Georgia Power will continue to educate its customers on benefits of these two measures. These measures might also be good candidates for an affinity group marketing campaign described below.

Further analysis of these measures shows that the older the home the more benefit there is in making the improvement (both to the customer and to the Georgia Power system). However, even in older homes there is not enough RIM benefit to cover the additional cost of marketing, promotion and administration of a traditional demand side program. Therefore, an innovative approach is needed.

Affinity Group Marketing Approach

Members of certain affinity groups such as Georgia Interfaith Power and Light ("GIPL") have an interest in implementing energy efficiency. An affinity group marketing concept will be implemented to leverage GIPL and at least one other affinity group's communication and marketing channels. Specifically, the affinity groups will promote duct testing and sealing and infiltration control to their membership through their newsletters, workshops, and other communication channels.

The programs will target homes that are 10 years old or older and use the affinity groups as marketing channels. Georgia Power will provide energy efficiency information materials to be distributed by the affinity groups and for the initial two years, will pay the affinity groups $25 for each Georgia Power customer who makes an improvement in duct sealing or duct sealing and infiltration control to their home as long as the home is 10 years old or older. The affinity group may be able to obtain discount pricing from duct sealing and infiltration control contractors for their members by aggregating homes and seeking competitive bids. This will even further improve the cost-effectiveness to their respective members.

[5] See the October 14, 2004 Compliance Filing in Docket No. 17687-U, Georgia Power Company's 2004 Integrated Resource Plan.

Utilization of this innovative approach to energy-efficiency will ensure that the economic benefits of duct testing and sealing and infiltration control are cost-effectively captured. The affinity groups will be able to promote these cost-effective demand side management ("DSM") measures to those customers who already have demonstrated a strong propensity for energy efficiency through their affinity membership.

Proposed Budget

The budget for this program over the next two years is not expected to exceed $300,000 with most of the cost being associated with customer education materials and rebates for successful improvements being made.

Proposed Schedule

The program implementation will begin as soon as it is approved by the Georgia Public Service Commission. The following table shows the schedule for the major program activities.

Program Activities	Expected Schedule
Develop Program Materials	March – June 2005
Work Shops with Affinity Groups	July 2005
Set Up Reporting Requirements	July 2005
Program Evaluation	January – December 2006
Program Evaluation Report Filing	April 2007

Cost Effective Analysis

The Duct Sealing and Infiltration Control Program is expected to pass the Participants Test, the Rate Impact Measure test and the Total Resource Cost test;. The program evaluation that will be conducted after the first two years will assess the actual cost effectiveness of the program as well as the ongoing feasibility of keeping the marketing payment at the $25 level.

Appendix 5

2004 IRP – DSM Working Group
Home Inspector Pilot Program
February 2005

General Discussion

Home inspectors are typically hired to inspect homes prior to home purchases. As a pilot, Georgia Power Company ("Georgia Power") and Savannah Electric and Power Company ("Savannah Electric"; or collectively, the "Companies") would initially work with a couple of the larger Home Inspection companies (in their respective service territories) to implement a two-year energy efficiency program in conjunction with typical home inspections in the Companies' service territories.

The program would train the home inspectors to identify energy efficiency improvement opportunities for resale homes and include energy efficiency recommendations to potential buyers. The program might be associated with the Energy Star Home Performance program. Special emphasis will be placed on duct sealing and infiltration control as part of the home inspectors' energy efficiency home audit. Additionally, the home inspector can increase customer awareness to the potential home buyers on Energy Star appliances in case new appliances might be bought at the time of home purchase and/or move-in.

During the two years, the program will be evaluated for process implementation and to determine if customers are making any improvements or Energy Star appliance purchases as a result of the home inspector's recommendations.

Goal: The goal of this pilot is to explore using home inspectors ("HI") as a vehicle to promote energy efficiency in existing homes and to increase the penetration of ENERGY STAR appliances. Home inspections are a nearly universal practice when a house is being purchased, and the HI is hired by the prospective buyer as a trusted source of technical information about the property's structure and systems. A description of the condition and age of many appliances is a standard part of the HI's report, and this represents an opportunity to educate the homebuyer on the advantages of home energy efficiency and ENERGY STAR products. There is probably no better time to educate homeowners about energy efficiency than at the time of a home inspection. Homebuyers have a keen interest in the condition and operation of their residential building systems.

Elements: The pilot program would incorporate the following elements;

- Investigate the HI industry in Georgia in order to determine the best partner(s) to use as conduit to HIs. This is most likely to be either trade groups, such as the Georgia Association of Home Inspectors, or franchises. The decision should be made on the basis of responsiveness to the concept, ability to engage an adequate force of HIs, and concern/commitment to energy efficiency.

- Identify list of features/appliances to cover in the pilot. (e.g. – furnace, boiler, air conditioner, refrigerator, dishwasher, windows.) Information distributed to homebuyers will tie in to current utility efficiency programs.
- Develop training curriculum, and train HIs on the program concept, inspection techniques, information delivery and advantage/value of appropriate ENERGY STAR products.
- Develop program promotional materials for HIs to distribute during inspection visits.
- Monitoring/evaluation. Build process and effectiveness evaluation into program design.

Savannah Electric will address the Home Inspector Pilot Program by implementation of a version of the Home Inspector program with characteristics of incentives to the home inspector as the inspectors provide energy audit information both to the Company and to the homeowner and will continue to monitor other aspects of the program as they are implemented statewide for possible incorporation into the Savannah Electric program.

Incentives: Incentives might be necessary to get HI participation, at least at the pilot stage. The following options that can be explored:

- Pay a $25 incentive to the HIs based on customer participation, at least for ENERGY STAR products and/or duct sealing improvements for ducts in unconditioned space.
- Pay HIs $25 per inspection for which they complete an appliance inspection and energy audit form, with copies to the utility. This form could also be used to contact the new homeowner after a period of time, to determine if they have in fact upgraded any appliances to ENERGY STAR or implemented any other efficiency recommendations.

Education and Training

Specialized training for participating HI's may be required. The HI's are familiar with residential building systems and appliances, but may need special training in adapting the home inspection procedure to include identification of opportunities for energy efficiency features. The scope of the training will include:

- Overview of energy efficiency survey techniques
- Energy-efficient HVAC systems and controls (i.e., thermostats)
- Duct sealing
- Energy-efficient ENERGY STAR appliances and equipment
- Water heating systems
- Insulation
- Energy-efficient windows
- Weatherization and infiltration control
- Energy-efficient lighting (permanently-installed and cord-connected)

- Promotion of available electric and gas utility services and efficiency programs such as duct sealing, available ENERGY STAR appliance discounts, available energy tariffs, more detailed energy audits and so forth.
- Preparation of a uniform energy efficiency report for the homebuyer.

- For uniformity of information and economies of scale, the training can be offered jointly by participating electric and gas utilities, most likely through a specialized training organization. If possible the training course will be designed to award continuing education credits to participants. The training curriculum will address both electric and gas use on a fuel-neutral basis.

Marketing Plan

As a pilot program, the home inspection information program will be marketed differently than a full-scale program available to all participants. The marketing plan will have two main components: recruiting HIs to participate in the pilot program; and marketing expanded home inspection services to home-buying clients during the pilot.

- **Recruiting participating home inspectors**. As mentioned earlier, participating home inspectors will be selected by working with the Georgia Association of Home Inspectors (GAHI) and/or with a franchised home inspection service. This is in order to test the pilot concepts with HI organizations that have standardized procedures and uniformly trained staff. Variability in delivery of the service will be minimized. Participating utilities will select suitable and willing HI firms and negotiate terms of participation. The participating HI's will go through the training course described above.
- **Marketing the service to homebuyers**. The expanded home inspection service for energy efficiency will be offered as an addition to the standard home inspection. The participating HI organization, working with the participating utilities, will negotiate and develop a marketing plan that will address the following points:
    - Offering the service to all or part of the HI's customers;
    - Developing an approach to sell the concept to realtors and address their concerns;
    - Fees for the service paid as a utility incentive to the HI, or directly to the HI as an add-on fee to the customer - in a pilot project, homebuyer participation will likely be higher if there is no additional cost to the homebuyer;
    - Marketing literature and brochures, including information on the features and benefits of the HI service and information on related utility efficiency programs; and
    - Design of energy efficiency reports presented to the homebuyers

Staffing

The Companies will decide how best to staff this program and deliver services. However, sufficient resources will be allocated to meet the pilot program objectives. The use of contractors is anticipated for technical training.

Evaluation Plan

An evaluation plan for the home inspection pilot program will be developed and may include some or all of the following components:

- Impact or effectiveness evaluation, based on the homebuyers' adoption of efficiency measures.
- Process evaluation, based on an assessment of service delivery, HI feedback and homebuyer satisfaction.
- Market assessment and evaluation (including an analysis of potential market penetration for the service in Georgia by utility service area)
- Home inspector debriefings and interviews,
- Homebuyer satisfaction survey and/or focus groups,
- Development of incremental cost information for delivering the HI service and costs of measures adopted by homebuyers , and
- Development of a cost-effectiveness analysis (Participants Test, Rate Impact Measure test and Total Resource Cost test).

Program Budget

The expected program budget for Georgia Power for the pilot program will be $300,000. The budget details will be worked out by participating utilities. The budget will cover the following major items:

- Incentives to participating HI's of approximately $25 per inspection;
- Development and production of marketing materials and brochures;
- Initial technical training and follow-up workshops;
- Tracking adoption rates on efficiency measures by homebuyers; and
- Program impact and process evaluations

The HI program is expected to process 2,000 efficiency survey during the pilot. Experience in other similar programs shows an average energy use reduction of 9% for electricity and 16% for natural gas. Homebuyers have spent about $300 on average for efficiency improvements and, as a group, implement at least some recommended measures in 50%-60% of the cases.

Program Schedule

The program implementation will begin once the Commission approves the pilot program plan. The following table provides an expected schedule for the major program activities.

Program Activities	Expected Schedule
Recruit and negotiate home inspector organizations	March – June 2005
Develop HI training course and materials	March - July 2005
Offer training to HI's	August 2005 – October 2005
Operate pilot program and track performance	August 2005 – December 2007
Program Evaluation	January – December 2006
Program Evaluation Results Filing	April 2007

Cost Effective Analysis

The Home Inspectors Program is expected to pass the Participants Test and Total Resource Cost test but fail the Rate Impact Measure test. However, Georgia Power considers it important customer service to increase customer awareness on energy efficiency and ENERGY STAR. Therefore, Georgia Power is providing funding of $300,000 to assist in increasing customer awareness specific to energy efficiency improvements and Energy Star appliances through the Home Inspectors work.

Appendix 6

The Status of Energy Efficiency Rates
In the United States in 2004

Prepared for

Georgia Environmental Facilities Authority
and
Southface Energy Institute

By

Jane Price Hill
and
Susan M. Zinga

September 14, 2004

Status of Energy Efficiency Rates in the United States in 2004

Electric utility rates are aimed at recovering "costs to serve." Because much of a utility's fixed cost is incurred in generating, transmission and distribution facilities, utilities may concentrate on providing incentives to constrain peak electric demand growth. While the incentives may be termed "energy efficiency," the emphasis is likely to be on reducing kW demand, not kWh usage. As a result, specific "energy efficiency" rates are somewhat rare. However, several such rates have been identified. These energy efficiency rates fall into several categories:

- Percentage reduction in bill: These tariffs involve a percentage discount, typically on the kW and kWh charges, but not including riders, for customers' facilities which meet certain requirements, such as those for an EnergyStar home.

- Bill credits: These tariffs offer credits in the form of flat amounts, $/kW credits, and/or $/kWh credits for customers who install high efficiency or solar equipment.

- Adjustments to kW billing demand: This type of rate permits an automatic adjustment downward in billing demand for customers' installing high efficiency equipment.

- Special rates for structures meeting high efficiency standards: Several utilities allow customers with structures meeting high efficiency standards to take service under tariffs which are more favorable than standard tariffs.

- Miscellaneous tariffs: These tariffs reward high efficient equipment in unusual ways.

Examples of these types of rates are listed below.

Percentage reduction in bill

Utility	State	EE Rate Description
Central Louisiana P&L	Louisiana	A ten percent discount on electric bills for November through April for "Energy Miser" homes.
Carolina P&L (Progress Power)	North Carolina	Rider RECD-1B, Residential Service Energy Conservation Discount, provides for a five percent discount on kW and kWh charges for homes meeting EnergyStar standards
Carolina P&L (Progress Power)	South Carolina	SC customers served by Progress Energy are eligible for a five percent discount on kW and kWh charges for homes meeting EnergyStar standards.
Blue Ridge EMC	South Carolina	The Total Electric Conservation Rate provides for a six percent deduction for residential customers with all electric homes that meet the Total Electric Conservation standards.

Bill credits

Utility	State	EE Rate Description
Maui Electric (MECO)	Hawaii	Maui Electric offers a $270 rebate, plus a $5 per month bill credit for residential customers who install high efficiency water heaters with timers.
MECO, HECO, and HELCO	Hawaii	For commercial customers, these utilities offer a $125 per coincident peak kW rebate plus $0.05/kWh (retrofits) or $0.06/kWh (new construction) for solar water heaters.
PacifiCorp	Washington	PacifiCorp's energy efficiency rate provides incentives of $50/kW and

		$0.12/kWh for commercial projects that exceed code by ten percent, capped at 50% of the energy efficiency measure's cost.
Energy Trust of Oregon	Oregon	This incentive is paid by the Energy Trust of Oregon, not a specific utility. The rate involves a $0.40/kWh rebate for solar water heating and $0.10/kWh for solar pool heaters.

Adjustments to kW billing demand

Utility	State	EE Rate Description
Florida Power and Light (FP&L)	Florida	FP&L offers a rider which adjusts billing demand downward for installing efficiency measures.
Southern Indiana Gas & Electric (Vectren Energy)	Indiana	SIGECO offers reduced demand charges to large power and high load factor customers through an efficiency incentive rider.

Special rates for structures and/or equipment meeting high efficiency standards

Utility	State	EE Rate Description
Alabama Power	Alabama	Alabama Power offers a special rate, FDE, for energy efficient homes.
Jackson EMC	Georgia	Jackson EMC offers Schedule AEA-4, Residential Energy Advantage Service, for homes qualifying as Good Cents or Comfort Home.
Upper Peninsula Power Company	Michigan	UPPC offers an Energy Efficiency Incentive Rate Alternative to large commercial & industrial customers to encourage energy efficiency.

Jersey Central Power & Light Co.	New Jersey	JCP&L offers a residential geothermal heat pump rate for installing equipment which meet specified high efficiency criteria.
Piedmont EMC	North Carolina	Piedmont EMC offers an energy efficiency rate (EER) for customers' having high efficient equipment and a premium level of insulation.
York EMC	South Carolina	Rate Code 5, Residential/Energy Efficient All Electric Rate rewards homeowners who have highly efficient homes.
South Carolina Electric & Gas	South Carolina	SCE&G offers Energy Saver Rate 6 for highly efficient homes.
Black Hills P&L	Wyoming	Customers with high efficiency equipment and demand controllers can take an optional demand service rate with up to 30% savings relative to the standard tariff.

Miscellaneous tariffs

Utility	State	EE Rate Description
Utah P&L	Utah	Utah P&L has a Demand Side Rider to recover the costs of its energy efficiency programs. In lieu of paying this rider, customers can "self direct" these payments to cost effective efficiency improvement projects within their own facilities.

Several tariffs were identified whose names would imply that they are energy efficiency rates, but in fact were intended for peak kW reduction. Examples include:

Utility	State	EE Rate Description
Public Service of Colorado	Colorado	Public Service of Colorado offers a "customer efficiency" program; however, this is actually a program to reduce peak kW demand, not to improve

		the efficiency of electricity usage.
Nevada Power	Nevada	Nevada Power has an "Optional Conservation Service" rate. However, it is in essence a curtailable rate.
Entergy Arkansas	Arkansas	Entergy Arkansas has an "Experimental Energy Reduction Rider (EER)," but this is more accurately described as an incentive program to reduce on-peak demands, typically by operating standby generators.

While many utility programs are aimed at reducing or shifting demands, they may have the effect of reducing overall energy usage as well. In one survey, 49% of Puget Sound Energy's Time-of-Use rate participants responded that they cut their overall energy consumption while shifting electric usage.

It should also be noted that there are a number of tariffs that are called "energy efficiency" rates or riders which are actually mechanisms by which utilities recover the cost of their conservation programs. For example, Idaho Power uses revenue collected under its Schedule 91, Energy Efficiency Rider, to support its energy efficiency and conservation programs. While this is certainly a valid use of the term "energy efficiency rate," it may cause confusion when searching for tariffs intended as specific incentives to promote energy efficiency.

In addition to tariffs to promote energy efficiency, most utilities offer rebate and low-interest loan incentives. Many states offer tax incentives, including income tax credits and sales tax exclusions. Local governments sometimes offer property tax exclusions for renewables or energy efficient equipment. While these are not "energy efficiency" rates per se, they may provide significant encouragement for energy efficiency.

Appendix A is a list of states in alphabetical order presenting the utility name and a description of each energy efficiency rate.

COMMISSIONERS:
ANGELA ELIZABETH SPEIR, CHAIRMAN
ROBERT B. BAKER, JR.
DAVID L. BURGESS
H. DOUG EVERETT
STAN WISE

Georgia Public Service Commission

244 WASHINGTON STREET, S.W.
ATLANTA, GEORGIA 30334-5701

(404) 656-4501
(800) 282-5813

DEBORAH K. FLANNAGAN
EXECUTIVE DIRECTOR

REECE McALISTER
EXECUTIVE SECRETARY

FAX: (404) 656-2341
www.psc.state.ga.us

DOCKET # 17687, 17688
DOCUMENT # 82743, 82744

DOCKETS NO. 17687-U and 17688-U:

Georgia Power Company's and Savannah Electric and Power Company's 2004 Integrated Resource Plans: Demand-Side Management Working Group Report

RECEIVED
MAY 25 2005
EXECUTIVE SECRETARY
G.P.S.C.

Order

In July,2005, the Georgia Public Service Commission ("Commission") established the Demand-Side Management Working Group ("Working Group")for the purpose of addressing certain issues raised in the course of the hearings in Dockets No. 17687-U and 17688-U . In its July 14, 2004 Order, the Commission directed the Working Group to accomplish three tasks:

- Bring the Commission a mix of Demand-Side Management ("DSM") initiatives to be recommended for approval, including detailed information regarding how each of the initiatives would be implemented;
- Recommend a process for the selection of DSM initiatives in the future; and
- Propose recommendations for the need for changes to the Commission's Integrated Resource Planning rules regarding DSM or for proposed legislation.

The Commission further ordered that no later than February 15, 2005, the Working Group shall conclude by submitting a proposed DSM Plan to the Commission. The Working Group filed its report with the Commission on February 16, 2005. .

The Working Group's report contained an evaluation process for selecting future DSM initiatives, as well as four pilot programs to be offered to the Commission for adoption:

1. The Energy Star Home Program
2. The Energy Star Appliance Program
3. The Duct Sealing and Infiltration Control Program
4. The Home Inspector Program

Georgia Power Company agreed to implement each of the four listed programs, and Savannah Electric and Power Company agreed to participate in the Energy Star Home Program.

,'

WHEREFORE IT IS ORDERED, that the Commission hereby adopts the report filed by the Working Group.

ORDERED FURTHER, that Georgia Power Company shall implement each of the four pilot programs included in the report.

ORDERED FURTHER, that Savannah Electric and Power Company shall participate in the Energy Star Home Program at the level included in the report

ORDERED FURTHER, that both Georgia Power Company and Savannah Electric and Power Company shall implement the evaluation process for selecting future Demand Side Management initiatives as presented in the report;

ORDERED FURTHER, that a motion for reconsideration, rehearing or oral argument or any other motion shall not stay the effective date of this Order, unless otherwise ordered by the Commission.

ORDERED FURTHER, that jurisdiction over this matter is expressly retained for the purpose of entering such further Order or Orders as this Commission may deem just and proper.

The above by action of the Commission during its Administrative Session held on May 17, 2005.

REECE MCALISTER
EXECUTIVE SECRETARY

5-24-05
DATE

ANGELA ELIZABETH SPEIR
CHAIRMAN

5/24/05
DATE

SPECIAL REPORT GLOBAL WARMING



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FLORIDA MEDICAL ASSOCIATION, INC.

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(850) 224-6496 • (850) 222-8827-FAX • Internet Address: www.fmaonline.org

Resolution 05-67
Health Risks of Florida's Coal-Burning Electric Power Plants
Passed FMA House of Delegates September 3, 2005

Whereas, Coal-burning power plants emit significant quantities of mercury, a potent toxin that attacks the human nervous system; nitrogen and sulfur oxides that produce smog; particulates that are especially dangerous to children and the elderly; and carbon dioxide that is linked to global warming; and

Whereas, Air pollution increases both asthma attacks and deaths due to heart and lung disease, with considerable financial and human costs to Floridians; and each year in Florida, pollution from power plants triggers an estimated 28,000 asthma attacks and 2,100 heart attacks while causing 180 deaths in individuals with lung cancer; and

Whereas, The U.S. Environmental Protection Agency and the Florida Department of Health have issued health advisories for every lake and river in Florida, as well as for our entire coastline, warning against eating certain types of fish because of the risks of mercury poisoning; and

Whereas, The Census Bureau estimates that Florida's population will experience a 58% increase (from 17 to 27 million) between 2004-2025, requiring significantly more electric power; and

Whereas, There are numerous new coal-burning power plants proposed for Florida over the next decade; and

Whereas, The Florida Medical Association has adopted policies articulating the specific health hazards of environmental mercury and of global warming; and

Whereas, We, as physicians, seek to protect children, seniors and people with asthma and other respiratory illnesses, who are especially vulnerable to air pollution; therefore be it

RESOLVED, That the Florida Medical Association urge state government and utilities to develop comprehensive energy conservation programs and to adopt improved energy efficiency standards for businesses, homes, appliances, and building construction, before approving new coal-burning power plants; and be it further

RESOLVED, That the Florida Medical Association urges that all options for meeting Florida's increased power needs be given careful consideration and full public debate, and that preference be given to the least polluting options; and be it further

RESOLVED, That the Florida Medical Association urge any new coal or fossil fuel power plants that are constructed in Florida be required to install and maintain equipment with the lowest polluting technology available at the time of plant construction, and that such controls shall be upgraded as improved technology becomes available; and be it further

RESOLVED, That the President of the Florida Medical Association write to the Governor, the President of the Florida Senate, and the Speaker of the House of Representatives communicating the public health risks associated with coal-burning power plants.

The NEW ENGLAND JOURNAL of MEDICINE

Volume 343:1742-1749 December 14, 2000 Number 24

Fine Particulate Air Pollution and Mortality in 20 U.S. Cities, 1987–1994

Jonathan M. Samet, M.D., Francesca Dominici, Ph.D., Frank C. Curriero, Ph.D., Ivan Coursac, M.S., and Scott L. Zeger, Ph.D.

ABSTRACT

Background Air pollution in cities has been linked to increased rates of mortality and morbidity in developed and developing countries. Although these findings have helped lead to a tightening of air-quality standards, their validity with respect to public health has been questioned.

Methods We assessed the effects of five major outdoor-air pollutants on daily mortality rates in 20 of the largest cities and metropolitan areas in the United States from 1987 to 1994. The pollutants were particulate matter that is less than 10 μm in aerodynamic diameter (PM_{10}), ozone, carbon monoxide, sulfur dioxide, and nitrogen dioxide. We used a two-stage analytic approach that pooled data from multiple locations.

Results After taking into account potential confounding by other pollutants, we found consistent evidence that the level of PM_{10} is associated with the rate of death from all causes and from cardiovascular and respiratory illnesses. The estimated increase in the relative rate of death from all causes was 0.51 percent (95 percent posterior interval, 0.07 to 0.93 percent) for each increase in the PM_{10} level of 10 μg per cubic meter. The estimated increase in the relative rate of death from cardiovascular and respiratory causes was 0.68 percent (95 percent posterior interval, 0.20 to 1.16 percent) for each increase in the PM_{10} level of 10 μg per cubic meter. There was weaker evidence that increases in ozone levels increased the relative rates of death during the summer, when ozone levels are highest, but not during the winter. Levels of the other pollutants were not significantly related to the mortality rate.

Conclusions There is consistent evidence that the levels of fine particulate matter in the air are associated with the risk of death from all causes and from cardiovascular and respiratory illnesses. These findings strengthen the rationale for controlling the levels of respirable particles in outdoor air.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060220
SEMINOLE ELECTRIC COOPERATIVE
PETITION TO DETERMINE NEED FOR ELECTRIC POWER PLANT

PRESENTATION OF E. LEON JACOBS, JR.
WILLIAMS, JACOBS & ASSOCIATES

ON BEHALF OF THE SIERRA CLUB
JUNE 7, 2006

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060220-EC Exhibit No. 39
Company/ Sierra Club
Witness: Leon Jacobs presentation before Comm.
Date: 06-07-06

POLICY SHIFT TO FAVOR COAL-FIRED GENERATION

† In the 2004 Ten Year Site Plan Review, the Florida Public Service Commission looked to promote a balanced and diverse electricity supply by asking the industry to diversify its fuel mix and build more solid fuel plants.

† The industry responded in their 2005 filings by proposing seven (7) new coal-fired plants.

† Projections of fuel costs and national trends imply an even more dramatic shift away from natural gas to coal in the mid-term.

FLORIDA PUBLIC SERVICE COMMISSION SHOULD REASSESS THIS POLICY IN LIGHT OF GROWING RISK ASSOCIATED WITH SOLID FUEL GENERATION

† Financial Risks

- Stability of Coal Prices in Global Markets
- Stability of Coal Prices Through Plant Planning Cycle
- Transportation Costs and Emerging Mine Regulatory Issues
- Growing Scrutiny of Corporate Governance to Manage Risk of Green House Gas Emission
- Expanded Transfer of Wealth Outside of the State
- Major Growth in Upfront Capital Costs Absorbed by Consumers

† Regulatory Risks

- Growing Reliability of Scientific Evidence Linking Climate Changes With Green House Gas Emissions
- Strong Linkages Between Green House Gases, Severe Environmental Effects and Climate Change
- States Unwilling to Await Federal Policy
- State Regulatory Responses Impose Dramatic Reductions in Emissions.

† Competitive/Reputational Risks

- Distinct Economic Benefits to Firms That Manage Risk Related to Green House Gas Emissions
- Clear Competitive Advantages to Firms That Effectively Market Products and Services to Reduce Risks of Price Volatility and of Climate Change

RECOMMENDATIONS

† Certainty and Consistency in Fuel Cost Projections To Include Emission Control Costs and Consideration of Market Volatility

† Coordination in Planning to Draw Down Maximum Dollars From Federal Agencies for Clean Coal

† Include Emission Reduction Benefits in Business Case for Demand Reduction, Including DSM and Efficiency

2006 Legislation to Reduce Mercury from Coal-Fired Power Plants

(As of 2/1/06)
Compiled by the National
Caucus of Environmental Legislators

www.ncel.net
State's that Have Already Taken Action on Mercury

Source: National Wildlife Federation Fact Sheet,
"States Tackling Mercury Pollution from Coal-Burning Power Plants".

State	Bill # or Agency Action (click to view)	Summary
Connecticut	HB6048	In 2003, the Connecticut General Assembly passed legislation that requires each coal burning power plant to reduce its mercury air pollution by 90 percent by 2008. Under the law, if a plant installs and properly maintains the best available control technology and still fails to meet the new emissions rate, it can request an alternative emissions rate from the Department of Environmental Protection.
Iowa	Agency Action	The Iowa Department of Natural Resources issued a permit that requires MidAmerican Energy's new Council Bluffs plant to meet an 83 percent mercury air pollution control limit when it comes online in 2007.The company plans to install activated carbon injection technology (ACI) to meet or exceed this standard.
Massachusetts	Agency Action	In 2004, the Massachusetts Department of Environmental Protection finalized a rule that requires coal-burning power plants to capture 85 percent of their mercury air pollution by 2008 and 95 percent by 2012.
Minnesota	Statute - 116.915 MERCURY REDUCTION	In 1999, the Minnesota Legislature passed a law requiring the Minnesota Pollution Control Agency to solicit voluntary reduction agreements from sources that emit more than 50 pounds of mercury annually.4 The law sets a state goal of reducing releases of mercury into the air and water by 70 percent from 1990 levels by 2006. A 2002 progress report found that virtually no reductions in mercury pollution occurred under the voluntary initiative.
New Hampshire	HB284	Pursuant to the 2002 Clean Power Act, New Hampshire's Legislature must set a cap on mercury emissions from the state's power plants.
New Jersey	Agency Action	In 2004, the New Jersey Department of Environmental Protection adopted a rule requiring coal-burning power plants to reduce 90% of their mercury air pollution by the end of 2007. The rules allow for some flexibility, giving plants the option of meeting the new emission standards in 2012 if they also make major reductions in their emissions of sulfur dioxide, nitrogen oxides, and fine particulates.
North Carolina	SB1078	In 2002, North Carolina adopted the Clean Smokestacks Act which imposes nitrogen oxides (NOx) and sulfur dioxide (SO2) limits on coal-burning power plants. A 55% reduction in mercury emissions is estimated to result as a co-benefit. As required in the bill, the State Department of Environmental & Natural Resources submitted a report to the legislature in 2005 that recommended the state adopt mercury controls at least as stringent as federal rules and that also meets any additional requirement that state deems appropriate.
Wisconsin	Agency Action	In 2004, the Wisconsin legislature gave final approval to a rule that requires in-state coal-burning power plants to reduce their mercury air pollution by 40% by 2010 and 75% by 2015. The Department of Natural Resources may enter into a multi-pollutant reduction agreement with a major electric utility as an alternative to complying with the initial 40 percent reduction level. The rule requires that the Department adopt revisions to reflect federal requirements within eighteen (18) months of the promulgation of federal mercury standard.

State that Have Introduced Legislation in 2006

(Source: NCEL research)

State	Bill #	Summary	Status
Idaho	*	Requires the state Dept. of Environmental Quality to promulgate rules and adopt a state mercury emissions control plan to ensure that a thermal power generating facility not in operation on January 1, 2006, that emits more than one pound of mercury per year into the air shall not be permitted or constructed in the state. Provides that current rules limiting the state's ability to promulgate rules stricter than federal rules do not apply to the mercury emission control plan.	1/20/06 Introduced
Maryland	*	Supporting a lawsuit brought by environmental organizations and fifteen states to challenge the US EPA's mercury emissions limits for power plants.	1/18/06 Introduced
Maryland	*	As part of a multi-pollutant strategy to eliminate emissions from coal fired power plants, this bill establishes a 90% reduction in mercury emissions from power plants by January 1, 20010. The bill regulates any emissions credits for mercury so that mercury emissions in the state cannot be traded. Beginning December 1, 2007, power plants must report to the state on amount of mercury emitted during previous calendar year.	HB169 - Hearing on 2/7 SB154- Hearing on 2/1
	*		
Maryland	*	Creates the Clean Power Grant fund to provide grants to power companies for the purpose of installing emission controls.	1/25/06 Introduced
New Hampshire	*	This bill provides for an 80 percent reduction of mercury emissions from coal-burning power plants by requiring the installation of scrubber technology no later than July 1, 2013 and provides economic incentives for earlier installation and greater reductions in emissions.	1/4/06 Introduced
New Mexico	*	Memorial requesting the Dept. of Health and Dept. of Environment to convene task force to develop a comprehensive mercury action plan for New Mexico.	1/19/06 Introduced
New York	*	As part of a multi-pollutant strategy to reduce emissions from coal-fired power plants, this bill requires a reduction in mercury emissions by 90% from 1999 levels.	1/4/06 Referred to Assembly Enviro & Cons.
New York	*	As part of a multi-pollutant approach to reduce emissions from coal-fired power plants, this bill requires the state to set a mercury emissions cap of 10% of all current emissions. Prescribes a method for setting the cap.	1/4/06 Referred to Sen. Enviro & Conservation
Ohio	*	On and after December 15, 2007, coal power plants shall achieve and maintain one of the following, whichever is more readily achievable by the affected unit or units as determined by the owner or operator: (A) A mercury emissions rate equal to or less than six-tenths of one pound of mercury per TBtu; or (B) A mercury emissions rate equal to a ninety per cent reduction of mercury from the measured inlet conditions for the affected unit. The bill provides options if pollution control equipment does not produce intended reductions. Requires mercury emissions monitoring. On or after December 15, 2012, the state may establish more stringent emissions standards.	Introduced 2005, carries over to 2006
Virginia	*	Clean Smoke Stack Act - As part of a multi-pollutant strategy to reduce emissions from coal-fired power plants, beginning on May 1, 2009, power plants must meet a mercury emissions rate equal	HB1055 - Introduced 1/11/06
	*		

		to, or less than, 3 mg/MWh, or meet a mercury emissions removal rate equal to 90% of mercury from the measured exhaust gas of the affected unit, whichever emissions rate is more readily achievable, as determined by the owner or operator, by such affected unit. By May 1, 2008, certain power plants must submit a plan for reducing mercury emissions..	SB242 - 1/24/06 Assigned Subcommittee on Emissions
		By July 1, 2007, the Department of Environmental Quality shall implement a strategy to achieve reductions in mercury emissions from non-electric generating units by 90%.	
Washington	*	By July 1, 2010, the owner or operator of a mercury-emitting facility must choose to reduce mercury emissions by a standard of equal to or less than 0.6 pounds per trillion British thermal units produced or an emission standard equal to or greater than a ninety percent reduction of mercury emissions. The owner or operator of a mercury-emitting facility that is operational before the effective date of this act may choose which emission standard to follow. Mercury-emitting facilities that become operational after the effective date of this act may only be deemed in compliance with this section if the facilities meets a standard of equal to or less than 0.6 pounds per trillion British thermal units produced The department shall determine a process for obtaining representative fuel samples and analysis in order to confirm compliance with this section. If the facility is not in compliance any of the two mercury emissions standards by July 1, 2010, its operating permit cannot be renewed.	1/27/06 Introduced

State Agencies Considering Action to Regulate Mercury from Power Plants

Delaware

State has a "start action" notice to convene meetings to develop muti- pollutant regulation for coal-fired power plants, which will include mercury.

Illinois

On January 5, 2005, Illinois Governor Rod Blagojevich called for new state rules to limit mercury pollution from coal-fired power by 90% by July 2009.

Indiana

According to the June 1, 2005 Indiana Register, the Dept. of Environmental Management is taking comment on options to meet the requirements in CAMR. The Air Pollution Control Board was petitioned by the Hoosier Environmental Council (HEC) in June of 2004 to regulate mercury emissions from power plants. This rulemaking notice includes the HEC petition as an alternative to adopting CAMR. The HEC petition requested mercury limits for coal fired electric generating units of six-tenths pounds of mercury per trillion British thermal units (0.6 lbs Hg/TBtu) or an emissions rate equal to 90% reduction of mercury from the measured inlet conditions, regardless of coal type. The HEC petition did not allow for emissions trading among sources and required compliance by July 2008.

Michigan

In response to a request from the Governor to provide a report to the Department of Environmental Quality, the Michigan Mercury Electric Utility Workgroup (Workgroup) was formed. In June 2005, it issued its final report. It recommended a two phase reduction strategy. Phase 1: follow federal CAIR and CAMR that will reduce mercury emissions by 2010; Phase 2: Provides two alternatives go beyond federal CAMR of which one would reduce emissions by 90% by 2013.

Montana

In 2005, citing lack of time for appropriate review, the Board of Environmental Review voted against a proposed rule that would require new plants to meet an emission rate of 1.5 pounds per trillion BTUs, or a 90% reduction in mercury. Existing plants would have until July 1, 2010 to meet this standard. Each plant would then operate its mercury control equipment for one year. If the plant was unable to meet the limit in that time period, despite its best efforts, it could receive an alternative emission limit from the State based upon what it can achieve in reality. An alternative emission limit would be reviewed by the State every five years to determine if the company could reduce its mercury emissions even further.

However, the Board voted to have the DEQ propose a similar if not identical rule at the Board's February 2006 meeting. Currently, the February agenda includes an item: "Status report on the development of a mercury emissions rule for Coal-Fired Power Plants." (Source:

Pennsylvania

On August 16, 2005, the Environmental Quality Board approved the Department of Environmental Protection's recommendation to develop a Pennsylvania-specific regulation to reduce mercury emissions from coal-fired electric generating units. News reports indicate that Pennyslvania will pursue an emissions standards more stringent than the federal Clean Air Mercury Rule.

Virginia

The Virginia Air Pollution Control Board voted unanimously Jan. 27, 2005 to seek public comment on three plans to reduce mercury.

One option would follow a developed by a national group of state air regulators ( ) that would require a 73% reduction in mercury emissions from Virginia's coal-fired power plants by 2013. This proposal would prohibit interstate emissions trading by electric utilities and set emissions limits for power plants in the states that adopt it.

The second option would reduce mercury emissions by 64% by 2015.

The third option would apply the second option to power plants AND any factories that emit mercury. (Source: BNA Daily Environment Report)

2006 Legislation to Limit a State From Setting

Mercury Standards More Stringent than Federal Clean Air Mercury Rule

Virginia	(Looks like an ALEC model bill to limit states from going beyond fed rules).	Prohibits the State Air Pollution Control Board from imposing mercury emission controls that (i) are more stringent than the federal Clean Air Mercury Rule or (ii) would be imposed earlier than necessary for Virginia to comply with the federal Rule. The bill also prohibits the Board from adopting any regulation or agreement that might restrict a facility's (source's) participation in the national mercury trading program.	1/19/06 Introduced

2006 Legislation to Implement Federal Clean Air Mercury Rule (CAMR)

A summary of CAMR is at the end of this list.

West Virginia		Authorizes the Department of Environmental Protection to promulgate a legislative rule relating to the Mercury Budget Trading Program to reduce mercury emissions.	01/27/06 Introduced

*Sponsored or co-sponsored by an NCEL participant

On March 15, 2005, the U.S. EPA established its Clean Air Mercury Rule. Through an emissions-trading strategy, the rule seeks to reduce emissions from power plants by 35 percent by 2010 and 50 percent by 2020, according to EPA. When fully implemented in the late 2020s, the rule will cut mercury emissions by 70 percent. It allows operators to meet the requirements via cap-and-trade. (Source: BNA Daily Environment, January 6, 2006)

CAMR is currently being challenged by 15 states and environmental groups contending that the Clean Air Act requires more mercury reductions sooner than the CAMR provides and that the emissions trading regulatory scheme under CAMR is much weaker than a technology-based emissions control structure.

National Caucus of Environmental Legislators
7272 Wisconsin
Ave, Suite 300, Bethesda, MD 20814
301-941-1920

A project of the Edmund S. Muskie Foundation