BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060635-EU

In the Matter of

PETITION FOR DETERMINATION OF NEED FOR ELECTRICAL POWER PLANT IN TAYLOR COUNTY BY FLORIDA MUNICIPAL POWER AGENCY, JEA, REEDY CREEK IMPROVEMENT DISTRICT, AND CITY OF TALLAHASSEE.
_____/

VOLUME 9

Pages 886 through 1149

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. TEW
DATE:	Friday, January 12, 2007
TIME:	Commenced at 4:20 p.m. Concluded at 7:58 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LORI DEZELL, RPR, CCR

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

BRADLEY KUSHNER

EXHIBITS

NUMBER:		ID. ADMTD.
71	HP-1	924
72	HP-3	924
73	HP-4	924
74	HP-5	924
21	PAA-1	954
22	TEC-1	954
26	JM-1	989
27	JM-2	989
28	JM-3	989
29	JM-4	989
30	JM-5	989
31	TEC-1	989
36	MP-1	1067
37	MP-2	1067
38	MP-3	1067
39	MP-4	1067
40	MP-5	1067
41	TEC-1	1067
42	MP-1R	1067
52	CK-1	1101
53	CK-2	1101
54	TEC-1	1101

PROCEEDINGS

CHAIRMAN EDGAR: Okay. We -- I know we had had some agreement about continuing to take some witnesses out of order. So let's see. Are we at Mr. -- and I'm not going to even get the names right. So why don't you tell me who you would propose that we call for the next witness.

MR. PERKO: I believe we agreed to take Hale Powell next.

MR. JACOBS: Yes, I believe we did.

CHAIRMAN EDGAR: Okay. Okay. Mr. Jacobs, that is your witness?

MR. JACOBS: Yes, Madam Chair.

HALE POWELL

was called as a witness on behalf of Sierra Club, and having been duly sworn, testifies as follows:

DIRECT EXAMINATION

BY MR. JACOBS:

Q Good afternoon, Mr. Powell. You've been previously sworn, correct?

A Correct.

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

A Hale Powell, 20 Acton Road, Westford, Massachusetts.

1.0 INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Hale Powell. I am an independent consultant and the owner of HPowell Energy Associates. My business address is 20 Acton Road, Westford, Massachusetts, 01886.

Q. PLEASE DESCRIBE YOUR FORMAL EDUCATION AND YOUR PROFESSIONAL EXPERIENCE.

A. I graduated from Hunter College with degrees in Political Science and Environmental Policy. I earned a Master of Science degree from the University of Pennsylvania in 1991 in Energy Policy. Since 1983 I have had a full time professional and academic commitment to the identification and implementation of energy efficiency resources and to the development of policies that support this objective. Prior to finalizing academic work in 1989 I had extensive field experience in the actual installation of efficient equipment in commercial and industrial settings. I have spent most of the last 14 years involved with Demand-side Management ("DSM") programs at National Grid USA, a major electric utility with operations in Massachusetts, New York, Rhode Island and New Hampshire. As an indication of the scale of this effort, the Massachusetts subsidiary of National Grid, Massachusetts Electric, in 2005 alone, expended a total of $47.7 million implementing DSM programs for all classes of customers. In 2005 642,481 residential and 1,363 commercial and industrial customers participated in these programs. 2005

Massachusetts Electric program activity acquired incremental savings of 201 GWH and 22.9 MW of Summer demand. Using the state mandated Total Resource Test the benefit cost ratio of these savings was calculated to be 2.98. See Exhibit 1 for the July 2006 DSM Annual Report as filed with Massachusetts regulators.

At National Grid, I designed and evaluated DSM programs for commercial, industrial and residential technologies and markets. I also conducted cost effectiveness screening of residential and business sector DSM programs, and contributed to a large annual DSM regulatory filings in Mass, RI and NH. Some of my major work products included metering based savings evaluations of high efficiency motors, roof top HVAC systems, and market assessments of potential savings for industrial motors and compressed air systems as well as other techologies.

2.0 SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony today?

A. I have reviewed the application for a certificate of need by Jacksonville Electric Authority, ("JEA"), the City of Tallahassee, Reedy Creek Improvement District ("RCID"), and the Florida Municipal Power Agency ("FMPA") (hereinafter "Applicants"), for a 765 MW pulverized coal plant to be known as the Taylor Energy Center ("TEC").

My testimony has several main purposes:

1. To assess the analysis of DSM resources as provided by the Applicants. In particular I will discuss the need for more uniformity in the methodologies and

assumptions made by the four applicants in their evaluation of DSM cost effectiveness. In addition, I will discuss the effect of forecast fuel and emissions allowance prices on the availability of cost effective DSM alternatives to TEC.

2. To demonstrate on the record for this docket that the implementation of cost effective energy efficiency programs in Florida can save the Applicants' ratepayers millions of dollars over the next decade.

3. Explain how energy efficiency programs can help address global warming, climate change, and other important environmental issues.

4. To highlight recommendations of immediate actions that should be taken with respect to aggressive implementation of energy efficiency programs.

5. To present up-to-date information on DSM success stories and DSM savings in other States.

Q. What is your opinion of the assessment by the Applicants of prospects of DSM as alternatives to the coal plant in meeting their projected demand?

A. In comparison to regulatory filings in which I have been involved, the DSM testimony in this docket appears to provide only a small fraction of the detail required to assess the scale of the past and present DSM efforts and the savings achievements of the TEC applicants. Perhaps more significantly in this case, the testimony fails to substantially address the actual "real world" magnitude of future demand side kW and kWh resources that might be available to displace a portion of the proposed TEC capacity.

An example of this sort of research would be a quantified assessment of the current efficiency levels and inventory of major categories of energy consuming equipment and

building stock contrasted with the cost and performance of higher efficiency equipment of the same type. For example, how many megawatts of total customer demand are comprised of commercial lighting loads; of this load what percentage could be displaced by the installation of commercially available high efficiency lighting products?

Broad end-use categories to be assessed in this manner would include lighting, HVAC, industrial process equipment, commercial refrigeration etc. Exhibit XXX presents an example of this type of research, in this case conducted by a collaborative of utilities in the field of industrial compressed air systems

Without detailed and accurate estimations of the cost and availability of demand side resources, I believe that regulators will be unable to make a considered decision in respect to a broad portfolio of supply and demand side resources.

Q. Given the data provided, have the Applicants conducted a reasonable comparison of the potential of DSM to the supply option of building a fossil fuel plant?

A. I believe that considerably more effort is required in order to produce this result. Comparison of potential DSM resources to supply side resources requires a complex calculation of the comparative values of different resources over an extended time period. There seems to have been limited uniformity in how the four applicants conducted these analyses. Details are also lacking in terms of the multiple assumptions made in the analysis and whether these assumptions reflect the best available information. Obviously, inaccurate assumptions about DSM measure attributes, savings and costs can produce inappropriately high or low valuations of those resources.

The following are several of the factors that are crucial to the accurate calculation of DSM values.

- Lifetimes of DSM Measures: Over what period will a specific measure produce savings? How are these assumptions made? Are they uniform across all applicants? Is there a regulatory standard in Florida for measure lifetimes?
- Measure Energy Savings: What is the magnitude of kW and kWh savings for each evaluated measure? How are these savings calculated? Are the savings estimates based on actual field studies of installed projects, metering or based on simple engineering algorithms?
- Costs of Specific DSM Measures; What costs were assumed for the range of DSM measures evaluated? What is the origin of these cost assumptions? Were the cost assumptions identical for all applicants?
- Assumptions of "baseline" equipment. In the "new construction" market savings are based on an assumed difference in efficiency between the cost of "standard" and "high" efficiency equipment or construction techniques. If baseline assumptions chosen do not reflect actual practices cost and savings estimates can be highly distorted.

If the above four factors are do not reflect actual performance of specific DSM measures the calculated value and cost effectiveness of that measure can be completely inaccurate. This would lead to its inappropriate inclusion or exclusion from the resource portfolio

Q. How would the DSM cost effectiveness test by Applicants be impacted by the price forecasts submitted by Applicants for oil, coal, natural gas as well as the costs of carbon dioxide allowances that would be likely required under a carbon regulatory regime?

A. First, price forecasting is a highly imprecise science that rarely predicts the extreme price volatility that occurs in the real world. This is underlined by the applicant's oil price

forecast of $45 a barrel for 2006. Political events, environmental disruptions, extreme weather events and other factors produce commodity price volatility and supply disruptions but cannot be predicted. In addition, prices predicted by applicants for carbon emissions allowances are considerably lower than those assumed in other states. Higher than forecast commodity and emissions allowance prices may well erode the economic viability of the TEC plant, reduce demand for its output and make its generation less competitive with other supply and demand side alternatives.

Under the methodologies used by the applicants, the level of forecast fuel and allowance prices is central to the evaluation of DSM cost effectiveness. In the applicants' analysis DSM cost effectiveness is measured against the forecast price of TEC generation. If forecast fuel and allowance prices are low, DSM resources appear costly by comparison and are deemed not cost effective. Conversely, high fuel and allowance costs would render a range of DSM resources more cost effective than TEC generation.

Of particular concern are the low prices for CO2 emissions allowances forecast by TEC applicants. A review of these forecasts indicates a predicted long term price path of between $5 and $10 per ton of CO2. As indicated elsewhere in intervenor testimony, these forecasts are considerably lower than those used for planning purposes in other states. A higher assumed emissions allowance price would considerably elevate the cost effectiveness of DSM resources. It appears that a range of more realistic and current assumptions about fuel and allowance prices will likely increase the future operating costs of the proposed TEC plant, rendering DSM resources a more cost effective element

of the power portfolio. In my opinion, the economic analysis of TEC should be expanded to include a broader range of price scenarios.

Q. What is your assessment of the analysis of DSM potential conducted by the City of Tallahassee, one of the Applicants in this docket?

A. In his testimony Mr. Kushner indicated that Tallahassee, in certain circumstances, could produce a five year deferral in need for TEC capacity by utilizing cost effective DSM resources. Of the four applicants the City of Tallahassee appears to have conducted the most thorough analysis of available DSM resources. Assumed DSM measure costs were developed specifically for Tallahassee. In addition, Mr. Kushner's testimony suggests that Tallahassee employed a slightly different cost effectiveness test that resulted in a number of DSM measures being judged cost effective. The result is a potential deferral in capacity need.

In contrast, JEA and FMPA both used the Rate Impact Test and concluded that no DSM measures were cost effective. It is unclear what assumptions were made in respect to measure costs, savings and other attributes. Beyond a general commitment to DSM RCIP testimony provide no analysis of available DSM resources, future plans for programming or DSM cost effectiveness. The conclusions that I draw from the above are threefold:

1) The methodologies and assumptions of the applicants are highly divergent, predictably producing very different results in respect to the availability of cost effective DSM. Some level of uniformity of effort and expertise is needed to produce a credible and reliable assessment.

2) Using the Rate Impact Test combined with assumptions of future low fuel and allowance prices will effectively preclude DSM alternatives and inevitably increase Florida's dependence on carbon based energy production. This dependency will increase Florida's vulnerability to future regulatory costs associated with carbon emissions.

3) A more thorough and systematic analysis of DSM alternative by all four applicants will likely identify viable DSM alternatives that could displace some of the proposed full capacity of TEC.

Q. Are the Applicants required to meet specific standards in the cost effectiveness tests you suggest in complying with the certificate of need provisions in section 403.519, Florida Statues?

A. I cannot offer a legal interpretation of the statute. However, by its language, the statute requires that the Florida Public Service Commission "take into account..... whether the proposed plant is the most cost effective alternative available. The [sic] commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant and other matters within its jurisdiction which it deems relevant." Based on my experience and understanding of DSM cost effectiveness, this imposes at least two prerequisites:

1) First, a uniform methodology should be utilized by all applicants. The sources and objectivity of all assumptions are critical to the final result and must be transparent.

2) Secondly, those conducting the DSM analysis should have experience with successful DSM programs and be thoroughly knowledgeable about efficiency markets, program design, end-use technologies and program evaluation techniques.

My testimony has already addressed the need for further detail in respect to critical assumptions made by Applicants. I believe this issue can be clarified when these details

are provided and documented. Dissimilarities in applicants' DSM analyses can also be clarified. In my opinion, the intent of the DSM certification requirement in Florida is "predictive" in nature. In essence, it is asking applicants to certify that, for the lifetime of the TEC plant, there are no DSM programmatic options capable of cost effectively displacing part or all of the proposed plant. This analysis is especially complex and seems lacking in Applicants' filing. Similarly, substantial experience with efficiency markets and methodologies is essential to produce a realistic forecast of achievable DSM resources.

Q. Are there examples or best practices of reviews or assessments which effectively predict the success or failure of future DSM programming?

A. In other regulatory settings there are a wide variety of metrics by which regulators can assess the ability of utilities to effectively design and implement DSM programs and capture available end-use opportunities. To cite a few measures of good program design, these include annual participation levels by customer class, annual and cumulative kW and kWh savings per customer, project cost effectiveness by customer end-use, number of customer training sessions or audits and the scale of market and technical research conducted to identify potentially new efficiency resources. See Exhibit for an example of a more thorough DSM performance assessment as submitted to regulators in July 2006 by National Grid USA.

With few exceptions, TEC applicants do not appear to have provided this sort of actionable information in respect to their past or current DSM activity. The record thu far indicates that the DSM activities of the TEC applicants, where they exist, are non uniform and don't appear to be well documented. Testimony provided on this issue provides few details of different technology markets served or customer participation by customer class.

Without this information it is impossible to assess the commitment, achievements or level of effort of past applicant DSM activities. Nor does it permit an assessment of the expertise or adequacy of applicant staffing and/or resources to identify or effectively implement DSM resources in the future.

Q. Are there any other utilities and government agencies that support making energy efficiency the resource that is the highest priority?

A. Yes. In July, a large group of electric and natural gas utilities, government agencies and other organizations published the "**National Action Plan for Energy Efficiency**". This dynamic plan is a call to action to bring diverse stakeholders together at the national, regional, state, or utility level, as appropriate, and foster the discussions, decision-making, and commitments necessary to take investment in energy efficiency to a new and more aggressive level. The overall goal is to create a sustainable, aggressive national commitment to energy efficiency through natural gas and electric utilities, utility regulators, and partner organizations. The Action Plan was developed by a Leadership Group composed of more than 50 leading organizations (including the Natural Resources

Defense Council) representing diverse stakeholder perspectives (utilities, government agencies, environmental organization, etc.). Based upon the policies, practices, and efforts of many organizations across the country, the Leadership Group offers five recommendations as ways to overcome many of the barriers that have limited greater investment in programs to deliver energy efficiency to customers of electric and gas utilities. The **five** key recommendations of the plan are listed below:

- Recognize energy efficiency as a high-priority energy resource.
- Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
- Broadly communicate the benefits of and opportunities for energy efficiency.
- Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.
- Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

These above recommendations may be pursued through a number of different options, depending upon state and utility circumstances. As part of the Action Plan, leading organizations are committing to aggressively pursue energy efficiency opportunities in their organizations and assist others who want to increase the use of energy efficiency in their regions. Because greater investment in energy efficiency cannot happen based on the work of one individual or organization alone, the Action Plan is a commitment to

bring the appropriate stakeholders together— including utilities, state policy-makers, consumers, consumer advocates, businesses, energy services companies, and others—to be part of a collaborative effort to take energy efficiency to a new level. As energy experts, utilities may be in a unique position to play a leading role.

Q. Do you have any statistics that show results to date for DSM programs in other regions of the country?

A. Yes. Table 5 below presents the latest available statistics for program mWh and MW savings for these successful DSM initiatives in other regions of the US, along with benefit/cost data. It is important to note that all efforts in other states are cost effective overall.

TABLE 5 - SUCCESSFUL ENERGY EFFICIENCY PROGRAM RESULTS FROM OTHER STATES AND REGIONS (1)

State or Region	Starting Year for Savings in This Table	Cumulative Annual mWh Savings	Cumulative Annual MW Savings	Program-to-Date Benefit/Cost Ratio
California	2000	6,727,000	1,559	NA
Efficiency Maine	2002	52,437		2.3
Efficiency Vermont	2000	251,500	75	2.3
New York Energy $mart Programs	1998	1,400,000	860	4.0
Energy Trust of Oregon	2002	974,919	96	NA
Northwest Energy Efficiency Alliance	1997	1,278,960	146	NA
Wisconsin Focus on Energy	2001	783,957	140	5.7

Note 1: The numbers in this table are presented for each State or Region for the time period starting at the beginning of the organization's programs, except for California which started energy efficiency programs in 1976.

Q. Why are DSM programs a critical part of a balanced energy resource portfolio?

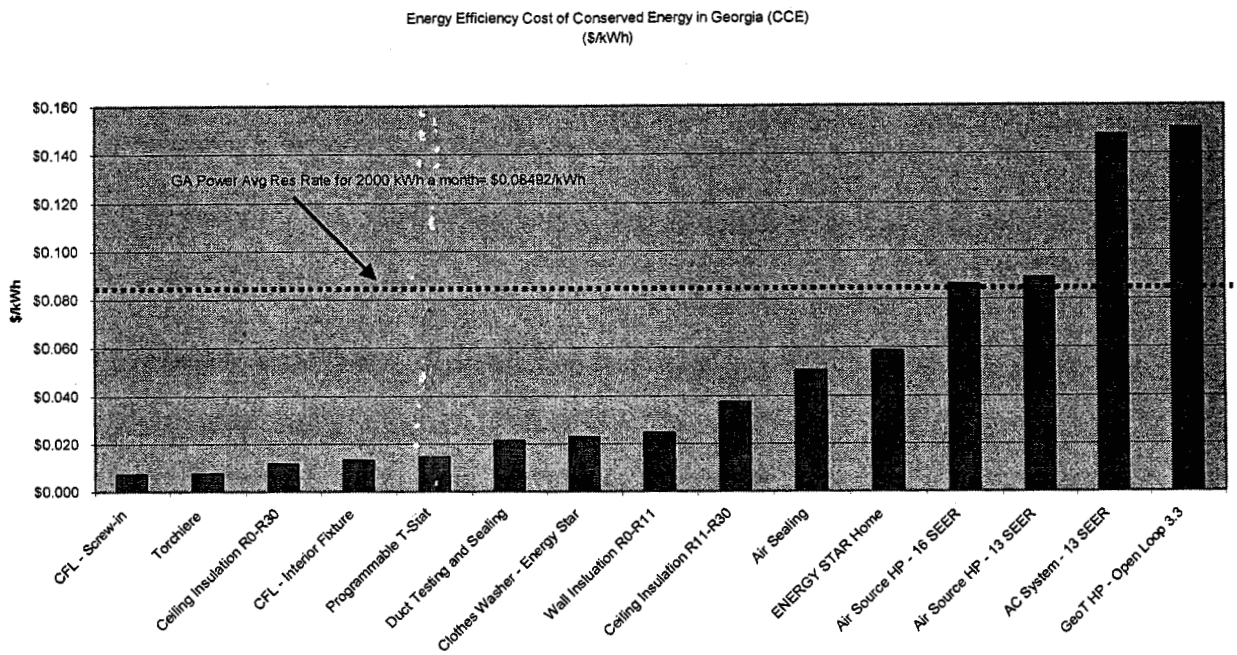
A. There are at least seven reasons why DSM programs are an essential component of a balanced energy resource portfolio:

1. First, DSM programs are a critical part of a balanced portfolio because numerous DSM measures are less expensive on a cost per kWh saved basis than supply-side resources. Figure 1 on the next page demonstrates that the cost per kWh saved of many DSM measures are less expensive than the cost of electric rates of the Applicants.

2. The majority of DSM resources have no "fuel costs", a huge advantage over supply-side resources. Once DSM measures like insulation are installed, they quietly provide energy savings for many years with no on-going fuel cost. This same feature is not true of fossil-fueled supply side resources such as coal and gas-fired generation plants.

DIRECT TESTIMONY AND EXHIBITS OF HALE POWELL
ON BEHALF OF THE SIERRA CLUB, JOHN HEDRICK AND BRIAN LUPIANI
FPSC DOCKET NO. 060635

FIGURE 1



3. DSM resources are indigenous (native) resources to Florida, and as such are not subject to supply cut-offs and uncertainties as are fossil fuel resources such as fuel oil and natural gas. Many of us remember the Arab oil embargo of 1974, for example, that created disruptions in supplies of oil to the United States.

4. DSM resources can help reduce emissions from coal and gas-fueled power plants, thus making the air we breathe cleaner, and reducing respiratory illnesses.

5. DSM resources are small scale and can be ramped up or down quickly to meet resource needs. Unlike a power plant, if only 50% of a DSM program is completed, the energy savings from the energy efficiency measure installations completed will provide energy savings over the useful life of the DSM measures. On the other hand, a new power plant that is abandoned halfway through construction is useless and cannot provide power. There are numerous examples of electric power plants that have been started but not completed, such as Seabrook 2, the Zimmer nuclear plant in Ohio, Grand Gulf Unit 2 in Mississippi, the Midland Nuclear Plant in Ohio, the Long Island Lighting Shoreham nuclear plant, the two nuclear plants cancelled in the 1980's by the Washington Public Power Supply System, and the two Bellafonte nuclear plants cancelled by TVA.

6. Every kWh saved though energy efficiency can help reduce the use of water in power plants. A recent study by the Land and Water Resources Fund indicated that each kWh saved through energy efficiency can save .67 gallons of water in a coal-fired plant and .33 gallons in a gas-fired generation plant.

7. Power plants are the largest U.S. source of greenhouse gas emissions, producing 2.5 billion tons of heat-trapping pollution every year. DSM resources, on the other hand, have no emissions, and can help reduce climate change impacts.

8. There are also substantial business development and job creation benefits resulting from the design and implementation of DSM programs. These benefits are discussed in more detail later in our testimony.

Q. Do DSM programs have any disadvantages as an energy resource?

A. No. DSM programs can save Florida ratepayers hundreds millions of dollars, they can provide significant economic and environmental benefits, and can help reduce respiratory ailments.

Q. Can DSM programs reduce the need for new transmission and distribution plant investment?

A. Yes. Several investor-owned electric utilities have used targeted DSM programs to defer the need for new power lines. Examples of successful DSM projects that have been undertaken to defer the need for new T&D investment include the Delta Project operated in the 1990's by Pacific Gas and Electric, the Espanola Project operated by Ontario Hydro, and the York Beach Ogunquit project conducted by Central Maine Power Company.

Q. Does the National Association of Regulatory Utility Commissioners have any resolutions in place that support expanded support of alternatives to the construction of new transmission lines?

A. Yes. Several such resolutions exist. For example, the Board of Directors of NARUC adopted a resolution at the summer 2000 NARUC meeting that stated "Resolved, that the Board of Directors of NARUC convened in its summer meeting in Los Angeles, California, finds that, in remedying situations of inadequate supply or constrained transmission, demand responses to market prices should be equally and fairly compared to alternatives which require the construction of generation or transmission." Exhibit ___ of my testimony provides a copy of several NARUC resolutions that support implementation of cost effective energy efficiency programs.

Q. Do you have any up-to-date information on the technical or economic potential for DSM programs?

A. Yes. Recent studies from Florida and other states show that the technical and achievable cost effective potential for DSM programs is huge. The technical potential for energy efficiency savings ranges from 18% to 33% of total electric load in recent studies completed for other States (such as Connecticut, California, Massachusetts, North Carolina, Vermont and the Southwestern U.S). The achievable cost effective potential ranges from 9% to 24% of electric sales for the nine studies that I examined.

Q. Finally, do you have any examples of any governors that fully support clean energy resources such as renewable energy and energy efficiency?

A. Yes. In mid-April of 2004, the Western Governors Association, representing 21 governors, announced its plans to support the development of clean energy policies for Western States that would boost support for energy efficiency and renewable resources. Provided below is the proclamation issued on April 12, 2004:

> "Today, the West has an important economic and environmental opportunity: the promotion of alternative energy development and energy efficiency that will help stabilize fluctuating energy prices, create lasting jobs, promote public health, and protect our environment.
>
> Together, western governors can make a huge contribution to meeting our nation's energy needs and protecting its energy security, while reducing the costs and instability created for consumers and businesses when energy prices and supplies are uncertain.
>
> The West is blessed with vast energy resources. These include sources that have been developed, such as oil and gas, coal, and hydro. Relatively untapped, and hugely promising, are other possibilities: solar, wind, zero-emission coal, biomass, and energy conservation. We are committed to an approach that will help secure a diversified energy supply, energy efficiency, and best practices in energy development.
>
> Clean energy and energy efficiency could become a significant economic growth center for many of our states, and could help create a national economic growth cycle from the domestic investment of energy dollars in new technologies and energy efficiency.
>
> To power the implementation of clean and renewable energy throughout the West, we recommend that the Western Governors' Association develop a project to explore clean energy and energy efficiency opportunities in the West, and the policies that will make them happen in our states. Our objectives should be to

develop at least 30,000 MW of clean energy in the West by 2015, and to increase the efficiency of energy use by 20% by 2020.

Clean and renewable energy and energy efficiency technologies are poised for broad success in the American West. Let us capture this moment and form a clean energy working group of diverse stakeholders who will create a set of western clean energy policy proposals for presentation to the Western Governors by June 2006."

Q. WHY IS INCLUSION OF DSM IN A UTILITY'S RESOURCE PORTFOLIO IMPORTANT?

A. As recognized and emphasized by the 2003 NARUC Resolution provided in Exhibit XX of my testimony, it is important for utilities to include DSM in a **balanced resource portfolio.** DSM resources can act as a hedge against supply constraints and fossil fuel price volatility.

The NPC report also made the following policy recommendations to Improve Demand Flexibility and Efficiency:

- Encourage increased efficiency and conservation through market-oriented initiatives and consumer education.
- Increase industrial and power generation capability to utilize alternate fuels.

Therefore, this Commission should look seriously at DSM and our detailed NRDC and Sierra Club recommendations.

4.0 THE BUSINESS CASE FOR DSM PROGRAMS IN FLORIDA

Q. Can you summarize for the commission the key factors making DSM programs a wise business decision for Florida's ratepayers?

A. Yes. It is unclear to this witness to what extent the four TEC applicants have financial incentives or disincentives for DSM A number of states have developed regulatory mechanisms which provide positive financial incentives for regulated utilities to develop and implement successful DSM programs. The non-profit American Council for an Energy Efficient Economy (ACEEE) has recently published a comprehensive review of these incentive systems entitled Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives. See Exhibit 5. This report confirms that the economic and environmental facts for DSM programs are compelling. The following list of key factors demonstrate that DSM resources must be included in action plans for utilities in Florida:

- Inclusion of a broad range of DSM programs will provide ratepayers with tools and cost effective choices to help offset upcoming rate increases due to the need for investment in new T&D facilities.
- DSM programs can help Florida utilities cope with the electric load requirements of the tens of thousands of new residential customers that are forecast to be added each year to the Florida electric grid.

- As demonstrated in Figure 1, the actual cost per kWh saved for DSM measures is often far less than the cost of existing and new supply-side resources. When DSM resources are added to the resource portfolios of Florida utilities, customer bills can decline substantially.
- DSM programs can help defer or eliminate the need for new T&D facilities. Many electric utilities in the US have used DSM programs to defer or eliminate the need for such T&D facilities.
- There are significant environmental benefits of DSM programs due to the reductions in emissions of CO2, SO2, NOX and particulates, and due to reductions in the use of water at power plants that can be deferred or avoided. These reductions can help mitigate global warming and climate change issues.
- DSM programs have significant job creation benefits. In fact, an American Council for an Energy Efficient Economy (ACEEE) study found that energy efficiency measures or programs create more jobs at the regional or state level as compared to energy supply projects. This ACEEE study found that energy efficiency improvements lead to more jobs and higher personal income at the national level, in addition to saving consumers money, reducing energy imports, and cutting pollutant emissions than economic activity associated with energy supply. In terms of energy policy objectives, it is unnecessary to choose either economic benefits and jobs on the one hand or environmental protection on the other. We can create more jobs **and** better protect the environment by adopting policies that enhance energy efficiency. Given the economic, energy, and

environmental challenges that our nation faces, we must include DSM as a resource in the resource portfolios of Florida utilities.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. JACOBS:

Q Mr. Powell, do you have a summary of your testimony?

A Yes, I do.

Q You may proceed.

A My name is Hale Powell. After many years of working as a full-time DSM professional for a large and aggressive electric utility DSM program, I am now a private consultant. Like all other utility resources, effective DSM assessment, program design and implementation requires careful research, strong analytic skills and appropriate and specialized expertise. Developing a strong DSM resource is not unlike designing a large power plant. Success in developing both resources requires a logical, systematic, step-by-step and sometimes prolonged process.

The Sierra Club has asked me to examine the DSM analyses of the four TEC applicants to determine whether the applicants have provided clear evidence that DSM resources in their individual service territories have been exhausted. I find the following shortcomings in the applicant's assessments of the availability of DSM resources to potentially displace or defer the need for TEC capacity.

One, while Tallahassee has made a laudable first effort, Reedy Creek has produced no quantified or documented evidence in respect to the availability of potential DSM resources within its customer base. Similarly, FMPA has provided no evidence that DSM is exhausted within the specific service territories of its member municipal utilities.

Two, at its most basic, a DSM assessment requires three elements: Thorough research; two, localized analysis and ultimately, finally, cost effectiveness screening. While FMPA and JEA have conducted a screening process, they have largely failed to complete the preliminary steps that are required to produce a credible cost effectiveness analysis.

Three, the DSM resources screen do not include many of the highly cost-effectiveness effective technologies successfully used in other DSM utility programs. It appears that the list of measures screened may not have been fully updated to reflect successful new technologies produced by the dynamic DSM market in other regions of the country.

Four, the potential DSM savings of important market sectors and customer classes have been excluded from the analysis. These sectors have been the source of significant DSM resources in other venues. The

industrial market is one, only one, conspicuous example of this omission.

Five, the accuracy of cross effectiveness results depends on well-documented, current and credible assumptions about savings, costs and other parameters associated with specific DSM measures. Without the opportunity to review the sources and validity of these numerous, numerous assumptions, I cannot ascertain whether cost effect resources have been inappropriately eliminated.

In sum, given my professional experience as a utility employee and a private consultant, do I believe there are available DSM resources in the service territories of the TEC applicants sufficient to defer or displays all or part of the TEC capacity? I reserve judgment on this issue.

However, I do believe that a great deal more effort, data, scrutiny and expertise is required before the PSC can conclusively determine that significant DSM resources have been exhausted in the individual service territories of the TEC applicants. Thank you.

Q Does that conclude your summary?

A Yes, it does.

MR. JACOBS: Thank you. Tender the witness for cross.

CHAIRMAN EDGAR: Thank you.

Ms. Brownless?

MS. BROWNLESS: I believe Mr. Simms has questions, but I do not, Your Honor.

CHAIRMAN EDGAR: Mr. Paben, do you have questions?

MR. PABEN: Not at this time.

CHAIRMAN EDGAR: Mr. Simms, do you have limited questions for this witness?

MR. SIMMS: I do. I apologize. I had to get Dr. Lashof off on his flight.

CROSS-EXAMINATION

BY MR. SIMMS:

Q I wanted to ask one question about issues pertaining to risk associated with customer nonparticipation in DSM measures. Are there ways to design and/or implement DSM measures so as to minimize this risk?

A There are a variety of risks associated with DSM as there are a variety of risks associated with supply resources. One of the risks as you mentioned is that participation rates, penetration rates, to use the technical term, will not be -- will not meet forecast levels. That's an issue of program design. And I think an important issue is to assess the successful program

strategies and other utility DSM programs and to structure incentives, technical assistance and other interventions to anticipate and encourage customer participation. I've been very involved in this particular issue.

Q Thank you. I have one more question and that will be it.

Are there DSM measures that are not susceptible to this kind of risk?

A Are there DSM measures not susceptible to what risk?

Q To the customer nonparticipation type of risk. And I speak specifically of this sort of not -- you know, taking the lightbulbs out after a week instead of --

A Well, that's not really participation. The technical term is persistence. A participation is -- is -- would be deemed to be initial signing up and installation of a measure, participation in a training program or a loan program or whatever. There are risks with persistence issues such that somebody unscrews a lightbulb or a business goes out of operation.

To address this issue, I was involved in the national grid's measurement and evaluation effort for six years, and we spent a lot of effort doing specific

analysis with the persistence of measures and these sorts of analyses involve surveys and metering of equipment and factors of persistence can be built into that, the estimate in calculation of savings either on an individual or an aggregate basis.

So basically to give you a very brief answer, yes, risks can be anticipated and they also can be measured and included in the estimation of net resource value of the DSM measures.

MR. SIMMS: Thank you for clarifying those. Those are all of my questions.

CHAIRMAN EDGAR: Thank you.

Mr. Paben, you had said not at this time. This is your chance. No questions?

Okay. Thank you very much.

Ms. Raepple?

CROSS-EXAMINATION

BY MS. RAEPPLE:

Q Good afternoon, Mr. Powell.

A Hi.

Q At your deposition, we spoke briefly about the FIRE model. And the FIRE model is the model that the Florida Public Service Commission has historically recognized as appropriate for determining cost effectiveness of DSM.

Isn't it true that you defer to this Commission as to whether that's an adequate and appropriate model for the Florida setting?

A I defer in the sense that they have made -- appear to have made the ruling historically that that's the appropriate model. I don't necessarily agree from a perspective -- a professional standpoint. However, I do emphasize, as I said in my summary of my testimony and in my testimony itself, the cost effectiveness screening is only a very small and final element of a DSM assessment process. That research and analysis are essential in order to produce an appropriate result.

Q With regard to a successful DSM program, wouldn't you agree that attaining a 4 percent reduction of annual sales would constitute a very successful DSM program?

A A -- I'm not sure what your -- what the intent of your question is. Typically utilities in DSM programs are able to obtain on a yearly basis -- obviously there's a range of attainment -- but between 4.4 and, say, .8 percent of reductions in sales on an annual basis.

A 4 percent savings would be successful; however, it would depend on the time period over which that was attained. It was attained over a period of

20 years, I would say well, that would not be a successful effort. If it was attained over a period of two years, I would say that would be a highly successful effort.

Q Okay. And when you talk of annual sales in that regard, is that the same as reduction in energy as opposed to reduction in capacity?

A Annual sales, I am specifically referring to kWh or megawatt hour sales in that respect.

Q And that's energy, correct?

A Correct.

MS. RAEPPLE: Thank you. I have no further questions.

CHAIRMAN EDGAR: Thank you.

Are there questions from staff?

MS. HOLLEY: Staff has no questions.

CHAIRMAN EDGAR: Mr. Jacobs, redirect?

MR. JACOBS: No questions. We'd move the exhibits.

CHAIRMAN EDGAR: Okay. Let's see. 71, 72, 73 and 74.

MR. JACOBS: Yes, yes.

CHAIRMAN EDGAR: Any objections? None?

Okay. Exhibits 71 through --

MS. RAEPPLE: I'm sorry, Madam Chairman. We

do want to preserve our objection as to hearsay as to Exhibit 71 and Exhibit 74, please.

CHAIRMAN EDGAR: Okay. I'm sorry, I couldn't find my list -- I'm sorry. Could you -- while I was looking for my list, repeat that -- I know it's on the record -- so I hear it and it sticks?

MS. RAEPPLE: Yes. I would like to preserve our objection as to hearsay on Exhibit 71 and 74.

CHAIRMAN EDGAR: Okay. Thank you. Is there a remaining objection?

MS. RAEPPLE: There is one other objection, and that is related to Exhibit 71. And that is we object on grounds of relevancy because there's been no showing that there are any DSM measures available and cost effective for any of the applicants, and there's no showing that an avoided unit is analogous.

CHAIRMAN EDGAR: Mr. Jacobs?

MR. JACOBS: Well, the first response is that there's been filed or ruled -- I think this was in the original objections and they were ruled on at prehearing. But of course, we would argue that these are absolutely appropriate benchmarks for -- that would apply in Florida and particularly apply in circumstances where the companies haven't even

looked at the range of measures that are included in this report. How can you say they're not relevant when they haven't looked at them?

CHAIRMAN EDGAR: Again, the objection is noted for the record. I am going to allow, again, for the weight they are deemed to be due, all exhibits, 71, 72, 73 and 74 to be entered.

(Exhibits Nos. 71, 72, 73 and 74 admitted into the record.)

MR. JACOBS: Thank you, ma'am.

CHAIRMAN EDGAR: Okay. Thank you. And the witness is excused.

THE WITNESS: Thank you very much.

CHAIRMAN EDGAR: Thank you.

Okay. Are we back to order? We are. Okay. Then, Ms. Raepple, your witness?

MS. RAEPPLE: It will actually be Mrs. Dailey's witness.

MS. DAILEY: And the applicants would like to call Paul Arsuaga.

PAUL ARSUAGA

was called as a witness on behalf of the Applicant, and having been duly sworn, testifies as follows:

DIRECT EXAMINATION

BY MS. DAILEY:

Q Can you please state your name and business address.

A Paul Arsuaga, A-R-S-U-A-G-A. I'm at 1000 Legion Place, Orlando, Florida, 32801.

Q And have you been sworn in this proceeding?

A Yes.

Q And did you submit prefiled testimony on September 19th, 2006, in this proceeding consisting of seven pages?

A Yes, I did.

Q And do you have any changes to that testimony?

A I do have one change. On -- on page 7 of that -- page 4, I'm sorry, of the testimony, it says that the notice for the request for proposal was published in seven major newspapers around the country. That should read it was submitted to six industry publications.

The reason for that was the -- my understanding is that the applicants chose to use the industry publications because that gave them a better target audience that would include more potential bidders that would bid on this type of a project.

Q Thank you.

If I were to ask you the same questions set forth in your testimony today, would your answers be the

same?

A Yes.

Q And are you sponsoring any exhibits to your testimony?

A Yes.

Q And is that the exhibit that's been marked as Exhibit 21, your resume?

A Yes.

Q Do you have any changes to that exhibit?

A No.

Q Are you also sponsoring any sections of the Need for Power Application that have been designated as Exhibit 22 as updated by the errata sheet, Exhibit 3?

A Yes.

Q And those are as listed in your testimony?

A Yes.

Q Do you have any changes to the sections of the Need for Power Application that you are sponsoring?

A Yes. There's a similar change that I just mentioned as in my direct testimony on page A.7-3.

MS. DAILEY: Madam Chairman, I request that Mr. Arsuaga's testimony be admitted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony of the witness will be entered into the record as though

read with the changes as noted in his testimony.

MS. DAILEY: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF PAUL A. ARSUAGA

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Paul A. Arsuaga. My business address is 800 North Magnolia Ave. Suite 300 Orlando, Florida 32803.

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

A. I am employed by R. W. Beck as a Senior Director.

Q. Please describe your responsibilities in that position.

A. As a Senior Director, I am responsible for the performance of consulting engineer's reports for official statements, financial analyses, acquisitions, damage studies, power purchase request for proposals and contract negotiations, and power supply studies and reports for municipal utilities and joint action agencies as well as other types of utilities.

Q. Please describe R. W. Beck.

A. R. W. Beck is a national management consulting and engineering firm with a multi-disciplined staff of 550 and 25 offices nationwide. R. W. Beck provides a variety of consulting and engineering services across several industries, including energy, water, and solid waste. For the energy industry, R. W. Beck provides power supply analysis, assistance with Request for Power Supply Proposals (RFPs), independent engineering reviews and financial feasibility assessments, appraisal evaluations, due diligence reviews, transmission and distribution design services, construction management, planning and owner's engineering services for generation and transmission facilities, preparation of environmental reports, monitoring, permitting, and licensing. Since its founding in 1942, some of the milestones that the firm has achieved include:

- Provided independent engineering and feasibility assessments associated with over $150 billion in capital investment.
- Performed due diligence reviews and/or designed and engineered over 400 power-related projects.

Q. Please describe your educational background and professional experience.

A. I have a Bachelors of Science degree in electrical engineering from Tulane University. I have a Masters of Business Administration from the University of Hawaii. I am a registered Professional Engineer in Florida, Mississippi, and Missouri. I have experience in the execution and evaluation of power supply requests for proposals; market price analyses; wholesale power supply contracts

and negotiation; planning for electric utility restructuring; electric power resource planning; reliability studies; litigation support; financial planning and analysis; gas fuel supply; and competitive analysis, mergers, and acquisitions. I have over 32 years of planning experience in utility infrastructure and electric power facilities.

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

A. The purpose of my testimony is to discuss the request for power supply proposals process. My testimony will include discussion of the request for power supply proposals, a description of the proposals received, and an overview of the proposal evaluation process.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit ____ [PAA-1] is a copy of my resume.

Q. Are you sponsoring any sections of the Taylor Energy Center Need for Power Application, Exhibit __ [TEC-1]?

A. Yes. I am sponsoring Section A.7 and Appendix A.1, which were prepared by me or under my direct supervision.

Q. Please describe the efforts to solicit power supply proposals.

A. On November 28, 2005, the Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (City) (collectively referred to as the Participants) issued an RFP, which is presented in

Appendix A.1 of the Taylor Energy Center Need for Power Application, Exhibit __ [TEC-1]. The RFP served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the Participants beginning on June 1, 2012, and continuing over a period of at least 10 years. The RFP requested a minimum of 100 MW (up to a maximum of 750 MW) to be allocated among the Participants and required that the proposed capacity and energy be delivered into each Participant's system on a firm, first-call, non-recallable basis. The RFP was distributed to more than 40 potential bidders and ~~published in~~ submitted to six industry seven major ~~newspapers around the country~~ publications.

The RFP was intended to elicit proposals from qualified bidders that included electric utilities, independent power producers (IPPs), qualifying facilities (QFs), exempt wholesale generators, nonutility generators, and electric power marketers who have received certification by the Federal Energy Regulatory Commission (FERC). Proposers unfamiliar to the Participants were required to provide proof of experience.

Q. Please describe the responses to the RFP.

A. The mandatory pre-bid conference was held on December 20, 2005, in Jacksonville, Florida, and was attended by potential bidders from seven companies. Of the attendees, two companies submitted a Notice of Intent to Bid Form on December 27, 2005.

The proposal due date was modified to March 7, 2006, and two bids were received, both from Southern Power Company (Southern). The first proposal was for a 797 MW (net) supercritical pulverized coal unit (the coal resource) to be constructed at the same site proposed for the Taylor Energy Center. The second proposal was for a natural gas fueled, 784 MW (net) 2x1 501G combined cycle unit (the combined cycle resource). This unit was proposed to be constructed in St. Lucie County, Florida.

Q. Please summarize the proposal evaluation process.

A. The Southern proposals were initially received, logged, opened, and distributed by JEA on behalf of the Participants. R. W. Beck performed a two phase evaluation process. The first phase involved a screening of the minimum requirements as described in the RFP.

We then prepared a busbar screening analysis for the two Southern proposals and the Participants' Self-Build Resource (TEC). The busbar analysis was undertaken in order to project annual power costs (in $/MWh) under a base set of assumptions as well as several sensitivity scenarios that reflected higher and lower than expected fuel prices and environmental, capital, and non-fuel operations and maintenance (O&M) expenses.

Q. Did Southern's two proposals each comply with the minimum requirements of the RFP?

A. No. R. W. Beck determined that four minimum requirements were questionable in their completeness.

Q. Were both of Southern's proposals carried forward to the busbar screening analysis despite not meeting all of the minimum requirements?

A. Yes.

Q. Were any adjustments made to Southern's proposals in this regard prior to R. W. Beck's busbar evaluation?

A. Yes. R. W. Beck incorporated emission allowance prices into each of Southern's proposals to be consistent with the busbar analysis of the Self Build Resource.

Q. Were any other adjustments made to Southern's proposals prior to R. W. Beck's busbar evaluation?

A. Yes. The Southern coal resource proposal did not include certain costs that were included in the Self Build Resource cost, and there were inconsistencies among the proposals relative to transmission interconnection and upgrade costs. To correct for these differences, certain adjustments were made to all of the proposals.

Q. Please summarize the results of R. W. Beck's evaluation.

A. The R. W. Beck evaluation of Southern's two proposals and the Self-Build Resource concluded that the Self-Build Resource is projected to have a lower delivered cost to the Participants than Southern's proposed coal resource or the combined cycle resource. Southern's proposed coal resource and combined cycle resource were projected to have higher costs than the Self-Build Resource over a range of evaluation scenarios.

Q. Does this conclude your testimony?

A. Yes.

BY MS. DAILEY:

Q Mr. Arsuaga, did you prepare a summary of that testimony?

A Yes, I did.

Q Would you please present that now?

A The purpose of my testimony is to discuss the request for proposal process, the evaluation of proposals and the results of that evaluation.

On November 28th, 2005, the applicants issued a request for power supply proposals which is presented in Appendix A.1 of the application. The RFP served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the applicants beginning in June 1, 2012, continuing over a period of at least ten years.

The RFP was distributed to numerous potential bidders and several Internet industry publications and Websites. And on March 7, 2006, two bids were received both from Southern Power Company. The first proposal was for a 797-megawatt net supercritical pulverized coal unit to be constructed at the same site as proposed for the Taylor Energy Center. The second proposal was for a natural gas fueled 784-megawatt net 2x1 501G combined cycle unit to be constructed in St. Lucie County,

Florida.

I conducted a multistage evaluation of the RFP responses and concluded that the Taylor Energy Center is projected to have a lower delivered cost to the applicants than either of Southern's proposed alternatives over a range of evaluation scenarios.

MS. DAILEY: Madam Chairman, we tender the witness for cross-examination.

CHAIRMAN EDGAR: Thank you.

Ms. Brownless?

CROSS-EXAMINATION

BY MS. BROWNLESS:

Q Mr. Arsuaga, just so I get the logistics down --

CHAIRMAN EDGAR: Ms. Brownless, do you have your mike on?

MS. BROWNLESS: I'm sorry.

BY MS. BROWNLESS:

Q The request for power supply proposal that was actually sent, the RFP, is Appendix A to Volume A; is that correct?

A It's -- it's -- it's Appendix A.1, you're right, to A.7.

Q Okay. All right. It's basically the back portion of Volume A?

A Yes, yes.

Q And let me ask you this question: The basic RFP indicated that you needed a June 1st, 2002 delivery date?

A 2012.

Q Oh, I'm sorry.

A Yes.

Q And it asked for a commitment of ten years?

A A commitment of at least ten years.

Q That was the minimum time?

A Yes.

Q Okay. And asked for capacity over that ten-year period anywhere from 100 megawatts to 750 megawatts?

A Yes.

Q Okay. And it also required that it be firm first call, nonrecall basis?

A That's correct.

Q Was this RFP limited by fuel type in any way?

A It was not. It says on -- I believe it's page 7 of the RFP, let's see, that the utilities would prefer solid fuel and prefer mature technologies but the utilities will consider other fuel types and technologies if the evaluations show these to be superior to solid fuel alternatives on the basis of

price and nonprice criteria.

Q And just so I understand the terminology, is natural gas considered a solid fuel alternative?

A No.

Q So what you're saying in layman's terms is you would consider natural gas as well as coal?

A That's correct. And we did receive a proposal for natural gas.

Q Okay. I understand you had a prebid conference on December 20th of 2005; is that right?

A That's correct.

Q And that seven companies attended that conference?

A That's correct.

Q And two companies filed a notice of intent to bid subsequent to that; is that right?

A That's correct.

Q Who were those two companies?

A One company was Southern Power Company. I'm sorry, I do not recall the other company right now.

Q Okay. But your March 7th date was the final date to submit a bid; is that correct?

A That's correct.

Q And only the Southern Power Company submitted a bid at that time?

A Yes.

Q Okay. Do you have the staff interrogatories No. 17 in front of you, sir -- 14 through 17, first set of interrogatories? I guess it's the second set of interrogatories. I think you prepared --

A I have 14 and 15, which are the ones I sponsored.

Q All right. My understanding is that some additional costs were added to the Southern Power Company bid in order to make it what you deemed to be comparable to the TEC unit; is that correct?

A That's correct. But we also -- we added costs to the self-build also. There were adjustments to both self-build and the Southern Company bids to make them all consistent.

Q Okay. And I understand that you added the cost of the land to the Southern Company bids; is that right?

A That's correct.

Q Did you add the entire 3,000 acres to the Southern Company bid?

A I added the amount of land that was included in the cost of the -- of the self-build, because that's the -- what the cost of the self-build was -- I understood was based on.

Q Okay. And is it your understanding that the self-build includes approximately 3,000 acres of land?

A I'm not sure that the -- I talked to Mr. Hoornaert and I asked him what amount of dollars was included in the plant cost that his proposal was based on, and that was the amount. The amount that he gave me was the exact amount that I added to the Southern Company proposal.

Q Okay. We've discussed chart A.3-5 which is the revised cost for the TEC plant. Do you know whether the amount shown for land on that cost is what was added to the bid?

A What -- I don't know what --

Q I can show you Mr. Hoornaert's --

A I recall the amount was $20 million is what I included. If that's the amount, then that --

Q Thank you.

Now, I assume that the Southern Power Company proposal -- that, for example, they only were proposing to bid one 797-megawatt supercritical pulverized coal plant on the site, correct?

A Yes.

Q And they were only proposing one 784-megawatt natural gas plant, right?

A That's correct.

Q You indicated, I think, in response to Staff Interrogatory No. 14 that you did a busbar analysis; is that right?

A Yes.

Q And is that analysis basically a dollar-per-megawatt hour analysis?

A Yes, it is.

Q Do you remember what the TEC dollar per megawatt hour figure was that you used for comparison?

A The -- I believe the TEC number came out to be around $62 per megawatt hour. That was on a levelized basis over a 20-year period, which was the same period as the -- as the offer from Southern.

Q Okay. And was that the cost at -- at the time that your evaluation of the bids was done, you were using the original cost estimates for TEC; is that correct? Because this was being done in -- what time did you do these evaluations?

A The evaluation was done between when we received the bids, March 7th, and around April 11th.

Q Of '06?

A Yes.

Q So that would have been prior to revising the construction costs for this unit?

A That's correct.

Q Have you done any subsequent analysis with regard to the cost effectiveness of either of these bids using the new numbers for the TEC unit?

A Yes, I did. I did -- I got the -- an updated number from Mr. Kushner. And I recalculated the comparison and it did not change the decision.

Q Okay. And did you make a 20 percent increase in the cost of the Southern Company's bids as well?

A No. No, that was -- I just -- I assumed that the Southern Company cost would -- would remain fixed. I just increased the cost of the self-build. Although the Southern bid was what they call an indicative bid which could have been increased by them within 45 days.

Q Did you have any CO_2 allowance included in the TEC busbar analysis you've just described?

A I did a -- I did a base case and I did some sensitivity cases. I did a sensitivity case including CO_2 allowances.

Q Can you tell us how much the cost per ton for CO_2 was that you used?

A I used an assumption of -- a value of around $7 in 2012 per ton escalating at inflation.

Q And that would be what rate, sir?

A I'm sorry? Oh, two-and-a-half percent is what I said.

Q Two-and-a-half percent a year?

A Per year, yes.

Q There's different types of RFPs when it comes to power plants, and I want to make sure I understand the kind of RFP this was. Sometimes you put out an RFP, and then the recipient of the RFP determines that they'll further negotiate terms. Was that the type of bid this was or was this a flat nonnegotiated bid; in other words, whatever they put on their bid was what you had to stick with?

A Well, we asked for a -- it was -- we were always hopeful to get a firm price, but the -- I guess the offer that we got was we had a firm price on one of them, which was the combined cycle offer, but we got indicative offer on the -- on the coal offer -- on the coal proposal. An indicative offer means that it's -- the way they stated was once we -- they were short listed, they would have had 45 days to firm up their price.

Q In other words, to modify the price they bid?

A Yes.

Q Did you make any attempt to contact them to see if they would further modify their price?

A Well, what we did was an initial screening to see if they were within a proximity of the self-build

proposal which they were not. So it didn't -- it didn't seem like they were -- well, we presented those results in our report, that they were not close to the self-build offer.

Q So you didn't approach the Southern Company again; is that correct?

A To reduce their price?

Q Yes.

A No. Well, I -- we -- I expected by them giving the indicative offer, that it was more likely that it would go in the other direction.

Q But you had no basis for that speculation?

A No.

Q I have only one other question which has to do with the transmission interconnection and upgrade cost which you reference on page 6 of your testimony.

A I'm sorry, could you repeat that?

Q On page 6 of your testimony, you talk about transmission interconnection and upgrade costs.

A Yes.

Q And can you tell me what adjustments were made regarding those costs?

A On page 6 of my testimony?

Q Yes, sir. You see down here on lines -- starts on -- the question -- the answer starts on line

18, goes through page 20. "Inconsistencies among relative to transmission, interconnection and upgrade costs."

A Okay. The proposal indicated that they had done a study and had indicated that there were -- that there were $125 million in upgrades required, but they didn't include it in their proposal. What I did was I added that 125 million to their proposal, but I also added the same amount to the self-build proposal.

Q Okay.

A And I -- the self-build proposal had a -- had a, I think, $12 million estimate in there, 11.7. I subtracted that out and added the 125 million, so that both of them would have the same amount of upgrades in their costs. And I made an adjustment for that.

Q Okay. Did you do any analysis to see the nature of that transmission they were talking about?

And let me tell you why I ask that question. We've heard testimony today that some types of transmission upgrades might be considered network improvements, and therefore, costs that would eventually be rebated back to a project and some might be transmission upgrades purely and directly associated with that project. Did you attempt to parse any of that out?

A No, I did not. I was -- I was assuming I would suppose a worst case scenario. And just assuming that, there was no credit back for either party.

Q With -- and one other question, and I truly am done. With regard to the 784-megawatt bid, that was to be built in St. Lucie County, correct?

A Yes.

Q Did you add any land component for that bid?

A A land component? No. They did not -- in -- in the case of the coal unit, the proposal actually said it did not include site costs. And that they didn't say that in the combined cycle bid. So I did not add any additional site costs.

MS. BROWNLESS: Thank you so much. I'm done.

CHAIRMAN EDGAR: Ms. Paben?

MS. PABEN: Just a few questions.

CROSS-EXAMINATION

BY MS. PABEN:

Q Good afternoon, Mr. Arsuaga. How are you doing?

A Good afternoon.

Q I have just a few questions for you. In the RFP, was there a fee associated with making a bid for this proposal?

A Yes.

Q And can you tell me what that fee was?

A It was $5,000 per proposal.

Q Okay. Would you consider that fee typical for a project of this size?

A I've seen -- I've seen a range of fees from no fee to $10,000. You know, it's a large project. I don't think -- that's not an unusual fee.

Q In other RFPs that you've been part of, have you had $5,000 bid for a similarly sized facility?

A I've been involved with -- I have been involved with an RFP where there was a $10,000 fee for a smaller project.

Q And what type of project was that?

A It was a combined cycle project, a -- I can't recall the exact amount of megawatts, but I believe it was in the 500-megawatt range.

Q Okay. At the prebid conference, you indicated that there were seven participants. Can you identify those seven participants?

A I don't have that -- I don't have that -- I don't -- I could get those, the people, but I don't have that in front of me now.

Q Is there anything that's included in the record here that would have that information for it?

A I don't think so.

Q If it would be possible, could you provide that as a late-filed exhibit at a later time?

MS. DAILEY: Madam Chairman, I'd like to object on the relevance of that request. There's no relevance to the issues in this proceeding, the identity of the attendees at that meeting.

CHAIRMAN EDGAR: Ms. Dailey?

MS. PABEN: Yes. I would argue that it's --

CHAIRMAN EDGAR: I'm sorry, I apologize.

MS. PABEN: That's okay. I didn't even notice you called me by a different name. I answer to just about anything with all of my siblings.

I think it is relevant to the proceedings. One of the issues that the PSC has to take into consideration is whether or not it's the most cost effective. And obviously to have the full amount of information related to what other types of facilities may have been proposed is part of making those evaluations.

CHAIRMAN EDGAR: And tell me again, if you would, the document that you are requesting.

MS. PABEN: Simply asking for a list of those that participated in the prebid conference as referenced in their documents they've submitted before you.

MS. DAILEY: Madam Chairman, those are people who did not actually submit bids. So they did not have bids that were compared to other bids in this proceeding -- in this project.

CHAIRMAN EDGAR: Okay.

MS. PABEN: But they expressed an interest in the RFP originally. And part of determining whether or not the process was competitive in the way that it should be is determining whether or not there may have been any factors leading to a less than competitive arrangement to look at alternatives. And so I think that having that information could lend to that knowledge.

CHAIRMAN EDGAR: And expression of potential interest to me seems to be a reach to get to competitive viability, quite frankly, if I'm being clear. If I'm not, I apologize. So I'm going to uphold the objection.

MS. PABEN: I just have a couple of more questions.

BY MS. PABEN:

Q Can you tell me in the RFP process whether or not you put specific limitations on the type of power or fuel source associated with the proposed bids?

A No. I think as I said on page 7 of the RFP,

it says, "The utilities prefer solid fuel and prefer mature technologies but the utilities will consider other fuel types and technologies if the evaluation shows these to be superior to solid fuel alternatives on the basis of the price and nonprice criteria."

So it was very clear that other types of fuel were -- although they were not -- not as preferred as solid fuel, they were -- they would be considered.

Q But also in the terms you just read, I would consider those some conditions, correct? It wasn't limitless?

A It said, "will consider other fuel types and technologies."

Q But within certain parameters, correct?

MS. DAILEY: Madam Chairman, I would just like to object again. She's asking him to read from the document and the document really speaks for itself. It is in the record.

CHAIRMAN EDGAR: Ms. Paben, your question?

MS. PABEN: I'm just asking him to clarify because there are different portions of the document that can be read together. And so I'm just asking him from his perception as putting together the RFP what he --

CHAIRMAN EDGAR: Why don't you pose the

question as a question again.

BY MS. PABEN:

Q I was just trying to clarify your response to the last question, which was just whether or not there was any limitations regarding the types of power or fuel sources associated with the facility. And if I understand your answer correctly, and please correct me if I misstate, you indicated you had a preference for solid fuel but would consider other power types. But I thought that in the sentence that you read, there were other -- some type of qualifiers that might not open the door for any other fuel source. That's all I was trying to clarify.

A No, that's not correct. It wasn't a qualifier. It just said if -- if they were deemed superior based on price and nonprice criteria which is everything we're looking at associated with the alternative. Everything would fall into that category, price or nonprice.

MS. PABEN: Okay. Thank you very much.

CHAIRMAN EDGAR: Mr. Jacobs?

MR. JACOBS: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. JACOBS:

Q Mr. Arsuaga, just two really brief questions.

I'm looking at Interrogatory No. 15 to staff's -- applicant's response to staff's second set, No. 15. And it indicates in there that the -- the one point is fuel cost projections, that the fuel cost projections -- that the vendors use in their RFP responses were derived from Southern or supplied by Southern?

A No. What it says is that what -- what I'm saying there is that we used for the Southern proposal the cost that was provided by Southern, but Southern was using the fuel forecast that was -- that was attached to the RFP. We -- we included with the RFP a fuel forecast for gas and many different types of coal to make sure that the process -- because fuel -- fuel would be a pass-through, you know. They weren't fixing the price of fuel, any proposer. So we wanted to make sure that fuel was being treated on a consistent basis.

Q I see.

A So we gave them a forecast to use so that we could make sure there would be a fair evaluation.

Q And that forecast that was used for the RFPs, was that indeed the projection that was used for the preparation of the -- of the petition for need?

A Yes, it was. It was the same as what was used for the base -- basic analysis, is my understanding.

Q And then finally, you indicate here also that

Southern's response proposed Powder -- that the fuel for this -- their plant would be Powder River Basin?

A Yes.

Q And -- and the self-build was projected for a blend of 7 percent Latin American, 30 percent petroleum?

A That is correct.

Q Did you reconcile that difference in any way in evaluating Southern's proposal?

A I did. I was asked by the applicants to do an analysis, just to see what that differential was. And I did look at -- I looked at using the Powder River Basin coal for the -- let's see. No, I used the -- I used the Latin American coal and the pet coke mix for the Southern proposal. And it -- it only made a difference of about $2 per megawatt hour. And it wasn't significant in the comparison of the two alternatives. It still gave me the same decision.

Q In your evaluation of Southern's response, was there any indication of why they chose Powder River Basin?

A I did -- they did not include a reason for why they selected that coal.

MR. JACOBS: Thank you. No further questions.

CHAIRMAN EDGAR: Other questions from staff?

MS. BRUBAKER: Staff has no questions.

CHAIRMAN EDGAR: Ms. Dailey?

MS. DAILEY: We have no redirect.

CHAIRMAN EDGAR: Exhibits?

MS. DAILEY: Yes. We would like to enter Exhibits 21 and 22 into the record.

CHAIRMAN EDGAR: Exhibits 21 and 22 will be entered into the record.

(Exhibits No. 21 and 22 admitted into the record.)

Thank you. You are excused.

Are we on Mr. Myers?

MR. PERKO: Yes, Jim Myers, please. Could you please --

CHAIRMAN EDGAR: I'm sorry, Mr. Perko. 30 seconds. Really, 30 seconds.

(Brief interruption.)

CHAIRMAN EDGAR: Yes. We are going to keep going for a while. I am -- I am optimist. And I'm ready to go.

MR. PERKO: Okay.

CHAIRMAN EDGAR: Thank you.

JIM MYERS

was called as a witness on behalf of the Applicant, and having been duly sworn, testifies as follows:

DIRECT EXAMINATION

BY MR. PERKO:

Q Could you please state your name and business address for the record.

A My name is Jim Myers, 21 West Church Street, Jacksonville, Florida, 32202.

Q Mr. Myers, did you submit prefiled direct testimony consisting of 13 pages on September 19th, 2006 in this proceeding?

A Yes, I did.

Q If I were to -- do you have any changes or additions to that testimony?

A No.

Q If I were to ask you the same questions today as set forth in that testimony, would your answers be the same?

A Yes, they would.

Q Are you sponsoring any exhibits with that testimony?

A Yes, I am.

Q What are those exhibits?

A JM-1 through 5 --

Q I believe those --

A -- are the numbers that I have.

Q I believe those have been marked as Exhibits 26 through 30; is that correct?

A That's correct.

Q Are you sponsoring the sections of the application that have been marked as Exhibit No. 31?

A Yes.

Q Do you have any changes or additions to those sections other than what appears in the errata sheet that's been offered into -- or included into evidence as Exhibit 3?

A No, I do not.

Q Thank you. Have you --

MR. PERKO: At this time, Madam Chair, I'd move Mr. Myers' prefiled direct testimony into the record as though read.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JIM MYERS

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Jim Myers. My business address is JEA, 21 West Church Street, Jacksonville, Florida 32202.

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

A. I am employed by JEA, where I am the Director of Fuel Management Services.

Q. Please describe JEA.

A. JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers all of Duval County and portions of Clay and St. Johns Counties within Florida. JEA's service area covers approximately 900 square miles and serves over 380,000 customers.

JEA consists of three financially separate entities: the electric system, the bulk power system St. Johns River Power Park Units 1 and 2 (the "Power Park" or "SJRPP"), and the bulk power system Robert W. Scherer Electric Generating Plant ("Scherer Unit 4").

Q. Please describe your educational background and experience.

A. I have a bachelor's degree in Industrial Engineering from Georgia Institute of Technology. I am also a licensed professional engineer in the State of Florida.

I have over 25 years of work experience, all of which has been with JEA. From 1981 to 1986, I worked on load and energy forecasting and load research, which included development of economic, energy, and peak demand models. My responsibilities also included the production of load and energy forecasts for generation planning.

From 1987 to 1995, I was involved in energy resource planning. During this time, I was responsible for long range planning, which included the development of corporate financial models and the preparation of official statements to support bond issues. While in this position, I also assisted in the development of JEA's first integrated resource planning (IRP) study in 1994/1995. I also served as Chairman for the Florida Electric Power Coordinating Group's Generation Task Force, in which I presented the Florida Ten Year Plan to the Florida Public Service Commission.

I have worked in the Fuel Management Services Group since 1995 and have held my current position as Director since 2003. In addition to my current role as Chairman for the Taylor Energy Center Fuels Committee (TEC Fuels) I have been a JEA representative on the SJRPP and Plant Scherer Fuel committees, achieved "Six Sigma Green Belt" designation in substantially reducing JEA's fuel procurement expenses, developed fuel acquisition strategies and market forecasts for JEA's electric system, negotiated agreements, and maintained documentation supporting fuel purchases.

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

A. The purpose of my testimony is to provide TEC's fuel procurement and delivery strategy and to present the forecast of delivered prices for various grades of coal from numerous coal producing regions, petroleum coke (petcoke), natural gas, and fuel oil (No. 2 distillate and No. 6 residual) which were used in the Taylor Energy Center Need for Power Application. I will address the methodology utilized to forecast delivered prices for these fuels based on commodity price forecasts, rail rate forecasts, and seaborne dry bulk carrier freight rate projections developed by other consultants involved in this Need for Power Application. I am testifying on behalf of TEC Fuels, a committee which consists of representatives from each of the four participating utilities.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit __ [JM-1] is a copy of my résumé. Exhibit __ [JM-2] is the delivered fuel price forecast developed by TEC Fuels for the reference case. Exhibit __ [JM-3] is the delivered fuel price forecast developed by TEC Fuels for the high sensitivity case. Exhibit __ [JM-4] is the delivered fuel price forecast developed by TEC Fuels for the low sensitivity case. Exhibit __ [JM-5] is the delivered fuel price forecast developed by TEC Fuels for the nationally regulated CO_2 fuel price analysis.

Q. Are you sponsoring any sections of the TEC Need for Power Application, Exhibit __ [TEC-1]?

A. Yes. I am sponsoring Sections A.3.4, A.4.6.8, and A.4.7.4, all of which were prepared under my direct supervision.

Q. Please describe TEC Fuels and its role in this proceeding.

A. TEC Fuels is a committee comprising representatives from each of the participating utilities: the Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (City), collectively referred to as the Participants. TEC Fuels was established to coordinate development of the fuel price forecast delivered to the proposed TEC site utilizing information provided by Hill & Associates. TEC Fuels is also responsible for developing the fuel procurement and delivery strategies for the TEC.

The TEC Fuel Procurement and Delivery Strategy

Q. Please explain the Fuel Procurement and Delivery Strategy for the Taylor Energy Center.

A. The TEC Fuels Committee is responsible for developing and implementing strategies for fuel procurement and delivery to TEC. The design of the TEC will allow the use of solid fuel from various international and domestic sources, utilizing rail only delivery or a combination of water and rail delivery. TEC's fuel strategy is to take full advantage of these sourcing and transportation flexibilities by establishing a plan that creates and exploits competitive opportunities in the marketplace. Throughout the life of the project, TEC Fuels' objective will be to promote competition between supply source regions, between suppliers within each region, between transport modes, and between transport service providers within each mode. For example, when it is economical to do so, oceangoing vessels may be used to provide partial delivery of coal and petroleum coke (petcoke) to TEC as an alternative to complete reliance on rail transportation. In addition, the TEC Fuels Committee will require multiple rail carriers to compete to supply service to TEC. Another key element of the fuel strategy is to use the competitive bidding process to evaluate all fuel options based on the "as-fired" cost to TEC so that a comparison can be made between fuels having different quality, combustion performance, and emissions potentials. This procurement process will offer supply opportunities to all viable suppliers, thus providing TEC with access to a full range of solid fuels from both international and domestic sources.

Q. Please describe the fuel supply options for the TEC.

A. A blend of Latin American coal and petcoke is expected to provide the lowest production costs for the TEC. As explained in more detail in Section A.3.4 of the Need for Power Application, Latin American coals and international petcoke supplies would be transported by deep-draft ocean vessel to a US Gulf or Atlantic Coast terminal and transloaded to rail for delivery to TEC. Domestic petcoke would typically be delivered by barge. TEC fuels has identified several potential port locations for terminaling services.

The next lowest as-fired cost of fuel for TEC is sub-bituminous coal from the Powder River Basin (PRB) blended with petcoke. The PRB has enormous reserve and mining capabilities. In addition, rail service in the PRB is provided by both the Burlington Northern Santa Fe (BNSF) and the Union Pacific (UP). Both of these western carriers link with Norfolk Southern (NS) and CSX Transportation (CSXT) in the east. The combination of very large scale and low-coast mining coupled with competitive rail transportation over a multiple route rail network ensures a reliable and economical coal supply from the PRB region for TEC.

The Central Appalachia (CAPP) coal region presents another domestic option for coal supply to TEC. It has historically been the source of the majority of domestic coal tonnages used by Florida utilities. Both CSX Transportation and NS provide rail service from numerous mines located with the CAPP region.

Multiple existing rail routes exist to reliably provide CAPP coal to TEC, if it becomes economical to do so.

Q. What are the advantages of having multiple coal supply options?

A. Domestic sourcing of coals for TEC will provide access to major coal supply regions presently producing over 75 percent of the coals mined in the United States. Coupled with the ability to access foreign sourced coals, these arrangements will provide a high degree of competition for fuel supply for the TEC. This will help mitigate fuel costs and increase reliability.

Q. Please describe the proposed rail interconnection to the TEC site.

A. Final delivery of all coal to TEC will utilize rail service provided by a spur-line extension from an existing Class III short line rail system – the Georgia, Florida Railroad (GFRR). This short line extends from Adel, Georgia, on its north end to a paper mill complex at Foley, Florida near the TEC site. The GFRR interconnects with both CSX Transportation and NS.

Q. How will fuel be transported to and unloaded at the TEC site.

A. Rail movements to the TEC site will entail use of high efficiency unit trains ranging from 115 to 135 cars in length. Unloading of the unit trains will utilize a high capacity railcar receiving system with a capability of approximately 4,000 tons per hour.

Q. Has TEC Fuels entered into contracts for coal or petcoke supply or delivery for the project?

A. No. Supply and transportation contracts will be established in a timely manner in advance of unit operation, but to enter into such contracts at this time is considered strategically premature. TEC is confident that the combination of abundant supply options and multiple transportation sources ensures that TEC will be reliably supplied with competitively priced fuel. Competitive bidding will be utilized to the extent possible to obtain fuel and transportation services. RFPs for fuel and transportation services will be issued after all necessary permits have been obtained for the project and sufficiently prior to commercial operation to ensure that a reliable fuel supply will be available.

Delivered Fuel Prices

Q. Please describe the components of the delivered coal price forecast.

A. Hill & Associates provided TEC Fuels with forecast coal prices for various qualities and grades in all the major coal producing regions in the US along with forecasts for coals mined in Latin America. The forecasts developed by Hill & Associates were on a constant 2005 dollar per ton basis for commodity, or freight on board (FOB), pricing only and were provided through 2030.

Hellerworx, Inc. (Hellerworx), provided Hill & Associates with a forecast of rail transportation rates from the various coal producing regions in the United States. Hellerworx also provided a rail rate forecast for a short haul to the proposed

TEC site for delivery of waterborne coal. The rail transportation rate forecasts were provided on a constant 2005 dollar per ton basis.

Simpson, Spence & Young Consultancy & Research Ltd (SSY) provided Hill & Associates with a forecast of shipping rates from a common point in Bolivar, Colombia to Florida. Freight rates were provided by SSY on a constant 2005 dollar per ton basis.

TEC Fuels estimated a transloading rate for coals delivered to a water-based terminal, which was intended to cover the cost of moving products from the ship to the land and then from the land to railcars.

Q. How did TEC Fuels develop the estimated transloading rate for coals delivered to a water-based terminal?

A. The transloading rate for coals delivered to a water-based terminal was developed based on discussions with experts at Hellerworx, Hill & Associates, and JEA regarding typical transloading costs.

Q. How did TEC Fuels use this information to develop the forecast of delivered coal prices?

A. TEC Fuels combined the commodity price forecasts with the appropriate transportation components to develop forecasts of the prices for various coals delivered to the proposed TEC site, in constant 2005 dollars per ton. For the domestic coals, the Hellerworx rail forecasts were added to the Hill &

Associates coal price forecasts. For Latin American coal, the shipping rates provided by SSY were added to the commodity price forecasts from Hill & Associates. Next, the short haul rates to the proposed TEC site provided by Hellerworx and the transloading rates developed by TEC Fuels were added.

The resulting delivered coal price forecasts were converted from the constant 2005 dollar per ton basis to a constant 2005 dollar per MBtu basis using the average heat content of each coal type. The constant 2005 dollar per MBtu forecasts were then converted to nominal (current year) dollars per MBtu using an assumed annual inflation rate of 2.5 percent.

Q. Describe the approach you took to develop the delivered price for petcoke.

A. Petcoke price forecasts were provided by Hill & Associates for various qualities (high and low sulfur and high and low grind quality specifications) for purchase along the US Gulf Coast in constant 2005 dollars per ton. TEC Fuels estimated a barge freight rate from the US Gulf Coast in constant 2005 dollars per ton.

To develop the forecast of delivered petcoke prices, TEC Fuels combined the commodity and barge transportation cost components, in constant 2005 dollars per ton. The transloading rates assumed by TEC Fuels and the short haul rates to the proposed TEC site provided by Hellerworx were then added. The resulting delivered coal price forecasts were converted from a constant 2005 dollars per ton basis to a constant 2005 dollars per MBtu basis using the average heat content of the petcoke, and the constant 2005 dollars per MBtu forecasts

were then converted to nominal (current year) dollars per MBtu using an assumed annual inflation rate of 2.5 percent.

Q. How did TEC Fuels determine the appropriate barge freight rate for use in developing delivered petcoke prices?

A. TEC Fuels estimated the barge freight rate based on actual experience utilizing barge delivery service to the Jacksonville area.

Q. Describe the approach you took to develop the delivered price for natural gas.

A. Hill & Associates provided TEC Fuels with a forecast of natural gas prices at the Henry Hub in Louisiana through 2030 in constant 2005 dollars per MBtu. The TEC Fuels Committee estimated a long-term variable charge for delivery of natural gas from Louisiana to Florida, which was added to the price forecasts at Henry Hub provided by Hill & Associates. The resulting variable delivered natural gas cost in constant 2005 dollars per MBtu was then converted to nominal (current year) dollars per MBtu using an assumed annual inflation rate of 2.5 percent.

Q. Please describe the variable costs you added to the Henry Hub price forecasts provided by Hill & Associates.

A. The variable charge consists of two components: a transportation fuel rate equal to 3.0 percent of the annual Henry Hub natural gas forecast and a variable usage fee for the delivery pipeline of $0.05/MBtu.

Q. How were natural gas pipeline demand charges accounted for in your delivered price forecast?

A. Fixed costs for pipeline demand charges were not included in the forecast natural gas prices.

Q. Why were they not included?

A. Pipeline demand charges represent fixed costs and are not tied to natural gas usage. Each of the Participants already has contracts in place for delivery of natural gas for their existing natural gas fired generating units, so including pipeline demand charges in the delivered price forecast would be "double counting" for these costs.

Q. Should pipeline demand charges be included when considering construction of new natural gas fired generating units?

A. Yes. Consideration of pipeline demand charges for new natural gas fired generating units is discussed in the testimony of Bradley Kushner of Black & Veatch.

Q. Describe the approach you took to develop the delivered price for fuel oil.

A. Hill & Associates provided TEC Fuels with a forecast of distillate and residual fuel oil prices in the Gulf Coast market region through 2030 in constant 2005 dollars per barrel. TEC Fuels added $5 per barrel (in constant 2005 dollars) to

the distillate fuel oil price forecasts provided by Hill & Associates to arrive at a delivered cost.

The resulting delivered fuel oil price forecasts were converted from a constant 2005 dollar per barrel basis to a constant 2005 dollar per MBtu basis using the average heat contents of No. 2 distillate fuel oil and No. 6 residual fuel oil, and the constant 2005 dollar per MBtu forecasts were then converted to nominal (current year) dollars per MBtu using an assumed annual inflation rate of 2.5 percent.

Q. Describe how you determined the 2.5 percent to be an appropriate annual inflation rate.

A. The 2.5 percent annual inflation rate is used throughout the TEC Need for Power Application, so our assumption was developed to maintain consistency. The basis for this assumption is discussed in the direct testimony of Myron Rollins of Black & Veatch.

Q. Does this conclude your testimony?

A. Yes.

BY MR. PERKO:

Q Mr. Myers, have you prepared a summary of your prefiled testimony?

A Yes, I have.

Q Could you please provide that now.

A Yes. The purpose of my testimony is to present the fuel strategy for Taylor Energy Center which was developed by the fuels committee for which I served as chairman.

Generally, that strategy is to take advantage of multiple fuel sources and transportation options to promote supplier competition for both fuel and transportation over the life of the facility.

A blend of Latin American coal and petroleum coke is expected to provide the lowest production cost. Powder River Basin and central Appalachian coals are also potential competitive options. Petroleum coke and international coal supplies will be transported by vessel to one of several U.S. terminals and transloaded to rail for delivery to Taylor Energy Center. Multiple rail carriers and routes exist for the reliable transportation of domestic coal supplies.

Contracts for fuel supply and transportation will be established in a timely manner prior to unit operation. The combination of abundant supply options

and multiple transportation sources will allow Taylor Energy Center to be reliably supplied with competitively priced fuel. The Taylor Energy Center fuels committee oversaw the development of reasonable delivered fuel price forecasts that include all appropriate cost components for use in the overall project evaluation.

This concludes my summary.

MR. PERKO: We tender the witness for cross-examination.

CHAIRMAN EDGAR: Thank you.

Ms. Brownless?

MS. BROWNLESS: Yes.

CROSS-EXAMINATION

BY MS. BROWNLESS:

Q Hi, Mr. Myers.

A Hello.

Q Are you in charge of TEC fuels, the group comprised of the four utility members?

A I serve as chairman of that committee.

Q Okay. And this is the group that developed, delivered fuel prices for TEC for the various types of coal, pet coke, natural gas, residual fuel oil and diesel?

A Yes.

Q And are those various prices set out in I

think what's been marked staff exhibits or Exhibits 27 through 30 and those are your JM-2 through JM-5?

A Yes.

Q Okay. And just so I kind of understand the process, did you start out with Mr. Preston's fuel numbers and then adjust them according to your group's actual experience?

A No. Mr. Preston provided commodity priced forecasts transportation rates, and we converted -- and that was in 2005 dollars. So it was in real dollars. We converted the numbers to dollars per MMBtu on a current year basis.

Q Okay. And I guess -- so these are Mr. Preston's numbers that have been converted on a MMBtu basis. There were not any changes other than that between Mr. Preston's numbers and your numbers?

A Well, we did add a transloading cost to make sure we accounted for that component for delivering fuel from -- taking it from vessel to a railcar. And we also added variable cost components for natural gas.

Q Okay. So is it fair to say that this is your group's best estimate of what the actual delivered costs will be at TEC?

A Yes.

Q Including all the costs?

A Yes.

Q Now, were these the prices that were used in Mr. Kushner's IRP analyses the ones that you developed?

A The prices in Mr. Kushner's analysis for the overall project were these prices, yes.

Q Okay. Now, I'm looking at the very first chart which is Exhibit 27, current year dollars per MMBtu delivered base case. Have you got that one?

A Let me get there.

MR. PERKO: I believe for the witness that's Exhibit JM-2.

MS. BROWNLESS: I'm sorry.

BY MS. BROWNLESS:

Q It's the very first chart.

A Got it.

Q I'm looking down here where it says natural gas. The first line says, "commodity." And the second like says, "commodity and variable charges." Are the variable charges what you just discussed?

A Yes.

Q So the commodity would be the price provided by Mr. Preston?

A Yes.

Q Now, it looks to me as a layman that the natural -- in your base case, natural gas prices

decrease until 2011 and then increase after that date; is that correct?

A Yes, that's correct.

Q Okay. And is that also true for the gas prices in the other sensitivities which are your JM-3, JM-4 and JM-5?

A Yes, that's correct.

Q Do you know whether the availability of natural gas would increase after the year 2016?

A 2016 is -- is -- when you talk about 2016, you're getting pretty far out there, and I would hesitate to speculate on the availability of gas at that point in time.

Q Is it fair to say that most fuel price forecasts are fairly accurate within a year or two, and longer than that, the longer out you get, the more inaccurate they become?

A Actually there's times when the near term forecast could be even more inaccurate because there's some volatility that moves prices around quite a bit especially in the natural gas market. I noticed natural gas dropped -- the futures dropped, I believe, 46 cents per MMBtu from yesterday's close. So it's -- but what we're dealing with in the long-term is expectations, and, you know, there's some underlying assumptions that

go into this. So we may not be totally accurate in a given year, but the numbers are based on a reasonable set of expectations for what may occur in the future.

Q Okay. And I'm just trying to nail this one specific thing down. Is one of those assumptions for the year 2016 and thereafter that natural gas availability will increase?

MR. PERKO: Objection. Madam --

MS. BROWNLESS: If he knows, he knows. If he doesn't, he doesn't. We'll move on.

MR. PERKO: I think we're going beyond the witness's testimony. She's talking about the total gas -- delivered prices of fuels. We have another witness to address --

MS. BROWNLESS: We're just talking about natural gas. That's it.

THE WITNESS: We're talking about availability?

BY MS. BROWNLESS:

Q Yes, sir.

A I can't answer that question in 2016, to be honest.

Q Thank you, sir.

Did Mr. Preston use these numbers in his CO_2 sensitivity analysis which was his MP-5 and I think

the Commission's Exhibit 40?

A He ran a CO_2 sensitivity and it had a set of assumptions in developing that, and I would defer to Mr. Preston on how that was developed.

Q Okay. So you don't know whether he used your fuel numbers or his own?

A Well, he used -- you know, he developed the commodity price forecast in all cases.

Q I understand that, but -- I understand that. I'll follow it up with Mr. Preston.

MS. BROWNLESS: That's all we have. Thank you.

CHAIRMAN EDGAR: Mr. Paben?

MR. PABEN: No questions. Thank you.

CHAIRMAN EDGAR: Thank you.

Mr. Jacobs?

MR. JACOBS: Thank you. Very briefly.

CROSS-EXAMINATION

BY MR. JACOBS:

Q Mr. Myers, you are -- in your -- the scope of your work with the fuels committee, I'm sure you explored many of the circumstances in the coal commodity markets and fuel delivery markets at this point in time?

A I would consider myself familiar with those areas, yes.

Q Did you provide the benefit of your analysis to -- to Mr. Kushner in support of his cost projections, or did he develop his own assessment of how those factors affected the coal prices?

A I'm not sure I understand which factors of Mr. Kushner you're referring to.

Q What I'm speaking are -- well, let me ask the question this way: Are you aware if Mr. Kushner integrated variables in his projections that address the volatility issues that are occurring in coal markets -- commodity markets and coal fuel delivery markets?

A I'm aware that Mr. Kushner in the running of his models and development of projections made assumptions concerning factors that need to go into the model to run the model, but I'm not aware of the -- the assumptions that you're speaking of.

Q Okay. There -- there is an issue outstanding of whether or not the owners of TEC should purchase railcars. Are you familiar with that issue?

A Yes, I am.

Q Can you just explain for us what the basis of that issue is?

A That's an issue for determination in the future. In the analysis that we have here, railcar leasing costs have been assumed. So we have the cost of

railcars covered in these numbers. From time to time a utility may lease cars, they may purchase cars for the long-term, and we will be making that decision. There's some considerations that will need to be made based on the ultimate route selected for delivery of fuel.

If we do go forward with Latin American coal and petroleum coke, both of those would arrive by water to a terminal location, and that would have different mileage considerations than if we were bringing fuel from the Powder River Basin over 2,000 miles. And those types of considerations would impact the decision that we make on purchasing or leasing railcars.

Q And finally, I note that in your analysis and we've heard prior testimony, that the primary fuel strategy for Taylor Energy is that it would use Latin American coal supplemented by pet coke with the option of using Powder River Basin.

Is there a -- is that scenario analysis of when that -- or why or when that choice would occur?

A The fuels committee has not put down a detailed schedule of when that would need to be made. But backing up, I see that that decision would probably be made by mid-2009 at the latest.

Q And if -- when made, I'm assuming that it would be made in sufficient time to acquire any

additional infrastructure that you described previous that would be needed to --

A That's correct.

MR. JACOBS: Thank you very much.

CHAIRMAN EDGAR: Questions from staff?

MS. HOLLEY: No questions.

CHAIRMAN EDGAR: Just a moment. Commissioner Carter?

COMMISSIONER CARTER: I guess there's no secret to anybody that I'm intrigued with the railcars.

THE WITNESS: Okay.

COMMISSIONER CARTER: In your anticipation of the purchase of these cars or the lease of these cars, did that -- what impact did that have on the price of getting the fuel from point A to point B? You were probably here yesterday when we had that discussion.

THE WITNESS: Yes. That component in our assumptions is two mills per ton mile. Basically that's .002 dollars per ton mile per year. And depending on how -- how many railcars we need, how many miles we're actually moving the product, that would vary, the actual dollars that are involved. But if we're using a short haul from -- that ended

up being Jacksonville --

COMMISSION CARTER: For 100 cars.

THE WITNESS: For around there, yeah. We're probably talking about $700,000 a year. And that's included in the delivery costs from the Hellerworx -- from Matt Preston subbed out to Hellerworx. Hellerworx actually developed those projections.

COMMISSION CARTER: Thank you, Madam Chair. I don't want to belabor the point. Whenever I hear the trains, the bells and the whistles go off. And maybe we'll find someone that can ask further details later on about this. Thank you.

CHAIRMAN EDGAR: Mr. Perko?

MR. PERKO: We do have a little bit of redirect.

But, Commissioner Carter, I think this probably would be the witness if you have additional questions about the rail traffic and the cost.

COMMISSION CARTER: With your indulgence, Madam Chair.

CHAIRMAN EDGAR: Yes, sir.

COMMISSION CARTER: Yeah. I would like to know how this purchasing the cars versus leasing

the cars, the impact that it has upon the cost of transportation as well as the cost of operating. I would think we got into this discourse about maintenance and operation for the plant. I mean, is this -- we're talking about a need determination. Does this increase the price or decrease the price?

THE WITNESS: Well, we're going to have to have railcars one way or the other because, you know, definitely we're -- whether we're utilizing water delivery, it's only to a certain point. So we are going to have railcars.

And then there's a matter of is it going to be more cost effective to lease or to buy. And there -- there -- there are instances where municipal utilities have found that buying cars may be cheaper because of the tax exempt status of a municipal utility. And those are the things that we're going to be evaluating.

But we have reasonable cost in there for the railcars. And that's -- you know, typically a railcar costs between -- you know, the price like any commodity fluctuates, but the price of a railcar could range from $400 per month to, say, $650 per month. That might be a typical range.

COMMISSION CARTER: I probably should have asked our last witness this question, but the railcar got my -- Madam Chairman, with your indulgence.

But the railcar got my attention. In your cost projections or financial analysis, do you guys look at the -- I know that we're talking about fuel diversity. So let's assume, for example, that's not part of what I'm asking you. Let's -- there's a system of gas pipelines that goes throughout the state of Florida. And I think there was a discussion about 750-megawatt gas plant down in St. Lucie. Were you here when they were talking about that?

THE WITNESS: I'm not sure I heard that, but I'm familiar with the gas industry as well.

COMMISSIONER CARTER: Okay. Thank you then. Well, my question would be, then, is that the cost of that -- I know we say that natural gas -- the price fluctuates. I know we said the City of Tallahassee is 90 percent on gas. But in the context of determining what is the best possible alternative, what would be the cost of buying gas on the pipeline setting up the 750-megawatt gas plant down in St. Lucie versus building a coal

plant in Taylor County?

Was that part of -- I know that you were not the guy that handled the RFP. I probably should have asked it earlier. I'm just trying to find -- I know sometimes when you ask questions like this, people say you're mixing apples and grapefruits. I'm really trying to find out what's the real number here.

THE WITNESS: I think I can comment on that. From a fuel standpoint, natural gas is more expensive than solid fuel, coal and petroleum coke. However, typically the capital cost of a gas-fired plant would be lower on a dollar per kW basis. So you really need to match the existing mix of a utility and the load curve in the projections going forward to determine the type of unit that is needed. Where a solid fuel unit typically meets base load requirements and you would want to have a coal and petroleum coke unit run on a continual basis, a combined cycle unit, for example, can go up and down on a daily basis.

So again, getting back to the fuel diversity, there's a -- it's helpful when a utility has a mix of generating resources. And one thing I can say, and it probably has already been said, but when I

came to work at JEA, that's been a little over 25 years ago, we were -- I remember my boss telling me, you know, when you go to work, just -- or when you go to a store and they ask for your ID, just tell them you work for the city because they didn't like us too well. We had very high rates.

Now, if we're not No. 1, we're No. 2 in the state of Florida. And a lot of that has to do with the fact we've brought in petroleum coke; we've brought in natural gas when all we had was oil. We've brought coal by wire. We've -- we used Powder River Basin coal with a unit that we owned with Florida Power & Light near Macon, Georgia. We've used central Appalachian coal, and we've used Latin American coal. In fact, with our CFBs that we have at JEA, we're now using a blend of petroleum coke from St. Croix and the Gulf coast with Latin American coal from Columbia. And just putting all of these pieces together has -- has been effective. That's on the supply side.

And we're doing what we believe to be the right things on the demand side as well because there's definitely the components on the demand side and with renewables.

COMMISSION CARTER: And just one final

statement. This is not really a question. Just one final statement, Madam Chairman. The reason I was saying that is that the -- in the -- I applaud your DSM efforts, by the way. I think I said that earlier today and as well as with Mayor Marks when he was here for the City of Tallahassee, is that it just seems to me that -- and I'm just kind of thinking aloud -- is that it may be cheaper in the short run, but you don't have trains with the gas. You just tap in.

Of course, in addition to that, you say well, there's no -- you would have to tap into the pipeline but you could also have a storage facility.

That's probably a different discussion for a different day. It's just interesting to me that today was the first time I've heard about this gas in this context. Because when the trains go off, you know, then my brain starts clicking.

THE WITNESS: There's -- if I can add this: There is transportation associated with natural gas too that has to be paid for. We take a portion of our gas on the Florida gas transmission pipeline. They have a couple of rate schedules, FTS-1 and FTS-2. And I don't have the exact numbers here,

but on FTS-1, which is the cheaper reservation charge, just to move gas in the pipe to have firm transportation, we pay about 38 cents per MMBtu of gas capacity. And we have -- overall we have 54,000 MMBtu a day of gas transportation. Fourteen thousand of that is FTS-2. And that's close to 80 cents an MMBtu.

So to reserve with the right to move gas on the pipeline on a firm basis, there's a significant cost there as well. So I know what the IRP study does, is that it takes into account all of the costs associated with natural gas and coal and including the railcars which are a piece of that cost as well. And our IRP study has shown that Taylor Energy Center is the right decision for this unit.

COMMISSION CARTER: Thank you, Madam Chair.

MR. PERKO: Just a little on redirect, Madam Chair, if I could.

REDIRECT EXAMINATION

BY MR. PERKO:

Q Mr. Myers, just so it's clear, you mentioned that you developed -- you essentially developed the delivered cost of the fuel based on the prices that Mr. Preston gave you; is that correct?

A Yes.

Q Now, I wanted to make sure, I believe you said that those costs that you included, included transloading costs?

A Yes.

Q And also included other costs like rail vessel, is that --

A That's correct.

Q Now, how did you account for rail costs?

A Excuse me. Well, with rail costs in the forecast that was provided by Mr. Preston, we had forecasted rates for each of the -- each of the coal regions. For example, we considered central Appalachian coal, so we had a price for transportation coming from the central Appalachian region to the Taylor Energy Center. We also had a price coming from the Powder River Basin. And as you can probably expect, the price for moving coal from the Powder River Basin to Taylor Energy Center was greater, because there's a greater distance to move that.

We also had the cost to move coal from one of the terminals or the various terminals that we may access for fuel coming by water. So we added that cost onto the commodity cost. Then we also added the -- for fuels coming by water, we added the transloading cost as

well and arrived at an overall delivered cost.

Now, the cost there for the rail delivery included that railcar cost as well and the maintenance on the railcars.

Q Did your delivered cost estimates also include pipeline transportation costs for natural gas?

A They included the variable charges but did not include the reservation charges.

Q Now, I understand that you -- if -- correct me if I'm wrong, but I believe your testimony was that you included the cost of railcars for leasing as part of the cost?

A That's correct.

Q And when would you -- why would you decide to go with owning cars instead of leasing? Was it because it's more cost effective?

A That's right. If we get a better rate, we would -- we would purchase cars and we expected to use that same number of cars. If there was any question, you know, perhaps if we went to Powder River Basin, one of the beauty of -- of our fuel plan here is there's -- you know, the unit is being built to use various types of fuel from different basins.

If we needed to switch to Powder River Basin for a period of time, and we may not continue to use

those cars over the long-term, we may lease an additional amount of cars to allow us to bring coal a longer distance.

MR. PERKO: Thank you. No further questions.

CHAIRMAN EDGAR: Exhibits?

MR. PERKO: Yes. If we can move Exhibits 26 through 31 in the record, please.

CHAIRMAN EDGAR: Seeing no objection, Exhibits 26 through 31 will be moved into the record.

(Exhibits No. 26, 27, 28, 29, 30 and 31 admitted into the record.)

And the witness can be excused, thank you.

That brings us to Mr. Preston.

MR. PERKO: Let's call Matt Preston to the stand, please.

CHAIRMAN EDGAR: Let's take a few. We'll come back at 5 minutes to.

MR. PERKO: Thank you.

(Break taken.)

CHAIRMAN EDGAR: Okay. We are back on the record. It is by my clock about 10 after 6:00. I was very, very hopeful that we could get done tonight. I would still be very pleased if we can get done tonight and I'm interested in trying to do

that.

However, it is my understanding that we have a number of conflicts late this evening. And recognizing that it is Friday night and that it is -- has been a very long week, I think, for everybody, I'm thinking that we can go to about 8:00-ish depending on, you know, if there's a natural break right around there.

And then as I mentioned earlier in the week, whatever day that was, that we've been able to clear some time for Thursday. Looks like we could -- we do have some business first thing in the morning, but then -- in the 10:30 range. So think on that. And right now we'll go till again about 8:00. If we do not finish, whatever we need to do legally to notice and all of that, Ms. Brubaker --

MS. BRUBAKER: All we have to do is announce it before we adjourn for the day.

CHAIRMAN EDGAR: Okay. Then we will plan to come back Thursday and begin our business then to conclude Thursday after the already-scheduled appointment that we have. So that will be about 10:30.

Okay. Any questions about any of that?

Okay. Then the next witness.

MR. PERKO: Matthew Preston.

MATTHEW PRESTON

was called as a witness on behalf of the Applicant, and having been duly sworn, testifies as follows:

DIRECT EXAMINATION

BY MR. PERKO:

Q Could you please state your name and business address for the record.

A Matthew Preston, 222 Severn Avenue, Annapolis, Maryland.

Q Mr. Preston, have you been sworn?

A Yes, I have.

Q And, Mr. Preston, did you file or submit prefiled testimony consisting of 22 pages on September 19th, 2006 in this proceeding?

A Yes, I have.

Q Do you have any changes or additions to that testimony?

A No.

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

A Yes.

Q Are you sponsoring any exhibits with that testimony, specifically Exhibits 36 through 40 as

indicated on the staff's comprehensive exhibit list?

A Yes.

Q Do you have any changes or additions to that --

A No, I do not.

Q -- two exhibits?

Are you also sponsoring sections of the cases listed on Exhibit No. 41 in the staff's comprehensive exhibit list?

A Yes.

Q Do you have any changes or additions to those sections of the application?

A No, I don't.

Q Now, Mr. Preston, did you also submit rebuttal testimony consisting of eight pages on November 21st, 2006?

A Yes, I did.

Q Do you have any changes or additions to that testimony?

A No, I don't.

Q If I were to ask you the same questions today, would your answers be the same?

A Yes, they would.

Q And are you sponsoring Exhibit 42-R with that rebuttal testimony?

A Yes.

Q Do you have any changes or additions to that exhibit?

A No, I don't.

MR. PERKO: With that, Madam Chairman, we would move Mr. Preston's prefiled direct testimony and rebuttal testimony into the record as if read.

CHAIRMAN EDGAR: The prefiled direct and rebuttal testimony will be entered into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MATTHEW PRESTON

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Matthew Preston. My business address is 222 Severn Avenue, Annapolis, Maryland 21403.

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

A. I am employed by Hill & Associates, Inc., where I am a partner.

Q. Please describe Hill & Associates.

A. Hill & Associates is a consulting firm that provides expertise to clients who require analyses related to coal demand, supply, pricing, and emissions in domestic and international markets. We perform numerous proprietary studies for individual clients evaluating specific mines, products, power plants, or ports.

In addition, we also publish multi-client market reports on the US steam coal market and the international coking and steam coal markets.

Hill & Associates also provides services in the deregulated electric market. Our group focuses in the following areas: market outlook studies forecasting generation by plant, transmission flows, and power prices; evaluation of investment opportunities in new or existing power plants; market dominance analysis; and the evaluation of the impacts of planned and potential new environmental regulations.

Hill & Associates provides services for senior management in the coal industry such as evaluation of mining company organization, market strategy, and management systems.

Hill & Associates provides due diligence economic evaluations of coal and utility assets to determine economic worth and profit potential for clients.

Hill & Associates provides assistance to clients in management of all aspects of the fuels procurement cycle.

Finally, Hill & Associates provides expert witness support for our clients involved in litigation such as dispute trials; arbitrators in coal price, quality, or volume disputes; and supporting experts in utility rate cases.

Q. Please describe your educational background and experience.

A. I have close to 30 years of experience in coal mining and in utility fuel procurement. As a mining engineer, I worked as Assistant Mine Foreman at one of the large longwall mines of Consolidation Coal Company. I then joined General Public Utilities (GPU) in Fuel Procurement and undertook a wide variety of analytical and administrative assignments ranging from coal supplier assessments to corporate strategy development. At Hill & Associates, I lead the company in the area of risk management, probability assessment, long- and short-term energy price forecasting, and am a primary participant in the development of the PRISM™ model. I have a Bachelor's of Science degree in Mining Engineering from the University of Arizona, and I am a Registered Professional Engineer in Pennsylvania. My résumé is attached as Exhibit __ [MP-1].

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

A. The purpose of my testimony is to present the commodity fuel price and allowance price projections prepared by Hill & Associates under my supervision for the Taylor Energy Center Need for Power Application. I will also focus my testimony on the areas related to coal demand, supply, and price outlooks through calendar year 2030. I will address applicable sources of coal that could be used for power production in the Florida region including: Central Appalachia (CAPP), Northern Appalachia (NAPP), Illinois Basin (ILB), Powder River Basin (PRB), and Latin America. I will also discuss Hill & Associates'

forecast projections for petroleum coke (petcoke) prices as well as emission allowance price projections for sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), and carbon dioxide (CO_2). Throughout my testimony the term "allowances" refers to the offset of 2,000 pounds and the term "allowance prices" refers to the price to offset 2,000 pounds of emissions for SO_2, NO_x, and CO_2. For Hg, these terms refer to the offset of 1 pound of emissions.

In addition to base case forecasts for coal and petcoke prices, Hill & Associates developed fuel and emission allowance price projections for both high and low price sensitivity scenarios as well as a specific forecast that includes the projected impact on fuel and emission allowance price projections of CO_2 emission allowance costs, should such costs result from potential future regulation of CO_2 emissions.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit __ [MP-1] is a copy of my résumé. Exhibit __ [MP-2] is Hill & Associates' base case fuel and corresponding emission allowance price forecasts. Exhibit __ [MP-3] is Hill & Associates' high fuel and corresponding emission allowance price sensitivity scenario forecasts. Exhibit __ [MP-4] is Hill & Associates' low fuel and corresponding emission allowance price sensitivity scenario forecasts. Exhibit __ [MP-5] is Hill & Associates' fuel and corresponding emission allowance price sensitivity scenario forecasts corresponding to the regulated-CO_2 fuel price analysis. This last exhibit is

offered for information purposes only since the regulation of CO_2 emissions, while being discussed, is not presently in place at the state or federal level.

Q. Are you sponsoring any sections of the Taylor Energy Center Need for Power Application, Exhibit __ [TEC-1]?

A. Yes. I am sponsoring Sections A.4.6 (excluding Sections A.4.6.3, A.4.6.4, A.4.6.5.3, A.4.6.5.4, A.4.6.6, A.4.6.7, and A.4.6.8) and A.5.5.

Q. How did Hill & Associates become involved in the Taylor Energy Center Need for Power Application?

A. JEA, Florida Municipal Power Agency (FMPA), Reedy Creek Improvement District (RCID), and the City of Tallahassee (the City) (collectively referred to as the Participants) retained Hill & Associates to develop a reasonable forecast of commodity prices for various fuels (coal, petcoke, natural gas, and distillate and residual fuel oils) and transportation costs for coal and petcoke. Hill & Associates also developed a forecast of emission allowance prices for SO_2, NO_x, Hg, and CO_2.

Q. How did Hill & Associates develop the commodity fuel and emission allowance price forecasts?

A. Hill & Associates developed the coal, petcoke, and emission allowance price forecasts using our proprietary PRISM^{TM} model. Hill & Associates subcontracted with Pace Global for natural gas and fuel oil forecasts.

Q. Please describe the PRISM™ model.

A. The PRISM™ model is a proprietary model developed by Hill & Associates for the purpose of forecasting coal, emission allowance, and electricity prices. PRISM™ is a linear programming model that integrates aspects of all fossil fuel markets as they relate to electricity demand. Additionally, the model allows incorporation of natural gas and fuel oil price projections provided by Pace Global in the study, which are discussed in the direct testimony of Dr. Theodore Breton. Projections of electricity demand growth were based on the Energy Information Administration's (EIA's) Annual Energy Outlook 2005 and were applied to the EIA Form 714 electricity demand.

Overall, the PRISM™ model captures the relationship between coal, natural gas, fuel oil, and electricity markets while maintaining compliance with local and national air quality standards. The model's objective is to satisfy US electricity demand at the lowest possible cost while complying with emissions regulations.

Q. What is Hill & Associates' assumption regarding the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR)?

A. The Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) are considered in the baseline of the PRISM™ model. The PRISM™ model assumes that CAIR and CAMR will be implemented as promulgated in 2005. The PRISM™ model simultaneously considers the potential impact that compliance scenarios such as fuel switching, running one plant instead of

another, or the installation of emissions cleanup equipment may have on fossil fuel supply, demand, and price.

Q. Describe the approach you took in developing the fuel forecasts.

A. The initial steps in developing the coal and emission allowance price forecasts were to input to the PRISM™ model specific coal supply curves, CAIR and CAMR environmental regulations, natural gas and fuel oil price forecasts, and electricity demand growth rates. Hill & Associates develops coal supply curves based on our ongoing detailed review of mining operations in all of the major basins. The modeling process includes mine cost, capacity, and reserve estimates for operating coal mines in the contiguous 48 states and Colombia and Venezuela. Mine cost and reserve estimates were also included for undeveloped reserves. Projections were provided for a relatively broad selection of coal qualities from the major producing basins as well as for various qualities of petcoke, allowing for a comprehensive basis from which to interpolate projected prices for any coals from those basins not directly represented.

PRISM™ simultaneously selects the optimum fuel choice for each power plant in order to satisfy electricity demand. The demand created by these choices is applied to the coal supply curves to determine commodity prices for each of the various types of coals modeled.

As previously stated, Hill & Associates assumes that CAIR and CAMR will be implemented as promulgated in 2005. Known local attainment issues and State

Implementation Plans (SIPs) have been addressed. In addition, Hill & Associates believes that CAIR and CAMR will provide the regulatory basis that will drive fossil fuel decisions through the forecast period.

The natural gas and fuel oil price projections were provided by Pace Global. Electricity demand growth rates were input into the model based on the EIA's Annual Energy Outlook 2005 data applied to baseline electricity demand taken from EIA Form 714.

The PRISM™ model combines all of the fuel price data and matches that with the electricity demand component to provide an integrated solution that takes into account the interrelationship of costs across all fuel types.

Q. Describe the varying characteristics of each source of coal that were factored into Hill & Associates' analysis and price forecasts.

A. Each region analyzed has unique characteristics in coal quality (sulfur content and heating content), and the logistics of extracting and transporting the coal. A summary of each region's characteristics that were factored into my analysis is provided below:

- CAPP:
  - High quality coal used in steam and metallurgical markets.
  - Large number of mines with relatively low production capacity.

- Increasing difficulties, such as labor shortages, permitting, bonding and trucking laws, and the increasing expense to develop new mines are creating emerging barriers to new mine development.
- Near-term demand will remain constant. Long-term demand will decrease as utilities transition to lower cost alternatives, including higher sulfur coal, as more existing plants install scrubber technology.
- Overall production to meet demand is expected to drop approximately 50 percent in the next 20 years as low cost reserves are depleted.

• NAPP:

- The bulk of production comes from a relatively low number of large underground mines in the Pittsburgh Seam.
- The balance of production comes from smaller surface and underground mines with production of less than 1 million tons per year.
- Pittsburgh Seam coal is highly valued by utilities, as it is characterized by high heat content, low sulfur content compared to ILB, and good combustibility and handling characteristics.

- Overall NAPP production will increase until 2016 when production is expected to decline as reserves in the Pittsburgh Seam begin to become depleted.

• ILB:

- Production has declined from 158 million tons per year in 1988 to a low of 88 million tons per year in the mid-1990s, primarily due to the passage of the 1990 Clean Air Amendments, which resulted in utilities switching to low sulfur alternatives.
- Typical surface operations are less than 1 million tons per year, while 65 percent of all production comes from underground mining. Production from underground mines averages more than 1 million tons per year per mine.
- Continuing installation of scrubbers will result in increased demand for ILB coal.
- Reserves are estimated to be 5 to 10 times as much as NAPP reserves.

• PRB:

- All production is from surface mining operations with coal classified as low sulfur.
- Total production in 2005 was 434 million tons which represents a 3 percent increase from 2004.

- Demand is expected to reach 700 million tons per year by 2023.

• Latin America:

- Colombia and Venezuela were the largest sources of imported coal to the United States in 2005, providing a total of 21.9 million tons.
- Coals from Latin America are comparable in quality to eastern US coal.
- Coals imported from Latin America are often economically competitive with domestic US coals.

Q. What was the method used to forecast petcoke prices in your analysis?

A. Petcoke is a byproduct of the oil refining process, and as such it has no meaningful "cost of production" by which to gauge future prices. Petcoke typically is priced at a discount to the coal market. Hill & Associates provided a commodity price forecast based on the average of historical petcoke prices.

Q. Have coal prices increased above historical levels?

A. Yes.

Q. What caused this increase in coal prices?

A. During 2003 and 2004, numerous events occurred that resulted in increased coal prices in the eastern United States. Overall demand for coal in the United States increased due to a strengthening US economy which resulted in increased

electricity demand and increased domestic steel production. At the same time, the recent trend of steadily decreasing coal exports was reversed in response to the increased demand for all commodities to feed the growing economies of India and China, including metallurgical coal from the United States. The expanding economies of India and China also led to a worldwide shortage in shipping vessels, resulting in extremely high ocean freight rates. The increased ocean freight rates led European buyers to turn from Asia to the United States for swing supply, resulting in increased demand for coal in the Atlantic Basin (further contributing to the reversal of the declining thermal coal export trend).

During this same time period, excess domestic coal production capacity fell to an all time low in the major coal producing regions. The problem was especially acute in the CAPP region due to the bankruptcies of several major mines and declining average productivity due to shifts in mining methods. Production costs increased due to increased costs for oil, natural gas, and steel (which led to higher mine operating costs). An aging workforce coupled with an acute shortage of trained workers to meet growing demand resulted in increased labor costs as producers were forced to raise wages to attract and/or retain workers.

Delivery capacity for coal in the United States was adversely affected by a shift in management focus of the major rail carriers that resulted in a shortage of locomotives, cars, experienced train operators, and dispatchers, all while coal demand was increasing. Rail carriers responded to this increased demand for

coal shipments by significantly raising rates, which further disrupted normal shipping patterns. Additionally, transportation was further complicated due to the shortage of barge capacity that resulted from the decades long decline in coal prices and barge shipping rates.

Q. How have these events affected Hill & Associates' coal price forecast?

A. As reflected in the base case forecast shown in Exhibit __ [MP-2], Hill & Associates viewed these recent events as short lived and, therefore, projects the current sellers' market for coal will once again revert to a buyers' market for a variety of reasons, including the belief that the US economy will slow its growth, partly due to higher energy costs. Worldwide supply of raw materials will begin to catch up with the demands of the Indian and Chinese economies, leading to stable or declining incremental shifts of US thermal coals to metallurgical coals. Additionally, investments in shipping will reduce ocean freight rates, and the decreased rates will reopen Asian coal sources to Europe, leading to a decrease in demand for US coals. Domestically, investment in railroad and river transportation infrastructure, as well as modified management practices, will ease the currently constrained coal transportation system and the recent sharp increase in rail and barge transportation costs will ease as well.

Q. Are you familiar with the capabilities of the proposed Taylor Energy Center to burn a wide variety of fuels?

A. Yes. The testimony of Paul Hoonaert on behalf of Sargent & Lundy indicates that the plant design will allow Taylor Energy Center to burn a wide variety of fuels.

Q. Are you familiar with the proposed source of fuel for the Taylor Energy Center?

A. Yes. I understand that the project team evaluated numerous coal sources and selected a blend of Latin American coal and petcoke as the proposed fuel source.

Q. Please comment on the reliability of the supply of Latin American coal.

A. Latin American coal producers have an excellent record of reliability in providing coal for customers in both the United States and around the world.

Q. Are there also domestic coal supplies reliably available to the proposed Taylor Energy Center?

A. Yes. All of the basins studied by Hill & Associates have the ability to reliably supply coal to the proposed Taylor Energy Center.

Q. One of the coal supply regions evaluated in the Need for Power Application was the Powder River Basin. Are you aware of the recent delivery problems associated with Powder River Basin coal?

A. Yes. Hill & Associates views these problems as short term and expects infrastructure improvements to match demand prior to operation of the proposed Taylor Energy Center. This is addressed in the testimony of James Heller.

Q. Please discuss the reliability of the supply of petcoke.

A. In excess of 50 million tons of petcoke is produced annually in the United States and the Caribbean, of which only a small fraction is utilized by the US utility industry for producing electricity. Petcoke production is expected to increase with the increased use of lesser quality crude oils and expansion of refining capacity. Thus, a reliable supply of petcoke should be available for the project.

Q. Did Hill & Associates provide emission allowance price projections?

A. Hill & Associates provided emission allowance price projections for SO_2, NO_x, and Hg in the base case forecast and high and low fuel and emissions allowance price scenarios, and also provided SO_2, NO_x, Hg, and CO_2 allowance price projections for a sensitivity scenario that reflects the projected impact on fuel prices due to consideration of potential implementation of a national CO_2 allowance cap-and-trade program.

Q. Please describe the process by which emissions allowance price forecasts were developed.

A. Emission allowance prices are forecast using the PRISM™ model. As a linear programming model, PRISM™ includes constraints on SO_2, NO_x, Hg, and, in the case of the sensitivity scenario, CO_2. PRISM™ uses a variety of compliance options in meeting these constraints. These options include fuel switching, running one plant in lieu of another, adding emissions control equipment, and buying or selling allowances. Each of the options has an associated cost. PRISM™ simultaneously weighs the economics of the compliance options as it solves for the least cost option to meet electric demand. The model provides the marginal price of emissions consistent with the optimum solution.

Q. Please discuss the assumptions used in developing SO_2 allowance price projections.

A. We anticipate that the reduction in SO_2 emissions associated with CAIR in 2010 will encourage the continued buildout of scrubber technology. Already, scrubber additions for 70 GW of existing generating capacity have been announced for installation by 2010. We assume that this early compliance will result in the banking of allowances prior to 2010. The bank of allowances will be drawn down beginning in 2010 at a rate that provides for a consistent level of power plant emissions. After the bank is exhausted, allowance prices will increase, and additional scrubbing will be required.

Q. Please discuss the assumptions used in developing NO_x allowance price projections.

A. NO_x emissions will be drastically reduced in the CAIR states beginning in 2010. CAIR will initiate a tremendous buildout of postcombustion NO_x controls. However, the price of NO_x allowances is expected to escalate relatively smoothly through the implementation of CAIR Phase I in 2010. Hill & Associates projects NO_x allowance prices will increase dramatically in 2015 corresponding to CAIR Phase II, when NO_x emission limits will be further reduced.

Q. Please discuss the assumptions used in developing Hg allowance price projections.

A. CAMR will set a 38 ton limit on Hg emissions in 2010 (Phase I) followed by a reduced cap of 15 tons in 2018 (Phase II). Phase I is expected to have minimal impact on the utility industry because the co-benefits of equipment installed to achieve emissions reductions associated with CAIR will virtually ensure compliance with CAMR Phase I Hg limits. Hill & Associates projects that no further emissions reductions will be necessary specifically for Hg compliance under Phase I of CAMR. However, we expect some early banking of Hg allowances in preparation for Phase II of CAMR. As a result, Hg allowances will begin to have a value prior the implementation of Phase II of CAMR in 2018.

Q. Please discuss the assumptions used in developing CO_2 allowance price projections.

A. Hill & Associates provided a specific fuel price forecast that included corresponding emission allowance prices for SO_2, NO_x, Hg, and CO_2 based on assumptions generally analogous to the proposed McCain/Liebermann *Climate Stewardship Act of 2005* (S.342). Currently, there is no national or state legislation that either limits or assigns a cost to CO_2 emissions in the United States or Florida.

More specifically, the following aspects of S.342 were adopted by Hill & Associates to develop the CO_2 scenario fuel and corresponding emission allowance price forecasts:

- Emission levels would be capped at year 2000 levels, with no second phase.
- CO_2 emission allowances would be created.
- CO_2 emission allowances would be fungible both inter- and intra-industries.
- CO_2 emission offsets would be able to be created from domestic and international sources.

In using the PRISM^{TM} model to develop the CO_2 fuel and corresponding emission allowance price sensitivity scenario, a CO_2 emission cap had to be designed specific to the electric generating units (EGUs) notwithstanding the likelihood of an economy-wide national standard as proposed in the *Climate*

Stewardship Act of 2005. Hill & Associates developed such a cap based on CO_2 emissions from EGUs as reported by the US Environmental Protection Agency (EPA) for the year 2000 in the preliminary *Summary Emissions Report (Quarter 4: Year-To-Date Values)*.

The preliminary *Summary Emissions Report (Quarter 4: Year-To-Date Values)* reported year 2000 EGU CO_2 emissions as 2.45 billion tons. An additional 10 percent was added to this emissions level to create the actual initial CO_2 emission cap for the years 2010 through 2014 used by Hill & Associates in developing the CO_2 fuel and corresponding emission allowance price sensitivity scenario. Beyond 2014 the CO_2 emission cap was increased an additional 0.5 percent per year. These projections were based on the following:

- The potential for relatively low cost CO_2 reductions by power plants (limiting emissions of other "greenhouse gases," improving station service efficiency, reforestation on company owned property, methane capture at coal mines, etc.).
- The potential for low cost CO_2 emissions offsets from other industries.
- Additional CO_2 emissions offsets/credits assigned to EGUs out of political expediency in an effort to buffer electricity customers from higher electricity costs.

The regulated-CO_2 fuel and corresponding emission allowance price sensitivity scenario also anticipates other changes in fundamentals as compared to the base case forecast in response to a carbon constrained economy, including the following:

- A reduction in electricity demand growth. In the regulated-CO_2 fuel and corresponding emission allowance price sensitivity scenario, electricity demand growth was limited to 1.0 percent in any area of the country that had exceeded 1.0 percent in the base case fuel price forecast.
- An increase in the amount of energy produced by renewables or other non-emitting sources (except nuclear). The renewable standards promulgated by regulation/legislation were used in states where such laws exist (as of year end 2005). States with no current renewable standards were projected to have an average of 12.0 percent of their energy produced by non-emitting sources by 2009 (including current non-emitting sources) with a 0.5 percent growth in renewable energy production every year until a maximum of 20 percent was achieved.
- An increase in the amount of nuclear capacity. The regulated-CO_2 fuel and corresponding emission allowance price sensitivity scenario includes 12 new nuclear units coming online between 2016 and 2020. The base case forecast includes no new nuclear additions throughout the forecast time horizon.

Q. Please describe the impact of considering CO_2 emission allowance price projections on the resulting fuel forecasts developed by Hill & Associates.

A. As shown in Exhibit __ [MP-5], Hill & Associates' fuel price projections for the scenario in which CO_2 allowance price projections are considered indicate that coal, SO_2, NO_x, and Hg allowance prices will trend lower than the base case.

A CO_2 emissions cap will reduce the rate of growth in demand for fossil fuel generation and will influence reversion in the long-term towards a buyers' market for coal (i.e., lower prices). Lower coal prices in the United States will cause Latin American suppliers to reduce prices to maintain market share.

Petcoke demand for electric generation will remain generally unchanged. Petcoke supply will likely decrease or grow more slowly in response to the transportation sector's activities to meet the restrictions of the proposed McCain-Lieberman *Climate Stewardship Act of 2005*. However, as utilities burn only a fraction of the petcoke produced, prices are less likely to be affected.

Q. Please describe the high and low fuel price projections developed by Hill & Associates.

A. Hill & Associates developed high and low commodity price projections for coals, petcoke, natural gas, and fuel oil. These projections are shown in Exhibits __ [MP-3] and __ [MP-4], respectively. In developing both the high and low fuel price forecasts, Hill & Associates chose to vary fundamental parameters that tend to correspond to high or low fuel prices. In doing so,

PRISM™ demonstrated the integrated impact on coal and emission allowance prices resulting from these assumptions.

In developing the high fuel price projections, Hill & Associates increased the annual base case (real 2005 $/MBtu) natural gas and fuel oil price projections by 20 percent. Electricity demand growth was increased by 0.2 percent year to year. Additionally, it was assumed that coal producers would encounter increased investment hurdles, thereby discouraging investments in new mine capacity. The end result is a scenario that is generally conducive to high coal prices, and also results in increased emission allowance prices.

In developing the low fuel price projections, Hill & Associates decreased the annual base case (real 2005 $/MBtu) natural gas and fuel oil price projections by 20 percent. Electricity demand growth was reduced by 0.1 percent year to year. Additionally, it was assumed that coal producers would encounter decreased investment hurdles, thereby encouraging investments in new mine capacity. The end result is a scenario that is generally conducive to low coal prices, and also results in decreased emission allowance prices.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF MATTHEW PRESTON

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. 060635-EU

NOVEMBER 21, 2006

Q. Please state your name and business address.

A. My name is Matthew Preston. My business address is 222 Severn Avenue, Annapolis, MD 21403.

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

A. I am employed by Hill & Associates, Inc., where I am a senior consultant.

Q. Have you previously submitted testimony in this docket?

A. Yes.

Q. Have you reviewed the direct testimony of Dian Deevy filed in this docket on November 2, 2006?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut Ms. Deevy's criticisms of the assumptions underlying Hill & Associates' carbon dioxide (CO_2) allowance forecast.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. I am sponsoring Exhibit No. __ (MP-1R), which provides a summary of historical allowance price trends.

Q. On page 7 of her testimony, Ms. Deevy states that while your CO_2 allowance forecasts "are not the lowest [she] has found in the literature, their erratic progression over time from low to high and then down again is unusual." Do you agree that it would be unusual for CO_2 allowance costs to be erratic?

A. No. Hill & Associates' CO_2 allowance price forecast is an output of the PRISM model. The PRISM model projects emission allowance prices, in this case CO_2, based on the congruence of a whole host of factors. These factors include fundamental assumptions such as electricity demand and fuel supply/price relationships as well as assumptions concerning the cost of various actions potentially necessary to meet environmental goals. The emission allowance prices projected by PRISM are not predetermined based on any defined set of compliance actions but rather represent the value of emissions reductions given all of the potential means of reducing emissions, nationwide, available to the model. The potential methods of reducing CO_2 emissions in the

model include re-dispatch and building less carbon-intense new generation. Because PRISM includes the influence of many factors, the emission price forecast produced by the model can fluctuate as the model responds to changes in these factors.

Historically, emission allowance prices have proven to be volatile and, like all commodities, prices have fluctuated in response to changes in the fundamentals of supply and demand. This is demonstrated in Exhibit No. __ (MP-1R), which presents historical prices for CO_2 allowances in Europe and for SO_2 allowances in the United States. Because CO_2 allowance prices will depend on the type of regulatory regime implemented, the prices shown on these charts are not necessarily representative of what might be seen if and when a CO_2 regulatory program is implemented in Florida. Nevertheless, the charts demonstrate the significant volatility seen in allowance market systems in general. Of particular note, these charts show the type of low-to-high-to-low trend that Ms. Deevy inexplicably finds "unusual." Because allowance prices respond to numerous market factors, I would find it unusual to see a straight-line or ever-increasing trend for CO_2 allowance prices.

Q. On page 8 of her testimony, Ms. Deevy questions why Hill & Associates set the initial CO_2 limit for electric generating units (EGUs) at 110% of the EGU CO_2 emissions in year 2000. Please explain the basis for that assumption.

A. As there is no existing nationwide legislation regarding the limiting of greenhouse gasses (GHG) and there are many competing proposals, I had to develop what I thought would be a plausible future scenario. In developing this scenario I considered both the desire to limit CO_2 and the potential economic impacts. I primarily relied on the McCain Lieberman Climate Stewardship Act (S.342) as the only Act, so far, to make it to a vote on the floor of the Senate. I also considered the Regional Greenhouse Gas Initiative (RGGI) Memorandum of Understanding because it was the only active policy at the time this scenario was created. The McCain Lieberman Act, the general basis for establishing the CO_2 Case does not specifically set a target for GHG emissions for EGUs but rather sets a nationwide cap that covers most sectors of the US economy. However, the PRISM model addresses only the response in the electric and fossil fuel markets. Considering the long lead time to make large scale changes in the demand, supply and distribution of electricity and the potential shock to electric rates and availability that a restrictive EGU CO_2 cap would engender, the ***useable*** limit of CO_2 allowances for EGUs was increased 10% beyond the year 2000 emissions (for EGUs). The increased limit could be from the banking of early compliance credits or from related industries (such as recovery of coal-bed methane). The practice of adjusting the EGU cap on the basis of economics is a feature of both S.342 and RGGI.

Q. Also on page 8 of her testimony, Ms. Deevy faults Hill & Associates for restricting electricity demand growth to 1% per year in the CO_2 case. Please explain the basis for that assumption.

A. In developing a plausible CO_2 case limited to the impact on only the electric industry, I considered the response of states and individuals to the prospect of a GHG constrained world. I considered it reasonable to assume that electricity demand growth would slow. This might manifest itself in three ways:

1. States may more generally support demand-side management programs and efficiency standards;
2. Individuals may make choices that limit electricity growth requirements; and,
3. The higher price of electricity, or the prospect of higher prices, may limit growth.

From a modeling perspective any or all of the above factors is represented by slower electricity growth. Note that by electricity growth I mean the rate of change in the number of annual MWhs required to meet demand by control area. For the purposes of modeling the CO_2 case, I limited the year-on-year annual growth in MWhs in any given control area to 1% in those control areas where the growth, in the Base Case, was greater than 1%. Growth rates below 1% were left unchanged.

Q. On pages 8 and 9 of her testimony, Ms. Deevy questions Hill & Associate's assumption that renewables would be at 12% of generation requirements by 2010 and later increase to 20%. Please explain the basis for that assumption.

A. First, let me clarify that by renewables, as used in the development of the CO_2 Case, I mean all generating technologies, with the exception of nuclear, that do

not emit GHGs in the stage where electricity for the grid is created. For the most part, this includes hydro, geologic heat sources, solar, bio-mass and wind. Biomass is included even though it emits CO_2 because the growth of the biomass fuel consumes the CO_2 emitted. Nationwide, about 10% of the nation's generation comes from these sources. Many states have already stipulated renewable standards as an initial step in limiting GHGs. In designing a plausible CO_2 scenario I assumed that states more generally would continue this practice. Although the real world implementation of such a strategy would likely result in a wide variety of state standards, I applied the 12% to all states generically for the purposes of developing this Case as I believe this is a reasonable projected average for state renewable standards in a carbon-constrained scenario.

Q. On page 9 of her testimony, Ms. Deevy asserts that Hill & Associates assumed that nuclear units will be considered "non-emitters." Did you account for CO_2 emissions sometimes associated with non emitting technologies such as nuclear?

A. To the extent that these emissions are associated with electricity demand, such as required for the enrichment of uranium, they are accounted for. In the model I added 12 nuclear plants in the CO_2 Case, again as a plausible response by the electric industry to provide affordable non GHG emitting generation. As I discussed previously, electricity demand was adjusted. This adjustment accounts for the additional electricity needed to process the nuclear fuel, manufacture solar photovoltaic panels, etc.

Q. On pages 9 and 10 of her testimony, Ms. Deevy questions Hill & Associates' assumption that aggressive reductions in other industries would be a source of CO_2 allowances for EGUs going forward. Why did you make that assumption?

A. I assumed that some relief would be provided to the EGU sector in the interest of maintaining affordable electricity rates because each $1 per ton of CO_2 adds about $1 dollar per MWh (1 mil/kwh) to the cost of coal-fired generation and about $.50 per MWh (.5mil/kwh) to gas-fired generation. The removal of CO_2 from conventional coal- and gas-fired EGUs, and even from IGCC plants, is expected to be very costly – perhaps as much as $20 to $40 per ton of CO_2 not including the cost of impounding the CO_2 once it has been sequestered. Additionally, while coal- and gas-fired EGUs, as a group, are the largest emitters of GHGs they only contribute just over 1/3 of the nation's total emissions. Given the high cost of removing CO_2 emissions from EGUs, I assumed that some of the reductions in other sectors would come at lower cost therefore providing some relief to the EGUs.

Q. Finally, on page 10 of her testimony, Ms. Deevy questions Hill & Associates' assumption that EGUs will be provided some form of relief to buffer electricity customers from higher electricity costs. Will energy companies profit from any such relief in the EGU related CO_2 cap?

A. It is very unlikely that *electric* companies will profit from this type of relief. Even with the relief there are few, if any, owners of fossil-fueled EGUs that will be able to profit from CO_2 cap relief. The fact that CO_2 allowances have

positive value indicates that they will be an additional cost born by EGU owners. The owners of EGUs will try to pass these costs on to customers. Relief from the cap would perhaps spare *rate payers* the capital and operational and maintenance (O&M) expense of sequestering and impounding CO_2. Competition will keep wholesale electricity prices at or near the price of the marginal unit which in turn will be lower due to the lower cost of CO_2 allowances.

Q. Do the points raised in Ms. Deevy's testimony lead you to question the reasonableness of your CO_2 allowance price forecast?

A. No. As discussed above, our allowance price forecast was developed using a comprehensive model which accounts for fundamental market factors such as electricity demand and fuel supply/price relationships as well as the cost of actions potentially necessary to meet environmental goals. Ms. Deevy's criticisms primarily relate to assumptions concerning the components of a CO_2 regulatory program that has not been adopted. This simply underscores the high degree of uncertainty inherent in developing CO_2 allowance price forecasts unless and until a specific regulatory program is enacted and the regulators determine how such a program would be implemented.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BY MR. PERKO:

Q Mr. Preston, have you prepared a summary of your prefiled direct testimony?

A Yes, I have.

Q Could you please provide that now.

A The purpose of my testimony is to describe the forecast of coal, pet coke and emission allowance prices that are provided for the Taylor Energy Center. The underpinning of my analysis is Hill & Associates proprietary PRISM^{TM} model. PRISM^{TM} is a linear program designed to optimize the cost of meeting the electric demand of U.S. and Canada while meeting all environmental constraints. The output of the model provides a long-term outlook on coal prices and emission allowance prices.

In my analysis, Florida was assumed to participate in the EPA's natural care around CAMR programs. In addition to the base case, I provided a high case and a low case forecast and a CO_2 case sensitivity analysis. All the coal basin studied are projected to have sufficient reserves and mining capacity to meet the potential requirements of Taylor Energy Center.

By coal, pet coke, emission allowance price forecasts were developed in an integrated fashion

reflecting worldwide market forces. This concludes my summary.

Q Mr. Preston, did you also prepare a summary of your rebuttal testimony?

A Yes, I have.

Q Could you please provide that now.

A The purpose of my testimony is to rebut Ms. Deevey's criticisms of the assumptions underlying Hill & Associates' CO_2 allowance forecast. Hill & Associates' CO_2 allowance price forecast is an output of the PRISM^{TM} model. Because PRISM^{TM} includes the influence of many factors, emission price forecasts produced by the model can fluctuate. Historically emission allowance prices have also fluctuated in response to changes in the fundamentals of supply and demand. As there is no existing nationwide scenario regarding the limiting of greenhouse gas emissions and there are many competing proposals, I had to develop a plausible future scenario limiting CO_2 emissions.

Considering the long lead time to make large scale changes in the demand, supply and distribution of electricity and the potential shock to electric rates and availability that a restrictive CO_2 cap would engender, the functional limit for CO_2 emissions from power plants was increased 10 percent beyond the year

2000 emission level.

I reduced the growth rate of electrical demand to no more than 1 percent per year assuming that states would support demand side management programs and efficiency standards and individuals might limit electricity requirements if for no other reason then electricity prices may or wouldn't be higher.

I also assumed that states would more generally stipulate renewable standards as many have already done. Although state programs would likely vary widely, I applied 12 percent generically for the purpose of developing the CO_2 case. Any CO_2 emissions associated with electricity requirements for uranium enrichment for new nuclear capacity is accounted for in PRISM^{TM}.

I assumed that CO_2 allowances from other industries would be available for generating unit compliance in the interest of maintaining affordable electricity rates. I also believe it is unlikely that owner/operators of power plants will profit from receiving offsets from other sectors of the economy.

This concludes my rebuttal testimony.

MR. PERKO: And we tender the witness for cross-examination.

CHAIRMAN EDGAR: Thank you.

Ms. Brownless?

CROSS-EXAMINATION

BY MS. BROWNLESS:

Q Good evening, Mr. Preston.

A Good evening.

Q To start off with, Mr. Preston, did you sponsor answer No. 2 through 13, 15 and 17 of NRDC's first set of interrogatories, and that's Exhibit No. 108?

A Which are those numbers again, please.

Q The numbers are 2 through 13, 15 through 17.

A And that's the NRDC's --

Q Yes, sir. NRDC's first set of interrogatories, Nos. 1 through 26. And I got that off of page 22, Mr. Preston. There's a list of the interrogatories there that you sponsored.

A Okay. Here we go. Now I'm getting there. Okay. So 2 --

Q Two through 13.

A Yes.

Q And 15 through 17.

A Yes, I did.

Q Okay. Thank you.

And are those true and correct to the best of your knowledge and belief?

A Yes.

Q And I'm going to try to go through this real quick because it's real late. But your PRISM^{TM} model is a program that forecasts fuel costs and it forecasts fuel costs for pet coke and coal; is that correct?

A It -- for coal, that is correct. For -- it produces a -- a -- an observation, I guess you would call it, of pet coke, but that is not the forecast that was actually used in this proceeding because pet coke has its own fundamentals that must be addressed.

Q Okay. As I understand it, if I'm looking at your Exhibit No. 40, which is MP-5 which is the CO_2 sensitivity study --

A Okay.

Q Okay. Pace global did the natural gas and the distillate oil forecast here?

A Yes, they did.

Q And all transportation cost for coal, pet coke, natural gas were done by some other entity, correct?

A For the purposes of developing the TEC RFP, yes. Those were performed by -- the rail transportation was performed by Hellerworx, the overseas transportation was performed by Simpson, Spence & Young.

Q Okay. As I understand it, the PRISM^{TM} model

covers the entire United States and Canada because it's an interconnected grid; is that right?

A That's right.

Q And the database, your basic database, is every electric generating unit and most industrial units that produce over 25 megawatts of power; is that right?

A There are probably some that aren't in there that have just been developed or come on line in the last year or two. But to the greatest extent that we can identify, that's true.

Q Okay. And you get all that information off energy information forms 860 and 861?

A Yes, that's true.

Q Okay. And then you also model transmission flows using a hub and spoke system?

A That's correct.

Q And that also takes into account all of the electric control areas in the United States and Canada?

A Yes.

Q Okay. Now, as I understand the inputs into your computer model, they are electricity demand inputs as forecasted by the energy information agency --

A The electricity demand --

Q Yes, sir.

A -- that's right.

Q And then you have hub gas price forecast, published hub gas price lists that are a data input?

A Yeah. The Henry hub price which is sort of the seed price for natural gas, it's the marker price used in the United States to identify the commodity price of gas was provided by Pace Global. The basis or the transportation cost of that gas to various parts of the country was developed from periodicals available in the industry.

Q Okay. And that's your hub and spoke idea for gas?

A Well --

Q I'm sorry, strike that. We'll move on.

You also modeled the operational details of each plant which would include the heat rate, the variable O&M, what type of emissions control equipment were on those plants; is that correct?

A Right. The plant's model included that piece of information, yeah.

Q And also the emission limits for the plants, correct?

A That's correct.

Q And all of that information is from various EIA forms?

A Yes, and any anecdotal that we have come

across in the process of working for clients.

Q Now, you have estimates as an input also of all the production costs for every coal mine in the United States and Latin America; is that right?

A Yes, that's true.

Q And that also includes transmission costs between control areas if this is included as an input for electricity?

A For the hub and spoke, yes. We estimate the cost of -- transmission cost between control areas, yes.

Q The assumptions with regard to CAMR and CAIR, the regulations for SO_2, NO_x and mercury are federal standards; is that right?

A That's generally how we applied it, yes.

Q And was that used in this case?

A Yes.

Q And the final input or one final major input is the cost for emission control equipment; is that correct?

A Yes, it is.

Q And for IGCC units, does that include the ability to partially sequester carbon, CO_2?

A Yes. We assume that -- we provided to the model the option to build IGC units that would partially -- could partially sequester CO_2.

Q Okay. Now, those are the major inputs into the model, the data that you input.

The major outputs of this model are the coal price forecasts that we see on Exhibit No. 40; is that right?

A Yes.

Q Okay. And you can also use this model to output the bulk power market prices in dollars per megawatt hour?

A Yes.

Q And emission prices as are listed on this exhibit which is SO_2, NO_x, mercury and CO_2?

A That's correct.

Q Okay. Now, every time you run this model, do you get the outputs for each category listed on Exhibit No. 40? In other words, does the cost number fall out for each one of these identified things?

A Yes, that's true.

Q So every time you run it, you get a CO_2 emission offset price?

A Only if we've instructed -- if we've provided a constraint in the model, which this is how the model works in an optimization model, we give it a cap on its CO_2 emission allowance prices. If that cap exists, it will throw a CO_2 price. And it will only throw a

price -- it will only give us a price if the cap is limiting the operation of the -- the solution of the model.

Q Okay. So, for example, when I look on Exhibit No. 40, for the years like up to 2011, I think that is, that there's just little lines, that means that the model did not think that CO_2 emissions exceeded the cap?

A Well, there was no cap placed on the model up until 2010 and then -- in that year, the cap was not exceeded or it was not met. It's not allowed to exceed the cap.

Q Okay. It was not met, and so therefore, you did not get a number?

A It was not met.

Q For Exhibits 37 through 39, which is the base case and the high fuel and low fuel forecasts, was the CO_2 emission price given or produced for those forecasts at the time you ran them?

A No, they were not.

Q And why was that?

A These weren't the CO_2 sensitivity cases and CO_2 was not -- it was not built into the constraints in the model.

Q Okay. The assumptions you used in putting together the constraints on your model for the

CO_2 sensitivity study, those were based on the McCain-Lieberman Climate Stewardship Act of 2005, Senate Bill 342?

A I believe in my prefiled testimony I say generally analogous to. It -- with important modifications, it's based on that.

Q That's where you started?

A Right. It had some provisions I thought were appropriate. Other provisions I modified to match what I believe.

Now, assuming, again, this is a very uncertain thing that anything is going to be done, but assuming that there would be some legislation, I made modifications along the lines of what I thought could possibly happen or plausibly happen.

Q A set of assumptions about -- that you placed into your model, and those assumptions acted as constraints on the model or parameters within which the model worked?

A That's right.

Q Okay. Now, am I correct that you capped CO_2 at 2000 levels and that there was no further reduction in the amount of CO_2, that was one of the constraints?

A That's not correct.

Q Please explain.

A I -- one of the important modifications I made, and again, this is to form what could be -- given the complete uncertainty that any of this is going to happen --

Q Sure.

A -- but given that I had to produce a CO_2 case, my estimate of a plausible cap was year 2000 plus 10 percent. So roughly the year 2000 emissions for power plants was about 2.45 billion tons. I increased that cap to about somewhere around 2.7 billion tons by adding 10 percent to it.

Q I guess I didn't ask my question very well. Your model does not assume that the amount of CO_2 will be decreased over time, does it?

A No. Again, that's one of the important modifications I made of -- I believe that one of the -- one of the things that really has to be studied when you're looking at the CO_2 cases, there's a whole host of unintended consequences that can occur and it's important to integrate those consequences.

One of the consequences of a CO_2 cap could very well be pushing the availability of natural gas to the point where essentially the lights go out. Either you have to -- you have to provide more

emissions allowable for the power plants or the lights will just plain go out. There won't be enough natural gas to meet the demand.

Q Okay. So the CO_2 limit that you -- the assumption that you made in your model was that throughout your study period, the CO_2 emissions would remain constant at the 2000 levels plus 10 percent?

A No, they increase over the -- over the period that I studied which is only going through 2030, they increase about half a percent per year.

Q Okay. So I guess the basic question I'm attempting to ask is: Did you assume the legislation would require a reduction in the level of CO_2 as time progressed?

A No. I did not feel that was a plausible scenario to address.

Q Now, the McCain-Lieberman Climate Stewardship Act applies to all emitters of CO_2, does it not?

A It --

Q Meaning electric --

A No, not all. But there -- there have been several versions. They've had slightly different acts. But in general, not to belabor the details, it covers the industrial sector, the transportation sector, the commercial sector, and the electric power sector.

Q Okay. And what is the number you put in the model -- well, let me back up. For the year 2000, what is the number that you started with for all of these sectors, the total number?

A The PRISM^{TM} model only addresses the power plant sector.

Q I understand that. And I guess the question I'm asking --

A So it wouldn't matter -- what I had to put in was a functional cap for the power plant sector. So I put in the power plant emissions from 2000 plus 10 percent was the initial level started from -- in 2010.

Q So this is actual power plant emissions as reported by who?

A It's reported by the EPA.

Q You made the assumption that CO_2 allowances would be fungible between these sectors, industrial, transportation and electric; is that correct?

A Yes, I did. And this is important to the model only in the sense that it provides a mechanism to fluctuate the functional cap without -- you know, for instance, it doesn't -- it doesn't necessarily mean that the McCain-Lieberman bill would not be met from the other sectors. It just meant since these were fungible,

that would be a source of allowances that would allow the power plant emissions to increase, if necessary.

Q And you also assumed there would be a worldwide trading market for these allowances?

A That's right. Another important source of potential offsets would be all kinds of efforts offshore, that in general sort of McCain-Lieberman said -- gave some general thought that the United States could participate in those markets.

Q Okay. Is there an international CO_2 market at this time?

A I know that there are the -- there are some exchanges that have been created that create offsets.

Q Okay. Do you know how extensive those are?

A I don't know the exact numbers.

Q Okay. The European union has a CO_2 allowance market, does it not?

A Yes.

Q Okay. And I think that was referred to in your rebuttal testimony, correct? You had a chart?

A That's right. In the sense that it shows that prices are fluctuating in terms of allowance prices.

Q Did you analyze assumptions associated with any of the other bills? And I won't list them.

A No. What I -- essentially what I was doing

was creating my own thoughts on what would be a plausible scenario for the future.

Q Okay. Am I correct that one of your assumptions was that 12 nuclear power plants would be built from 2016 to 2020?

A Yes, that's true.

Q Now --

A I was just noting in that -- the letter that Mr. Paben distributed, that the NRC, Nuclear Regulatory Commission, noted that they expected to receive 30 applications for nuclear power plants.

Q Okay. But applications don't mean that plants actually get built; isn't that correct?

A That's right. And that's why -- one of the reasons why I've only suggested that perhaps 12 would be built.

Q Okay. Are there possible constraints on the construction of nuclear power plants; for example, the disposal of waste?

A Certainly.

Q Is the nuclear power industry -- how many nuclear power plants have been built in the United States over the past ten years?

A I -- I can't confirm this. There may be one -- TVA may actually have one under construction or

refurbishment, but that's about the only activity that's taken besides incremental increases at existing power plants.

Q And such incremental increase would be, for example, the request of Progress Energy to increase their existing nuclear plant in Florida; is that correct?

A I'm not -- I'm not familiar with that particular situation. But I'm speaking of just capacity increases, improvements in efficiency at the plant that would allow for 10, 15, 20, 35 megawatts to be added to the existing site.

Q Would there also be a problem with the supply of nuclear fuel, possible constraints on that?

A I -- I don't believe so.

Q Okay. Are there any problems with securing the actual boilers, reactors, that type of thing, any constraints on the construction equipment end of it?

A For -- for what -- I mean, it sounds like a lot. But for a mere 12 units, I don't believe so.

Q Does this take into account other nuclear units that are being sited and built around the world that might be competing for those same resources?

A In my opinion, that would not make a difference.

Q Now, am I correct that you escalated the amount of CO_2 allowances that would be available in your sensitivity study over the term of the study?

A That's correct. About a half a percent per year.

Q I think you also testified that you limited the growth rate in the control areas in your model to 1 percent annual growth?

A Yes, that's true.

Q Okay. I know you've been here for the --

A Unless -- unless, of course, they were projected to be less than 1 percent, then I didn't change them.

Q Right. Okay. I know you've been here to hear the testimony of the other witnesses. Has Florida historically exceeded this 1 percent per year growth?

A Well, no. But in developing this case, I'm assuming a world where the United States has decided to participate in CO_2 restrictions. So I generally assume that Florida would be -- step up to the plate and make their contributions just like any other state.

Now, for purposes of the model and purposes of the forecast either for CO_2 or coal or any of the other things in this forecast, whether Florida was a little over or a little under wouldn't make a big difference in

the actual outcome of the forecast.

Q Well, if Florida had a historic growth rate of greater than 1 percent, and let's assume its CO_2 emissions allowances were allocated at some point in time by either some federal agency or -- by some federal agency, then the amount of growth would impact its ability to run the power plant or it would have to impact the ability -- its cost of production for that plant, correct?

A That is totally speculative. The allocation of allowances is probably one of the most politically fraught pitfalls of any of these many, many, many potential bills that have been proposed out there. It's one of the uncertainties that makes it very difficult to even think of what could happen. There's going to be so many competing interests, that there's a likelihood in my mind there won't even be a federal program. And I'm not speaking of competing interests in terms of whether we want to or not. It's just that who is going to take the brunt of the problems.

Q Okay. Here's my only question: If you were advocating for allocations, wouldn't one of the arguments you make be that your state is a high growth state, and that, therefore, your electric demand could not be significantly reduced?

A It -- I mean, there's going to be all kinds of political reasons for making allocations.

Q Okay. You modeled the 12 percent renewables up to 20 percent renewables over a period of time; is that correct?

A That's right.

Q Does Florida have a renewable standard at this time that requires a certain percentage of renewables?

A Not that I know of. But again, my assumption is that Florida would step up to the plate and participate. Now, again, to the -- in terms of the function of the forecast itself, it doesn't matter if Florida is at 5 percent and some other state is at another percent. I just applied it generally across the states, which by the way are already at 10 percent.

Q The CO_2 sensitivity analysis does not assume any technology is available to remove CO_2 from standard pulverized coal plants, does it?

A No, it does not.

Q In your analysis in the year 2016, and I'm looking at the numbers that are across the top of the chart, the emissions is $8.89; is that correct?

A You're speaking of what --

Q MP-5, the last one.

A Right.

Q Exhibit 40.

A That would be $8.89 constant 2005 dollars.

Q Yes, sir. And then the very next year it drops to $2.43?

A That's correct.

Q And why do you assume -- what's your explanation for that drop?

A Well, the model itself is balancing 2 million separate variables. So there's lots of things going on in the model. It's balancing all kinds of competing interest. The increase in the cost of coal due to exhaustion and reserves, if there is such a thing, in each individual basin or the demand growth and all of these interests are competing in the model. And it's trying to come up with the best solution.

Now, one of the major inputs into the model is demand -- a gas volume forecast. That was provided by Pace Global as well as the gas prices. And that fluctuates year on year. It does grow from the current volume going forward. And as it's applied in the model, it's -- there is a possibility. I don't know exactly why this is, but I would suspect it's because at this point in time, more gas was made available to the model based on that forecast.

Q Okay. During your deposition, we asked you if

you had done any other CO_2 studies, and you indicated you had done two full-blown CO_2 emission price sensitivity studies; is that correct?

A Full blown in that we published numbers or provided numbers to clients, yes.

Q And I believe you told me one was confidential and one was not; is that right?

A That's right.

Q For the nonconfidential study, what type of company requested the study?

A We -- well, we produced that forecast that was published in our, essentially, public available -- what we call a multiclient study. It would be a study that we would sell multiple copies to anybody who wanted to purchase one. And that --

Q May I stop you? So was that an internally generated study that no one specifically asked for but you internally generated yourself?

A That's right. And before we get -- the purpose of that study was essentially to show that McCain-Lieberman as proposed would wreck the U.S. economy, is essentially what it showed.

Q Okay. And obviously in that study different assumptions were used; is that correct?

A Yes.

Q Okay. And did it produce CO_2 emission allowance costs that were higher than those produced in this exhibit?

A After wrecking the U.S. economy, yes, it did.

Q At the deposition, you stated that those CO_2 emission allowance costs were higher by 5 percent at least; is that correct?

A Yeah. Again, after wrecking the U.S. economy, yes, it was at least 5 percent higher.

Q Well, can you just tell us today what -- how much greater that sensitivity study -- I'm sorry, let me ask this question correctly.

A Well --

Q If I can get my question right. I'm sorry.

A Okay.

Q Can you tell us today how -- what percentage difference, how much greater the CO_2 emission allowance costs were in that multiclient study than the one you've done here?

A Well, insomuch as it's a meaningless number that we couldn't survive it --

Q That's fine. Tell us anyway.

A And I'm trying to -- I'm trying to think what the numbers were. I don't know. At least -- well, perhaps 100 percent.

MS. BROWNLESS: Thank you so much. That's all we have.

CHAIRMAN EDGAR: Ms. Paben?

MS. PABEN: In the interest of efficiency, if Mr. Jacobs could go ahead. I'm going to see if I can deplete a lot of my questions on what Ms. Brownless covered.

CHAIRMAN EDGAR: Thank you. We can do that. If you're ready, Mr. Jacobs.

MR. JACOBS: Yes, Madam Chair.

CROSS-EXAMINATION

BY MR. JACOBS:

Q Good evening, Mr. Preston.

A Good evening.

Q In your -- in your testimony, you -- you reference -- you've done an assessment of each basin where coal is mined and delivered in the country. And you -- in the instance of each basin, you identified various issues and problems that have arisen in that -- in that basin; is that correct?

A Right. In the -- described each basin in the testimony that -- and the issues associated with that as well as using the PRISM^{TM} model which gathers all of those issues and puts them together in an integrated fashion to provide a -- a coherent forecast that

includes all of those issues.

Q Now, your conclusion is that presently or in recent -- recent history, prices of coal have risen to historic levels?

A Yes.

Q And --

A Well, let me preface it. That was back in 2005. Now we're two years away from that point. So, yeah, up to 2005 that's where they were. They're not there now.

Q Do you have an opinion as to how -- how -- what the difference is between 2005 and now?

A Well, I produced this forecast in 2005 when prices were at this historical level. We projected that they would come down by 2007. And I was just looking on -- at some publications in the industry. And the prices we projected are within pennies of what they actually are today.

So the prices have come down about 50 percent for PRB. About -- well, probably about 25 percent or more, just slightly more, for central Appalachian coal. They've gone down maybe 20 percent for Latin American coal.

Q In your testimony, many of the factors that -- that led to those -- to those price increases you

indicated were short-term in duration. Is it your experience that the difference in prices that have occurred is a result of those market imperfections having been corrected?

A Yes, it is. And those historical prices were a confluence of -- it's literally the perfect storm of bad things on both the supply and demand side. It's unlikely that those events, those particular set of events, would occur again in concert with each other.

Q Could you give us an idea of, first of all, the events and then why they wouldn't reoccur?

A Well, there was a -- well, I don't want to lecture too long about this. I can go on for hours. But -- well --

Q Let's talk -- please don't talk about -- let's talk about reduction, the decline in production.

A The decline in production or price?

Q The decline in production.

A Well, beginning in -- throughout the '90s, the market tended to be over supplied. And because it was over supplied, prices were depressed. People -- participants in the market started leaving the marketplace. So you had this sort of natural attrition on supply; coupled with a series of environmental disputes in West Virginia that caused a sort of slow

down in the permitting process of new coal mines which sort of caused delays in the ability to bring on new production; coupled with an aging workforce that was -- that was beginning to retire. And coupled -- that, again, with a sort of change in the lat -- in the attitude of the Chinese as to whether they were going to import or export coal. Couple that with a similar sort of decline in ocean-going vessels.

That, again, they had been over supplied, attrition and supply had led to a short-term shortage. Couple that with a -- with sort of mishandling of transportation, infrastructure issues in Australia. Again, there's a whole litany of events that all occurred at one time that caused a shortage in the market.

So the exports of U.S. coal have been declining severely for years. All of a sudden because of issues in China and Australia, there was a demand for coal from central Appalachian for the export market. Once that -- that took off, that meant a desire for increased demand from central Appalachia. They ran up against the problems of permitting and labor. And those caused a quick escalation in the cost of coal.

Q Just to be real focused on my point, your -- your conclusion that those -- all of those elements are

not cyclical, they are -- they are anecdotal and --

A Right, they're anecdotal. And what -- and the coal industry has this cycle that is very, very long lived, it's about 25 years, in which the market tends to be over supplied and low priced for 25 years and then -- then they have this correction in the market. Our model takes that into account.

If you look closely at these forecasts, you'll see that towards the end of the forecast, prices begin to climb in the expectation that, again, supply will have declined to the point that new investments are going to be made in order to bring on a new supply of coal. So the prices begin to climb at the end of the forecast in real terms, not just in escalation terms.

Q Now, Powder River Basin coal, there is a reason why it is preferred, is there not?

A I wouldn't say -- well, yeah, it's preferred because it's less expensive than a lot of other coal for some people.

Q Is that the only reason?

A Well, each power plant is a -- usually has a SIP limit. That's the allowable rate of emissions of sulfur. And Powder River Basin coal is very low in sulfur. So it allows the plant to burn coal without installing cleanup equipment like such as a wet

scrubber.

Q Let me project then. In the event -- and I'll just cut right to my point. In the event where a company is faced with an enhanced regulation of CO_2, plus having to respond to SO -- SO_X regulation, isn't it a commonplace resort that they try and look at PRB coal?

A A plant with a scrubber would not be beholding the PRB. They would be able to take the cheapest coal that they would calculate based on its impact on their operation of their plant.

Q But if the company were in a position where they had to retrofit, then?

A Yeah. But the TEC plant will be -- it will have all of the scrubbing equipment.

Q So the likelihood then is very low that TEC would want to look at PRB coal?

A It would look -- my understanding of their fuel plant from what I read seems to be excellent, they're going to have the potential to use PRB coal when it is the most optimal fuel price wise and whatever operations, considerations they have.

Q And then my -- my last question is then, should they -- should that happen, would that -- that decision will incorporate -- I think I've heard in

testimony, it will incorporate some infrastructure issues, not just to coal but will incorporate whether they have to do some other infrastructure issues and some operational issues, would it not?

A I believe the preliminary planning -- and that's the stage we're in -- the preliminary planning of the plant is going to have design issues. It will be designed to burn PRB coal if that's what's necessary.

Q Here's the final point: Should -- should there be a carbon regime, carbon regulated regime, isn't it more likely that TEC would look to burn Powder River Basin --

A No.

Q No?

MR. JACOBS: Thank you.

CHAIRMAN EDGAR: Ms. Paben?

MS. PABEN: Madam Chair Person, just a few questions, if I can get my voice.

CROSS-EXAMINATION

BY MS. PABEN:

Q When you were discussing the model to evaluate costs that you-all used with Ms. Brownless, you indicated that that was based on assumption that the demand growth was limited to 1 percent, correct?

A Yes.

Q Okay.

A Except for those areas of the country where it's less.

Q Where it was less, like limited to, not more than. Thank you.

You also indicated that it was based on assumption that states without renewable energy standards including Florida would aggressively shift to carbon-free energy. And I think your estimates were by 2009 12 percent and moving up to 20 percent pretty quickly?

A It moves up at about a half a percent a year, I believe. And again, assuming this theoretical world of carbon constraint, and, in fact, all the bills that I have seen already have a strong renewables and demand side management standards and support in them, I judge that to be a fair estimate of what could happen.

Q And just to clarify that, so beginning in 2009, those states that have none would be at 12 percent?

A As an average across the country. I applied it generally across the states. But from the terms again of how it would impact the forecast, it wouldn't matter if it was lumpy or not because really what it's doing is just decreasing the demand for electricity.

Q But the model assumes 12 percent, correct, beginning in 2009?

A That's right.

Q Also the model also assumes 12 new nuclear plants built before 2020, correct?

A Yes.

Q And the model indicates that nonelectric generating industries would aggressively reduce their carbon dioxide emissions?

A Well, this is -- this is to give a little more credence to the McCain-Lieberman bill. It's -- it's -- in the sense that if we wanted to meet a year 2000 limit, the other industries would have to give up allowances. There's no plausible way the power industry could survive -- well, let's put it this way: The lights would start to go out if we didn't change the functional limit of emission allowances for the power plants.

Q And the model assumes that, correct?

A Assumes what?

Q Let me clarify. The model assumes that aggressive reduction by nonelectric generating industries?

A It only assumes that the functional cap of emission allowance for power plants is increasing as

we've discussed. It starts at 10 percent and then increases by a half a percent a year. It's the functional limit that the model works against. All of those other issues about where those limits come from are a discussion. But from the point of view of the model, it only matters that the functional limit increases.

Q It also states in your testimony, to make sure that I understand this correctly, I'm sorry, that based on the comments that you made with the questions Ms. Brownless was talking about, that the electrical generating utilities would likely get some type of economic relief as part of any regulatory activity associated with McCain-Lieberman?

A The question that that was addressed to, I think that's part of the rebuttal to Ms. Deevey's interrogatory -- or her questions. She suggested that if -- that apparently by benefitting from this reallocation of allowances, there would be some profit that could be -- you know, we'd be sort of supporting some kind of nefarious profit motive for the power plant. And I'm just suggesting that because emitting CO_2 would be a cost, it would be very unlikely that power plants could profit from the cost.

Q Just to be clear, I'm not talking about a

profit from the cost. I'm asking in a -- in the model that you conducted, does that assume any type of relief for your industry?

A Only in the sense that the functional cap of emission allowances is as I stated before.

Q Okay. Thank you.

Are you familiar with other types of -- or other instances of legislation other than McCain-Lieberman Act that have been in draft form and circulated regarding carbon dioxide emissions?

A Yes. In fact, the EIA has released -- just the other day, they released another draft of another potential bill.

Q Is it fair to articulate that some of the draft legislation that's been out there has been more restrictive on the electric utility industry than the McCain-Lieberman Act, some, not all?

A I can't give those credence. I mean, it's fair to say that they're Draconian in their efforts to cap emissions from EGUs. I can't believe that they -- they just -- they'll -- the lights will go out.

Q And last question. The assumptions that you indicated with Ms. Brownless as well as you did here with respect to the states increasing renewable energy, the 12 new nuclear plants, the limitations on growth to

1 percent, all of those actually have to take place for the model to evaluate costs that you did, yes or no answer, to be accurate, correct?

A Yes, or the lights will go out.

MS. PABEN: Thank you.

CHAIRMAN EDGAR: Other questions from staff?

MS. FLEMING: Staff has no questions.

CHAIRMAN EDGAR: Mr. Perko?

MR. PERKO: Thank you, Madam Chairman.

REDIRECT EXAMINATION

BY MR. PERKO:

Q Mr. Preston, Ms. Brownless and again Ms. Paben asked you a number of questions concerning some of your exceptions in the CO_2 allowance forecast, and you mentioned that there have been some other forecasts made by others. Are you aware of any other forecasters -- fuel and allowance forecasters who have created CO_2 allowance forecasts with assumptions of limited demand growth?

A Yes, I have.

Q And how do those assumptions generally compare to yours?

A They are very comparable.

Q And likewise, have other forecasters of CO_2 allowance prices made assumptions about increased

renewable and efficiency efforts?

A Yes, they do.

Q And how have those assumptions generally compared to your assumptions?

A They're also very comparable.

Q And have CO_2 allowance forecasters similarly assumed that there would be increased -- there would be an increase in nuclear generation in the fairly short-term?

A Yes. Most forecasts, notably the EIA, expects much more nuclear energy to be developed.

Q Now, Ms. Paben asked you some questions regarding a number of different forecasts developed on various drafted CO_2 legislations. Are those compiled in a Synapse report that's been attached to Ms. Deevey's testimony?

A Yes, they have.

Q And does Synapse provide an indication of what they -- of potential CO_2 costs?

A Well, they have gathered the existing literature. And without -- other than -- other than sort of a commentary on them, they've grouped them into categories and sort of come up with a high level of --

MS. PABEN: Excuse me, Madam Chairman.

CHAIRMAN EDGAR: Just a moment. Ms. Paben?

MS. PABEN: Yes. I'd like to object to the question. I think it's beyond the scope. He's actually characterizing a question I did not ask at all. And I believe he's actually using it to supplement his testimony. I didn't ask about forecasts.

MR. PERKO: She asked about the other legislation. I'm asking about how those were analyzed.

MS. PABEN: The question was asked specifically if he's familiar with the legislation and whether they're more stringent on the utilities. That's it. He's asked about forecasts beyond the legislation and indicated that's what I had asked. And that's a much further extrapolation, and I was not trying to go down that road at all, nor did I.

CHAIRMAN EDGAR: Mr. Perko?

MR. PERKO: I'm trying to get the record straight on these other forecasts that he's referring to.

MS. PABEN: I never mentioned any forecast in any of my questions. I simply was --

MR. PERKO: And the legislation that she mentioned.

MS. PABEN: I didn't --

CHAIRMAN EDGAR: Okay. Let's -- do you want to try and rephrase?

BY MR. PERKO:

Q Ms. Paben mentioned a number of different legislative analyses. Do you recall that questioning?

A Yes.

Q And have various forecasts been made based on assumptions based on those various legislative forecasts?

A Yes. The EIA and others have produced forecasts based on those assumptions.

Q And has a company named Synapse reviewed those in a report that's attached to Ms. Deevey's testimony?

A Yes, they have.

Q And does Synapse provide a general indication of what they feel to be potential CO_2 allowance prices?

A Again, they grouped them and categorized them and came up with what they thought was a low case, a mid case and a high case for allowances.

Q And how do your allowance price forecasts compare to those presented by Synapse?

A It fell somewhere -- it fell between the mid case and the low case on a levelized cost basis.

MR. PERKO: Thank you. No further questions.

MS. BROWNLESS: Your Honor, if we may have just one brief recross, because this is an area, the forecast, which Mr. Preston did not address.

CHAIRMAN EDGAR: I'm just not going to go there. I'm just not. So...

MS. BROWNLESS: I appreciate it. Thank you.

CHAIRMAN EDGAR: Let's do the exhibits -- oh, excuse me. Commissioner Tew.

COMMISSIONER TEW: Mr. Preston, I have a few questions with the chairman's indulgence particularly about wrecking the U.S. economy. Got my attention a little bit even at this late hour.

I think you indicated given certain CO_2 regulations that it could have impacts on the gas markets such as that the lights could go out; is that correct?

THE WITNESS: Well, the lights going out is -- well, they literally could. What happens is if you limit CO_2, you're going to shift away from coal-fired generation to gas-fired generation. You're going to increase the demand for gas. There's a limited amount of gas. At some point you either have to decide whether you're going to burn gas or you're going to meet the CO_2 cap. If you want to meet the CO_2 cap, you stop burning gas,

there's not enough electricity.

COMMISSIONER TEW: And to follow up on that, are the impacts on the gas market as a result of the CO_2 regulations that you were talking about, is that the basis for the statement wrecking the U.S. economy, or is there more to it than that?

THE WITNESS: Well, that's the biggest piece. But a legislation like this, this broad reaching is bound to have unintended consequences. For instance, just like when we had the oil embargo, everybody started burning wood. Well, when everybody start burning wood, now you had pollution problems of a different sort. This is -- those are the kinds of things that are going to happen when this legislation, if -- I mean, again, it's -- I think there are so many competing interests that I'm concerned that there's -- that there's even a possibility it could be done on a national level.

So given -- given all of these unintended consequences, there could be other things that will -- that will pop up that could cause, you know, minor catastrophes.

COMMISSIONER TEW: Is there some certain version of that bill -- I've heard discussion about different versions and drafts of these bills and I

know nothing has been passed. Is there some certain version you submit would have the effect, or is it any versions of that same bill?

THE WITNESS: Well, I think of the many competing versions, the ones that try to revert the cap from roughly the 2010 level backwards are going to have the biggest issues. So that would be anyone that's trying to set the cap at year 2000 levels or 1990 levels or those kinds of issues.

The bills that seem to address this issue best though are the ones that -- that have a phased-in approach. They start with a later year in terms of the cap. They -- they have safety valves and safety triggers so that they -- so that essentially the electric utility industry and the lights stay on more or less. The one released just recently, the EIA's analysis of it, is a good example of that particular type of legislation.

COMMISSIONER TEW: I was going to ask you, were there more reasonable -- in your view, more reasonable proposals before Congress in respect to CO_2?

THE WITNESS: Yeah. I haven't reviewed all of it. But the analysis I saw from EIA -- it's called the Bingaman, Landrieu, Lugar and Murkowski's

bill -- it seems to give in my mind the most -- be the most appropriate that I've seen so far because it addresses many of these issues that -- that -- that I believe are -- are -- would prevent any kind of legislation.

COMMISSIONER TEW: Okay. And I'm getting there, Chairman. I have got a couple more.

Can you remind me how the sensitivities you ran with respect to CO_2, including congressional proposals such as McCain-Lieberman, did it only include McCain-Lieberman? I think as you've described, I understand that you sort of adjusted the McCain-Lieberman proposal.

THE WITNESS: McCain-Lieberman was only used because it had some of the issues in terms of trading allowances and such that I thought it was useful. The modifications are very important that I made to that in terms of what would be a plausible future case. And those modifications by the way are very similar to the modifications you'll see -- not modifications, but those other bills I was talking about, the more reasonable bills.

COMMISSIONER TEW: So would it -- so would it be correct to say that you used somewhat of a

middle of the road version of CO_2 proposals?

THE WITNESS: Well, I developed this case based on my best estimate, my professional estimate, of what the world could look like. It turned out to be in the middle of the road.

COMMISSIONER TEW: Okay. I have one more, Chairman.

In some of the questioning, something came up about renewable standards. In the bills that you've referred in preparing your analysis, did those bills also include renewable portfolio standards or were there some that did and some that didn't?

THE WITNESS: I can't say for sure whether they had actual standards that required people. But I think most -- all of them have some -- they address it in some issue. They'll either provide monies to develop renewable standards or to enhance renewable standards or to provide subsidies to renewable industries. I don't believe it went so far as to establish -- well, some of them might. I don't recall any that went so far as to establish renewable standards by state or region.

COMMISSIONER TEW: Thank you. That's all.

CHAIRMAN EDGAR: Okay.

MR. PERKO: At this time, Madam Chairman, we'd move Exhibits 36 through 42 into the record.

CHAIRMAN EDGAR: Okay. Seeing no objection, Exhibits 36 through 42 will be entered into the record and the witness is excused. Thank you.

(Exhibits No. 36, 37, 38, 39, 40, 41 and 42 admitted into the record.)

MR. PERKO: We call Chris Klausner.

CHRISTOPHER KLAUSNER

was called as a witness on behalf of the Applicant, and having been duly sworn, testifies as follows:

DIRECT EXAMINATION

BY MR. PERKO:

Q Could you please state your name and business address for the record.

A Chris Klausner. My business address is 11401 Lamar Avenue, Overland Park, Kansas, 66211.

Q Excuse me, while I shovel some paper here.

Mr. Klausner, did you file prefiled direct testimony on -- consisting of 12 pages on September 19th, 2006?

A Yes.

Q And do you have any changes or additions to that testimony?

A No, I do not.

Q If I were to ask you the questions in that testimony today, would the answers be the same?

A Yes.

Q Are you sponsoring any sections of the Need for Power Application that's been identified as Exhibit -- or in Exhibit 58?

A I'm sponsoring Section A.6.2.

Q Are there any changes or additions to that section, other than what's revealed on the errata sheet that's been admitted into evidence? I'm sorry. That was Exhibit 54 for your Section A.6.2; is that correct?

A Yes. A.6.2 is the one that I'm sponsoring.

Q Other than any changes indicated on the errata sheet that's been admitted into evidence as Exhibit 3, are there any additional changes to that section?

A Yes. On Table A.6-37 for the three 1x1 train IGCC option, the EPC cost should be 1808.2. The owner's cost should be 542.4. The total cost should be 2350.6, and the total cost dollars per kW should be 2720.6.

Q Could you please explain why you made those changes?

A They were just presented in the table incorrectly.

Q Thank you.

With those additions, are those the only

additions or changes to your Exhibit A.6.2?

A Yes, other than those identified on the errata sheet.

Q Now, Mr. Klausner, did you also submit supplemental testimony consisting of four pages on December 26, 2006?

A Yes.

Q Do you have any changes or additions to that testimony?

A No, I do not.

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

A Yes.

MR. PERKO: At this time, Madam Chairman, I would move Mr. Klausner's prefiled direct testimony of September 19, 2006, and his supplemental testimony of December 26, 2006, into the record as if read.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF CHRIS J. KLAUSNER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Chris Klausner. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

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

A. I am employed by Black & Veatch Corporation. My current position is Senior Consultant/Project Manager in the Enterprise Management Solutions Division.

Q. Please describe your responsibilities in that position.

A. As a senior consultant and project manager, I am responsible for the management of various projects for utility and non-utility clients. These projects encompass a wide variety of consulting services for the power industry. The services include development of generating unit alternatives, screening

evaluations, analysis of production cost simulations and optimal generation expansion modeling, economic and financial evaluation, sensitivity analysis, risk analysis, power purchase and sales evaluation, feasibility studies, qualifying facility and independent power producer evaluations, independent engineering assessments for lenders, and power plant financing evaluations.

Q. Please describe Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering, consulting, and management services to utility, industrial, and governmental clients since 1915. Black & Veatch specializes in engineering, consulting, and construction associated with utility services including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, rate and financial reports, appraisals, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of Kansas. I have a Master of Business Administration with a concentration in finance from the University of Kansas. I am also a licensed professional engineer in the State of Kansas.

I have over 15 years of experience in the power industry specializing in generation design, feasibility analysis, planning, due diligence, independent engineering, and project development. In the past few years, I have been the project manager for nine projects. In addition, I have participated in the development of three Need for Power applications that have been filed on behalf of Florida utilities, and have testified previously before the Florida Public Service Commission. I also have been engaged in integrated resource planning and power supply studies for electric utilities. Florida utilities for which I have worked include Florida Municipal Power Agency (FMPA), JEA, Orlando Utilities Commission (OUC), Reedy Creek Improvement District (RCID), and the City of Tallahassee (the City). I have participated in more than 30 feasibility study and independent engineering assignments that have required assessment of simple cycle, combined cycle, circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), wind, biomass, and other power generation technologies. These assignments have involved development, review, and analysis of generating technology performance characteristics, operation and maintenance (O&M) costs, capital cost, reliability, and emissions rates.

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

A. The purpose of my testimony is to provide an overview and summary of the conventional and emerging supply-side alternatives. I will discuss the numerous supply side alternatives that were considered in the economic analyses conducted in determining that the Taylor Energy Center (TEC) is part of the

least-cost capacity expansion plans for FMPA, JEA, RCID, and the City (collectively referred to as the Participants).

Q. Are you sponsoring any exhibits as part of your pre-filed testimony?

A. Yes. I am sponsoring Exhibit __ [CK-1], which is a copy of my résumé, and Exhibit __ [CK-2], entitled "Generating Unit Alternatives for Selected Sites." These exhibits are attached to and included in my pre-filed testimony.

Q. Are you sponsoring any sections of Exhibit __ [TEC-1], the Taylor Energy Center Need for Power Application?

A. Yes. I am sponsoring Section A.6.2, which was prepared by me or under my direct supervision.

Q. What are emerging technologies?

A. Emerging technologies are those technologies that are not yet considered conventional because of poor reliability, lack of demonstrated performance, or political/regulatory impediments. Over time, it is expected that these emerging technologies will become conventional.

Q. What emerging technologies were evaluated?

A. Emerging technologies considered include IGCC, the General Electric (GE) LMS100 combustion turbine (CT), and nuclear fission. IGCC is considered emerging because of poor initial reliability and because units operating in the United States have thus far required government subsidies. The GE LMS100 is

a new CT model that has only recently entered commercial service and lacks sufficient operating experience and hours to be considered a conventional unit. Although there are over 100 nuclear plants operating in the United States, and more worldwide, a new nuclear unit has not been constructed in over 20 years, and the next generation of nuclear units will utilize new designs. Therefore, these technologies have been considered emerging.

Q. When were these emerging technologies assumed to be available for commercial operation as conventional units?

A. The GE LMS100 was assumed to be available in 2011. The LMS100 began operation in 2006. The 2011 date is based on 3 years of demonstrated performance, 1 year of licensing, and 1 year of construction for a new unit. The IGCC was assumed to be available in 2018. New IGCC units such as the proposed Stanton B demonstration unit for OUC are scheduled to begin operation in 2010. The 2018 date is based on 3 years of demonstrated performance by such units, followed by 2 years of licensing and 3 years of construction for a new unit. Nuclear units were not considered in the economic evaluations because they are too large for the Participants to consider by themselves, and the commercial availability of the next generation of nuclear units is expected to be well beyond the initial and near-term capacity requirements for the Participants.

Q. What conventional and emerging supply-side alternatives were considered?

A. As TEC includes multiple Participants, conventional and emerging supply-side alternatives included competing joint development alternatives, individual Participant options at existing sites, and individual greenfield Participant options. Including joint development options and options specific to each Participant provides a broad range of alternatives for consideration.

Joint development options included a three train 1x1 General Electric (GE) 7FB IGCC, and a 3x1 GE 7FA combined cycle alternative. Existing site individual options included simple cycle turbines (GE LM6000, GE LMS100, GE 7EA, and GE 7FA), GE LM6000 and GE 7FA 1x1 combined cycle alternatives, 250 MW CFB alternatives, and 1x1 GE 7FB IGCC alternatives. Greenfield individual Participant options included simple cycle turbines (GE LM6000, GE LMS100, GE 7EA, and GE7FA), GE 7FA 1x1 combined cycle alternatives, 250 MW CFB alternatives, and 1x1 GE 7FB IGCC alternatives. The conventional and emerging supply-side alternatives represent a wide range of technologies, plant sizes, and fuel types, and thus provide a mix of potential peaking, intermediate, and baseload generation alternatives. Exhibit __ [CK-2] summarizes the supply-side alternatives evaluated for the Participants.

Q. Was a 501G combined cycle self-build alternative evaluated?

A. No. A combined cycle based on the 501G gas turbine technology was not evaluated as a potential self-build alternative to TEC for this application, although this technology is considered viable. A 2x1 501G combined cycle

would offer a total capacity similar to the 3x1 GE 7FA combined cycle alternative. When in combined cycle, the 501G offers similar output levels to a 3x1 GE 7FA with about 3 to 4 percent improvement in heat rate. Each gas turbine unit offers more output and, therefore, fewer units are required. The 501G 2x1 combined cycle base power island consisting of the gas turbines, heat recovery steam generators (HRSGs), and steam turbine has a similar cost in comparison to a comparable size 3x1 GE 7FA combined cycle. More extensive pollution control equipment would be required for the 501G because of its higher gas turbine emissions rates. Other site-specific factors will affect the overall total cost of 501G alternatives as well. Given the small heat rate differential and comparable cost, the 3x1 7FA combined cycle is considered a similar alternative to a 2x1 501G combined cycle for purposes of the supply-side alternatives analysis. The slight improvement in efficiency offered by the 501G would not change the results of the economic evaluations. Moreover, since the Southern Power Company's response to the Participants' request for proposals (RFP) included a 501G combined cycle alternative, this technology was in fact evaluated as an alternative to participation in TEC for each Participant.

Q. Please describe the methodology used to develop the capital costs of the conventional and emerging supply-side alternatives?

A. In developing the cost and performance estimates, a specific manufacturer (General Electric) and specific models were analyzed for simple and combined cycle alternatives. These alternatives were evaluated, not to indicate a preference to a specific manufacturer, but rather to generalize the properties of

similar generating technologies with similar attributes. Capital costs were developed using direct and indirect costs, with an allowance for Owners' costs. General assumptions, site-specific assumptions for individual Participant options, as well as assumptions for direct and indirect costs are presented in Section A.6.2 of Exhibit __ [TEC-1]. Potential Owner's cost items are presented in Table A.6-14 of the same exhibit. Fixed and variable O&M cost estimates were developed for each of the conventional and emerging alternatives. Performance estimates for output and heat rate were also developed at various ambient conditions and load points. Degradation was included in the output and heat rate performance estimates. The construction and development period for the conventional and emerging alternatives also was estimated.

Q. How are self-build conventional alternatives different than emerging technologies?

A. Conventional technologies are those technologies that are currently considered commercially proven and do not face the same challenges as emerging technologies, such as poor reliability, lack of demonstrated performance, or political/regulatory impediments. As discussed previously in my testimony, emerging technologies are anticipated to be available in the future as reliable generating resources.

Q. How were self-build conventional alternatives selected for each Participant?

A. Alternatives were selected based on each Participant's system size, availability of existing sites to support additional generation without substantial improvements to site infrastructure, and each Participant's operating experience with specific technologies and desire to solely own and operate certain types of generation. Although all generation alternatives were not evaluated for all Participants, the evaluations included sole ownership or joint participation in at least one solid fuel pulverized coal (TEC) or CFB, IGCC, and combined cycle for each Participant. In addition, simple cycle alternatives were evaluated for all Participants, except for RCID. As a result, a wide range of peaking, intermediate, baseload, and fuel types were considered.

Q. What fuel types were considered for the conventional alternatives?

A. Depending on the alternative, various fuel types were considered. The simple cycle CT alternatives were assumed to burn natural gas as the primary fuel with ultra-low sulfur fuel oil as a backup fuel. Dual fuel capability was assumed because it is cost prohibitive to obtain firm natural gas transportation for simple cycle units and because of the potential supply disruptions related to interruptible gas transportation. The combined cycle alternatives were also assumed to fire natural gas as the primary fuel with ultra-low sulfur fuel oil as backup. Firm natural gas transportation was assumed for the combined cycle alternatives as described in the testimony of Bradley Kushner.

The City of Tallahassee and FMPA IGCC considered self-build options assumed to burn bituminous coal, while the joint development and JEA self-build IGCC options were assumed to burn petroleum coke. The CFB options for the City of Tallahassee and FMPA were assumed to burn bituminous coal, while the JEA CFB existing site options were assumed to burn a blend of 80 percent petroleum coke and 20 percent bituminous coal. JEA's solid fuel alternatives at existing sites were assumed to utilize petroleum coke as these sites currently have barge delivery access. Greenfield site CFB options for JEA were assumed to burn bituminous coal since barge delivery access may not be available for a new generation site.

Q. Please describe the range of capacity sizes considered.

A. The simple cycle CTs range in capacity from approximately 47 MW to approximately 160 MW. The combined cycle alternatives were assumed to be approximately 59 MW for the 1x1 GE LM6000 alternative, 299 MW for the self-build 1x1 GE 7FA options, and 907 MW for the 3x1 joint participation alternative. The CFB alternatives were assumed to be approximately 250 MW. IGCC options ranged from 288 MW for 1x1 alternatives to 864 MW for the three 1x1 train alternative.

Q. Are the capital costs for these alternatives inclusive of all expected costs?

A. Yes. The capital costs include the engineer, procure, and construction (EPC) costs plus an allowance for owner's costs, or costs that are not included in the EPC capital cost estimates. Although in Black & Veatch's experience owner's

costs can vary significantly from project to project, a representative amount was added to the capital costs for each alternative. The capital costs are exclusive of escalation, financing fees, and interest during construction. These costs were calculated and included separately during the economic modeling process.

Q. Were any new greenfield alternatives considered?

A. Yes. Although greenfield alternatives generally will be more expensive in comparison to building at an existing site, these were considered.

Q. What existing generation sites were considered for placement of supply-side alternatives?

A. Existing generation sites, which can provide reduced capital costs through sharing of existing infrastructure, were considered as available for each Participant. The available sites are summarized in Exhibit __ [CK-2] attached to my testimony.

Q. Please describe the methodology used to develop the operating cost and performance characteristics of the conventional and emerging supply-side alternatives?

A. As with the capital cost estimates, in developing the cost and performance estimates, a specific manufacturer (GE) and specific models were analyzed for simple cycle, combined cycle, and IGCC options. These alternatives were evaluated not to indicate a preference to a specific manufacturer, but rather to

generalize the properties of similar generating technologies with similar attributes.

Performance estimates for output and heat rate were also developed taking into account output and heat rate performance degradation. Fixed and variable O&M cost estimates were developed for each of the conventional alternatives. Availability estimates were derived from estimated scheduled maintenance requirements and forced outage rates for each alternative. The construction and development period for each of the conventional alternatives also was estimated.

Q. Were any other supply-side alternatives considered in addition to the conventional and emerging technologies?

A. Yes. Cost and performance estimates were developed for renewable, emerging, advanced, energy storage, and distributed generation technologies. Renewable, advanced, energy storage, and distributed generation technologies are discussed in the testimony of Ryan Pletka.

Q. Does this conclude your pre-filed testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF CHRIS J. KLAUSNER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. 060635

DECEMBER 26, 2006

Q. Please state your name and business address.

A. My name is Chris J. Klausner. My business mailing address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

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

A. I am employed by Black & Veatch Corporation. My current position is Senior Consultant/Project Manager.

Q. Have you previously submitted testimony in this proceeding?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my testimony is to provide updated capital cost estimates for the supply-side alternatives considered in the TEC Need for Power Application, Exhibit No.__ (TEC-1).

Q. Have there been any market changes that would impact the capital cost estimates used for the available alternatives?

A. Yes. Certain market impacts on the costs of major equipment, commodities, and labor have occurred that would increase the capital cost estimates for the available alternatives.

Q. Are you familiar with the updated capital cost estimate for TEC discussed in the supplemental testimony of Paul Hoornaert?

A. Yes. I have reviewed the updated capital cost estimate for TEC.

Q. By how much did the capital cost estimate increase for TEC?

A. As stated in Mr. Hoornaert's supplemental testimony, the increase is approximately 19 percent.

Q. By how much do you estimate the capital costs for the coal-fired alternatives presented in the TEC Need for Power have increased?

A. Based on my independent analysis, I estimate that the costs of the coal-fired alternatives presented in the Need for Power Application have increased by approximately 20 percent. This is because market influences that have led to the updated capital cost estimate for TEC, a supercritical pulverized coal unit, are

similar to those that would be expected to impact the coal-fired alternatives in the TEC Need for Power Application since these alternatives utilize relatively the same proportions of commodities such as steel and concrete, construction labor, and pollution control equipment and other equipment unique to coal fired units such as chimneys.

Q. Would the estimated change in the capital cost estimates for coal fired generation be the same as for natural gas fired generation?

A. No. Natural gas fired generation would be subject to some degree of capital cost increases associated with major equipment and labor, similar to the coal fired alternatives. However, the impact on the capital cost estimates for coal fired alternatives would likely be more pronounced than for natural gas fired generation. The estimated percentage increase in the capital cost of natural gas fired generation alternatives from that in the Need for Power Application is approximately 12 percent. The lower percentage increase in the capital cost for natural gas fired generation alternatives compared to coal fired alternatives is due to the fact that there are proportionally less commodities such as concrete and steel in natural gas fired generation compared to coal generation as well as proportionally less construction labor required. Also costs for major engineered equipment such as combustion turbines for natural gas fired generation are not increasing as fast as the major engineered equipment for coal units. Furthermore cost increases for pollution control equipment would be less for natural gas fired generation than for coal units.

Q. Is it unusual for capital costs to change over time?

A. No. Capital costs for generating alternatives are subject to change based on changing prices for equipment, labor, commodities and other items. Fundamental supply and demand forces will affect capital costs for generating alternatives.

Q. Does this conclude your testimony?

A. Yes.

BY MR. PERKO:

Q Mr. Klausner, have you prepared a summary of your prefiled direct and supplemental testimonies?

A Yes.

Q Could you please provide that at this time?

A The purpose of my testimony is to provide an overview and summary of conventional and emerging supply-side alternatives that were considered in the economic analyses for the Taylor Energy Center. The conventional and emerging supply-side alternatives included both individual and joint options at both new and existing sites.

The conventional and emerging supply-side alternatives represent a wide range of technologies, plant sizes and fuel types and thus provide a mix of potential peaking, intermediate and base load generating alternatives. I developed capital costs, O&M costs, performance estimates for each alternative.

Consistent with Mr. Hoornaert's supplemental testimony, my supplemental testimony provides undated costs for all conventional, emerging supply-side alternatives. My evaluations included solid fuel, IGCC and natural gas combined cycle units for each applicant.

Because I considered both joint and individual supply-side alternatives for each applicant at both new

and existing sites and a cross-section of technology, sizes and fuels, a broad range of options were included in my evaluation.

That concludes my summary.

MR. PERKO: We tender the witness for cross-examination -- oh, I guess we do. Thank you. Getting late.

CHAIRMAN EDGAR: Ms. Brownless?

CROSS-EXAMINATION

BY MS. BROWNLESS:

Q Hey, Mr. Klausner, how are you?

A I'm doing well.

Q Did you provide the response to Interrogatory No. 1 in NRDC's first set of interrogatories No. 1 through 26?

A Yes.

Q And is that true and correct to the best of your knowledge and belief?

A Is it true and correct to the best of my knowledge?

Q And belief, yes.

A Yes.

Q Okay.

A With the exception that the three train 1x1 GE IGCC, those costs as I updated earlier, those may not be

correct. I don't have those in front of me, but they would be adjusted based on the testimony I provided previously.

Q Okay. And because it's late, if you can just -- that's the table. If you can just tell me which one you think needs to be adjusted. You don't have to give me the numbers. Just tell me on this chart where I look to see what needs to be adjusted.

A Three train 1x1 GE IGCC, the EPC cost through the total cost, dollars per kW, 2096.9 through 3433.4.

Q Oh, I see.

A I have -- those may potentially need to be adjusted as well based on my previous comments.

Q And just so I know I'm in the right place, that's under joint ownership options, the second joint ownership options?

A Yes.

Q Now, you developed the self-build options as alternatives to the construction of TEC; is that correct?

A Yes. Those were prepared under my direct supervision.

Q Okay. And you developed self-build options for the individual participants here, some of which included plants they could construct totally owned by

themselves and some of which included plants that they could own jointly with other members?

A That's correct.

Q And IGCC units were considered for Tallahassee, FMPA and JEA, is that right, either individually or jointly?

A I believe so. IGCC was considered for all applicants because it was a joint option.

Q So that also included Reedy Creek?

A That particular option, yes.

Q Okay. Is that the only scenario as a self-build that IGCC was considered as? In other words, no individual utility -- did you consider for any single individual utility an IGCC? Because I thought you did. I mean, when I looked at your --

A Yes. As shown on that table, there was one for JEA, there was one for FMPA --

Q Okay.

A -- and there was one for Tallahassee.

Q All right. So you had one IGCC which was a joint?

A Correct.

Q And one that was individually sited for those three. And Reedy Creek was not a person for whom there was an individual IGCC proposed?

A That's correct.

Q Okay. Thank you.

Now, did you consider an IGCC to be available only after 2018 or as a self-build option in 2012?

A I believe that's addressed in the application, but I think the 2018 date is when we consider those available. Brad Kushner could confirm that.

Q All right. Do IGCC units allow for CO_2 capture and sequestration at this time? Is the technology currently available?

A Can you repeat the question?

Q Is the technology currently available to allow IGCC units to capture and sequester CO_2?

A The capture of CO_2 is an emerging type technology. It is not demonstrated on any large scale project, power plant project. That would be IGCC pulverized coal, gas-fired combined cycle. The capture of CO_2 is -- is often done in process type applications which are much smaller.

Q Okay. But I guess my question was, so there is technology currently in use doing this?

A In use doing -- on an IGCC plant?

Q Yes.

A No.

Q There are no projects on an IGCC plant of any

size that are capturing and sequestering CO_2?

A As long as you say IGCC, the answer is no.

Q Okay. In your testimony, you state that -- I'm sorry. Are you aware of capture and sequestration of CO_2 in North Dakota, a gasified unit that's not an IGCC?

A Yes, I'm aware of that.

Q So there is technology available to capture and sequester CO_2?

A I believe I stated there is technology. It's not demonstrated on large scale power plant applications.

Q Thank you.

On page 5 of your testimony, I think you indicate that new nuclear -- a new nuclear unit has not come on line in the last 20 years, and that you consider nuclear units to be, for that reason, an emerging technology; is that correct?

A The reason that nuclear units are considered an emerging technology is because although there are numerous nuclear plants in the United States and around the world in operation, the next generation of nuclear plants is going to have -- is currently going through a permitting and approval process and they'll use new designs. And so there is some regulatory and approval

risk with getting those types of plants permitted and getting new designs approved. So for -- for the purposes of our study, we considered nuclear and emerging technology.

Q When will you consider the new generation of nuclear units to be an established technology with demonstrated reliability?

A I don't know exactly when nuclear units would be available. There's a lot of speculation on how -- how long the overall permitting process would take and the approval process. But probably not before 2020. No earlier than that, I would say. They probably wouldn't be available.

Q Mr. Preston estimated, as we've just heard him testify, that there be there would be 12 nuclear power plants operational and on line between 2016 and 2020. In light of what you said, does that estimate seem plausible to you?

A The -- it's -- it's plausible simply because there's no -- if you look at the construction cycle of a nuclear plant, you're probably looking at six to seven years. It's possible that if the approvals are obtained in the next three to four years, that -- that we could probably have those -- that many units on line.

Q And would you consider those units to be

established technology with demonstrated reliability?

A I believe they will be established technology. There's -- the changes that are being made in the technology and nuclear is getting a little beyond my expertise.

Q Sure.

A But they're not significant enough that you would expect that there would be significant challenges with the operation of those units. The main issue with nuclear is getting those approved.

Q Okay. So if I'm hearing you correctly, you've told me that the new generation of nucs would not be -- you would not consider them to be an established technology with demonstrated reliability until 2020 and yet you believe it plausible to have 12 nuclear power plants come on line by 2020?

A Well, I think I would like to clarify that the 2020 date was what is -- is a rough estimate, but I think it's plausible that you could have -- what was the number, 10, 11?

Q Twelve.

A Twelve nuclear plants on line by -- what was the date again?

Q 2020.

A By 2020? I think that's plausible.

Q But their demonstrated reliability might be at issue; is that correct?

A I think I mentioned that the main issue with nuclear is getting the regulatory and permitting approvals, not necessarily the demonstrated reliability.

Q Okay. Looking at your supplemental testimony, did you include -- did you assume that IGCC costs would increase by 20 percent as well as those of the supercritical pulverized coal plants when you were talking about capital cost changes?

A Yes, I did not estimate supercritical pulverized coal, but I did assume that IGCC would increase approximately 20 percent.

Q Okay. So to the same degree as a pulverized coal plant?

A Yes. And judging by recent press releases, I think that's conservative because AEP has indicated that the differential between pulverized coal and IGCC is where they had previously thought it would be 20 percent differential in capital CAMR costs, now they're getting feedback that it's going to be substantially more than that.

Q And is that the new generation of IGCC plants?

A Yes. So that would make our assumption favorable to IGCC.

Q Okay. Mr. Rollins testified that the operating TECO IGCC unit had an availability of approximately 74 percent. Would you consider the operating TECO unit to be old IGCC technology?

A I would like to clarify one thing. The -- the availability that Myron mentioned was a five-year availability. The actual availability since commercial operation is approximately 69 percent.

Q And that's ten years. What's happened in the last two years?

A I don't have current data for 2006, but it's in the 80 -- 80 percent range.

Q Would you predict that for the new generation of IGCC technology, the availability factors would be higher?

A I would say not. They will not be higher than what's been demonstrated especially in the short run. I think any IGCC plant, because they are so complicated, is going to have a startup curve where the availability is initially, you know, 30, 40 percent and it gradually builds up over a five- or six-year time frame until you get to an availability that is higher and more in line with what you would hope to get.

But I don't think IGCC will -- because it is so complicated, it may never get to the availabilities

that are demonstrated by supercritical coal units.

Q But obviously Tampa Electric has a ten-year-old IGCC plant that's putting out an 88 percent availability factor and that's comparable with the supercritical coal unit, is it not?

A No, it's putting out -- if you look at maybe one or two years, the availability is at 80 -- 81, 82 percent when operating the gas fires, which is substantially lower than 90 percent which you can achieve with a supercritical pulverized coal unit.

Q Do plants in Europe and Japan currently operating IGCC plants have a higher availability than that?

A Can you repeat that, please.

Q Do IGCC plants in Europe and Japan have a higher availability than that 88 percent?

A I'm not familiar with every IGCC plant in the rest of the world, but there are some that are operating at higher availabilities but those do not fire petroleum coke or coal. They're not solid fuel-fired gasification plants.

MS. BROWNLESS: Thank you, Mr. Klausner.

CHAIRMAN EDGAR: Mr. Paben?

MR. PABEN: No questions for this witness.

MR. JACOBS: Very briefly.

CROSS-EXAMINATION

BY MR. JACOBS:

Q Hello, Mr. Klausner. You described with regards to the nuclear as emerging some factors that qualify that. Do any of those factors apply to the supercritical pulverized coal plants?

A I don't think so.

Q So there are no issues with regard to their heat race -- sup -- the new generation of supercritical pulverized plants, there's no issues with regard to them achieving availability standards, heat rating standards and reliability standards?

A Not the current generation of supercritical coal units, no.

Q Are there any new current generation plants that are operating in the U.S.?

A I'm not familiar with all of the units. I'm not sure when the last supercritical unit was built in the U.S.

Q Okay. One -- one -- one additional point.

(Telephonic interruption.)

MR. JACOBS: Not that one. I had it on silent and my wife figured out how to get it to ring. I don't know how she did that. I lost my total concentration.

(Laughter.)

CHAIRMAN EDGAR: Take a moment.

BY MR. JACOBS:

Q The -- the -- so the whole idea in your testimony of what is emerging and what's not is my point. Your conclusion is that pulverized supercritical coal plants are not emerging and you determined that IGCC, it sounds like, the new generation nuclear are emerging technologies?

A That's correct. I mean, if -- if nuclear can get through the regulatory and permitting processes, then I think those will be -- those will be built and constructed. The -- you know, that's the main hurdle to nuclear right now.

Q Okay. I think there was one other question I have. In -- in -- in your -- in your -- in your testimony, you looked at the whole idea of capital costs. And I believe you came -- you came to the opinion that the assumptions that had been made as relates to the volatility of capital costs are correct, and, therefore, that the new level of capital costs are stable?

A There is some indication in the markets that there will be stabilizing -- recent indications that pricing will be stabilizing. If you look at copper,

which is a -- a commodity that's used throughout power generation projects for electrical equipment, copper has seen substantial declines in price recently. So there are some factors that are causing capital costs to stabilize.

Q Now, it's my understanding that some of the more prevailing factors in causing the capital costs to fluctuate are labor costs?

A That's correct.

Q Material cost? I guess copper would be one of those. And I guess other support, construction. And one of the reasons that those costs are escalating is because of the -- we'll call it the rush to build new coal plants?

A Right.

Q Is it your view that -- that that -- that new high activity in building of coal plants is going to -- is going to decline?

A The rush to build coal plants is showing some signs of moderating as well. My company is seeing that clients that had evaluated building coal-fired power plants are holding off on committing to those because of the pricing. So there are factors that could potentially moderate prices going forward.

And I think if you look back at the recent

build out of combined cycles, once the demand let up, the price on combined cycle price -- combined cycle plants dropped significantly. So it's -- it's -- there are stabilizing factors starting to emerge.

MR. JACOBS: Thank you. No further questions.

CHAIRMAN EDGAR: Questions from staff?

MS. FLEMING: Staff has no questions.

CHAIRMAN EDGAR: Mr. Perko?

MR. PERKO: Very briefly.

REDIRECT EXAMINATION

BY MR. PERKO:

Q Mr. Klausner, you were here for Mr. Preston's questions, were you not?

A For most of them.

Q And you heard the questions regarding his assumptions concerning nuclear generation, correct?

A I believe so.

Q And those were in the context of the potential CO_2 regulatory environment?

A Yes.

Q Now, would you imagine or would you believe that interest in nuclear generation would be increased both by regulators and industry in the event a CO_2 regulatory environment is imposed?

A Yes.

MR. PERKO: Thank you. No further questions.

CHAIRMAN EDGAR: Okay. Exhibits? I have 52, 53 and 54.

MR. PERKO: That's correct.

CHAIRMAN EDGAR: Oh, 52, 53 and 54 exhibits will be entered into the record. The witness is excused. And let's go ahead and call Mr. Kushner.

(Exhibits No. 52, 53 and 54 admitted into the record.)

MR. PERKO: Bradley Kushner.

BRADLEY KUSHNER

was called as a witness on behalf of the Applicant, and having been duly sworn, testifies as follows:

DIRECT EXAMINATION

BY MR. PERKO:

Q Please state your name and business address for the record.

A My name is Bradley Kushner, K-U-S-H-N-E-R. Business address is 11401 Lamar Avenue, Overland Park, Kansas.

Q And, Mr. Kushner, have you been sworn?

A Yes, I have.

Q You might want to step up to the microphone.

Mr. Kushner, did you submit prefiled direct testimony consisting of 18 pages on September 19th,

2006?

A Yes, I did.

Q And did you submit -- did you -- are you sponsoring exhibits with that testimony that have been designated as 57, 58, 56, 57 and 58?

A That's correct.

Q 55, 56, 57, 58?

A Yes, I am.

Q Okay. And I believe two of those exhibits, specifically 57 -- I'm sorry, 56 and 57, have been revised through your supplemental testimony; is that correct?

A That is correct.

Q Now, are there any changes or additions to your prefiled direct testimony submitted on September 19th, 2006?

A Yes. In addition to the changes reflected in my supplemental testimony, I do have three changes.

Q And what are those?

A The first change is on page 12, line 15, change 790 million to 823 million. The next page, page 17, line 3, change 66 to 74. And on line 4, change 24 to 28.

Q Are those the only changes in your testimony?

A Yes, they are.

Q Are you sponsoring sections of the application identified in Exhibit 58?

A Yes. The sections I am sponsoring are listed on page 3 of my direct testimony.

Q And other than the changes in the errata sheet that's been admitted into evidence as Exhibit 3, are there any other changes or additions to those sections?

A No, there are not.

Q If I were to ask you the same questions in your prefiled direct testimony of September 19th, would your answers be the same?

A Yes, they would be.

MR. PERKO: At this time, Madam Chairman Madam Chair, I would move for admission of Mr. Kushner's prefiled direct testimony as if read.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Bradley E. Kushner. My business mailing address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

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

A. I am employed by Black & Veatch Corporation. My current position is Senior Consultant/Project Manager.

Q. Please describe your responsibilities in that position.

A. I am responsible for the management of various projects for utility and non-utility clients. These projects include production cost modeling associated with power system expansion planning, feasibility studies, and demand-side

management (DSM) evaluations. I also have involvement in the issuance and evaluation of requests for proposals (RFPs).

Q. Please describe Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering, consulting, and management services to utility, industrial, and governmental clients since 1915. Black & Veatch specializes in engineering, consulting, and construction associated with utility services including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, rate and financial reports, appraisals, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries.

Q. Please state your educational background and professional experience.

A. I received my Bachelors of Science in Mechanical Engineering from the University of Missouri – Columbia in 2000. I have more than 6 years of experience in the engineering and consulting industry. I have experience in the development of integrated resource plans, ten-year-site plans, demand-side management plans, and other capacity planning studies for clients throughout the United States. Utilities in Florida for which I have worked include Florida Municipal Power Agency (FMPA), JEA, Kissimmee Utility Authority (KUA), OUC, Lakeland Electric, Reedy Creek Improvement District (RCID), and the City of Tallahassee (City). I have performed production cost modeling and

economic analysis, and otherwise participated in three previous Need for Power Applications that have been filed on behalf of Florida utilities and approved by the Florida Public Service Commission (FPSC). I have also testified before the FPSC in previous Need for Power filings.

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

A. The purpose of my testimony is to discuss the economic analyses of supply-side resources performed individually for FMPA, JEA, RCID and the City of Tallahassee (the Participants) that show the Taylor Energy Center (TEC) represents the least-cost alternative for each Participant. I will also discuss each Participant's evaluation of demand-side management measures.

Q. Have you prepared any exhibits to your testimony?

A. Yes. Exhibit __[BEK-1] is a copy of my resume. Exhibit__[BEK-2] is a series of graphs presenting the results of the base case supply side analyses for each Participant. Exhibit ____ [BEK-3] is a series of tables presenting the results of the sensitivity case supply-side analyses performed for each Participant.

Q. Are you sponsoring any sections of Exhibit ____ [TEC-1], the Taylor Energy Center Need for Power Application?

A. Yes. I am sponsoring Sections A.8.0, A.9.0, B.5.0, B.6.0, B.7.2 through B.7.4, C.5.0, C.6.0, C.7.2 through C.7.4, D.5.0, D.6.0, E.5.0, E.6.0, E.7.2, and Appendices B.1, C.1, D.1, and E.1, all of which were prepared by me or under my direct supervision.

Q. How were the detailed economic analyses conducted?

A. The detailed system economic analyses were conducted using an optimum generation expansion model (POWROPT) and a detailed chronological production costing model (POWRPRO) for each Participant on an individual system basis.

POWROPT and POWRPRO are proprietary expansion planning and production costing models that have both been used in numerous Need for Power Applications approved by the FPSC, as well as for other clients throughout the United States.

Both POWROPT and POWRPRO operate on an hourly chronological basis using the same set of input files related to each Participant's existing capacity resources, load projections, and fuel price projections. POWROPT was used to identify the timing of capacity additions comprising the least-cost capacity expansion plan from among the alternatives which passed the screening process described in the testimony of Myron Rollins. Once the least-cost capacity expansion plan was identified in POWROPT, the selected units were integrated with each Participant's existing capacity resources and POWRPRO was used to obtain the annual production costs for the capacity expansion plan.

The POWRPRO results were used to generate a cumulative present worth cost (CPWC) of the expansion plan being considered, which accounts for all system

fuel costs, non-fuel variable O&M costs, fixed O&M costs for new capacity additions, startup costs, and levelized capital costs for new capacity additions. The CPWCs of various capacity expansion plans were compared to one another to identify the least-cost capacity expansion plan.

Q. What supply-side alternatives were included in the detailed economic analysis?

A. The detailed economic analysis included all of the technologies which passed the supply-side screening described in the testimony of Myron Rollins. These included simple cycle combustion turbines, combined cycles, a circulating fluidized bed (CFB) alternative, integrated gasification combined cycle (IGCC) alternatives, and the Taylor Energy Center (TEC).

Q. How was the least-cost capacity expansion plan identified for each Participant's system?

A. Each Participant's least-cost expansion plan was identified by using POWROPT to develop two unique capacity expansion plans for each Participant. The first plan developed considered participation in TEC beginning May 1, 2012, and POWROPT was used to select the optimum capacity additions prior to and beyond TEC necessary to satisfy forecast capacity requirements. The second plan did not include participation in TEC and POWROPT was used to select other optimum capacity additions to satisfy forecast capacity requirements. This approach identified the least-cost capacity expansion plan including

participation in TEC as well as the least-cost capacity expansion plan not including participation in TEC for each Participant.

Q. What evaluation period was used for the economic evaluation for each Participant?

A. The evaluation period extended from 2006 through 2035.

Q. Did your evaluation reflect fuel price forecasts developed for the TEC Need for Power Application?

A. Yes, my economic analyses for each Participant used the fuel price forecasts prepared by TEC Fuels, as described in the testimony of Jim Myers.

Q. Did the economic analyses consider the costs associated with emission allowances?

A. Yes. As described in the testimony of Matt Preston of Hill & Associates, forecast allowance prices were provided for emissions of SO_2, NO_x, and Hg associated with the base case fuel forecast, as well as high and low fuel forecast sensitivities. Emission allowance price forecasts for SO_2, NO_x, Hg, and CO_2 were also provided for a hypothetical sensitivity scenario in which emissions of CO_2 would be regulated in the U.S.

Q. Since the fuel and emission allowance price forecasts provided by Mr. Myers and Mr. Preston, respectively, only extend through 2030, and your analyses extended through 2035, how were fuel and emission allowance price forecast developed for 2031 through 2035.

A. Fuel and emission allowance price forecasts were extrapolated beyond 2030 using the applicable escalation rates between 2029 and 2030 for each fuel and emission allowance price forecast.

Q. Were load forecasts develop through 2035 for each Participant?

A. No. Each Participant provided a load forecast through 2025. Each Participant's loads were held constant beyond 2025 for purposes of the economic analyses.

Q. How was firm natural gas transportation accounted for in the economic analysis?

A. Each Participant's existing daily allocation of firm natural gas transportation was considered in the economic analyses. The costs for incremental firm natural gas transportation associated with combined cycle unit additions were accounted for in the economic analyses. Simple cycle combustion turbines selected for each Participant's capacity expansion plans were assumed to utilize interruptible natural gas service, and therefore no firm natural gas transportation costs were included for simple cycle combustion turbine options.

Q. How were emission allowance costs considered in the economic analysis?

A. The emission rates for each Participants' existing units that will be regulated under the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), as well as all candidate units considered, were used to develop emission cost adders on a $/MBtu basis. These adders were added to the fuel price projections for each unit based on the forecast emission allowance prices and were included in the dispatch modeling to ensure the most cost-effective dispatch of both existing and new generating units.

Q. Was the cost of TEC's initial coal inventory considered in the economic analysis?

A. Yes. Costs for the initial coal inventory were developed, assuming coal inventory purchases would be made during the latter part of 2011 and the early part of 2012. Therefore, the cost of the initial coal inventory was based on the average TEC fuel forecast for 2011 and 2012.

Q. How were the capital and fixed operating and maintenance costs for TEC allocated among the Participants?

A. Each Participant will be responsible for these costs in proportion to their ownership share of TEC.

Q. How were transmission system losses and associated costs considered in the economic evaluations?

A. Transmission system losses and costs were considered differently for each Participant to account for each Participant's likely transmission requirements. FMPA would utilize the Progress Energy Florida (PEF) transmission system for its share of TEC. FMPA's network service agreement with PEF is based upon FMPA's network load and not upon FMPA's individual capacity resources. FMPA's network transmission losses are supplied through the PEF system and not by specific FMPA capacity resources. FMPA's transmission losses and costs are therefore equivalent among individual resource plans since FMPA's network load does not change between plans. Therefore, no transmission system costs or losses were factored into the FMPA's economic analyses of TEC.

JEA will utilize the transmission systems of both PEF and Florida Power & Light (FPL) for its share of TEC. As a result, the line losses for the PEF and FPL and associated transmission tariff costs were accounted for in JEA's economic analyses of TEC.

Both RCID and the City of Tallahassee will utilize the PEF transmission system for their shares of TEC. Therefore, the line losses for the PEF transmission system and associated transmission tariff costs were accounted for in RCID's and the City of Tallahassee's economic analyses of TEC.

Q. How were the community contribution costs considered in the economic analyses?

A. The initial community contribution has been included in the TEC capital cost estimate. It was assumed that the Participants would pay an annual community contribution of $2.5 million beginning in 2012, and escalating at 2.5 percent annually thereafter. As with the other fixed costs for TEC, it was assumed that each Participant would be responsible for a percentage of the annual community contribution in proportion to its ownership share of TEC.

Q. What were the results of the economic analysis for FMPA?

A. The CPWC of FMPA's least-cost expansion plan including participation in TEC was approximately $403.6 million less than the plan not including participation in TEC. These results are shown in Figure 1 of Exhibit __[BEK-2].

Q. What were the results of the economic analysis for JEA?

A. The CPWC of JEA's least-cost expansion plan including participation in TEC was approximately $39.1 million less than the plan not including participation in TEC. These results are shown in Figure 2 of Exhibit __[BEK-2].

Q. What were the results of the economic analysis for RCID?

A. The CPWC of RCID's least-cost expansion plan including participation in TEC was approximately $270.8 million less than the plan not including participation in TEC. These results are shown in Figure 3 of Exhibit __[BEK-2].

Q. What were the results of the economic analysis for the City of Tallahassee?

A. The CPWC of the City of Tallahassee's least-cost expansion plan including participation in TEC was approximately $152.6 million less than the plan not including participation in TEC. These results are shown in Figure 4 of Exhibit __[BEK-2].

Q. Is TEC the most cost-effective alternative available to each Participant?

A. Yes. As previously discussed in my testimony, TEC is the most cost-effective alternative available to each Participant. Participation in TEC will result in combined CPWC savings of approximately $866 million.

Q. Will TEC provide adequate electricity at a reasonable cost to each Participant?

A. Yes. TEC will help to meet each Participant's electric generation needs at the lowest cost of all the alternatives evaluated.

Q. Will TEC meet each Participant's need for electric system reliability and integrity?

A. Yes. As described in the testimony of Paul Hoornaert from Sargent & Lundy, TEC will utilize proven supercritical technology. The use of proven generating technology for TEC will provide each Participant with a reliable generating resource.

Q. How would the economics of TEC be affected for each Participant if the transmission interconnection costs are not classified as network improvements?

A. As discussed in the testimony of Gary Brinkworth, preliminary cost estimates for the four interconnection alternatives developed by PEF and FPL vary between $86 million and $112 million. The majority of these costs likely will be classified as network improvements which will be reimbursed to the Participants as offsets to their respective transmission service charges for delivery of the power from TEC. Nevertheless, an analysis was performed that increased the capital cost of TEC by $100.3 million to capture the upper end of the project's transmission interconnection cost exposure based on the preliminary estimates provided by PEF and FPL. The results of such analysis indicate that participation in TEC is still the most cost-effective alternative available to each Participant. Under such a scenario, participation in TEC will result in combined CPWC savings of approximately ~~$790~~ $823 million.

Q. Did you conduct any sensitivity analyses relative to TEC?

A. Yes.

Q. Please provide an overview of those sensitivity analyses.

A. Several sensitivity analyses were performed to supplement each Participant's base case economic analysis and to demonstrate the robustness of the capacity expansion plans including each Participant's participation in TEC. These analyses measure the impact of varying key assumptions used in the base case

economic analysis, as well as the impacts of considerations not included in the base case.

The general methodology used in the sensitivity analyses was similar to the methodology used in the base case analysis described previously in my testimony. POWROPT was used to determine the optimal capacity expansion plan for all cases considered under different sensitivity scenarios. POWRPRO was then utilized to calculate production costs of each plan to compare each plan's CPWC and determine the least-cost expansion plan.

Q. What sensitivity analyses were conducted?

A. For each Participant, input parameter sensitivity analyses were performed by varying key input assumptions used in the base case economic analysis. These sensitivity analyses include high and low fuel price scenarios, high and low load and energy growth scenarios, high and low capital cost scenarios, high and low emission allowance price scenarios, and a potential CO_2 emission regulation scenario.

External parameter sensitivity analyses were also performed, including consideration of other joint development alternatives (one considering participation in a 3x1 combined cycle, and one considering participation in a three train 1x1 IGCC), participation in a second jointly-owned pulverized coal (PC) unit scenario, an all natural gas capacity expansion plan scenario, a direct-

fired biomass supply-side alternative scenario, and a scenario in which TEC uses Powder River Basin coal instead of Latin American coal.

Both the joint development 3x1 combined cycle and three train 1x1 IGCC alternatives were assumed available in May 2012 to allow for a comparable evaluation of these options versus participation in TEC. This is a favorable assumption for the IGCC, as it is considered an emerging technology that the Participants would likely not commit to for commercial operation until 2018, as described in the testimony of Chris Klausner.

In addition, Southern Power Company (Southern) responded to the Participants' request for proposals (RFP) and provided bids for a pulverized coal unit and a 2x1 combined cycle unit. The RFP process is described in the testimony of Paul Arsuaga, who is with R.W. Beck. Although both of Southern's bids were determined by R.W. Beck to be higher in cost than TEC on a levelized cost basis, these bids were evaluated for each Participant's system as sensitivity scenarios to further demonstrate the cost-effectiveness of each Participant's participation in TEC.

Q. What were the results of these sensitivity analyses?

A. Exhibit____[BEK-3] presents a summary of the results of the sensitivity analyses performed for each of the Participants. As shown in Exhibit____ [BEK-3], participation in TEC is included in each Participant's least-cost capacity expansion plan under all sensitivity scenarios.

The results of the sensitivity analyses, coupled with the results of the base case analysis, demonstrate that the capacity expansion plan including participation in TEC is a robust plan for each Participant, and is sufficiently flexible to overcome variations and deviations from the base case assumptions.

Q. How was DSM and conservation evaluated in the TEC Need for Power Application?

A. As required by Section 403.519 of the Florida Statutes, in its determination of need, the FPSC must take into consideration conservation measures that could mitigate the need for the proposed plant. To address this requirement, FMPA, JEA, and the City of Tallahassee have each individually tested potential DSM measures for cost-effectiveness. RCID's consideration of DSM measures is discussed in the testimony of Nick Guarriello of R.W. Beck.

FMPA and JEA utilized the FPSC-approved Florida Integrated Resource Evaluator (FIRE) model for their DSM evaluations. The City of Tallahassee's DSM evaluation was developed based on projections of total achievable energy and capacity reductions and their associated annual costs developed specifically for the City of Tallahassee.

Q. Please provide a brief overview of the FIRE model.

A. The FIRE model requires three main sources of input. The first is the characterization of the DSM and conservation measures. The second is the cost

and characteristics of the unit to be avoided with the DSM and conservation, which in this case is participation in TEC. Finally, utility system specific information such as rates is required with separate rates used depending on the customer class each measure pertains to.

The FIRE model provides three tests designed to measure the cost-effectiveness of DSM and conservation from different perspectives, including the Total Resource Test, the Participant Test, and the Rate Impact Test.

If the benefit-to-cost ratio of these tests is greater than 1.0, then the DSM and conservation measures are cost-effective under the test. Consistent with the FPSC's past actions, both FMPA and JEA relied on the Rate Impact Test for their determination of cost-effectiveness of DSM and conservation measures. The FPSC has also consistently found the Rate Impact Test to be appropriate for determining cost-effectiveness.

Q. Did any of the DSM and conservation measures pass the Rate Impact Test?

A. No. None of the measures considered by FMPA or JEA had a Rate Impact Test score greater than 1.0. Thus, none of the DSM or conservation measures were found to be cost-effective.

Q. Did any of the DSM and conservation measures pass the Total Resource Test for FMPA and JEA?

A. Yes. For FMPA, ~~66~~ 74 measures passed the Total Resource Test for residential and commercial rate classes combined, and ~~24~~ 28 measures passed the Total Resource Test for residential and commercial rate classes combined for JEA.

Q. Have you evaluated the capacity savings that would occur if DSM and conservation measures that passed the Total Resource Test for FMPA and JEA were implemented?

A. Yes. The evaluation indicated that there would not be sufficient capacity reductions to displace either FMPA's or JEA's ownership shares of TEC.

Q. Please provide an overview of the DSM evaluation methodology utilized by the City of Tallahassee.

A. The City of Tallahassee's DSM cost-effectiveness evaluation methodology was based on projections of total achievable energy and capacity reductions and their associated annual costs developed specifically for the City of Tallahassee.

Candidate DSM measures were initially reviewed using a cost-effectiveness test based on the levelized cost of energy saved by each measure compared to a comparable levelized supply-side resource cost, where the levelized cost of the supply-side resource was computed over the DSM measure life. Based on the results of the screening, all of the individual DSM measures were combined into bundles, where the energy and capacity benefits along with implementation

costs were determined for each bundle. Load shapes were then developed for the bundles and combined into an overall DSM portfolio load shape, which was then applied as a load shape adjustment to the base demand and energy forecast.

Instead of screening individual measures, the combined DSM measures were analyzed in a portfolio as a reduction to the City of Tallahassee's annual load projections, and the resulting system was evaluated using production cost modeling.

Q. What were the results of the City of Tallahassee's DSM cost-effectiveness evaluation?

A. Based on the analysis conducted, the peak demand savings projected for the DSM portfolio would defer the City of Tallahassee's initial capacity requirement from 2011 to 2016. However, despite the potential deferral of the need for capacity, the results of the DSM analysis indicated that the City of Tallahassee's participation in TEC in 2012 would provide significant additional CPWC savings when compared to a capacity expansion plan with the DSM portfolio that does not include participation in TEC.

Q. Does this conclude your testimony?

A. Yes.

BY MR. PERKO:

Q Now, Mr. Kushner, did you also submit supplemental testimony in this docket consisting of four pages on December -- I'm sorry, six pages on December 12th, 2006?

A Yes, I did.

Q Are there any changes or additions to that testimony?

A No, there are not.

Q And are you sponsoring any exhibits with that testimony?

A Yes, I am.

Q What are those exhibits?

A Exhibits BEK-2R.

Q And those are the two exhibits that we mentioned are listed as 56 and 57 on the prehearing order?

A That is correct.

Q Okay. Thank you.

Mr. Kushner, if I were to ask you the same questions today that are set forth in your supplemental testimony, would your answers be the same?

A Yes, they would be.

MR. PERKO: At this time, Madam Chair, I'd move for admission of Mr. Kushner's supplemental

testimony dated September 12th, 2006, as if read.

CHAIRMAN EDGAR: The supplemental testimony will be entered into the record as if read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. 060635-EU

DECEMBER 12, 2006

Q. Please state your name and business address.

A. My name is Bradley E. Kushner. My business mailing address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

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

A. I am employed by Black & Veatch Corporation. My current position is Senior Consultant/Project Manager.

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my supplemental testimony is to discuss the results of the economic analyses that were updated to reflect the updated capital cost estimate of $2,039,074,000 for the Taylor Energy Center (TEC) as discussed in the Participants' response to Staff Interrogatory No. 58 (served November 20, 2006) and the rebuttal testimony of Paul Hoornaert (filed November 21, 2006), as well as updated capital cost estimates of the supply-side alternatives as discussed in the rebuttal testimony of Chris Klausner (filed November 21, 2006). I will demonstrate that TEC remains the least-cost alternative for the Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (collectively referred to as the Participants) when considering the updated capital costs for TEC and the supply-side alternatives. I also will demonstrate that the conclusions related to the cost-effectiveness of demand-side management (DSM) discussed in my direct testimony are not affected by the updated TEC capital cost estimate.

Q. Have you prepared any exhibits to your testimony?

A. Yes. Exhibit No. ___ [BEK-2R] is a revised version of Exhibit No. __ [BEK-2] to my direct testimony. Exhibit No. ___ [BEK-2R] is a series of graphs presenting the results of the base case economic analysis for each Participant taking into consideration the increased capital costs of TEC and the supply-side alternatives. Exhibit No. ___ [BEK-3R] is a revised version of Exhibit No. __ [BEK-3] to my direct testimony. Exhibit No. ___ [BEK-3R] is a series of tables presenting the results of the economic analyses performed for each

Participant taking into consideration the increased capital costs for TEC and the supply-side alternatives.

Q. Were there any changes to the methodology described in your direct testimony related to the economic analysis?

A. No.

Q. What were the results of the updated economic analysis for FMPA?

A. The cumulative present worth cost (CPWC) of FMPA's least-cost expansion plan including participation in TEC was approximately $417.1 million less than the plan not including participation in TEC. These results are shown in Figure 1 of Exhibit No.__ [BEK-2R].

Q. What were the results of the economic analysis for JEA?

A. The CPWC of JEA's least-cost expansion plan including participation in TEC was approximately $38.1 million less than the plan not including participation in TEC. These results are shown in Figure 2 of Exhibit No. __ [BEK-2R].

Q. What were the results of the economic analysis for RCID?

A. The CPWC of RCID's least-cost expansion plan including participation in TEC was approximately $255.6 million less than the plan not including participation in TEC. These results are shown in Figure 3 of Exhibit No.__ [BEK-2R].

Q. What were the results of the economic analysis for the City of Tallahassee?

A. The CPWC of the City of Tallahassee's least-cost expansion plan including participation in TEC was approximately $188.6 million less than the plan not including participation in TEC. These results are shown in Figure 4 of Exhibit No. __ [BEK-2R].

Q. Is TEC the most cost-effective alternative available to each Participant when considering the updated capital cost estimates for TEC and the supply-side alternatives?

A. Yes. As previously discussed in my testimony, TEC is the most cost-effective alternative available to each Participant when considering the updated capital cost estimates for TEC and the supply-side alternatives. Participation in TEC will result in combined CPWC savings of approximately $899.3 million.

Q. Were all of the sensitivity analyses discussed in your direct testimony updated to reflect the updated capital costs for TEC and the supply-side alternatives?

A. Yes.

Q. What were the results of these sensitivity analyses?

A. Exhibit No. ___ [BEK-3R] presents a summary of the results of the sensitivity analyses performed for each of the Participants. As shown in Exhibit No. ___ [BEK-3R], participation in TEC is included in each Participant's least-cost capacity expansion plan under all but one sensitivity scenario. The lone

exception is JEA's low fuel price sensitivity, which indicates the least-cost expansion plan not including participation in TEC would be approximately $12.7 million lower in CPWC than participation in TEC. It is important to note that the least-cost expansion plan for JEA under the low fuel price sensitivity includes a coal-fired circulating fluidized bed (CFB) alternative in lieu of participation in TEC.

The results of the sensitivity analyses, coupled with the results of the base case analysis, continue to demonstrate that the capacity expansion plan including participation in TEC is a robust plan for each Participant, and is sufficiently flexible to overcome variations and deviations from the base case assumptions, even in light of the updated capital cost estimates.

Q. How was DSM and conservation evaluated in your updated analyses?

A. The DSM evaluation was consistent with the methodology discussed in my direct testimony.

Q. Did any of the DSM and conservation measures evaluated for FMPA or JEA pass the Rate Impact Test when considering the updated TEC capital cost estimate?

A. No. Consistent with the results of the DSM evaluation discussed in my direct testimony (and also as stated in my rebuttal testimony), none of the measures considered by FMPA or JEA had a Rate Impact Test score greater than 1.0 when

considering the updated TEC capital cost estimate. Thus, none of the DSM or conservation measures were found to be cost-effective.

Q. What were the results of the City of Tallahassee's DSM cost-effectiveness evaluation when considering the updated TEC capital cost estimate?

A. The results were consistent with the results of the City of Tallahassee's DSM evaluation discussed in my direct testimony. The City of Tallahassee's participation in TEC in 2012 (taking into consideration the updated TEC capital cost estimate) would provide significant additional CPWC savings when compared to a capacity expansion plan with the DSM portfolio that does not include participation in TEC.

Q. Does this conclude your supplemental testimony?

A. Yes.

BY MR. PERKO:

Q Finally, Mr. Kushner, did you submit revised rebuttal testimony in this docket consisting of 11 pages on December 26, 2006?

A Yes, I did.

Q Are there any changes or additions to that revised rebuttal testimony?

A No, there are not.

Q If I were to ask you the same questions today as are set forth in that testimony, would your answers be the same?

A Yes, they would be.

MR. PERKO: At this time, Madam Chairman, I'd ask for the admission of Mr. Kushner's revised rebuttal testimony as if read.

CHAIRMAN EDGAR: The rebuttal testimony will be entered into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REVISED REBUTTAL TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. 060635-EU

DECEMBER 26, 2006

Q. Please state your name and business address.

A. My name is Bradley E. Kushner. My business mailing address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

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

A. I am employed by Black & Veatch Corporation. My current position is Senior Consultant/Project Manager.

Q. Have you previously submitted testimony in this proceeding?

A. Yes.

Q. Have you reviewed the testimony of Dian Deevey that was filed in this docket on November 2, 2006?

A. Yes, I have.

Q. Have you reviewed the testimony of Dale Bryk that was filed in this docket on November 2, 2006?

A. Yes, I have.

Q. Have you reviewed the testimony of Hale Powell that was filed in this docket on November 3, 2006?

A. Yes, I have.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to address several assertions in the testimony of Ms. Dale Bryk, Mr. Hale Powell and Ms. Dian Deevey. I will rebut the claims by Ms. Bryk that DSM, biomass, and IGCC were not evaluated in the TEC Need for Power Application, Exhibit No. __ (TEC-1). I will rebut Mr. Powell's claims that demand side management (DSM) was not adequately evaluated nor detailed in the TEC Need for Power Application, and will show that even in light of the updated capital cost estimate for TEC and the potential for higher fuel costs that DSM will still not be cost-effective.

Q. Are you familiar with the updated capital cost estimate discussed in the supplemental testimony of Paul Hoornaert?

A. Yes.

Q. On page 7 of her testimony, Ms. Bryk suggests that DSM was not "fully explored" by all of the Participants. Do you agree with Ms. Bryk's suggestion?

A. No. The cost-effectiveness of DSM was appropriately considered for each Participant.

Q. Please explain how DSM was considered in the analysis for each Participant.

A. The Commission-approved Florida Integrated Resource Evaluator (FIRE) model was used for the DSM evaluations for FMPA and JEA. The City of Tallahassee's DSM evaluation was based on a utility-specific approach that the City developed as part of its ongoing integrated resource planning effort. The City's approach, with which Ms. Bryk does not take exception, is based on projections of total achievable energy and capacity reductions and their associated annual costs developed specifically for the City of Tallahassee. A renewed evaluation of the potential cost-effectiveness of DSM for Reedy Creek Improvement District (RCID) was not performed as discussed in the direct testimony of Nicholas Guarriello because RCID's customers have already applied all reasonably available conservation measures and will continue to install conservation measures, as appropriate, in the future.

Q. How many potential DSM measures were evaluated using the FIRE model for FMPA and JEA?

A. Approximately 180 potential DSM measures were evaluated for both FMPA and JEA, encompassing DSM measures that target both residential and commercial customers.

Q. How is the cost-effectiveness of DSM measures evaluated by the FIRE model?

A. The FIRE model requires three main sources of input. The first is the characterization of the DSM and conservation measures which includes the detailed cost and kWh and kW savings of the measure. The second is the cost and characteristics of the unit to be avoided with the DSM and conservation, which in this case is participation in TEC. Finally, utility system specific information such as rates is required with separate rates used depending on the customer class each measure pertains to.

The FIRE model provides three tests designed to measure the cost-effectiveness of DSM and conservation from different perspectives, including the Total Resource Test, the Participant Test, and the Rate Impact Test.

If the benefit-to-cost ratio of these tests is greater than 1.0, then the DSM and conservation measures are cost-effective under the test. Consistent with the Commission's past actions, both FMPA and JEA relied on the Rate Impact Test for their determination of cost-effectiveness of DSM and conservation measures. The FPSC has also consistently found the Rate Impact Test to be appropriate for determining cost-effectiveness.

Q. Were any DSM measures determined to be cost-effective for either FMPA or JEA?

A. No. None of the additional measures considered by FMPA or JEA had a Rate Impact Test score greater than 1.0. Thus, none of the additional DSM or conservation measures were found to be cost-effective. Consideration of the TEC capital cost estimate discussed in the supplemental testimony of Paul Hoornaert does not change these conclusions.

Q. Is the scope and methodology of the DSM evaluation presented in this docket on behalf of FMPA and JEA consistent with previous DSM evaluations presented to and approved by the Florida Public Service Commission?

A. Yes. Evaluations using the same or similar methodology were presented to and approved by the Commission in the need determination proceeding regarding FMPA's Treasure Coast Energy Center Unit 1 Need for Power Application (Docket 050256-EM) and in the need determination proceeding for Orlando Utilities Commission's Stanton Energy Center Unit B Need for Power Application (Docket No. 060155-EM). The Commission approved those need applications in Order No. PSC-05-0781-FOF-EM (July 2005) and Order No. PSC-06-0457-FOF-EM (May 2006), respectively. I personally oversaw the DSM evaluations in those proceedings and presented the results in testimony filed with the Commission.

Q. Mr. Powell's testimony suggests that the Need for Power Application does not provide sufficient detail to assess the Participant's DSM cost-effectiveness evaluations. Do you agree?

A. No. Section 7.0 of Volumes B and C discuss each of the 180 DSM measures considered in the analysis, as well as the methodology utilized and results of the cost-effectiveness evaluations. The level of detail provided in the TEC Need for Power Application is consistent with, if not greater than, that presented in the afore-mentioned Docket No. 050256-EM and Docket No. 060155-EM, which the Commission found to be appropriate. Due to the volume of material comprising the input and output of the FIRE model (i.e. thousands of pages), it was not practical to file all the supporting background materials with the Need for Power Application.

Q. How were the various DSM measures selected for evaluation?

A. The DSM measures evaluated in the FIRE model were chosen to represent a wide range of various end-use measures across residential and commercial customer classes, and also differentiate between existing and new construction. The DSM measures also are consistent with those evaluated in previous dockets as discussed above.

Q. Are the end-uses, customer classes, and differentiation between existing and new construction delineated in the TEC Need for Power Application?

A. Yes. The descriptions of the DSM measures in Section 7.0 of Volumes B and C identify the end-use and customer class of each measure, as well as whether

each measure targets existing or new construction. Further, the tables presented at the end of Section 7.0 of Volumes B and C reiterate these parameters.

Q. The testimony of Hale Powell (Page 19) states that achievable cost-effective potential DSM ranges from 9 percent to 24 percent. Do you believe this is an appropriate range?

A. Dr. Powell does not identify the "nine studies" he relied upon in calculating that range. It is impossible to assess this range of cost-effective DSM potential without reviewing the studies that Powell references. For comparison purposes, Florida Power & Light Company (FPL), which has the largest demand savings from conservation of any utility in the United States, has realized demand and energy savings of 12 percent and 4 percent, respectively as presented in their 2006 Ten-Year Site Plan.

Q. The testimony of Hale Powell (Page 17) states that even if only 50 percent of a DSM program is completed it will provide energy savings over the useful life of the DSM measure. Do you agree with that statement?

A. Not necessarily. Some DSM programs lose their energy savings over time. Good examples of this are compact fluorescents which sometimes get replaced before the end of their life with incandescents due to customer dissatisfaction with delay when they are turned on or the difference in the color of the light. Another example is low flow shower restrictors that are sometimes removed because the customer does not like the reduced water flow. Besides the above examples, another important point associated with Mr. Powell's comment is the

cost-effectiveness of the DSM program. If the planned DSM expenditures are made and the program only achieves half of the penetration, then the program is twice as costly as planned. Likewise, if the DSM savings are half of what was planned, the program is twice as costly as planned.

Q. On Page 7 of her testimony, Dale Bryk suggests that a biomass supply-side resource alternative was not "fully explored" by each Participant. Has each Participant appropriately considered biomass resources?

A. Yes. A sensitivity analysis was performed for each Participant that included 30 MW of conventional direct fired biomass capacity in their portfolio of supply-side additions. The results of these analyses are summarized in Section 6.0 of Volumes B through E of the TEC Need for Power Application, and are also presented in Exhibit No. BEK-3R Supplemental (~~BEK-3~~) of my ~~direct~~ testimony. The results of these sensitivity analyses indicate that biomass in lieu of TEC is not a cost-effective for any of the Participants.

Q. On page 9 of her testimony, Ms. Bryk suggests that the Participants must "realistically evaluate (in light of CO_2-related cost implications and other factors) the relative benefits of natural gas-fired generation and the benefits of IGCC technology." Did your analysis consider natural gas-fired generation alternatives?

A. Yes. We included an alternative of a 3x1 natural gas-fired combined cycle unit instead of TEC in our analysis.

Q. Was natural gas-fired generation found to be a cost-effective alternative to TEC when the cost of CO_2 allowances are considered?

A. No. TEC remains the most cost-effective alternative under the hypothetical regulated-CO_2 scenario.

Q. Did your analysis consider integrated gasification combined cycle (IGCC) alternatives?

A. Yes. A 1x1 IGCC alternative was considered for FMPA, JEA, and the City of Tallahassee. Each of the Participants also evaluated a joint-development IGCC alternative to participation in TEC.

Q. Was IGCC found to be a cost-effective alternative to TEC?

A. No.

Q. Page 8 of Powell's testimony contemplates the impact of higher than expected emission allowance prices. How would higher than expected emission allowance prices affect the cost-effectiveness of TEC for each Participant?

A. Section 6.0 of Volumes B through E of the TEC Need for Power Application presents a sensitivity scenario in which emissions annual allowance prices are increased by 25 percent above the annual base case emission allowance price forecasts. TEC was found to be cost-effective for each of the Participants under this high emission allowance price sensitivity.

Q. Page 8 of the testimony of Powell also theorizes that DSM would be more cost-effective under scenarios in which fuel prices are higher than expected. Has any analysis been performed to determine if DSM is cost-effective in a scenario in which fuel prices are higher than expected?

A. Yes. The DSM cost-effectiveness analysis has been performed for FMPA and JEA using the high fuel price sensitivity scenario. The results of this analysis indicate that no DSM measures pass the Rate Impact Test for either FMPA or JEA.

Similarly, the DSM cost-effectiveness analysis has been performed for FMPA and JEA using the regulated-CO_2 sensitivity scenario. The results of this analysis indicate that no DSM measures pass the Rate Impact Test for either FMPA or JEA.

Q. On Page 8 of her testimony, Dian Deevey states that Synapse Energy Economics was responsible for an evaluation of potential CO_2 compliance costs for the City of Tallahassee. Ms. Deevey further states that Synapse's estimates should have been used by all of the Participants. Why were Synapse's CO_2 allowance price projections not considered in the TEC Need for Power Application?

A. The CO_2 allowance price projections presented in the TEC Need for Power Application were developed by Hill & Associates, and were therefore consistent with the parameters and assumptions used in developing their fuel forecasts.

Thus, it is appropriate to use Hill & Associates' CO_2 allowance price projections in the base case rather than introduce a forecast of CO_2 allowance prices that is decoupled from the overall fuel price forecasts, which is the case when using Synapse's projections.

Q. Does this conclude your testimony?

A. Yes.

BY MR. PERKO:

Q Mr. Kushner, have you prepared a summary of your prefiled testimony and supplemental testimony?

A Yes, I have.

Q Could you please provide that at this time.

A Yes. A detailed economic analyses were performed for each applicant to evaluate the cost effectiveness of participation in the Taylor Energy Center. The analyses were performed using the chronological optimum generation expansion planning model POWROPT and the chronological production costing model POWRPRO.

In addition to each applicant's share of the Taylor Energy Center, the supply-side alternatives evaluated included various simple cycle, combined cycle, CFB and IGCC alternatives appropriate to each applicant. Each applicant's least cost capacity expansion plan over the 2006 through the 2035 period was identified by developing two unique capacity expansion plants, one with Taylor Energy Center and one without it. And these economic analyses considered transmission system costs and losses specific to each applicant as well as costs for compliance with the applicable air emission and other regulations.

In addition to the base case analysis,

numerous sensitivity scenarios were evaluated for each applicant. Out of the more than 70 total cases analyzed in all but a single case for one applicant the results showed participation in the Taylor Energy Center is included in each applicant's least cost expansion plant.

Taylor Energy Center is also more cost technical effective than either bid received in response to the applicant's RFP. The comprehensive economic analysis including the base case and sensitivity scenarios in comparison to the RFP responses demonstrate that the capacity expansion plan including participation in the Taylor Energy Center is a robust plan for each applicant and is sufficiently flexible to overcome variation and deviations from the base case assumptions.

Evaluation of conservation measures taken by or reasonably available to the applicants demonstrate that there are none which might mitigate the need for the Taylor Energy Center.

This concludes my summary.

Q And, Mr. Kushner, have you also prepared a summary of your revised rebuttal testimony?

A Yes, I have.

Q Could you present that at this time.

A Yes. The Commission-approved FIRE model was used to evaluate the cost-effectiveness of 180 different

DSM measures for each FMPA and JEA. The Commission has consistently found the rate impact test or RIM test to be appropriate for determining cost effectiveness. Consistent with the Commission's previous actions, the results of the RIM test were used as the basis for the DSM cost-effectiveness evaluation.

The scope and methodology of the DSM evaluations performed for FMPA and JEA were consistent with those presented to and approved by the Commission and the Need for Power Applications for FMPA's Treasure Coast Energy Center Unit 1 and OUC's Stanton Energy Center Unit B Need for Power Applications. None of the DSM measures were found to be cost effective for either FMPA or JEA when considering the updated Taylor Energy Center capital cost estimate. This holds true when also considering the high fuel forecast and regulated CO_2 sensitivity scenarios.

The level of detail provided for the FIRE model analysis is consistent with or greater than the level of detail provided in prior need filings approved by this Commission. DSM measures selected for evaluation represent a wide range of various end use measures across residential and commercial including industrial customer classes and differentiate between new and existing construction.

For DSM measures that are implemented, associated savings are dependent upon the DSM measure being continually implemented over its assumed useful life. And the cost effectiveness of DSM is dependent upon the levels of participation and actual costs occurred.

The evaluation of biomass alternatives for each participant shows that biomass is not a cost-effective alternative to the Taylor Energy Center. The Taylor Energy Center remains the most cost-effective alternative for each applicant when considering the high emission allowance price and regulated CO_2 sensitivity scenarios.

MR. PERKO: We tender the witness for cross-examination.

CHAIRMAN EDGAR: Thank you. Let's see. It's about ten minutes till 8:00. Can we take just a second and talk about where we are?

I'm showing Mr. Kushner and Mr. Urse and then Mr. Rollins are -- are -- is -- sorry -- the witnesses that we have remaining. Can you give me an idea as either individually or as a group about how much cross for Mr. Kushner, about how long so I've got a feel?

MR. JACOBS: My guess would be it would be

approaching an hour.

CHAIRMAN EDGAR: Okay. Then --

MR. JACOBS: I don't want to speak out of turn, but I know I have a fair amount and I think NRDC has a fair amount.

CHAIRMAN EDGAR: Ms. Brownless?

MS. BROWNLESS: Yes.

CHAIRMAN EDGAR: All right. Then let me make a few comments. First off, as I said earlier, I hoped we could push to the end. But I -- we are all made of sturdy stock, but I think we're starting to push the envelope on fatigue.

With that in mind, I'm sorry to have to say that we're all going to have to come back another day. So as I said earlier, we will plan to come back at 10:30 on Thursday. The fact that we have some additional time to -- to rest and clear our thoughts in between is not an invitation to extend questioning. If anything, it is an opportunity to further refine and make questions productive and efficient.

Ms. Brubaker?

MS. BRUBAKER: Madam Chairman, I would like to point out that briefs under the current schedule are due on the 18th. So I think some extension is

appropriate. However, I would also note that with the exception of Mr. Kushner's testimony, Mr. Urse and Mr. Rollins' rebuttal, we have covered extensive ground. And we do have daily transcripts available with much gratitude to the court reporters who have been working so hard on this case.

So I think first of all, my sense is there's a lot to work with even prior to the 18th. I note that under the current schedule, the staff recommendation is due on the 1st and Agenda is the 13th. To the extent we have an extension of briefs, I would, of course, ask for a commensurate extension to late file the staff rec.

CHAIRMAN EDGAR: I would expect that that request would be favorably considered.

MS. BRUBAKER: Okay. And certainly welcome the thoughts of the parties, but I was thinking perhaps an extension to the 23rd.

MS. BROWNLESS: What day is that, Jennifer?

MS. BRUBAKER: That would be a Tuesday -- I'm sorry. The 18th to the 23rd. The 18th is a Thursday. Tuesday is the 23rd.

CHAIRMAN EDGAR: For briefs?

MS. BRUBAKER: For briefs.

MS. BROWNLESS: Okay.

CHAIRMAN EDGAR: I'm seeing some nods. Mr. Perko? Nods.

Okay. Then we will go ahead and work from that schedule from this point forward which will be for briefs of the parties to be to the Commission on January 23rd. Does that work?

Thank you. All right. Any other questions, comments, clarifications?

Seeing none, okay. Then everybody get a -- get some sleep. And we will begin on Thursday taking up the cross of Mr. Kushner. We are done for the evening. Thank you all.

(Hearing adjourned.)

(Please go to Volume 10.)

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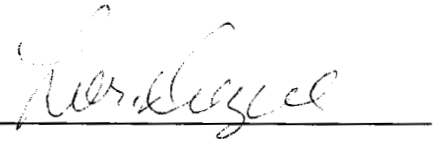
CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, LORI DEZELL, RPR, CCR, certify that I was authorized to and did stenographically report the proceedings herein, and that the transcript is a true and complete record of my stenographic notes.

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

WITNESS my hand and official seal this 15th day of January, 2007.



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