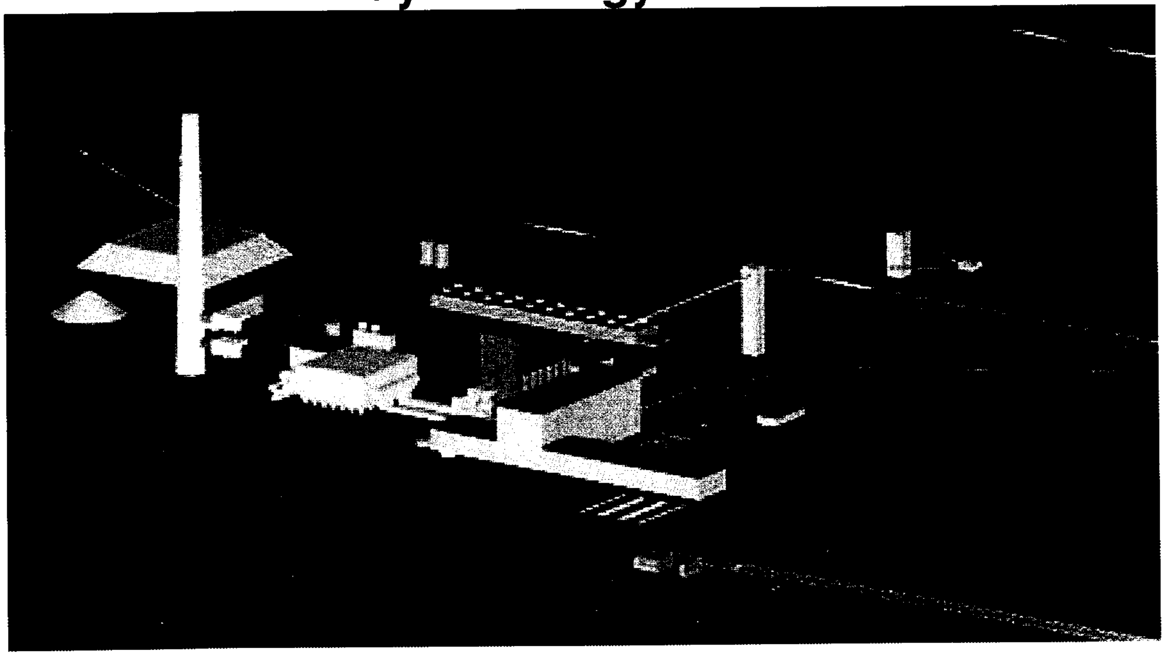
Pre-Filed Testimony

Florida Electrical Power Plant Siting Act
Need for Power Application

060635-EU

Taylor Energy Center



Submitted by:

Florida Municipal Power Agency
JEA
Reedy Creek Improvement District
City of Tallahassee
September 2006

Florida Municipal Power Agency

REEDY CREEK
IMPROVEMENT DISTRICT

City of Tallahassee
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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 seven major newspapers around the country.

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.

Docket No. ________
Taylor Energy Center
Paul Arsuaga
Exhibit ____ [PAA-1]
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RESUME OF

Paul Arsuaga, Senior Director

R. W. Beck, Inc.

Qualifications and Experience:

Mr. Arsuaga, a Senior Director with R. W. Beck, Inc., has over 32 years of planning experience in utility infrastructure and electric power facilities. Since joining R. W. Beck in 1981, he has prepared or supervised numerous consulting engineer's reports for official statements, financial analyses, acquisitions, damage studies, power purchase contract negotiations and power supply studies and reports for municipal utilities and joint action agencies. Prior to joining the firm, Mr. Arsuaga served as a corporate planning engineer for an investor-owned utility in the Midwest where he performed generation planning studies and managed a corporate model.

Mr. Arsuaga has a Masters of Business Administration from University of Hawaii and a Bachelors of Science in Electrical Engineering from Tulane University. He is a registered professional engineer in Florida, Mississippi, and Missouri.

Market Price Analyses

Mr. Arsuaga has supervised several projects involving the preparation and/or review of market price projections for both industrial and joint action agency clients. These projections have been prepared for market regions including PJM, FRCC, SERC and SPP. Some of these projects have included developing and using various computer models of electric utility market regions to simulate various market pricing structures under a market based restructured electric utility environment. Mr. Arsuaga has also reviewed and evaluated numerous market price projections prepared by other consultants as part of independent engineering reviews and work related to rate filings for stranded costs. Mr. Arsuaga is a member of the firm's Market Pricing Task Force through which he has been involved in evaluating and communicating issues related to market pricing in the electric utility industry.

Wholesale Power Supply Contracts and Negotiation

Mr. Arsuaga has participated in evaluating wholesale power contracts for Conway, Arkansas; West Memphis, Arkansas; Hagerstown, Maryland; Thurmont, Maryland; Front Royal, Virginia; City of Columbia, Missouri; the Municipal Energy Agency of Mississippi; the City of St. Cloud, Florida; Alabama Municipal Electric Authority; and the Florida Municipal Power Agency.

Mr. Arsuaga has been involved with developing an appropriate methodology for compensating members of the Florida Municipal Power Agency for supplying power supply resources to the all-requirements project.

Mr. Arsuaga has assisted in the development of a stranded cost analyses for the Florida Municipal Power Agency and the Municipal Energy Agency of Mississippi.

He has also been involved in directing a hold harmless analysis to determine the potential rate impact and hold harmless costs associated with making remaining members of the Municipal Energy Agency of Mississippi whole after a certain member terminated the power supply arrangements.

Planning for Electric Utility Restructuring

Mr. Arsuaga has directed analyses for industrial clients, providing assistance with capital decisions in a deregulated environment. This work involved developing scenarios for long-range sustainable pricing practices in a deregulated electric utility market for generation. It also involved preparing projections of both time-of-day marginal costs and market clearing prices for various market regions of the United States based on these pricing practices. These analyses take into account transmission import and export capabilities between market areas, load and resources in several NERC reliability regions, annual economic conditions, market behavior, reliability standards and other factors.

Mr. Arsuaga also assisted the Municipal Energy Agency of Mississippi with its input to the Mississippi Public Service Commission staff's Proposed Transition Plan for Retail Competition in the Electric Industry and in this capacity, has met with the staff to discuss restructuring in Mississippi.

Electric Power Resource Planning

Mr. Arsuaga has an extensive background in preparing electric resource planning studies for municipal utilities and joint action agencies. He has either prepared or directed the preparation of electric resource planning studies for the City of Columbia, Missouri; the Florida Municipal Power Agency; the Municipal Energy Agency of Mississippi; the Bahamas Electricity Corporation; the City of Tallahassee, Florida; the Utility Board of the City of Key West, Florida; the Sebring Utilities Commission; the City of St. Cloud, Florida; the Fort Pierce Utilities Authority; the City of Vero Beach, Florida; and a large improvement district. These studies, which make conclusions and recommendations regarding the client's participation in specific power supply projects, have included screening type analyses which focus on identifying a list of reasonably attainable potential alternatives as well as comprehensive studies which cover power supply related areas such as load forecasts, reliability, environmental impact, economic/financial feasibility, bond requirements, rate impact and risk analysis.

Request for Proposal Services

Mr. Arsuaga has been a lead team member or project manager on power supply solicitations involving the City of Tallahassee, Florida; the Florida Municipal Power Agency; the City of Hagerstown, Maryland; the Town of Thurmont, Maryland; the Town of Front Royal, Virginia; the Alabama Municipal Electric Authority; the City of St. Cloud, Florida; Golden Spread Electric Cooperative, Inc.; the Municipal Energy Agency of Mississippi; the Jacksonville

Electric Authority; the Orlando Utilities Commission; Idaho Power Company; Hydro Quebec; the City of Columbia, Missouri; North Little Rock, Arkansas; Benton, Arkansas; Conway, Arkansas; and the City of Mt. Dora, Florida. This process included preparation of the Request for Proposal and evaluation manual, evaluation of the proposals and negotiations with the potential power suppliers. Mr. Arsuaga has also participated in meetings and discussions with state public commission staff's in Florida and Texas, and has testified in a Public Utility Commission Hearing relative to the RFP Process.

Reliability Studies

Mr. Arsuaga has been involved in evaluating electric system reliability and determining reliability criteria for electric utilities. These studies have involved estimating various measures of reliability, such as loss of load probability (LOLP), loss of load hours (LOLH) and expected unserved energy (EUE) for isolated and interconnected power systems. He is currently involved in a reliability study for the City of Tallahassee, Florida that involves modeling the reliability of the electric system including peninsular Florida and Georgia.

Litigation Support

Mr. Arsuaga has been involved in litigation support services associated with wholesale electric rate filings, territorial disputes and damage studies.

He has prepared analyses and testimony for Case No. 87-00103 CIV before the U.S. District Court Southern District of Florida, Miami Division, City of Homestead vs. Imo Delaval and Transamerica Corporation, which was amicably settled. He has also prepared analyses and testimony in cases for the Municipal Electric Authority of Georgia, the City of Tallahassee, the Florida Municipal Power Agency and industrial clients relating to wholesale power costs, territorial issues and transmission access.

Mr. Arsuaga has testified before the Florida Public Service Commission with regard to territorial issues involving the Fort Pierce Utilities Authority and Florida Power & Light; before the Public Utility Commission of Texas with regard to the selection of resources through an RFP process; and before the Mississippi Public Service Commission regarding deregulation issues and has submitted testimony to the Federal Energy Regulatory Commission regarding power supply issues.

Financial Planning and Analysis

Mr. Arsuaga has been involved with the preparation of numerous official statements for bond refunds and the financing of new electric generation facilities including the North Carolina Eastern Municipal Power Agency, the Utility Board of the City of Key West, the Florida Municipal Power Agency, the Municipal Energy Agency of Mississippi, the Municipal Electric Authority of Georgia and the City of Tallahassee, Florida. Mr. Arsuaga has also assisted financial institutions with the evaluation of a merchant generation project in California; Arizona;

Nevada; Texas; Mississippi; and Alberta, Canada. Mr. Arsuaga's experience has enabled him to analyze the financial aspects of municipal projects including pro forma results, adequacy of liquidated damages, bond indenture requirements, various financing methodologies, tax-exemption considerations, arbitrage and other financial related factors.

Gas Fuel Supply

Mr. Arsuaga has performed various studies relating to gas fuel supply for the Fort Pierce Utilities Authority ("Authority") and the City of Vero Beach Electric Utilities ("City") to determine the most economic level of firm gas service and the most economic mix of firm transportation versus firm service with the Florida Gas Transmission Company ("FGT"). The analysis involved projecting the daily gas usage for the combined Authority and City electric production facilities and determining the level of firm gas transportation and firm service that represented the lowest cost, taking into account the cost of generating on alternative fuels, potential curtailments of interruptible gas and take or pay gas supply charges. The Authority and the City based nominations for FGT's Phase II and III gas pipeline expansions on these analyses.

Competitive Analyses, Mergers and Acquisitions

Mr. Arsuaga has performed analyses associated with determining the economic benefits of mergers and acquisitions for electric utilities. One such analysis evaluated the impact of acquiring an additional service territory for the Sebring Utilities Commission. This analysis, which was submitted to the Florida Public Service Commission, indicated the impact on the Sebring Utilities Commission's existing and transferred customers of the proposed acquisition of an additional service territory.

Another analysis, which was prepared for the Fort Pierce Utilities Authority, evaluated the impact on Fort Pierce's customers of a proposed transfer and acquisition of service territories and associated customer accounts between Fort Pierce and Florida Power & Light. This analysis included an evaluation of equipment value, incremental and decremental revenues and potential load growth for the areas involved.

Mr. Arsuaga evaluated the competitiveness of the City of Homestead, Florida to address potential future events such as the commencement of purchased power contracts for which the City is committed, power supply sales, acquiring additional territory and potential changes in administration costs.

Training and Information Presentations

Mr. Arsuaga has made numerous presentations before Utility Boards and City Commissions relating to electric resource planning and was a guest lecturer on Integrated Resource Planning in an IEEE Power Generation Seminar lecture series. He prepared technical papers on the RFP process, determining the market value of generation capacity in a deregulated utility environment, and local marginal pricing which were presented at technical conferences and published.

Employment History:	1981-Present	R. W. Beck, Inc.
	1977-1981	Kansas City Power and Light
Education:	MBA	University of Hawaii
	B.S.	Electrical Engineering, Tulane University

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF DR. THEODORE R. BRETON
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 Dr. Theodore R. Breton. My business address is 4401 Fair Lakes Court, Suite 400, Fairfax, Virginia.

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

A. I am employed by Pace Global Energy Services (Pace Global), where I am the Chief Economist and a Director in our Utility and Risk Management Services Division.

Q. Please describe Pace Global Energy Services.

A. Pace Global is an independent energy management and consulting company that provides strategic and technical expertise in fuels, electric power, finance, risk management, and energy management in both domestic and international energy markets. We provide an independent source of energy expertise support to energy developers, financial institutions, public utilities, commercial and industrial consumers, and public sector agencies. Our headquarters are near Washington, DC, and we have regional offices in Houston, Columbia, London, Moscow, and New York City.

As an extension of our Energy Management service, Pace Global provides outsourcing services related to mid- and long-term contracting for supplies of natural gas, coal, petroleum coke, and electric power. Under this service, we serve as an outsourcing partner, executing transactions on behalf of our clients.

Pace Global also provides energy services in the areas of strategic and business planning, risk management, financial advisory, market assessment and forecasting, litigation and regulatory support, and advisory services that encompass fuels, power, and environmental regulations. We provide an executive decision framework to help clients manage their energy growth and risk in today's rapidly changing business environment. As part of these services, we provide expertise and advice to support complex litigation and regulatory proceedings both at the state and federal levels. In these proceedings, we have provided expert testimony across natural gas, electric, and other markets, focusing on market dynamics, commercial requirements, and valuation.

Q. Please describe your educational background and experience.

A. I have more than 25 years of experience with world and US energy markets specific to petroleum and natural gas. As an economist, I worked at ICF Resources where I directed the analysis and marketing of a multi-client service that provided power and fuel market forecasts for 19 US power markets. I then joined Putnam, Hayes and Bartlett, an independent economic and management consulting firm, and undertook a wide variety of energy-related assignments. At Pace Global Energy Services, I supervise and am responsible for the fuel and power market forecasts. I oversee the preparation of the Pace Global Oil Market and Natural Gas Market Outlooks, a set of energy market forecasts and reports.

I have a Ph. D. in Economics from George Mason University, an M.S. in Economics from the London School of Economics, and a B.S. in Chemical Engineering from Lehigh University. My resume is attached as Exhibit ___ [TRB-1].

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

A. The purpose of my testimony is to present the expected natural gas and fuel oil price projections developed by Pace Global Energy Services and provided to Hill & Associates for the Taylor Energy Center Need for Power Application. More specifically, my testimony will discuss Pace Global's 4Q 2005 annual price and market forecasts through 2030 for natural gas at the Henry Hub (Louisiana) as well as Pace Global's annual price forecast through 2030 for distillate and residual fuel oils in the US Gulf Coast market.

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

A. Yes. Exhibit __ [TRB-1] is a copy of my resume. Exhibit __ [TRB-2] is Pace Global Energy Services' expected price forecast for natural gas at the Henry Hub in Louisiana and a national gas supply and demand balance from our 4Q 2005 Gas Market Outlook. Exhibit__ [TRB-3] is Pace Global Energy Services' expected price forecast for distillate and residual fuel oil prices in the US Gulf Coast developed from our 4Q 2005 Oil Market Outlook.

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.4.6.3, A.4.6.4, A.4.6.5.3, and A.4.6.5.4, all of which were prepared under my direct supervision.

Q. **How did you become involved in the Taylor Energy Center Need for Power Application?**

A. Pace Global Energy Services was retained by Hill & Associates to provide the market forecasts for natural gas and fuel oils. I was responsible for developing those forecasts, which are set forth in Exhibits__[TRB-2] and__[TRB-3], respectively.

Q. Describe the approach you took in developing the Henry Hub natural gas price forecast set forth in Exhibit __ [TRB-2].

A. Our forecast of US gas market prices is generated by forecasting the demand for gas and the supply of gas as a function of prices and then determining the price of gas that will bring supply and demand into balance over time.

Our gas consumption forecast is provided for the residential, commercial, industrial, and power sectors. These forecasts are developed based on a series of other assumptions, including gross domestic product (GDP) growth, weather, and the price elasticity of demand for gas. Econometric relationships are used to forecast gas demand outside the power sector. Power sector demand for gas is the most difficult to forecast accurately since it is affected by so many factors, including load growth, the price of gas and alternative fuels, and environmental emission controls. Pace Global utilizes a linear programming model of the North American power market to forecast the consumption of gas in the power sector.

Our gas supply forecast is provided for US production, Canadian and Mexican net imports, and imported liquefied natural gas (LNG). These forecasts are developed based on our review of natural gas reserves in North America, production costs, and consumption forecasts for Canada and Mexico. The near- and medium-term supply of imported LNG is based on our assessment of the amount of LNG available from existing and new liquefaction terminals worldwide, taking into account contracts and forecast requirements for LNG worldwide. Longer term supplies of LNG (after 2012) are forecast to be available to meet demand at a price consistent with world oil prices and the potential to convert "stranded" gas reserves to liquids.

Q. Describe the factors influencing Pace Global's North American natural gas supply outlook.

A. High natural gas spot market prices have encouraged considerable increased exploration and drilling in North America since 2002, but this increased activity has not resulted in net annual production increases. Natural gas producers report that production declines in existing wells have been more rapid than in the past, while production from new wells has been less than the historic norm. A growing share of gas production is from unconventional wells that have much higher gas production costs than were the historic norm for conventional gas production.

Overall, net North American pipeline imports to the United States are forecast to decline in the near-term as pipeline exports to Mexico increase to meet growing demand for power generation. However, as new LNG terminals begin operation in Mexico in 2008 and 2009, US net pipeline exports to Mexico are likely to decrease.

Q. Please discuss LNG's expected contribution to US natural gas supplies.

A. We see the United States becoming increasingly dependent on LNG imports to meet natural gas consumption over time. Our 4Q 2005 forecasts project that this dependence will rise annually, with LNG imports as a percentage of forecast natural gas consumption reaching 15 percent in 2012. This level of LNG imports is feasible as long as current plans for new liquefaction facilities overseas remain on schedule. Given the current capacity of regasification terminals and the construction of additional terminals that is under way, any constraints on US LNG supplies are unlikely to be due to limited terminal capacity in the United States. The limitations are more likely to be due to a lack of LNG supplies available for shipment to the United States from foreign sources.

Q. What effect can hurricanes have on US natural gas supply and price?

A. As demonstrated by Hurricanes Ivan, Katrina, and Rita, hurricanes can have a substantial adverse impact on natural gas supply in the US and cause price increases that last for years. Some of the natural gas production rigs that were recently damaged will likely never be replaced.

Q. Please discuss the most significant drivers of natural gas demand factored into your natural gas price forecast.

A. Pace Global's 4Q 2005 forecast assumed that the U.S. economy would grow over time, causing an increase in the demand for natural gas. Over the 2004-2010 period, annual natural gas consumption was projected to increase by 0.9 percent in the residential/commercial sectors, to decline by 0.4 percent in the industrial sector, and to increase by 4.3 percent in the power sector. As a result of the current era of higher-cost natural gas, many industries that formerly used low-cost natural gas to produce energy-intensive commodities, such as fertilizer, are no longer competitive, so production of these commodities is moving to other parts of the world.

Even though high natural gas prices make natural gas-fired power generation relatively expensive, the growing US electricity demand cannot be met over the next 6 years without increasing the utilization of existing natural gas-fired combined cycle units. Our forecasts indicate particularly strong growth in natural gas consumption in the power sector near the end of the decade when more natural gas will become available from LNG imports, and natural gas prices are expected to decline. Over the longer-term, Pace Global expects that a share of incremental US power generation will be natural gas-fired, with natural gas consumption in the power sector forecasted to be growing, but at a slower rate.

After 2010, there is considerable uncertainty in the level of industrial demand for natural gas. In 2002, US facilities consumed 8 billion cubic feet per day (bcf/day) to make chemicals and primary metals. During 2005, some of these facilities reduced operations in response to higher natural gas prices. All of this demand is potentially at risk of being permanently lost, depending on whether sufficient capacity is constructed in the Middle East and elsewhere to replace US production of these chemicals and metals. Pace Global's forecast assumes that no new capacity is constructed to make energy-intensive commodities, but that existing capacity resumes operation when natural gas prices decline.

Beyond 2015, natural gas consumption in the US is likely to grow very slowly. Incremental power generation will largely come from new baseload generating units that are not likely to be natural gas-fired. Energy-intensive industrial activity will not be sited in the United States. High natural gas prices in the residential and commercial sectors are likely to encourage more energy conservation and greater reliance on electricity for space heating.

Q. Please discuss Pace Global's near-term natural gas price forecast compared to the futures prices listed on the New York Mercantile Exchange (NYMEX).

A. Futures prices for natural gas on the NYMEX are quite volatile over relatively short periods of time, particularly when unexpected events, such as hurricanes or periods of unusual weather, occur. When the Pace Global forecast of natural gas prices was developed, the NYMEX prices were above the Pace Global price forecast. NYMEX prices are used principally for near-term hedging over periods of 1 to 2 years. As a result, NYMEX prices are not particularly relevant for the period beginning in 2012 when the proposed Taylor Energy Center is expected to begin operation.

Q. How will natural gas prices in Florida be affected by the US outlook developed by Pace Global?

A. The natural gas supplied to Florida is transported from the US Gulf Coast, so the price in Florida is closely tied to the Henry Hub price. With the exception of the transportation cost elements specific to Florida, natural gas prices within Florida are affected by the same factors that affect natural gas prices throughout the nation.

Q. How did Pace Global Energy Services prepare its fuel oil price forecast?

A. Under normal market conditions fuel oil prices are primarily determined by crude oil prices. The principal US crude oil marker is WTI crude oil, located in Cushing, Oklahoma, which is the crude oil listed on NYMEX. Pace Global forecasts the price of WTI and uses this price as the basis for forecasting United States and world prices of petroleum products. Over 95 percent of the historic variance in the price of No. 2 fuel oil and over 85 percent of the historic variance in the price of No. 6 fuel oil is explained by changes in the price of WTI crude oil.

Pace Global has developed regression equations to predict fuel oil prices as a function of the level of WTI crude prices for products that have been traded for many years. Fuel oil prices rise when WTI prices rise due to the higher cost of producing petroleum products. Twelve years of monthly historic US Gulf Coast spot prices were used to estimate the regressions used to develop the price forecast. For the new very-low-sulfur fuel oils, which did not have historic prices, Pace Global utilized engineering cost estimates to determine the incremental costs to produce these fuels. These incremental costs were added to the price of the traded products to estimate the likely future price of the very-low-sulfur fuels.

Our expected price forecast for WTI crude is developed differently for the near-term and longer-term. In the near-term the WTI price is estimated based on a forecast of the worldwide supply and demand for oil. The supply is based largely on forecast production, taking into account the effect of insurgencies and other non-economic factors. The demand is estimated based on GDP growth and price elasticities to estimate the world demand response to higher prices.

In the longer-term (2012 and beyond), the expected price forecast is based on the projected marginal cost of providing liquids to the world market from unconventional sources, including tar sands, natural gas (in gas-to-liquids plants), and coal. Pace Global's estimates of these costs are affected by our forecast of the value of the US dollar, which is expected to lose value over time due to the need to bring US imports and exports back into balance. As the dollar devalues, the marginal cost of oil produced outside the United States, which sets the world price, rises in dollar terms. Even though the OPEC and non-OPEC countries have sufficient oil reserves to meet world demand for some time without using unconventional oil sources, only a small portion of these reserves are being made available to the major oil companies. Pace Global assumes that government production policies and other political events will require the production of liquids from unconventional sources to meet rising world demand for liquid fuels.

Q. Did Pace Global provide forecasts for natural gas and fuel oil delivered to the Taylor Energy Center site?

A. No. Pace Global only provided natural gas price forecasts at Henry Hub, and did not develop any costs associated with delivery of natural gas from Henry Hub to the Taylor Energy Center. Fuel oil price forecasts were provided for the US Gulf Coast.

Q. Did Pace Global develop any high and/or low price projections for natural gas and fuel oil?

A. No. Pace Global only developed fuel price projections for a single, expected price case.

Q. Have Pace Global's forecasts of natural gas and fuel oil prices changed since the forecasts in the 4Q 2005 Market Outlooks were developed?

A. The forecast of near-term prices are different, since these prices are affected by unexpected events, including abnormal weather conditions, that continue to occur. Pace Global's oil and gas price forecasts for the period after 2011 are essentially the same.

Q. Does this conclude your testimony?

A. Yes.

RESUME OF

Theodore R. Breton, Director

Pace Global Energy Services, LLC

Qualifications and Experience:

Dr. Breton, the Chief Economist at Pace Global Energy Services, is an expert on world and U.S. energy markets with over 30 years experience. Dr. Breton is a Director in the Utility and Risk Management Services Division. He supervises the preparation of the Pace Global *Oil Market, Natural Gas Market, Coal and Petcoke Market, and Power Market Outlooks*, a set of energy market forecasts and reports that are provided to clients quarterly on a subscription basis. As part of this process, he supervises the preparation of load forecasts and the calibration of a power market model to simulate 58 U.S. power markets. He has been in the energy and environmental field for over 30 years and in the consulting business for over 25 years. His consulting experience has been focused on the analysis of energy market structure and price behavior in the U.S. and overseas.

Dr. Breton has analyzed petroleum and natural gas markets since 1980, and he has authored numerous articles on crude oil and product markets in the *Petroleum Economist* and the *Oil and Gas Journal.* He has submitted and presented testimony as an expert witness on power and gas market regulatory issues. He is regularly quoted in the press on oil market developments. He advised the U.S. Department of Energy's Strategic Petroleum Reserve Office on leasing, crude mix, and drawdown issues for ten years, and he directed the development of a National Plan for the Development of the Hydrocarbon Sector in Ecuador.

Dr. Breton has a Ph.D. in Economics from George Mason University, an M.Sc. in Economics from the London School of Economics, and a B.S. in Chemical Engineering from Lehigh University. He is a member of the American Economics Association. He is fluent in Spanish.

Strategic Services

U.S.

- *Northeast Fuel Oil Market Strategy.* He directed an analysis of the Northeast heating oil market and the analysis of the benefits of a federally-financed regional heating oil reserve for the U.S. Department of Energy and contributed to their preparation of a Report to Congress in 1996-97. As part of this analysis, he examined the effect of futures markets on private primary heating oil stockholding and examined the behavior of the Northeast market during the December 1989 cold spell.
- *Ethanol Suitability for Strategic Storage.* He directed a study of the feasibility and desirability of producing and storing ethanol for use as a gasoline extender (and high-octane additive) during oil supply disruptions. This study was submitted as a Report to Congress and resulted in the cancellation of hearings on this politically-popular but uneconomic concept.
- *Strategic Storage of Petroleum.* He advised the U.S. Strategic Petroleum Office on numerous issues related to their petroleum storage program, including the optimal mix of crude oils, the

value of surplus storage facilities, facility leasing options, and distribution facility planning. He directed an analysis of the bidding patterns of traders and refiners for SPR crudes during the 1990 Test Sale and the Desert Storm sale to determine the values of various crudes during the sales and the relative interest of purchasers in different locations for pipeline versus marine distribution. He also identified some SPR crudes for which bids were unjustifiably low and recommended a marketing program to educate potential purchasers about the true quality of the various crude oil grades.

- *Cogeneration Project Potential.* He estimated the technical potential for industrial cogeneration in the U.S., examined the economics of a variety of cogeneration applications by size of steam load, and provided an analysis of the institutional barriers to greater use of efficient cogeneration in the U.S.
- *Global Warming Response Strategy.* He co-directed a detailed study of the cost of addressing the global warming problem through energy conservation and fuel substitution in the U.S.

Europe

- *UK Salt Dome Storage Project.* He evaluated the likely effect of injection and drawdown of natural gas from a large proposed natural gas storage facility in the UK. He determined that the facility was so large that its operation would reduce substantially the current price volatility in the UK market, thereby limiting the facility's potential earnings from the purchase and sale of gas.

- *Czech Republic Energy Strategy.* He reviewed and critiqued the Czech Republic's national energy plan and provided the Ministry for Economic Policy and Development with a comprehensive review of potential options for privatizing the electric, gas, and heat utilities.
- *Cross-Spain Power Wheeling Contract.* He directed a study for a Spanish utility of the (opportunity) costs and benefits of a long-term firm contract to wheel French power to Portugal. This study was used to negotiate a power wheeling contract.

Asset Divestiture Services

U.S.

- *PEPCO Stranded Generation Cost Study.* He participated in the estimation of Potomac Electric Power's "stranded costs" associated with transition to a competitive power market. The focus of this work was on simulating the behavior of prices in the Eastern interconnected power market using GE's MAPS model under alternative assumptions about 1) future fuel and environmental emission allowance prices and 2) the future dependence of the market on dispatchable demand and interpool wheeling to replace pool reserve margins for generation capacity.
- *Nuclear Power Plant Stranded Cost Study.* He simulated the U. S. New England regional power market, as part of a study to value a New England nuclear power plant. The focus of this work was on simulating the behavior of wholesale electric prices using GE's MAPS model, given projections of new plant commencement dates and future fuel and environmental emission allowance prices.

- *PEPCO Stranded Generation Cost Study.* He participated in the estimation of Potomac Electric Power's "stranded costs" associated with transition to a competitive power market. The focus of this work was on simulating the behavior of prices in the Eastern interconnected power market using ICF's Integrated Planning Model (IPM), under alternative assumptions about 1) future fuel and environmental emission allowance prices and 2) the future dependence of the market on dispatchable demand and interpool wheeling to replace pool reserve margins for generation capacity.

Forecasting and Market Assessments

U.S.

- *World Fuel Market and North American Power Market Forecasts.* He directs Pace Global' analysis and quarterly forecasting of world oil, natural gas, and coal markets and the regional North American power markets. These forecasts include an expected case and stochastic price forecasts for numerous products in numerous locations.
- *Regional Fuel and Power Market Forecasts.* He directed ICF Resources' analysis and marketing of a multi-client subscription Energy Service, providing power and fuel (coal, gas, and fuel oil) market forecasts for 19 U.S. power markets. These forecasts were based on surveys and simulation of these markets using regional power market and national gas market simulation models.
- *SO2 Allowance Market Outlook.* He directed the preparation and sale of a multi-client study of the U.S. SO2 allowance market outlook. This study included an analysis of the EPA annual

auction and forecasts of SO2 allowance prices based on the results of a national model of power generation and coal consumption within the U.S. regulatory system for trading SO2 emission permits.

- *Gas Supply Model.* He developed a new statistical approach for simulating and forecasting U.S. non-associated natural gas exploration and production and used it to create alternative future market price scenarios within the framework of the (deregulating) U.S. gas market.
- *Gas Demand Model.* He developed an econometric and a structural model of regional U.S. residential gas demand. As a check on the econometric gas share forecast, he also performed regional life-cycle cost analyses of new gas furnaces and electric heat pumps.

Russia

- *Russian Power Market Simulation.* As part of the USAID-funded Joint Energy Alternatives Study (JEAS), he directed the fuel-related and hydroelectric elements of the development of an eight-region simulation model of Russia's power sector, as well as managing the contract and subcontractors.

South America

- *Development Cost and Pricing of Camisea Gas.* He advised the Electric Tariff Commission in Peru on options for pricing non-marketed gas supplies for purposes of calculating the wholesale electric energy price within the context of the Electricity Concession Law. As part of the project he analyzed the cost of supplying Camisea gas to different locations within Peru for different size development projects.

- *Master Plan for Hydrocarbon Development in Ecuador.* He directed a $750,000 Project for the Ministry of Energy and Mines in Ecuador to develop a hydrocarbon sector planning model and a twenty-year Master Plan for investment in oil refining, pipelines, and production.

Regulatory Services

U.S.

- *Transmission Pricing Options.* He directed a study for a U.S. electric utility comparing transmission pricing regulatory approaches in nine countries that have created competitive wholesale power markets.
- *Electric Power Contract Dispute.* He directed a statistical study of the key factors determining the Florida Power Corporation's "as available" rate for Qualifying Facility purchase of power, as part of an analysis of the project's financial risk related to potential revenue stream variation. The analysis determined that load, nuclear plant and QF availability, oil prices, and coal prices were the key factors affecting this rate.
- *Retail Electricity Tariff Analysis.* He testified as an Expert Witness on the outlook for generation capacity prices in the PJM (Pennsylvania-Jersey-Maryland) market during 1998, as part of a hearing to determine the portion of the PECO Energy retail tariffs that should be charged to marketers selling to PECO's retail customers.
- *Natural Gas Market Legislation.* He participated in studies supporting the deregulation of the U.S. natural gas market in the 1980s.

Europe

- *Transition to Wholesale Power Markets in Spain.* He advised the National Electric Regulatory Commission in Spain in its efforts to create a regulatory structure suitable for a competitive wholesale power market. The focus of this work was to identify alternative procedures to determine prices for wholesale power at different locations and to specify the conditions for external agent participation in the Spanish wholesale market.

Due Diligence Services

Caribbean

- *Refinery Upgrade Project in Trinidad.* He analyzed the economic feasibility of a proposed upgrade of the Trintoc refinery in Trinidad.

Mexico

- *Load Forecast for Northern Mexico.* He directed a load forecast study for GE Industrial and Power Systems to determine whether the forecast load would be sufficient to support the Samayaluca II power plant subsequent to a Mexican financial crisis.
- *Carbon II Power Project.* He performed a review of the Mexican electric system's procedures for load forecasting, fuel pricing, and dispatching as part of a due diligence review for the potential privatization and (re)financing of the Carbon II power project.

South America

- *InterAmerican Development Bank Project Analysis.* He analyzed proposed natural gas, coal, and hydroelectric projects in Argentina, Bolivia, Peru, Mexico, El Salvador, and Brazil.
- *Gas-fired Generation Projects in Argentina.* He directed three gas-fired power plant feasibility studies in Argentina for a U.S. commercial bank and a U.S. investment bank. As part of these studies Mr. Breton provided in-depth analyses of the Argentine wholesale power market and the wholesale gas market. He performed a review of the Mexican electric system's procedures for load forecasting, fuel pricing, alternative power market scenarios. He forecast a surplus wholesale power market with unattractive prices for incremental generation capacity.
- *Colombian Power Market Analysis.* He reviewed a Colombian consulting firm's model of the Colombian wholesale power market and its forecast of power prices and prepared a report for a U.S. developer to assist in the developer's efforts to obtain equity investors for a gas-fired merchant plant.

South Asia

- *Lakhra Coal-fired Generation Project in Pakistan.* He performed an economic feasibility study for a proposed 700 MW coal-fired power plant in Pakistan.

Employment History:	2004-2006	Director, Pace Global Energy, Fairfax, VA
	2002- 2004	Adjunct Professor, George Mason University, Fairfax, VA

1997-1999	Principal, Putnam, Hayes, and Bartlett, Washington, DC
1987-1997	Vice President, ICF Resources, Fairfax, VA
1986-1987	Economist, InterAmerican Development Bank, Washington, DC
1975-1986	Project Manager and Vice President, ICF Inc., Washington, DC
1972-1974	Economist, U.S. Environmental Protection Agency, Washington, DC
1968-1970	Mathematics Instructor, U.S. Peace Corps, Colombia, South America

Education:	PhD	Economics, George Mason University
	M.S.	Economics, London School of Economics
	B.S.	Chemical Engineering with Honors, Lehigh University

Countries of Experience: Argentina, Bolivia, Brazil, Colombia, Czech Republic, El Salvador, Ecuador, Mexico, Pakistan, Peru, Poland, Russia, Spain, UK, Trinidad and the United States.

Languages: English (Native), Spanish, Portuguese (read)

Publications:

Academic Articles

- Breton, Theodore R., 2004, "Can Institutions or Education Explain World Poverty? An Augmented Solow Model Provides Some Insights," Journal of Socio-Economics, Volume 33, Issue 1, 45-69

Non-Academic Articles

- Breton, Theodore R., "Fueling the Deregulated Energy Sector," *Natural Resources & Environment*," Spring 1998
- Breton, Theodore R., and Blaney, John C., "Low Gas Prices Make Natural Gas an Attractive Fuel," *IAEE Proceedings*, October 1992
- Breton, Theodore R., and Blaney, John C., "Production Rise, Consumption Fall May Turn Soviet Oil Exports Higher," *Oil and Gas Journal*, November 18, 1991
- Breton, Theodore R., and Blaney, John A., "Outlook for OPEC's Competitors," *Petroleum Economist*, October 1987
- Breton, Theodore R., "Low Prices Forecast in Short-Term," *Petroleum Economist*, December 1985
- Breton, Theodore R., "World Residual Fuel Outlook," *Petroleum Economist*, June 1984
- Breton, Theodore R., and Cohen, Laura, "Future Petroleum Product and Natural Gas Price Relationships," *Energy Economics, Policy and Management*, Winter 1983

Industry Recognition:

*Tau Beta Pi (*Engineering honor society)

Scott Paper Award for Leadership (two-year merit scholarship)

Professional Societies:

American Economics Association

Canadian Economics Association

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Exhibit ____ [TRB-2]
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Henry Hub Natural Gas Price Projections and National Natural Gas Demand Forecast

Year	Henry Hub $2005/MMBtu	Gas Demand Million Cubic Feet
2006	9.02	21,990,139
2007	7.63	22,414,737
2008	7.20	22,926,106
2009	6.12	23,522,576
2010	5.36	24,292,422
2011	5.10	24,881,129
2012	5.20	25,144,935
2013	5.31	25,390,777
2014	5.41	25,643,807
2015	5.52	25,904,231
2016	5.63	26,054,137
2017	5.74	26,205,160
2018	5.86	26,357,310
2019	5.98	26,510,596
2020	6.09	26,665,029
2021	6.22	26,820,618
2022	6.34	26,977,373
2023	6.47	27,135,305
2024	6.60	27,294,422
2025	6.73	27,454,737
2026	6.86	27,616,258
2027	7.00	27,778,996
2028	7.14	27,942,961
2029	7.28	28,108,166
2030	7.43	28,274,619

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Exhibit ____ [TRB-3]
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Fuel Oil Price Projections – US Gulf Coast ($2005/BBl)

Year	GC #6 1%	GC #6 3%	GC #2 0.5%	GC #2 0.05%	GC #2 0.0015%
2006	45.32	37.32	73.31	74.63	77.15
2007	41.79	34.80	63.90	64.95	69.13
2008	40.26	33.65	60.75	61.71	65.69
2009	38.79	32.54	57.83	58.71	62.69
2010	37.03	31.17	54.48	55.25	59.33
2011	35.74	30.17	52.12	52.83	57.90
2012	35.50	29.98	51.66	52.36	56.89
2013	35.48	29.97	51.64	52.34	56.38
2014	35.48	29.97	51.64	52.34	55.94
2015	35.53	30.00	51.72	52.42	55.64
2016	35.88	30.28	52.38	53.09	56.31
2017	36.31	30.62	53.15	53.89	57.11
2018	36.74	30.96	53.95	54.70	57.93
2019	37.18	31.28	54.75	55.53	58.75
2020	37.61	31.62	55.56	56.37	59.59
2021	38.05	31.96	56.39	57.22	60.45
2022	38.48	32.29	57.23	58.09	61.31
2023	38.92	32.63	58.08	58.97	62.19
2024	39.36	32.97	58.95	59.85	63.08
2025	40.25	33.64	59.82	60.75	63.97
2026	40.25	33.64	60.71	61.67	64.89
2027	40.69	33.98	61.62	62.61	65.83
2028	41.14	34.31	62.54	63.55	66.77
2029	41.59	34.65	63.46	64.50	67.73
2030	42.03	34.98	64.40	65.47	68.70

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF GARY S. BRINKWORTH
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 address.

A. My name is Gary S. Brinkworth. My business address is 400 East Van Buren Street, Tallahassee, Florida 32301.

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

A. I am employed by the City of Tallahassee (the City) as the Manager of Electric Utility Strategic Planning.

Q. Please describe your responsibilities in that position.

A. I supervise the Electric System Planning Division and have overall responsibility for all system planning tasks undertaken on behalf of the City's electric utility, including generation and transmission planning, load forecasting, energy conservation studies, financial assessments, retail rate analysis, and revenue budgeting studies. I am also responsible for development of strategic plans for the electric utility and for coordinating those plans with other utility departments in the City.

Q. Please state your educational background and professional experience.

A. I have a Bachelor's and Master's degree in Electrical Engineering from Auburn University. I am also a registered Professional Engineer in Alabama, Florida, Georgia, and Mississippi.

I have worked for the City since 1988 in a variety of electric utility system planning roles, including generation planning, transmission planning, load forecasting, engineering economic studies, energy conservation cost/benefit studies, retail rate analysis, and financial modeling. I also have 4 years of experience managing certain retail utility service functions, including customer service operations, meter reading, CIS support and billing, underground utility locates, marketing and environmental services. Prior to the City, I worked for the Southern Company Services for 6 years where I gained experience as a Generation Planning Engineer and a Transmission Planning Engineer.

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

A. I will provide a description of the City's existing generating system, summarize the City's load forecast, and describe the City's projected capacity requirements. In addition, I will provide a summary of the City's existing demand-side management (DSM) and conservation programs, briefly discuss several strategic considerations that led the City to participate in TEC, and review the City's ability to finance its share of TEC. In addition, in my role as chairman of the TEC project transmission study team, I will present an overview of the transmission interconnections for the TEC.

Q. Are you including any exhibits as part of your testimony?

A. Yes. Exhibit __ [GSB-1] is a copy of my résumé.

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.3.3.7, E.1.0, E.2.0, E.3.0, E.4.0, E.7.1, E.8.0, and E.10, all of which were prepared under my direct supervision.

Q. Please briefly describe the City of Tallahassee's existing power generation system.

A. The City currently operates three generating stations with a total summer net capacity of 746 MW and a total net winter capacity of 797 MW. Of the three generating stations, the City has two natural gas and oil fueled generating stations, Sam O. Purdom Generating Station and Arvah B. Hopkins Generating Station, which contain combined cycle, steam, and combustion turbine electric generating facilities. The City also generates electricity at the C.H. Corn Hydroelectric Station. Currently, approximately 98 percent of the City's generating capacity is fueled by natural gas and oil.

Q. Does the City currently have any firm long-term capacity sales contracts in place?

A. The City has no firm long-term capacity sales contracts in place. The City does, however, conduct short-term and intermediate sale transactions as available.

Q. Does the City have power purchase contracts in place?

A. The City currently has a long-term firm capacity and energy purchase agreement with Progress Energy Florida (PEF), which will expire December 3, 2016. In addition to the PEF purchase agreement, the City continues to evaluate other power purchase opportunities as they become available.

Q. Are there any planned unit retirements that will affect the City's existing generating capacity?

A. Table E.2-2 of Exhibit __ [TEC-1] shows the City's current retirement schedule for existing units within the planning horizon of the Need for Power Application. In total, approximately 180 MW of summer capacity and 188 MW of winter capacity are projected to be retired by 2025.

Q. Is the City planning any additional modifications to its existing generating system?

A. Yes. The City is currently planning to repower the existing Hopkins Unit 2 steam turbine to a 1x1 combined cycle configuration through the addition of a combustion turbine and a heat recovery steam generator. The repowering is expected to provide an additional 68 MW of summer capacity and 96 MW of winter capacity while increasing the efficiency of the unit. The repowered Hopkins Unit 2 is expected to begin commercial operation in the summer of 2008.

Q. Please describe the methodology used in developing the City of Tallahassee's load forecast.

A. The load forecast is developed from a set of 10 multi-variable linear regression models which are based on detailed examination of the City's historical growth, usage patterns, and population projections for the years 2006 through 2025. The forecasts are revised each year and are estimated for residential and commercial customers, and the models are capable of separately predicting commercial customer consumption by rate sub-class: general service non-demand (GSND), general service demand (GSD), and general service large demand (GSLD). The City also uses two additional regression models to separately predict summer and winter peak demand.

Q. Are the impacts of conservation and DSM, curtailable load, and system losses reflected in the load forecast?

A. Yes. The forecasts of seasonal peak demand and annual energy requirements account for each of these factors. After the initial load forecast has been developed, the effects of conservation and DSM programs are applied as demand and energy reductions to produce the final forecast. System losses are also computed and applied in the same manner, so that the resulting base forecast reflects adjustments for all these factors.

Q. Please discuss the results of the City's base case load forecast.

A. The City's base case load forecast indicates that summer peak demand is projected to grow at an average annual rate of approximately 1.3 percent over the 2007 through 2025 period (from 626 MW to 793 MW), while winter peak demand is projected to grow at an average annual rate of approximately 1.8 percent over this same period (from 570 MW to 779 MW). Net energy for load requirements are projected to increase at an average annual rate of approximately 1.7 percent over the 2007 through 2025 period (from 2,976 GWh to 4,025 GWh).

Q. Were any alternative load forecasts developed for the City of Tallahassee.

A. Yes. High and low load growth forecasts were developed.

Q. Please discuss the results of the City's high load forecast.

A. The City's high load forecast was developed by altering the assumptions for population, Heating Degree Days, and Cooling Degree Days from those used in the base energy forecast. In addition, the demand model was modified by increasing summer peak temperatures and decreasing winter peak temperatures, along with changes to the customer count. The resulting forecast indicates that summer peak demand, winter peak demand, and net energy for load reach 824 MW, 835 MW, and 4,282 GWh, respectively, by 2025.

Q. Please discuss the results of the City's low load forecast.

A. Much like the high load forecast sensitivity, the City's low load forecast was developed by altering the assumptions for population, Heating Degree Days, and Cooling Degree Days from those used in the base energy forecast. In addition, the demand model was modified by decreasing summer peak temperatures and increasing winter peak temperatures, along with changes to the customer count. The resulting forecast indicates that summer peak demand, winter peak demand, and net energy for load reach 769 MW, 725 MW, and 3,812 GWh, respectively, by 2025.

Q. In your opinion is the process used for developing the demand and energy forecasts reasonable for planning purposes?

A. Yes. The process used in developing the demand and energy forecasts is appropriate for planning purposes.

Q. What reserve margin does the City use for planning purposes?

A. The City plans to maintain a 17 percent reserve margin for both the summer and winter seasons. This reserve margin was originally established based on evaluations of the reliability of the City's electric system using a Loss-of-Load Probability (LOLP) analysis.

Q. Please describe the City's expected need for additional capacity to satisfy reserve margin requirements under the base case load forecasts.

A. The City is forecast to initially require additional capacity in 2011, at which time approximately 22 MW will be required. The need for capacity is forecast to increase to approximately 294 MW by 2025. Tables E.4-1 and E.4-2 of Exhibit __ [TEC-1] present the City's forecast capacity requirements for the summer and winter seasons, respectively.

Q. Please discuss the City's existing conservation and DSM programs.

A. The City has offered energy conservation and DSM programs to its customers since the early 1980s. Currently the City offers numerous programs to both its residential and commercial customers, including the following:

- Residential Secured Energy Efficiency Loans
- Residential Natural Gas Rebates
- Residential Low-Income Ceiling Insulation Grants
- Residential Low-Income Energy Retrofit Grants
- Residential Information and Audits
- Commercial Low Interest Energy Efficiency Loans
- Commercial Custom Loans
- Commercial Demonstrations
- Commercial Information and Audits

Q, **What benefits have the City's existing conservation and DSM programs provided?**

A. Based on analysis of the City's1996 DSM Plan, over the past 10 years, current conservation and DSM programs have reduced peak demand by 20 MW and annual energy use by 80 GWh.

Q. **Are there any advantages that the installation of TEC will have on fuel diversity?**

A. Yes. TEC will provide a unique opportunity for the City to increase fuel diversity and will increase fuel diversity throughout the State of Florida as a whole. The project will have the ability to source solid fuels from both domestic and international coal producing regions including the Powder River Basin (PRB), Central Appalachia, Latin American, and other regions, as well as petroleum coke from the Gulf Coast region and the Caribbean. Historically, coals from these regions and petroleum coke have experienced significantly lower prices on a $/MBtu basis than oil and natural gas. As a result, TEC will not only provide solid fuel capacity for the City and the State of Florida, but it will also provide further fuel diversification through the capability to source coal and petroleum coke from numerous different regions which will help mitigate exposure to high natural gas and fuel oil prices. The low cost baseload energy from TEC will help the City and the State of Florida reduce dependence on higher cost energy from natural gas and oil.

Q. Are there any advantages that the installation of TEC will have on fuel supply reliability?

A. Yes. The addition of solid fueled generation increases the reliability of the City's fuel supply. Coal and petroleum coke inventory for up to approximately 90 days of operation can be stored onsite at TEC, reducing the potential supply disruptions associated with natural gas like those resulting from hurricanes in the Gulf Coast. Furthermore, the ability to store up to approximately 90 days of fuel mitigates potential transportation disruption.

Q. Are there any advantages that the installation of TEC will have on the stability of the City's electric rates?

A. Yes. TEC will help to satisfy the need for low cost, baseload energy within the City's service territory and the State of Florida as a whole. The addition of low cost, baseload energy from TEC will help to limit electric rate increases for consumers and businesses. Electric rate stability will be beneficial in long-term planning and should also help facilitate more stable growth within the economy.

Q. Will the economic advantages of TEC end after 2035?

A. No. Although economic evaluations have been conducted through 2035 for this Taylor Energy Center Need for Power Application (Exhibit __ [TEC-1]), TEC will be designed for, and is expected to have, a service life significantly greater than the 23 years of operation captured by the analysis period. The benefits of TEC's expected actual service life of 35 to 50 years or more have not been captured in the economic analysis but are expected to be realized by the City and the other project participants. Therefore, the total cost savings and benefits of TEC are understated in the economic analysis.

Q. Are there any advantages that the installation of TEC will have on geographic diversity?

A. Yes. For the City, the other project participants, and the State of Florida as a whole, TEC will provide geographic diversity because it will be constructed on a greenfield site. The greenfield site provides the City with baseload generation without increasing the concentration of its generation resources at one location or within its service territory. This diversity should increase reliability and availability of generating resources, particularly in the event a hurricane or other extreme condition causes forced outages in a localized area.

Q. Do you agree with the testimony offered by Brad Kushner of Black & Veatch that the resource plan including the TEC project represents the least cost alternative for the City?

A. Yes. In addition to reviewing the results of the model runs performed by Black & Veatch for this application, the City has evaluated the cost effectiveness of the TEC project as part of its own Integrated Resource Planning Study.

Q. Did the City's resource planning study show similar results to the results shown in Exhibit __ [TEC-1]?

A. Yes. Using additional sensitivity analyses and risk assessments particular to the City's electric system, the Integrated Resource Planning Study confirmed that TEC should be part of the least-cost plan for the City's electric utility.

Q. Are there other important factors that the City considered in its decision to participate in TEC?

A. Yes. As discussed in the testimony of Paul Hoornaert, TEC will utilize proven supercritical technology and include the Best Available Control Technology to minimize plant emissions. Because of the City's concerns about reliability, it was important that TEC utilize proven and reliable technology. The City has a long history of environmental stewardship related to its utility operations, and in keeping with that commitment we believe it important that TEC minimize impacts to the environment.

Q. How does the City of Tallahassee intend to finance its ownership share of TEC?

A. The City typically finances its capital projects using two funding sources. During preliminary design, engineering, and permitting, the City may draw on its working capital within the electric utility fund. As the initial development concludes and construction commences, the City will need to initiate an electric system revenue bond issuance for long-term project funding. For large projects such as a coal fired power plant, the City could expect to issue either fixed or floating rate revenue bonds with a term of up to 30 years.

Q. Does the City of Tallahassee have the funding sources available to finance its share of TEC?

A. Yes. The City has the necessary funding sources available to finance the development and construction of the City's ownership share of the TEC. The City's electric system has credit ratings of A1 from Moody's Investors Service, AA- from Standard and Poor's, and AA- from Fitch. With its excellent credit rating, the City should expect that it will have no difficulties in obtaining bond financing for its share of TEC.

Q. Please summarize your role as chairman of the TEC project transmission study team.

A. In my role as chairman of the transmission study team, I coordinate the analysis by the TEC partners of the proposed interconnection of the project into the regional grid, and lead negotiations between the TEC project and the transmission providers that will be facilitating the interconnection.

Q. What transmission system will the Taylor Energy Center be connected to?

A. The proposed TEC site is located within the Progress Energy Florida (PEF) transmission system and will be connected to it.

Q. Will the Taylor Energy Center partners be developing the associated transmission facilities to connect the plant to the statewide grid and facilitate the transfer of power to the project participants?

A. No. Transmission facilities for the TEC project will be designed and constructed by PEF pursuant to rules set forth by the Federal Energy Regulatory Commission (FERC) for the interconnection of large generators. This rule prescribes a process under which the TEC partners submitted a request for interconnection of the proposed project. The rule also prescribes the set of studies that PEF will conduct to determine if the project can be reliably connected to the grid and to identify the extent of the facilities that will be required. Because of the particular interconnection options being considered for the project, even though the plant site is within the PEF transmission system boundaries, the studies have been performed jointly by PEF and Florida Power & Light (FPL).

Q. What studies are required to determine the impact of the proposed TEC on the transmission system?

A. The FERC process requires the transmission provider to complete three studies as part of the generator interconnection analysis: a feasibility study, a system impact study, and a facilities study. These studies are based in part on proposed interconnection alternatives developed jointly by the TEC partners and PEF/FPL, and reflect power transfers modeled by the transmission providers consistent with transmission service requests submitted by the TEC partners.

Q. What is the current status of the studies?

A. The feasibility and system impact studies have been completed, and the facilities study is expected to be finished in early 2007.

Q. What are the results of the feasibility study?

A. The feasibility study indicated that under a variety of scenarios there is, in general, no adverse impact caused by interconnecting TEC to the transmission grid.

Q. What is the objective of the system impact study?

A. The objective of the system impact study is to identify the specific impacts on the transmission system associated with the interconnection of the TEC project and to propose general strategies to mitigate any of those impacts through necessary improvements as identified by PEF or FPL. As a part of the system impact study, PEF and FPL also developed a set of preliminary interconnection plans and associated budget estimates.

Q. What are the results of the system impact study?

A. The system impact study evaluated three power transfer scenarios for four different interconnection alternatives, and also assessed the impact of the addition of the TEC on the Southern-Florida Interface. All these evaluations were conducted jointly by PEF and FPL. The analysis included a review of thermal overloads and voltage limit violations, a short-circuit study, and a dynamic stability study. Based on the results presented in the system impact study report, there are no significant impacts to the regional grid or the Southern-Florida Interface due to the interconnection of the TEC project.

Q. How will the project interconnect to the PEF system?

A. The TEC Participants (Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and the City of Tallahassee) are continuing to review the results of the system impact study in order to select the interconnection alternative that best meets our needs. In all four of the alternatives studied, there will be two 230 kV transmission lines constructed from the plant site to PEF's Perry substation in addition to other required interconnections. The alternatives differ with regard to what additional facilities would also be constructed to ensure reliable delivery of the output of TEC to the Participants. Currently, the Participants plan to select one of the four interconnection alternatives prior to the execution of the facilities study agreement.

Q. Please describe the costs associated with the TEC interconnection.

A. For evaluation purposes, the Participants assumed the direct interconnection costs to be based on three 6.5 mile 230 kV transmission lines from TEC to the Perry substation. The estimated cost for these lines, developed by Sargent & Lundy, was projected to be about $11.7 million. This cost has been included in the TEC capital cost developed by Sargent & Lundy and is discussed in the testimony of Paul Hoornaert. The preliminary cost estimates for the four interconnection alternatives developed by PEF and FPL and included in the system impact study vary between $86 million and $112 million. This is a conceptual cost estimate and will be refined in the next stage of the interconnection analysis.

Q, How have the interconnection costs been included in the analysis?

A. In the facilities study phase of the interconnection analysis, the costs of connecting TEC to the grid will be identified by PEF and then classified as either direct connection facilities or network improvements. All interconnection costs will be initially funded by the TEC Participants, and then the costs of all network improvements will be credited to the participants as offsets to their respective transmission service charges for delivery of the power from TEC. In our analysis, in addition to the $11.7 million included in the project's capital cost, we have included the transmission service charges for TEC as costs to the project for each Participant as appropriate to deliver their capacity and energy under the presumption that the interconnection facilities will be classified as network improvements.

Q. What if the facilities are not classified as network improvements?

A. While we remain confident that the majority of the costs identified in the system impact study report will be classified as network improvements, the TEC participants performed a sensitivity analysis that increased the capital cost of the project by about $100 million to capture the upper end of the project's transmission interconnection cost exposure based on the conceptual estimates provided by PEF and FPL in the system impact study report. That sensitivity analysis is presented in the testimony of Brad Kushner.

Q. What is the objective of the facilities study?

A. The primary objective of the facilities study is to develop the formal interconnection plan and cost estimate and to identify the required facilities and anticipated timeframe to interconnect the proposed TEC project to the transmission grid.

Q. When will the required transmission systems improvements be completed?

A. Once the facilities study is complete, the TEC project owners will execute an agreement with PEF for funding of the facilities, and detailed design and engineering work will begin. All required transmission system improvements will be completed prior to commercial operation of TEC.

Q. Does this complete your testimony?

A. Yes.

Docket No. ________
Taylor Energy Center
Gary Brinkworth
Exhibit ____ [GSB-1]
Page 1 of 2

RESUME OF GARY S. BRINKWORTH, P.E.

Manager, Electric Utility Strategic Planning
City of Tallahassee
400 E. Van Buren St.
Tallahassee, FL 32301

SUMMARY

I have over 20 years of experience in various aspects of electric utility system planning, including generation planning, transmission planning, load forecasting, engineering economics studies, energy conservation cost/benefit studies, retail rate analysis, and financial modeling. I also have 4 years of experience managing certain retail utility service functions including customer service operations, meter reading, CIS support and billing, underground utility locates, marketing and environmental services.

PROFESSIONAL EXPERIENCE

Manager, Electric Utility Strategic Planning, City of Tallahassee (2003 to present)
I supervise the Electric System Planning Division and have overall responsibility for all system planning tasks undertaken on behalf of the City's electric utility, including generation and transmission planning, load forecasting, energy conservation studies, financial assessments, and retail rate analysis and revenue budgeting studies. I am also responsible for development of strategic plans for the electric utility, and for coordinating those plans with other utility departments in the City of Tallahassee.

Director, Utility Business & Customer Services, City of Tallahassee (1997 to 2003)
Responsible for the direction of several centralized support functions for the City's utility departments, including customer service operations, meter reading, CIS support and billing, underground utility locates, utility marketing, wireless co-locations and fiber leasing, and environmental services.

Manager, Electric System Planning, City of Tallahassee (1990 to 1997)
Responsible for the direction of all planning studies and evaluations conducted on behalf of the electric utility including generation and transmission planning, load forecasting, energy conservation studies, financial assessments, and retail rate analysis and revenue budgeting studies.

Chief Planning Engineer, City of Tallahassee (1988 to 1992)
Responsible for conducting or supervising the preparation of all planning studies for the City's electric utility including generation and transmission planning, load forecasting, energy conservation studies, financial assessments, and retail rate analysis and revenue budgeting studies.

Transmission Planning Engineer, Southern Company Services (1986 to 1988)
Responsible for various transmission planning studies, including system transmission reliability analysis, contingency modeling, interface studies, regional transmission power flow studies, and various operations planning studies on behalf of the operating companies of the Southern electric system.

Generation Planning Engineer, Southern Company Services (1982 to 1986)
Responsible for various generation planning studies, including system expansion planning, annual production costing analysis, loss of load probability evaluations, marginal costing studies, fuel budgeting analysis, and financial planning studies for the operating companies of the Southern electric system.

A. EDUCATION

Bachelor of Science (Electrical Engineering), Auburn University – 1979
Master of Science (Electrical Engineering), Auburn University – 1982

B. REGISTRATION

Registered Professional Engineer in Alabama, Florida, Georgia and Mississippi since 1987.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF STEVEN M. FETTER

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, title, and business address.

A. My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, Nevada 89014.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Taylor Energy Center (TEC), a joint project of four municipal entities, the Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and the City of Tallahassee.

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

A. I am President of Regulation UnFettered, a utility advisory firm I formed in April 2002.

Q. What is your educational background?

A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979.

Q. Please summarize your professional experience related to the electric utility industry.

A. In October 1987, I was appointed as a Commissioner to the three-member Michigan Public Service Commission (Michigan PSC) by Democratic Governor James Blanchard. In January 1991, I was promoted to Chairman by incoming Republican Governor John Engler, who reappointed me in July 1993. During my tenure as Chairman, the Michigan PSC eliminated the agency's case backlog for the first time in 23 years.

Q. What did you do after leaving the Michigan PSC?

A. In October 1993 I accepted a position with Fitch, Inc. (Fitch), a credit rating agency based in New York and London. Initially I served as Senior Vice President of Regulatory and Government Affairs within Fitch's Global Power Group, responsible for interpreting the impact of regulatory and legislative developments on utility credit ratings. In 1999, I was promoted to Global Power

Group Head and Managing Director. In that role, I served as group manager of the combined 18 person New York and Chicago utility team along with continuing to carry out my responsibilities related to tracking regulatory and legislative developments. In April 2002, I left Fitch to start Regulation UnFettered, a utility advisory firm. I note that Fitch retained me as a consultant for a period of approximately six months shortly after I resigned.

Q. Please briefly describe your role as President of Regulation UnFettered.

A. I serve as an advisor to persons and organization with an interest in the utility industry using my financial, regulatory, legislative, and legal expertise. In that role, my goal is to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include investor owned and municipal electric, natural gas and water utilities, state public utility commissions and consumer advocates, nonutility energy suppliers, international financial services and consulting firms, and investors.

Q. How does your experience relate to your testimony in this proceeding?

A. My experience as Chairman and Commissioner on the Michigan PSC and my subsequent professional experience analyzing the U.S. investor owned and municipal electric and natural gas sectors from a credit rating perspective – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of fuel diversity for generating facilities, both for internal utility operations as well as for how electric utilities are viewed by the financial community. Fuel diversity related to power supply, whether internally generated or procured through power purchases, is a factor that enters into the process of utility credit analysis and formulation of individual company credit ratings.

Q. **Have you previously sponsored testimony before regulatory and legislative bodies?**

A. Since 1990, I have on numerous occasions testified before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, and various state legislative and regulatory bodies on the subjects of credit risk within the utility sector, electric and natural gas utility restructuring, fuel and purchased power and other energy adjustment mechanisms, performance-based ratemaking, utility securitization bonds, and nuclear energy. More specifically, I have testified on several occasions about the issues of volatility and pricing related to the presence or absence of fuel and purchased power cost recovery mechanisms (FACs). The goal of fuel diversity is similar to the intent of FACs: that is, to minimize the negative financial impacts on utilities and their customers during times of unusual stress within the fuel or purchased power markets related to power or gas supply and price.

My full educational and professional background is attached in Exhibit _____ [SMF-1].

Q. What is the purpose of your testimony?

A. In this testimony, I offer my opinion, based upon my prior experience as head of the utility ratings practice at a major credit rating agency, chairman of a state public utility commission, and consultant to utilities, commissions and consumer advocates, that the Florida Public Service Commission (Florida PSC), in its consideration of the need for the coal-fired TEC, should give significant weight to the benefits gained through the addition of generating facilities that enhance the diversity of fuels utilized within the state. Analysis of the framework of the project, coupled with review of Florida's current and projected generation fuel mix, shows that the proposed TEC would be an effective means of meeting the state's growing power supply needs while diversifying fuel use in a way that reduces overall supply and price volatility and risk for utilities and their customers.

Q. What is fuel diversity?

A. Fuel diversity within the context of the electric utility industry refers to a utility's procurement of power supply encompassing a range of types of electric generation facilities, fuel sources, or purchased power agreements (PPA).

Q. Does fuel diversification affect the risks associated with electricity generation?

A. Yes. Fuel diversification allows a utility to minimize the risks that accompany its operations and enable it to withstand the ups and downs that are unanticipated specifically, but certainly foreseeable generally. Such risks include fuel price and supply volatility and price and supply effects from international political events or regional weather patterns or unforeseen events. Basically, fuel diversity supports the mitigation of price and supply risks and the achievement of an appropriate level of reliability and service quality for a utility and its customers on an ongoing basis.

Q. Does fuel diversification affect the reliability and integrity of electric power generation?

A. Yes. Fuel diversity assists a utility in dealing with future unanticipated occurrences and, thereby, enhances the reliability and integrity of electricity supply.

Q. Do you have concluding thoughts?

A. I do. In these times of global unrest coupled with rapidly expanding international economies resulting in uncertainty in the price and supply of fuel, I believe it would represent a major mistake for the Florida PSC to forgo the benefits that can come with a focus on fuel diversity related to new generating facilities. Earlier this year, Fitch highlighted the growing importance of fuel diversity under current circumstances within the electric industry by discussing the particular challenges of the region related to fuel diversity, but also citing with approval the path that Florida is taking to deal with them:

> [T]here is growing cry from regulators and other industry participants for fuel diversity in the face of high gas prices. For example, in its energy

> plan (published January 2006), the Florida Department of Environmental Protection outlined its support and recommended policies that encourage greater fuel diversity and lessen the dependence on natural gas. Additionally, the 10 year plans recently submitted by Florida utilities to the Public Service Commission indicated that more nongas capacity additions are expected to meet growing load.

I agree with the emphasis that Florida has placed on promoting fuel diversity, and encourage the Florida PSC to adopt policies in this proceeding consistent with that goal for the benefit of both the state's electric utilities and also their customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. _________
Taylor Energy Center
Steven Fetter
Exhibit ____ [SMF-1]
Page 1 of 4

STEVEN M. FETTER

1489 W. Warm Springs Rd. -- Ste. 110
Henderson, NV 89014
732-693-2349
RegUnF@comcast.net
www.RegUnF.com

Education University of Michigan Law School, J.D. 1979
Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. (Communications) 1974

April 2002 – Present
President – REGULATION UnFETTERED – Henderson, NV/Rumson, NJ

Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy, water and telecommunications sectors; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; and skills training in ethics, negotiation, and management efficiency.

- Service on Boards of Directors of: CH Energy Group (Chairman, Governance and Nominating Committee; Member, Audit; Previous Chairman, Audit and Compensation Committees), National Regulatory Research Institute (at Ohio State University), Keystone Energy Board, and Regulatory Information Technology Consortium; Member, Wall Street Utility Group and American Public Power Association; Participant, Keystone Center Dialogue on Financial Trading and Energy Markets.

October 1993 – April 2002
Group Head and Managing Director; Senior Director -- Global Power Group, Fitch IBCA Duff & Phelps -- New York/Chicago

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance.

- Led an effort to restructure the global power group that in three years time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

- Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

- Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002
Consultant -- NYNEX -- New York, Ameritech -- Chicago, Weatherwise USA -- Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993
Chairman; Commissioner -- Michigan Public Service Commission -- Lansing

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

- Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

- Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant twelve-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

- Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability; Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987
Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary -- U.S. Department of Labor -- Washington DC

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (U.S. Labor Law and the Future of Labor-Management Cooperation, w/S. Schlossberg, 1986).

January 1983 - August 1985
Senate Majority General Counsel; Chief Republican Counsel -- Michigan Senate -- Lansing

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 - January 1983
Assistant Legal Counsel -- Michigan Governor William Milliken -- Lansing

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982
Appellate Litigation Attorney -- National Labor Relations Board -- Washington DC

Other Significant Speeches and Publications

- Perspective: Don't Fence Me Out (Public Utilities Fortnightly, October 2004)
- Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998)(unpublished)
- Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)
- The Feds Can Lead...By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)
- Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)
- Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)
- Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF DON GILBERT

ON BEHALF OF

JEA

DOCKET NO. _______

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Don Gilbert. My business address is 21 West Church Street, Jacksonville, Florida 32202.

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

A. I am employed by JEA. My title is Manager, Electric System Planning.

Q. Please describe your responsibilities in that position.

A. I am responsible for planning activities including generation, transmission, and distribution related to JEA's electric system. It is my responsibility to ensure that JEA will be able to continue to reliably serve retail electric load at a reasonable cost.

Q. Please state your educational background and professional experience.

A. I received my Bachelor of Electrical Engineering degree from the Georgia Institute of Technology in 1982. I am a licensed professional engineer in the State of Florida, with more than 28 years of experience in the electric utility industry, including 4 years in Georgia Power Company's corporate planning, 3 years in JEA's corporate planning, 20 years in JEA's system operations, and more than 1 year as current manager of JEA's Electric System Planning.

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

A. The purpose of my testimony is to provide a description of JEA's existing system, summarize JEA's forecast of electrical demand and consumption, and describe JEA's need for capacity. I will also discuss several strategic considerations that led JEA to participate in Taylor Energy Center (TEC), and I will describe how JEA will finance its share of the unit.

Q. Are you sponsoring any exhibits as part of your pre-filed testimony?

A. Yes. I am sponsoring Exhibit ___ [DG-1], which is a copy of my résumé.

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

A. Yes. I am sponsoring Sections C.1 through C.4, C.7.1, C.8, and C.10.

Q. Please describe JEA's existing system.

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. JEA's service area covers approximately 900 square miles and serves more than 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). The Electric System includes the Brandy Branch, Northside, and Kennedy generating stations. JEA also has a contract with Southern Company for the purchase of 207 megawatts (MW) of coal fired capacity and energy from June 1995 through May 2010 (Southern UPS). The total summer net capability of the Electric System, Power Park, and Scherer Unit 4 is 3,473 MW and the total winter net capability is 3,661 MW. For the purposes of this Need for Power Application, it has been assumed that Kennedy combustion turbine (CT) 4 and CT 5 are in long-term reserve shutdown. Therefore, the total available summer net capability is 3,371 MW, and the total available winter net capability is 3,535 MW in the near term.

Q. What is the current status of Kennedy CTs 4 and 5?

A. Kennedy CTs 4 and 5 had been in long-term reserve shutdown earlier this year. However, the Northside CTs 5 and 6 are currently unavailable as a result of a failure of the step-up transformer that these two units share. As a result, Kennedy CTs 4 and 5 have been returned to service while this step-up transformer is repaired or replaced. Upon successful repair or replacement of the Northside CT 5 and 6 transformer, it is planned that Kennedy CTs 4 and 5 will return to a long-term reserve status.

Q. Are there any planned retirements in JEA's fleet?

A. Similar to Kennedy CTs 4 and 5, it has been assumed that Kennedy CT 3 will be placed in long-term reserve shutdown in 2008. The decision to retire these units will be made after the successful commissioning of Kennedy CT 8 planned for operation in December 2008.

Q. Describe JEA's clean power program.

A. JEA is working closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to create and update an action plan entitled "Clean Power Program Action Plan." The "Clean Power Program Action Plan" establishes an Advisory Panel, comprised of participants from the Jacksonville community, who provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program Initiative. Current members of the Advisory Panel include the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board. The Clean Power Program Initiative calls for development of the JEA Clean Power Program Strategic Plan. The JEA Clean Power Program Strategic Plan incorporates practices and technologies including green power, demand-side management (DSM) and efficiency programs, clean fuels, pollution control technologies, and improvements to power generation efficiencies. The Advisory Panel determines the capacity credits obtained from the JEA Clean Power Program Strategic Plan. JEA has installed significant capacity under the JEA Clean Power Program Strategic Plan. JEA currently has approximately 91 MW installed under the

JEA Clean Power Program Strategic Plan, including approximately 321 kW of solar photovoltaic capacity, 9 MW of solar thermal capacity, 6 MW in landfill biogas capacity, 800 kW in digester biogas capacity, 10 MW of wind capacity, 22 MW of proposed landfill and biomass projects, and 43 MW of generating unit efficiency improvements. Over the past several years, JEA has received several awards for its clean power program.

Q. **Are there other large clean power projects that JEA has pursued?**

A. Yes. In 2001, JEA signed a 15 year power purchase agreement with Biomass Investment Group (BIG) to purchase 70 MW of renewable energy. This developer proposed to grow a biomass crop (e-grass or arundo donax) as a fuel for a gasification plant in Florida. The project has been delayed many times, and since the commercial operation date of this unit is not firm, this project is not included as a resource for JEA's system. Although JEA committed to this project, the developer has not been able to bring it to commercial status as was originally planned. JEA will continue to review this opportunity and other biomass projects as they are presented.

Q. **Have any of the planned generator efficiency improvements been completed?**

A. Yes. Turbine upgrades for Northside 1 and Northside 3 have been completed under the Clean Power Program. These improvements have resulted in an increase in capacity without an increase in fuel use. Tables C.4-1 and C.4-2 in the TEC Need for Power Application Exhibit ___ [TEC-1] include 36 MW of additional capacity from these upgrades. To date, approximately 27 MW of this increase has been achieved (18 MW for Northside 3 and 8.5 MW for Northside 1). Northside 2 is planned to have the turbine upgrade implemented toward the end of 2006.

Q. Please briefly describe the methodology used to determine the load forecasts for JEA.

A. JEA prepares forecasts of both Net Energy for Load (NEL) and peak demand. JEA currently furnishes wholesale power to Florida Public Utilities Company (FPU) for resale in the city of Fernandina Beach in Nassau County, north of Jacksonville. JEA is contractually committed to supply FPU until December 31, 2007. Currently, FPU does not have a contract with JEA to renew this sale. Therefore, starting in January 2008, sales to FPU are not included in JEA's NEL and peak demand forecasts. If the FPU contract is renewed, JEA's loads will be higher than forecast.

The NEL forecast is developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. Inputs into the forecast include historical energy production, JEA territory sales, sales to FPU, and heating and cooling degree-days. The JEA forecast modeling methodology separately accounts for and projects the temperature-dependent and non-temperature-dependent energy requirements over time, then combines these components to derive the system total NEL forecast. The temperature-dependent NEL is modeled as a function of parameter estimates for historical and projected heating and cooling degree-days.

To forecast peak demand, JEA has developed a nonlinear regression analysis that utilizes Statistical Analysis Software (SAS) and Excel software. JEA develops a forecast of total peak demand, including interruptible and curtailable customers, and then subtracts these customers to derive an estimate of firm demand only. The peak demand forecast is driven by temperature and time-series data. The forecasting process involves the collection of historical hourly system load data and daily temperature data. A nonlinear regression analysis is conducted to forecast the summer and winter peaks. The forecast temperature used in the regression is the 20 year median of the seasonal extreme temperatures (summer 99° F and winter 24° F) wherein the winter seasonal extreme for a year is the lowest temperature during the months of December, January, and February, and the summer seasonal extreme is the highest temperature during the months of July, August, and September.

Q. Please summarize the results of the forecast of NEL and peak demand.

A. The NEL is forecast to increase at an average annual growth rate of 2.2 percent during the 2007 through 2024 forecast period. NEL is forecast to increase from 14,456 GWh in fiscal year 2007 to 20,851 GWh in fiscal year 2024. These figures assume that FPU requirements are not part of JEA's total NEL beginning January 1, 2008. The results of the NEL forecast are summarized in Table C.3-5 of the TEC Need for Power Application, Exhibit ___ [TEC-1].

During the forecast period, total summer peak demand is forecast to increase at an average annual growth rate of 1.9 percent overall. The annual growth rate in summer interruptible peak demand is 1.5 percent, and the average annual increase in summer firm peak demand is 1.9 percent. During the winter period, the total growth rate in winter peak demand is projected to increase at an average annual growth rate of 2.7 percent. The average annual increase in winter interruptible peak demand is 1.5 percent, and the average annual increase in winter firm peak demand is 2.7 percent. Total JEA peak demand in 2007 is projected to be 3,099 MW in the winter, compared to a summer total peak demand of 2,893 MW. The 2024 total winter peak demand is projected to be 4,856 MW, compared to 3,957 MW during the summer period. A similar pattern holds for the firm peak demand projections. The firm winter peak demand is projected to increase from 2,924 MW in 2007 to 4,630 MW in 2024, and the firm summer peak demand is projected to increase from 2,716 MW in 2007 to 3,729 MW in 2024. The results of the summer and winter peak demand forecasts are summarized in Table C.3-2 of the TEC Need for Power Application, Exhibit ___ [TEC-1].

Q. Historically, when has JEA experienced its peak demand?

A. Since 1986, JEA has experienced its annual peak demand 14 times in the summer and 6 times in the winter. However, recent historical peaks have occurred during the winter in 4 of the past 6 years. As the forecast described above indicates, JEA's season of system peak is transitioning from the summer to the winter, resulting in a divergence of these peaks.

Q. Were low and high load and NEL forecasts developed?

A. Yes. Moderate (low) and extreme (high) load forecasts were developed. The moderate case assumes a summer temperature of 93° F and a winter temperature of 30° F. The extreme case assumes a summer temperature of 103° F and a winter temperature of 7° F. In the low case, winter firm demand is forecast to increase from 2,461 MW in 2007 to 3,846 MW in 2024, while summer firm demand is forecast to increase from 2,572 MW in 2007 to 3,684 MW in 2024. Similarly, the NEL for the low case is forecast to increase from 13,808 GWh in 2007 to 20,581 GWh in 2024. In the high case, winter firm demand is forecast to increase from 3,462 MW in 2007 to 5,583 MW in 2024, while summer firm demand is forecast to increase from 2,778 MW in 2007 to 3,732 MW in 2024. Similarly, the NEL for the high case is forecast to increase from 16,069 GWh in 2007 to 23,597 GWh in 2024. Tables C.3-3 and C.3-6 of the TEC Need for Power Application, Exhibit ___ [TEC-1], show the high and low forecasts.

Q. In your opinion is the process used for developing the demand and energy forecasts reasonable for planning purposes?

A. Yes. The process used in developing the demand and energy forecasts is appropriate for planning purposes.

Q. How does JEA determine its reserve requirements?

A. JEA determines its reserve requirements by comparing net system capacity and system peak demand plus reserves for the summer and winter peaks. JEA adheres to a minimum 15 percent reserve margin in both the summer and winter seasons. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load forecasts. JEA plans to maintain the 15 percent reserve margin only for firm load obligations. Interruptible load and curtailable load are not considered in setting the 15 percent reserve margin.

Q. When does JEA forecast a need for capacity?

A. The projected reserve requirements for the winter base case and the summer base case (based on JEA's currently available capacity resources) are presented in Tables C.4-1 and C.4-2, respectively, of the TEC Center Need for Power Application, Exhibit ___ [TEC-1]. The tables show that JEA's capacity will fall below its required 15 percent reserve margin in the winter of 2011/12. At this time, JEA's reserve margin is projected to fall to 13.0 percent, 67 MW short of the 15 percent required reserves. The deficit continues to increase in the winter of 2012/13, when the margin is projected to be 9.7 percent, 182 MW short of the 15 percent required reserve margin.

Q. Are there any advantages that the installation of TEC will have on fuel diversity?

A. Yes. JEA's resource plan calls for continuing its well balanced and diversified mix of fuels with a combination of gas fired, simple cycle CTs as well as TEC. TEC will provide an increase in fuel diversity for JEA's system and Florida as a whole. The project will have the ability to source solid fuels from both domestic and international coal producing regions, including the Powder River Basin (PRB), Central Appalachia, Latin America, and other regions, as well as petroleum coke (petcoke) from the Gulf Coast region and the Caribbean. Historically, the regions from which these coals and petroleum coke will be sourced have experienced less fluctuation in price and generally have had lower commodity prices than oil or natural gas on a $/MBtu basis.

As a result, TEC will not only provide additional solid fuel capacity for JEA and Florida, but it will also provide further fuel diversification through the capability to source coal and petcoke from numerous different regions, which will help mitigate exposure to high natural gas and fuel oil prices. The low cost energy from TEC will be beneficial for JEA and Florida in meeting baseload requirements.

Q. Are there any advantages that the installation of TEC will have on fuel reliability?

A. Yes. The addition of solid-fueled generation increases the reliability of JEA's fuel supply. A coal and petcoke inventory for up to approximately 90 days of operation can be stored onsite, reducing the potential supply disruptions associated with natural gas like those resulting from hurricanes in the Gulf Coast. Furthermore, the ability to store up to approximately 90 days of fuel mitigates potential transportation disruption.

Q. Are there any advantages that the installation of TEC will have on the stability of JEA electric rates?

A. Yes. TEC will help to satisfy the need for low cost, baseload energy within JEA's service territory and the State of Florida as a whole. Additional low cost, baseload energy from TEC will help to limit electric rate increases for consumers and businesses. In May 2010, JEA's 207 MW purchase agreement with Southern Company expires, leaving JEA with a void in baseload capacity and potentially more dependency on natural gas. TEC will maintain JEA's capacity at approximately 50 percent solid fuel and 50 percent gas and fuel oil, with the ability to produce 70 to 80 percent of the system energy requirements from either fuel type. Electric rate stability will be beneficial for long-term planning and should also help facilitate more stable growth within the economy. In addition, when low cost baseload energy from TEC is available in conjunction with cost-effective DSM measures and biomass, or other renewable energy when available to JEA, even greater benefits to rate stability may be achieved.

Q. Will the economic advantages of TEC end after 2035?

A. No. Although economic evaluations have been conducted through 2035 for this TEC Need for Power Application, Exhibit ___ [TEC-1], TEC will be designed for, and is expected to have, a service life significantly greater than the 23 years of operation captured by the analysis period. The benefits of TEC's expected actual service life of 35 to 50 or more years have not been captured in the economic analysis, but are expected to be realized by JEA and the other Participants. Therefore, the total cost savings and benefits of TEC are likely understated in the economic analysis. In addition, JEA's current 2006 generation expansion plan has identified a need for additional baseload generating capacity after the commercial operation of TEC.

Q. Are there any advantages that the installation of TEC will have on geographic diversity?

A. Yes. For JEA, the other participating utilities, and the State of Florida as a whole, TEC will provide geographic diversity because it will be constructed on a greenfield site. The greenfield site provides JEA with additional baseload generation without increasing the concentration of its generation resources at one location or within its service territory. JEA currently has approximately two thirds of its generating resources located at two adjacent sites (Northside and SJRPP). This diversity should increase the reliability and availability of generating resources, particularly in the event of a local natural disaster affecting forced outages at the adjacent Northside and SJRPP sites.

Q. Are there other important factors that JEA considered in its decision to participate in TEC?

A. Yes. As discussed in the testimony of Paul Hoornaert, TEC will utilize proven supercritical technology and include the Best Available Control Technology to minimize plant emissions. It was important to JEA that TEC utilize proven and reliable technology and also minimize impacts on the environment. TEC also provides favorable economies of scale, with sharing of risk associated with owning and operating a large project.

Q. How does JEA intend to finance the construction of TEC?

A. JEA typically finances large generation capital projects using fixed and floating rate subordinate long-term debt. Up to a maximum of 30 percent of the debt may be floating rate. During the preliminary design, engineering, and permitting, JEA may use internal funds from operations or from prior issuances to fund early project costs. As the initial development concludes and construction commences, JEA may initiate various series of revenue bond issuances for long-term financing with terms of up to 30 years. For large projects, JEA may issue bonds every 1 to 2 years to cover expected construction related capital costs over these periods. By having multiple issuances, JEA will limit the amount of interest incurred during the construction of the plant. In addition, JEA may pool the financing for TEC with other smaller capital addition costs that may be required concurrent with TEC. JEA's senior electric system debt has very favorable ratings of AA- from S&P, Aa2 from Moody's Investor Services, and AA- from Fitch. To protect against fluctuations in the interest rate, JEA may use interest rate swap contracts to take advantage of favorable market conditions and caps to limit the risk associated with variable rate debt.

Q. In your opinion will JEA be able to obtain the financing for the construction of TEC?

A. Yes. Based on the project's favorable economics and JEA's excellent credit rating, JEA will be able to issue debt to cover its share of the project cost.

Q. In your opinion is the economic analysis performed and represented by Black & Veatch consistent with JEA's analysis?

A. Yes. The results of the economic analyses performed for JEA by Black & Veatch and presented in the Need for Power Application (Exhibit ___ [TEC-1]) are consistent with JEA's own Integrated Resource Plan.

Q. Does this complete your testimony?

A. Yes.

Docket No. _________
Taylor Energy Center
Donald Gilbert
Exhibit ____ [DG-1]
Page 1 of 2

RESUME OF

Donald (Don) Gilbert, Manager, Electric System Planning

JEA

Qualifications and Experience:

Mr. Gilbert has over 28 years experience in the electric utility business including four years in Georgia Power Company's Corporate Planning, three years in JEA's Corporate Planning (transmission & generation planning), and 20 years in JEA's system operations. Don has held chair positions of the Florida Coordinating Group (FRCC) Telecommunication committee, Florida/Southern Inter-utility data exchange working group, and the technical subcommittee responsible for the implementation of the Automated Interchange Matching System. Don served on JEA's management team as a System Operation Control Systems manager from April 1998 until October 2001. Since June 2005, Don has been the Manager of JEA's Electric System Planning area responsible for Generation, Transmission, and Distribution planning activities. Since 1985, Don has been licensed to practice as a Professional Engineer in the state of Florida.

Employment History:	1982-Present	JEA
	1979-1982	Georgia Power Company
Education:	B.S.	Electrical Engineering, Georgia Institute of Technology

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF NICHOLAS GUARRIELLO
ON BEHALF OF
REEDY CREEK IMPROVEMENT DISTRICT
DOCKET NO. _______
SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Nicholas Guarriello. My business address is 1000 Legion Place, Suite 1100, Orlando, Florida 32801.

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

A. I am employed by R.W. Beck. My current position is Principal and Immediate Past President/CEO.

Q. Please describe R.W. Beck.

A. R.W. Beck is a national management consulting and engineering firm with a multidisciplined 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 requests for 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; and monitoring, permitting, and licensing. Since its founding in 1942, some of the milestones that the firm has achieved include the following:

- Providing independent engineering and feasibility assessments associated with more than $150 billion in capital investment.
- Performance of due diligence reviews and/or design and engineering of more than 400 power-related projects.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the Polytechnic University. I have a Master of Business Administration from New York University. I am also a registered Professional Engineer in the State of Florida.

I have more than 30 years of experience in the electric, gas, solid waste, water, and wastewater industries. My experience includes financings, appraisals, retail rate studies, wholesale rate work, power supply planning, load forecasting, consulting engineer's reports for bond financing, contract analyses and negotiations, annual and biennial reports required by bond resolutions, and expert testimony and litigation support. I also have significant experience in strategic and long-term planning for electric utility clients. I have been involved in several internal task forces and external presentations addressing the competitive and restructuring issues facing the utility industry in the United

States, including transmission access, deregulation, technological improvements, and retail wheeling.

I have been involved in providing expert assistance or testimony regarding open access transmission filings in light of a changing utility environment and increased competition.

In addition, more recently, I have made several presentations regarding the renewed interest in coal generation and the future of the electric power industry. I have been staying abreast on utility trends impacting the industry and, over the years, have spoken at several executive forums on the resurgence of coal fired generation in the power industry and have researched this trend and its impact on the industry.

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

A. The purpose of my testimony is to provide an overview of Reedy Creek Improvement District (RCID) and its participation in the Taylor Energy Center (TEC). I will summarize RCID's existing generating system as well as its available purchase power resources. I will also discuss RCID's load forecast and its need for capacity. I will provide an overview of the demand-side management (DSM) and conservation programs currently offered by RCID, as well as RCID's ongoing commitment to evaluate new conservation opportunities. In addition, I will discuss strategic considerations that support

RCID's decision to participate in TEC, and RCID's ability to finance its ownership share of the TEC project.

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

A. Yes. I am sponsoring Sections D.1.0, D.2.0, D.3.0, D.4.0, D.7.0, D.8.0, and D.10.0, all of which were prepared under my direct supervision.

Q. Please provide a summary of RCID's existing electric utility system.

A. RCID owns, operates, and maintains facilities associated with the electric generation and distribution of power solely within RCID. The current net summer generating capacity totals 60 MW.

RCID's Central Energy Plant (CEP) consists of a 1x1 combined cycle unit utilizing a General Electric (GE) LM6000 combustion turbine, with a net summer output of 55 MW. In addition to the CEP site, the Epcot Central Energy Plant (ECEP) consists of two packaged diesel generating units to provide peaking and emergency backup service to vital loads. Each diesel unit has a maximum permitted capacity limit of 2.5 MW.

RCID currently meets a major portion its electric system requirements through power purchases from Tampa Electric Company (TECO), Progress Energy Florida (PEF), and Orlando Cogen Limited (OCL). Table D.2-1 of Exhibit __ [TEC-1] summarizes these purchase power contracts.

Q. Please briefly describe the methodology used in developing RCID's load forecast.

A. RCID's primary customer is the Walt Disney Resort Complex (WDW), which represents approximately 85 percent of its load. The remaining 15 percent of RCID's load is primarily from commercial customers consisting of hotels and service businesses and approximately 10 residential customers. As such, load forecasts for RCID are generally driven by its customers' baseload business models. RCID's load growth is forecast to occur in increments due to new facilities developed as part of its customers' business models.

For each forecast, the initial year values are established based on the previous year's actual loads, adjusted for anomalies and any known incremental additions or subtractions. While the types and locations of future development within RCID's boundaries have been defined, the timing of these developments is not known with certainty. As a result, the forecast is essentially a straight-line approximation of the growth rate.

Q. Please discuss the results of RCID's base case load forecast.

A. Incremental annual additions for the RCID load forecast range between 1 MW and 3 MW over the 2006 to 2010 time frame. Incremental additions beyond 2010 are based on the average additions of approximately 1 MW per year through 2025. The firm summer peak demand is projected to increase from 191 MW in 2006 to 213 MW in 2025 (an average annual growth rate of approximately 0.6 percent). RCID's annual energy requirements are expected to increase from 1,259 GWh in 2006 to 1,395 GWh in 2025 (an average annual growth rate of approximately 0.5 percent). Table D.3-1 of Exhibit__[TEC-1] summarizes RCID's net annual peak demand and energy requirements for the years 2006 through 2025.

Q. **Were any alternative load forecasts developed?**

A. Yes. High and low load forecasts were developed.

Q. **Please discuss the results of RCID's high load forecast.**

A. RCID's high load forecast reflects that summer peak demand is projected to grow at an average annual rate of approximately 0.7 percent over the 2006 through 2025 period (from 195 MW to 223 MW). Annual energy requirements are projected to increase at an average annual rate of approximately 0.7 percent over the 2006 through 2025 period (from 1,279 GWh to 1,468 GWh).

Q. **Please discuss the results of RCID's low load forecast.**

A. RCID's low load forecast reflects that summer peak demand is projected to grow at an average annual rate of approximately 0.3 percent over the 2006 through 2025 period (from 190 MW to 203 MW). Annual energy requirements are projected to increase at an average annual rate of approximately 0.4 percent over the 2006 through 2025 period (from 1,246 GWh to 1,336 GWh).

Q. In your opinion is the process used for developing the demand and energy forecasts reasonable for planning purposes?

A. Yes. The process used in developing the demand and energy forecasts is appropriate for planning purposes.

Q. What reserve margin does RCID use for planning purposes?

A. RCID plans to maintain a 15 percent reserve margin for planning purposes.

Q. Please describe RCID's expected need for additional capacity to satisfy reserve margin requirements under the base case load forecast.

A. RCID is expected to encounter a capacity shortfall in 2011, taking into account load growth and the expiration of the PEF purchased power contract, at which time approximately 134 MW of additional capacity will be required to maintain a 15 percent reserve margin. The need for additional capacity increases to approximately 185 MW by 2025. Table D.4-1 of Exhibit __[TEC-1] summarizes RCID's forecast annual capacity requirements for the years 2006 through 2025.

Q. Please discuss RCID's existing DSM and conservation programs.

A. Throughout its history, RCID has demonstrated a strong commitment to conservation. RCID has assisted and participated in numerous conservation and efficiency programs. A vast majority of the DSM and conservation activities within the RCID service territory have been implemented for and/or by WDW.

The DSM and conservation programs assisted with or provided by RCID, in conjunction with its customers, include the following:

- Customer implemented DSM and conservation programs.
- Energy Efficient Lighting Solutions – Green Lights Program.
- Thermal Storage Facility/Program.

Q. Are the impacts of DSM and conservation reflected in the load forecast for RCID?

A. Yes. The load forecast for RCID reflects the DSM and conservation measures already implemented by RCID and its customers.

Q. Does RCID plan to consider any new DSM and conservation programs in the future?

A. Yes. RCID and its customers will continually evaluate opportunities for energy conservation. As new facilities are built, by the RCID or its customers, consideration will be given to the application of existing energy conservation programs to those new facilities, and any appropriate new DSM options will be evaluated for the new facilities.

Q. Are there any advantages that the installation of TEC will have on fuel diversity?

A. Yes. RCID's existing generation is fueled by natural gas and diesel fuel, with a majority of its demand and energy requirements met through purchase power agreements with TECO, PEF, and OCL. These purchase power agreements provide RCID with power from a diverse mix of resources and fuel types. Based on available summer capacity and including purchased power broken down by generation fuel types for TECO and PEF, RCID currently meets its capacity needs through nuclear resources (4 percent), coal fired resources (16 percent), natural gas fired resources (63 percent), and oil fired resources (17 percent). Under the least-cost expansion plan, by 2011, RCID will become primarily dependent on natural gas fired resources at 84 percent of its total available capacity. Of the remainder, coal fired resources represent 13 percent and oil fired resources provide the remaining 3 percent.

This change in capacity resources is primarily driven by the expiration of the PEF agreement and the addition of a new LM6000 combined cycle resource in that year. With the inclusion of TEC in 2012, RCID's available capacity under the least-cost expansion plan would shift back to a more diverse fuel mix. Coal fired resources would increase to 32 percent of total available capacity, gas fired resources would decrease to 65 percent, and oil fired resources would represent the remaining 3 percent. Therefore, the low cost baseload energy from TEC will help RCID reduce its dependence on volatile, higher cost energy from natural gas and oil.

In addition, the project will have the ability to source solid fuels from both domestic and international coal producing regions, as well as petroleum coke (petcoke) from the Gulf Coast region and the Caribbean. Historically, the regions from which these coals and petcoke will be sourced have experienced less fluctuation in price and generally have had lower commodity prices than oil and natural gas on a $/MBtu basis. As a result, TEC will not only provide solid fuel diversity for RCID, but it will also provide further fuel diversification through the capability to source coal and petcoke from numerous different regions, which will help mitigate exposure to high natural gas and fuel oil prices.

Q. Are there any advantages that the installation of TEC will have on fuel reliability?

A. Yes. The addition of solid-fueled generation increases the reliability of RCID's fuel supply. A coal and petcoke inventory for up to approximately 90 days of operation can be stored onsite, reducing the potential supply disruptions associated with natural gas like those resulting from hurricanes in the Gulf Coast. Furthermore, the ability to store up to approximately 90 days of fuel mitigates potential transportation disruption.

Q. Are there any advantages that the installation of TEC will have on the stability of RCID's electric rates?

A. Yes. TEC will help to satisfy the need for low cost, baseload energy within RCID's service territory. Additional low cost, baseload energy from TEC will help stabilize volatility in electric rates for consumers and businesses. Electric rate stability will be beneficial for long-term planning.

Q. Will the economic advantages of TEC end after 2035?

A. No. Although economic evaluations have been conducted through 2035 for this Taylor Energy Center Need for Power Application (Exhibit __ [TEC-1]), TEC will be designed for, and is expected to have, a service life significantly greater than the 23 years of operation captured by the analysis period. The benefits of TEC's expected actual service life of 35 to 50 or more years have not been captured in the economic analysis, but are expected to be realized by RCID and the other project Participants. Therefore, the total cost savings and benefits of TEC are understated in the economic analysis.

Q. Are there any advantages that the installation of TEC will have on geographic diversity?

A. Yes. For RCID, the other project participants, and the State of Florida as a whole, TEC will provide geographic diversity because it will be constructed on a greenfield site. The greenfield site provides RCID with baseload generation without increasing the concentration of its generation resources at one location or within its service territory. This diversity should increase the reliability and availability of generating resources, particularly if a hurricane or other extreme condition causes forced outages in a localized area.

Q. How will participation in TEC affect RCID's portfolio of generating resources?

A. RCID currently purchases approximately 80 percent of its capacity requirements through agreements with TECO, PEF, and OCL. Participation in TEC will provide RCID with additional low cost, baseload generating capability and will reduce its dependence on potentially higher cost capacity and energy from power purchases in the volatile electric energy market in the future.

Q. Are there other important factors that RCID considered in its decision to participate in TEC?

A. Yes. As discussed in the testimony of Paul Hoornaert, TEC will utilize proven supercritical technology and include the Best Available Control Technology to minimize plant emissions. It was important to RCID that TEC utilize proven and reliable technology and also minimize impacts to the environment.

Q. How does RCID intend to finance its participation in the construction of TEC?

A. RCID has not yet made a firm decision in regard to funding for its participation in TEC. RCID may draw on its working capital to fund its participation in the TEC project during the preliminary design, engineering, and permitting phases. RCID will likely obtain financing through a fixed or floating rate long-term revenue bond to fund its participation in the TEC project as construction begins. RCID's current bond rating is A- from Fitch and Standard & Poor's, and A3 from Moody's.

Q. Will RCID be able to obtain the financing for its participation in the construction of TEC?

A. Yes. Based on RCID's bond ratings and reputation, RCID will be able to obtain financing for its ownership share of TEC.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JAMES HELLER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _______

SEPTEMBER 19, 2006

INTRODUCTION

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

A. My name is James Heller. My business address is 4803 Falstone Avenue, Chevy Chase, Maryland 20815.

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

A. I am the founder and President of Hellerworx, Inc. (Hellerworx).

Q. **Please describe Hellerworx.**

A. Hellerworx is a consulting firm that assists power generators, transportation companies, and energy producers in solving economic and technical problems related to energy and transportation markets and environmental compliance issues. The types of work in which we have experience include negotiating transportation and fuel supply agreements, risk and competitor analysis, strategy development, fuel and transportation planning and management, fuel price forecasting, siting new energy facilities, rail fleet planning and management, and litigation and regulatory support services.

Q. **Please describe your educational background and experience.**

A. I have more than 30 years of experience with coal, energy, and transportation issues. My tenure with rail related energy issues and transportation began as Director of Management Studies at Energy and Environmental Analysis, Inc. In that capacity, I directed coal market and transportation studies for railroads and coal producers while also developing energy efficiency plans. Some of our clients included the US Department of Energy, Executive Office of the President, the US Presidential Commission on Coal, the US Congress Office of Technology Assessment, and various coal producers.

I then established a company called Fieldston Company, Inc., and shortly thereafter formed Fieldston Publications, Inc. (together referred to as the Fieldston Companies). The Fieldston Companies provided energy and transportation consulting services to the energy supply, transportation, and electric utility sectors. We provided expert assistance to the fuels supply, transportation, and electric generation industries in hundreds of commercial matters. The publication staff developed and published leading business periodicals in the coal, rail transportation, and environmental fields. I also co-founded Fieldston Transportation Services, which managed railcars for various customers.

After selling the Fieldston Companies, I joined PA Consulting (PA), where as a Senior Partner I worked on launching the Environmental and Resource Analytics practice. The practice provided strategic and analytical services to clients in the electric generation, coal, and transportation markets; performed various studies and modeling activities related to compliance with environmental regulations; and conducted environmental risk assessments.

During my career, I have served as an arbitrator and as an expert witness before various state commissions, federal district and state courts, arbitration panels in the United States and overseas, the Surface Transportation Board, and the Federal Energy Regulatory Commission.

I have a Bachelor of Science degree in Electrical Engineering from Northwestern University and an MBA from Harvard Business School. My résumé is attached as Exhibit ___[JH-1].

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

A. The purpose of my testimony is to present the annual forecast of rail rates developed through 2030 by Hellerworx under my supervision and provided to Hill & Associates in support of the Taylor Energy Center (TEC) Need for Power

Application. More specifically, my testimony will address forecast rail rates for movements from selected coal origins to the proposed TEC site.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit ___ [JH-1] is a copy of my résumé. Exhibit ___ [JH-2] is the rail rate forecast provided to Hill & Associates.

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

A. Yes. I am sponsoring Section A.4.6.6, which was prepared under my direct supervision.

Q. How did you become involved in this proceeding?

A. Hill & Associates retained Hellerworx to provide a forecast of rail rates from specific coal origination points to the proposed TEC site. I was responsible for developing the forecast, which is presented in Exhibit __[JH-2].

Q. Describe the approach you took in developing the forecast of rail rates.

A. Our forecasting approach was based on a model of bidding behavior known as "next best" pricing. For any route where competition exists between two or more railroads, the rail rate is assumed to be determined by the lowest amount the railroad with the second best route is willing to bid. The railroad with the best route would generally be expected to bid just below its estimate of the "second-best" railroad's bid, in order to maximize the value of its superior route.

In order to conduct this "next best pricing" analysis, we calculated the CSX Transportation and Norfolk Southern/Georgia-Florida Railroad (NS/GFRR) mileages from a representative origin for each type of coal considered in the analysis to the proposed TEC site near Perry, Florida.

Q. **Have rail rates increased in recent years?**

A. Yes.

Q. **What caused this increase in rail rates?**

A. Beginning with the Surface Transportation Board (STB) decisions in the Duke Energy and Carolina Power & Light rail rate reasonableness cases in late 2003, which allowed for rate increases of up to 60 percent on some captive coal movements, the railroads have become much more aggressive in seeking rate increases from coal shippers. Carriers have often sought double digit rate increases at the expiration of existing contracts between 2003 and 2005.

Additionally, a portion of the rail rate increases is due to fuel surcharges that the railroads began imposing as world oil prices began to increase sharply. While fuel surcharges may occasionally rise to higher levels, over the long run, we would expect fuel surcharges to average 2 to 3 percent of the overall rail rate.

Q. How have these events affected the rail rate forecast developed by Hellerworx?

A. Although we do not believe that the magnitude of the rate increases recently imposed by the railroads will continue over the long term, recent rate increases applicable to competitively served coal shippers within the State of Florida are included in our base rates used in the forecast. We estimate that these have totaled approximately 25 percent between 2003 and 2005. We do not expect rate increases of this magnitude to be applied to base rates for competitive rail movements in the future.

The base rates assumed in our forecast reflect increased oil prices. However, given the expected long-term decline in real oil prices from recent historically high levels, and the relatively small component of overall rail rates that oil prices comprise, we do not expect fuel surcharges to have a significant impact on rail rates over the long term. Therefore, we do not treat fuel surcharges explicitly in our rail rate forecast.

Q. Are you familiar with the capabilities of the proposed TEC 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 TEC to burn a wide variety of coals and petroleum coke from various regions.

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

A. Yes.

Q. Do you believe that coal from the PRB can be reliably delivered to the proposed TEC site?

A. Yes. The Burlington Northern Santa Fe (BNSF) and Union Pacific (UP) railroads have and are making substantial investments to expand capacity for PRB shipments. Between 2005 and 2007, BNSF and UP are planning to add a total of approximately 72 miles of additional triple and quadruple tracks to their existing Joint Line trackage in the Wyoming portion of the PRB, at a total cost of approximately $200 million. This includes 14 miles of track added in 2005, 19 miles of track that are expected to be fully operational by the end of September 2006, and an additional 39 miles of track that are expected to be completed by the end of 2007. In total, these additions are expected to increase the capacity of the Joint Line to approximately 400 million tons/year, which represents a 75 million ton increase over actual 2005 Joint Line shipments of 325 million tons.

While the derailments and emergency track maintenance on the Joint Line during 2005 caused disruptions, not only have those largely dissipated, but the carriers are setting records for PRB shipments. Although BNSF and UP will likely continue to plan their capacity additions in the PRB to match rather than exceed demand (and therefore congestion is likely to recur periodically when demand for PRB coal is higher than expected), past events also suggest that, over the long term, investment in the PRB rail system is likely to be adequate to meet demand growth. For example, between 1995 and 2004, Wyoming PRB coal production increased by approximately 135 million tons, from 246 to 381 million tons. Over this period, BNSF alone invested a total of about $2.1 billion to increase its coal-hauling capacity (primarily in the Wyoming PRB), including over $1.5 billion invested in locomotives and railcars, and approximately $550 million invested in track expansions. Although similar data for UP are not publicly available, UP's investments in coal-hauling capacity over the same period were likely of roughly similar magnitude.

Furthermore, there are also two additional rail projects under consideration in the PRB that do not involve routes currently served by BNSF or UP. The Dakota, Minnesota, and Eastern Railroad (DM&E) is currently seeking financing to build a third rail line into the Wyoming portion of the PRB, at a track construction cost of approximately $2 billion. If this project is completed, it would have the capacity to haul up to 100 million tons/year of PRB coal. The proposed Tongue River Railroad (TRR) project in Montana would extend BNSF's existing trackage in the Montana portion of the PRB by up to 120 miles to allow the development of additional Montana coal reserves. Although the TRR's projected full capacity of 37.5 million tons/year is much smaller in scale than the Wyoming PRB rail operations, this would still be a very significant addition to the PRB rail system.

Q. Does this conclude your testimony?

A. Yes.

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Taylor Energy Center
James Heller
Exhibit ____ [JH-1]
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RESUME OF

James N. Heller

Hellerworx, Inc.

4803 Falstone Avenue

Chevy Chase, Maryland 20815

Phone 301-654-1980

Fax: 301-718-1878

Mobile: 202-425-3524

Email: jamie@hellerworx.com

EDUCATIONAL BACKGROUND

- Harvard Business School — Master of Business Administration, 1972
- Northwestern University — Bachelor of Science, Electrical Engineering, 1970
- Member, Eta Kappa Nu and Tau Beta Pi Engineering Honorary Societies

PROFESSIONAL EXPERIENCE

Current Position

Jamie Heller is the founder and president of Hellerworx, Inc. Hellerworx was developed to provide strategic and economic consulting services to electric generators, coal and energy producers and transportation companies. Mr. Heller is an expert in coal, energy, environmental and transportation issues. His specialties include coal market analysis, transportation market analysis, electric utility planning, electric power market analysis, analysis of environmental compliance options, utility fuel procurement, energy property valuation, and litigation support. Mr. Heller has served as an arbitrator, and as an expert witness before various state commissions, federal district and state courts, arbitration panels in the U.S. and overseas, the Surface Transportation Board and the Federal Energy Regulatory Commission. He has made numerous speeches and presentations before various conferences and seminars in the U.S. and abroad. His comments have appeared in various trade publications.

Consulting Specialties

- Strategic planning
- Transportation procurement planning
- Transportation management studies
- Providing litigation and regulatory support
- Conducting market assessments and forecasts
- Negotiating fuel and transportation agreements
- Estimating fuel production and transportation costs
- Fuel price and transportation rate forecasting
- Evaluating alternative Clean Air Act compliance strategies
- Siting new energy facilities
- Performing reserve acquisition analyses
- Evaluating equipment purchases
- Energy supply planning.

Prior Professional Experience

- PA Consulting (October 2000-July 2002). Senior Partner. As Senior Partner within the PA Management Group worked on launching the Environmental and Resource Analytics practice within PA. The practice provided strategic and analytical services to clients in the electric generation, coal and transportation markets; performed various studies and modeling activities related to compliance with environmental regulations; and conducted environmental risk assessments. The principal areas of focus were environmental compliance with Clean Air Act standards, providing fuel and environmental analyses in support of electric generating unit asset acquisition and financing activities, and a major effort to support Firestone Tire in its dispute with Ford Motor Company and NHTSA.
- Hagler Bailly (October 1998-October 2000). Senior Vice President. Served as head of Hagler Bailly's fuels and environment practice area and an expert in coal, energy, and transportation issues. His activities supported the firms forecasting and analysis of electric power, fuel and transportation markets and various clean air compliance issues. In October 2000, PA Consulting purchased Hagler Bailly.
- Fieldston Company, Inc. and Fieldston Publications, Inc. (1981-1998). Founder and President. Founded The Fieldston Companies in 1981 to provide energy and transportation consulting services to the energy supply, transportation and electric utility sectors. The 60+ person staff provided expert assistance to the fuels supply, transportation and electric generation industries in hundreds of commercial matters. The publication staff developed and published leading business periodicals in the coal, rail transportation and environmental fields. A joint venture company, Fieldston Transportation Services,

provided rail transportation and railcar maintenance services to various shippers and short line rail carriers. In 1998, Mr. Heller sold the consulting and publishing companies to Hagler Bailly, and the transportation services company to DTE.

- Teknekron, Inc. of Berkeley, Calif. (1979–1980). Senior Analyst. Strategic planning, market analyses, rail merger studies, transportation market analysis and rate estimation, plant siting, and public policy development.
- Energy and Environmental Analysis, Inc. (1975-1979). Director of Management Studies. Directed coal market and transportation studies for railroads and coal producers. Conducted economic evaluation of air and water regulations. Developed energy efficiency plans. Clients included U.S. Department of Energy, Executive Office of the President, U.S. Presidential Commission on Coal, U.S. Congress Office of Technology Assessment, and various coal producers.
- Office of Water Quality Planning and Standards (U.S. Environmental Protection Agency) (1972–1975). Section Chief. Developed and promulgated industrial water pollution control guidelines.

PUBLICATIONS

- James N. Heller and Charles A. Mann. Coal and Profitability: An Investor's Guide. McGraw-Hill, 1979.
- James N. Heller. Coal Transportation and Deregulation: An Impact Analysis of the Staggers Act. Serif Press and the Energy Bureau, 1984.

Docket No. ________
Taylor Energy Center
James Heller
Exhibit ____ [JH-2]
Page 1 of 1

Rail Rate Forecasts for Proposed New Plant Site Near Perry, FL (Constant 2005 $/Short Ton)

	Real Escalation:		-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%
Coal Type	Coal Heat Content (Btu/lb)	% Sulfur	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Central App.	12,400	0.70%	$ 18.91	$ 18.72	$ 18.53	$ 18.35	$ 18.16	$ 17.98	$ 17.80	$ 17.62	$ 17.45	$ 17.27	$ 17.10	$ 16.93	$ 16.76	$ 16.59	$ 16.43	$ 16.26	$ 16.10	$ 15.94	$ 15.78	$ 15.62	$ 15.47	$ 15.31	$ 15.16	$ 15.01	$ 14.86
Central App.	12,000	1.00%	$ 19.50	$ 19.31	$ 19.11	$ 18.92	$ 18.73	$ 18.55	$ 18.36	$ 18.18	$ 18.00	$ 17.82	$ 17.64	$ 17.46	$ 17.29	$ 17.11	$ 16.94	$ 16.77	$ 16.61	$ 16.44	$ 16.28	$ 16.11	$ 15.95	$ 15.79	$ 15.63	$ 15.48	$ 15.32
Northern App.	13,115	1.60%	$ 26.33	$ 26.07	$ 25.81	$ 25.56	$ 25.30	$ 25.04	$ 24.79	$ 24.55	$ 24.30	$ 24.06	$ 23.82	$ 23.58	$ 23.34	$ 23.11	$ 22.88	$ 22.65	$ 22.42	$ 22.20	$ 21.98	$ 21.76	$ 21.54	$ 21.32	$ 21.11	$ 20.90	$ 20.69
Northern App.	13,115	2.50%	$ 26.33	$ 26.07	$ 25.81	$ 25.55	$ 25.30	$ 25.04	$ 24.79	$ 24.55	$ 24.30	$ 24.06	$ 23.82	$ 23.58	$ 23.34	$ 23.11	$ 22.88	$ 22.65	$ 22.42	$ 22.20	$ 21.98	$ 21.76	$ 21.54	$ 21.32	$ 21.11	$ 20.90	$ 20.69
Illinois Basin (IL)	11,000	3.00%	$ 25.84	$ 25.58	$ 25.32	$ 25.07	$ 24.82	$ 24.57	$ 24.33	$ 24.08	$ 23.84	$ 23.60	$ 23.37	$ 23.13	$ 22.90	$ 22.67	$ 22.45	$ 22.22	$ 22.00	$ 21.78	$ 21.56	$ 21.35	$ 21.13	$ 20.92	$ 20.71	$ 20.51	$ 20.30
Illinois Basin (WKY)	11,000	3.00%	$ 25.84	$ 25.58	$ 25.32	$ 25.07	$ 24.82	$ 24.57	$ 24.33	$ 24.08	$ 23.84	$ 23.60	$ 23.37	$ 23.13	$ 22.90	$ 22.67	$ 22.45	$ 22.22	$ 22.00	$ 21.78	$ 21.56	$ 21.35	$ 21.13	$ 20.92	$ 20.71	$ 20.51	$ 20.30
WY PRB 8,800 Btu	8,800	0.35%	$ 33.07	$ 32.74	$ 32.41	$ 32.08	$ 31.76	$ 31.45	$ 31.13	$ 30.82	$ 30.51	$ 30.21	$ 29.90	$ 29.61	$ 29.31	$ 29.02	$ 28.73	$ 28.44	$ 28.15	$ 27.87	$ 27.59	$ 27.32	$ 27.04	$ 26.77	$ 26.51	$ 26.24	$ 25.98
PRB 8,400 Btu	8,400	0.35%	$ 33.07	$ 32.74	$ 32.41	$ 32.08	$ 31.76	$ 31.45	$ 31.13	$ 30.82	$ 30.51	$ 30.21	$ 29.90	$ 29.61	$ 29.31	$ 29.02	$ 28.73	$ 28.44	$ 28.15	$ 27.87	$ 27.59	$ 27.32	$ 27.04	$ 26.77	$ 26.51	$ 26.24	$ 25.98
South American Coals	11,000	1.00%	$ 8.51	$ 8.43	$ 8.34	$ 8.26	$ 8.18	$ 8.10	$ 8.02	$ 7.94	$ 7.86	$ 7.78	$ 7.70	$ 7.62	$ 7.55	$ 7.47	$ 7.40	$ 7.32	$ 7.25	$ 7.18	$ 7.11	$ 7.03	$ 6.96	$ 6.89	$ 6.83	$ 6.76	$ 6.69
(via Jacksonville)	11,500	1.00%	$ 8.51	$ 8.43	$ 8.34	$ 8.26	$ 8.18	$ 8.10	$ 8.02	$ 7.94	$ 7.86	$ 7.78	$ 7.70	$ 7.62	$ 7.55	$ 7.47	$ 7.40	$ 7.32	$ 7.25	$ 7.18	$ 7.11	$ 7.03	$ 6.96	$ 6.89	$ 6.83	$ 6.76	$ 6.69
	11,800	1.00%	$ 8.51	$ 8.43	$ 8.34	$ 8.26	$ 8.18	$ 8.10	$ 8.02	$ 7.94	$ 7.86	$ 7.78	$ 7.70	$ 7.62	$ 7.55	$ 7.47	$ 7.40	$ 7.32	$ 7.25	$ 7.18	$ 7.11	$ 7.03	$ 6.96	$ 6.89	$ 6.83	$ 6.76	$ 6.69

Notes:

1) Only CSX can originate Western Kentucky coal. CSX would likely attempt to set rail rate for this coal at a level that would be competitive with Illinois coal on a delivered price basis.
2) All rates include railcar costs.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF PAUL HOORNAERT

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 Hoornaert. My business address is 55 East Monroe Street, Chicago, Illinois 60603.

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

A. I am employed by Sargent & Lundy, LLC as a Senior Project Manager, Fossil Power Technologies.

Q. Please describe your responsibilities in that position.

A. As Senior Project Manager I am responsible for the overall planning, coordination, and performance monitoring of Sargent & Lundy, LLC project work. These projects include coal fired unit design, combined cycle unit design, power plant conceptual design, technology assessments, and plant betterments.

In performing these projects, I coordinate engineering activities across all engineering disciplines and work directly with our clients. I am currently managing the preliminary engineering and design work for the Taylor Energy Center (TEC) on behalf of the Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (City) (collectively referred to as the Participants).

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science degree in Mechanical Engineering from Purdue University. I am a registered professional engineer in Illinois, Florida, Michigan, Utah, and Wyoming. I have expertise in project management, conceptual designs, technology assessment, coal fired power plant design, selective catalytic reduction (SCR) design, combined cycle design, repowering, plant betterment, heat exchangers, pumps, and other power plant systems. I have over 34 years of experience in electric power facilities.

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

A. The purpose of my testimony is to discuss the technical aspects of TEC, and projected capital costs, operation and maintenance (O&M) costs, plant performance, availability, and schedule. My testimony will also include a discussion of advanced technology features that will be incorporated into the design of TEC.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit ____ [PH-1] is a copy of my résumé.

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.3.2, A.3.3 through A.3.3.6, A.3.3.8, A.3.5, A.3.6, A.3.7, A.3.8, and A.3.9, all of which were prepared under my direct supervision.

Q. Please describe TEC.

A. TEC will be an advanced supercritical pulverized coal unit that will be constructed on a 3,000 acre greenfield site located approximately 5 miles from Perry, in Taylor County, Florida. The boiler will be designed for 3,600 pounds per square inch gauge pressure (psig), 1,050° F main steam, and 1,100° F reheat steam temperature, which will make it a supercritical unit. The higher steam pressure in comparison to subcritical boilers, which generally operate in the 2,400 psig range or lower, will improve efficiency and, therefore, reduce overall fuel consumption per unit of output. TEC will include one boiler, one steam turbine generator with efficient steam cycle, cooling system with mechanical draft cooling towers, water and wastewater treatment systems, material handling, air quality control systems, electrical systems, and other balance-of-plant systems. A 3.5 mile Georgia-Florida rail extension to the proposed site and an onsite rail loop will be constructed to provide delivery of fuel to the plant.

Water will be supplied from a system of wells. The average use is estimated to be approximately 8 million gallons per day (MGD) with a maximum use of 10 MGD.

TEC will be electrically interconnected to the Progress Energy Florida (PEF) system at 230 kV. Transmission lines of approximately 5.5 miles in length will connect the plant to the Perry Substation. An additional 230 kV transmission line will also likely be required. The exact location of this additional transmission line is under evaluation. Transmission system studies are discussed in the testimony of Gary Brinkworth.

A more detailed description of TEC is presented in Section A.3 of Exhibit ___ [TEC-1], the TEC Need for Power Application.

Q. Will TEC include best available control technologies to minimize environmental impacts?

A. Yes. TEC will be designed to include the most advanced pollution control systems to minimize plant emissions. Low nitrogen oxide (NO_x) burners, over-fire air ports, and SCR will be used to limit NO_x emissions. A wet flue gas desulfurization (FGD) system will be utilized to reduce sulfur dioxide (SO_2) emissions, and a reverse air baghouse will be used to control particulate emissions. A wet electrostatic precipitator (WESP) will further reduce particulate matter, hazardous air pollutants in particulate form, and acid mists.

Mercury (Hg) emissions will be reduced through the co-benefits of these systems. Collectively, these pollution control systems will control TEC emissions to very low levels in compliance with all applicable regulatory standards.

In addition, process wastewaters generated from the plant will either be recycled within the plant or processed in a zero liquid discharge facility to eliminate process wastewater flows from the plant.

Q. Does the base capital cost estimate developed for TEC include appropriate costs for all these control systems?

A. Yes. The base capital cost estimate for TEC includes costs for all the control systems discussed above.

Q. Are there other important features that will be included in the design of TEC?

A. Yes. TEC will be unique among solid fuel plants in its ability to burn a wide variety of fuel types. The TEC boiler, material handling, and other systems will be designed to burn up to 30 percent petroleum (petcoke) blended with a variety of coals. In addition, TEC will be capable of burning coals from Latin America, the Powder River Basin (PRB) region in Wyoming, and Central Appalachia regions. This will provide fuel diversity and flexibility, producing additional benefits to the Participants including the ability to competitively bid coal suppliers and transportation among multiple suppliers, and increased fuel supply reliability resulting from the ability to source from multiple geographic regions.

TEC will also include space to accommodate up to approximately 90 days of fuel storage for increased reliability by reducing the impact resulting from the unlikely event of a short-term fuel supply disruption. Startup fuel will be low sulfur No. 2 fuel oil, or ultralow sulfur No. 2 fuel oil if available.

Q. Please describe the construction costs for TEC.

A. The construction costs include direct costs for purchased equipment and materials, construction contract costs, and indirect costs. Construction costs are based on a multiple construction contracts contracting approach, which is the planned construction approach for the project. The construction cost estimate also includes costs for training, contractor general and administrative (G&A), and contractor contingency. Allowances have also been included for escalation, labor per diem, overtime differential for 50 hour workweeks, transmission lines to Perry Substation, spare parts, sacrificial coal bed, and commissioning consumables and initial fills.

Owner's costs have been separately estimated and include staffing, construction management, consultants, travel, insurance, services, supplies, rentals, one-time set-up costs, and energy and fuel for startup. Costs have also been included for land purchase and an allocation for an upfront community contribution. Ongoing community contributions are discussed in the testimony of Bradley

Kushner. An allowance for funds used during construction is also included in the estimate based on an assumed 5.0 percent interest rate, which is consistent with the economic assumptions.

The total capital cost is estimated to be $1,743,399,000 in 2012 dollars, and is summarized in Table A.3-5 of Exhibit ___ [TEC-1], the TEC Need for Power Application.

Q. **Please provide the estimated fixed O&M costs.**

A. Fixed O&M costs are estimated to be $17,710,227 in 2005 dollars, and are based on a full-time staff level of 149. Payroll costs of $11.36 million for the 149 full-time staff are included in the $17,710,227 fixed O&M costs. Fixed O&M is assumed to increase at the assumed inflation rate.

Ongoing capitalized expenditures are an additional aspect of fixed O&M expenses that have been included in the TEC estimates. These have been estimated to be $2.50/kW-yr in 2005 dollars. The escalation rate for ongoing capital expenditures is conservatively estimated to be 2.0 percent per year over the assumed inflation rate to account for increasing capital expenditures as the unit ages.

Q. **Please provide the estimated variable O&M expenses.**

A. Variable O&M includes FGD reagent, water treatment chemicals, ammonia for the SCR, an allocation for SCR catalyst replacement, allocation for baghouse bag replacements, and other variable costs incurred during plant operation. Variable O&M expenses will also vary depending on the fuel blend being used. Assuming a 28 percent petroleum coke and 72 percent coal blend, the variable O&M estimates in 2005 dollars are $1.36/MWh for the Latin American coal blend, $1.37/MWh for the PRB coal blend, and $1.15/MWh for the Central Appalachia coal blend. Variable O&M is also assumed to escalate at the assumed inflation rate.

Q. Are emissions allowance costs included in the variable O&M expense estimates?

A. No. These were modeled separately as discussed in Bradley Kushner's testimony.

Q. What outage rates have been assumed for TEC?

A. TEC is assumed to have an annual forced outage rate of 5.23 percent over the analysis period. TEC is assumed to have an annualized scheduled outage rate of 16 days per year or 4.38 percent.

Q. Please describe the estimated performance for TEC.

A. Actual plant performance (including net plant output and net plant heat rate) will be a function of ambient conditions, fuel characteristics, and other factors. Estimated performance was developed for a summer condition, winter condition, and average annual condition. Part load performance was also developed for 35 percent load, 50 percent load, and 75 percent load. These performance points were developed with three fuel blends consisting of 28 percent petcoke and 72 percent coal for each of the three coals, including Latin American, PRB, and Central Appalachia. For the base case fuel blend of petcoke and Latin American coal, the valves wide open net plant output is estimated to be 765.5 MW, and the net plant heat rate is estimated to be 9,238 Btu/kWh at average ambient conditions. The heat rate has been increased by a 1.5 percent allowance for degradation. Additional performance data is provided in Table A.3-7 of Exhibit ___ [TEC-1], the TEC Need for Power Application.

Q. What is the overall schedule for construction completion of the project?

A. The schedule is based on TEC achieving commercial operation on April 27, 2012. An air permit for the plant is expected to be received by April 1, 2008, which will allow for site construction activities to commence. Approximately 49 months will be required for construction of the plant after receipt of the air permit. To support this schedule, preliminary engineering and specification of major plant components will commence during the second half of 2006. These activities will primarily consist of development of specifications, identification of potential suppliers, prebid meetings with potential suppliers, and commencement of the procurement process for major long lead equipment items such as the turbine generator and steam generator (boiler).

Q. How many construction workers are estimated to be required for the construction of TEC?

A. Construction of TEC is estimated to require 1,500 construction workers during the peak construction period.

Q. Does this conclude your testimony?

A. Yes.

Docket No. ________
Taylor Energy Center
Paul Hoornaert
Exhibit ____ [PH-1]

RESUME OF

PAUL HOORNAERT
Senior Project Manager
Fossil Power Technologies

EDUCATION
Purdue University – B.S. Mechanical Engineering – 1972

REGISTRATIONS
Professional Engineer – Illinois, Florida, Michigan, Utah and Wyoming

EXPERTISE
Project management
Conceptual designs
Technology assessment
Coal-fired unit designs
SCRs
Combined cycle unit designs
Repowering
Backfit and betterment
Feedwater heaters (FWH) and heat exchangers
Pumps
Waste-to-energy

RESPONSIBILITIES
Mr. Hoornaert is responsible for the overall planning, coordination, and performance monitoring of Sargent & Lundy project work. He leads the project staff in the preparation of a project's scope of work, of procurement and installation specifications, and of design deliverables. He is responsible for project planning and scheduling. He advises the client on the project's status in regular progress reports, during review meetings, and in day-to-day communications. He coordinates the project engineering across all disciplines. During the conceptual design phase of a project, Mr. Hoornaert works with the project team to optimize the plant site and the plant general arrangements. He directs and coordinates input from the discipline engineers involved in the project.

EXPERIENCE
Since joining Sargent & Lundy in 1972, Mr. Hoornaert has been involved in several plant designs involving sub and supercritical pulverized coal (PC)-fired, fluidized bed, combined cycle and waste-to-energy technologies. Mr. Hoornaert is currently managing the backfit of SCRs on four (4) 450 MW (each) units at the same station. Mr. Hoornaert has recently completed a repowering project in which two existing coal units were repowered to a combined cycle configuration with an output of 1,750 MW. The resulting output from the station increased by over 50%. One of the PC units on which Mr. Hoornaert worked was designed to fire lignite and western sub-bituminous coal, and to be a standard design capable of being located at many sites. Mr. Hoornaert's assignments have also included a significant amount of backfit and betterment work involving all facets of fossil plant design. Mr. Hoornaert has managed over 200 betterment projects/studies.

His experience includes:

COAL-FIRED UNIT DESIGNS

- **Tampa Electric**

- Big Bend Units 1 thru 4.
Retrofit of SCR on four nominal 450 MW pulverized coal units (2004 to present)

- **JPEPC**

- Yangzhou 1 & 2 (pulverized coal)
600 MW each
Project Manager (1997 to 1998)

- **JLEPC**

- Ligang 3 & 4 (pulverized coal)
350 MW each, turbine island
Project Manager (1994 - 1997)

- **Mitsui & Co., Ltd.**

- Point Aconi 1, coal, (fluidized bed) 165 MW.
Engineering project manager (1989 to 1993)

- **Middle South Services, Inc.**

- Six standard units, coal and lignite, 750 MW each.
Mechanical project engineer responsible for turbine-generator and all turbine island equipment specification and procurement, piping and instrumentation diagrams (P&ID), piping design, and equipment data books. (1978 to 1983)

- **American Electric Power Service Corporation**

- Cardinal 3, pulverized coal, 615 MW, supercritical
Mechanical engineer on new coal-fired plant. Responsibilities included P&IDs, equipment procurement, and supervision of piping design. (1972 to 1977)

COMBINED CYCLE DESIGNS

- **Tampa Electric**

- Bayside 1&2 (gas)
Unit 1 - 750 MW, Unit 2 - 1,000 MW
Project Manager (1999 to 2004)

CONCEPTUAL DESIGNS

- **Tampa Electric Company**

- Big Bend Units 1 to 4
Comprehensive study of 17 options intended to meet environmental compliance requirements while still providing safe, reliable and cost effective power. (2003/2004)

- **Montana Power Company**

- J. E. Corette, 163 MW.
FGD conceptual design and CFB petroleum coke repowering study. (1994)

- **Mitsui & Co., Ltd.**

- Barbers Point, coal, 160 MW;
- Cedar Bay, coal, 250 MW;
- Riverside, coal, 200 MW.

Participated in conceptual design of three atmospheric fluidized bed combustion units to support independent power producer's turnkey bid. (1988)

- **Middle South Services, Inc.**

- Six standard units, coal and lignite, 750 MW each.

Participated in the development of a conceptual design for a standard plant capable of multi-site locations. Worked on general arrangements and P&IDs. (1977 to 1978)

TECHNOLOGY ASSESSMENT

- **Confidential Client**

- Site selection, environmental screening and permitting for a two unit 800 MW each greenfield installation in the southeast. (2003 to present)

- **Lower Colorado River Authority**

- Assessment of pulverized coal, CFB and IGCC technologies for consideration at an existing and a greenfield site. (2003)

- **Electric Power Research Institute (EPRI)/TU Electric**

- North Lake 2, gas.

Project manager for the demonstration of heat rate performance guidelines. (1987 to 1991)

- **TU Electric**

- Impairment Study - Project Manager for estimation of the value of plant components which the client wished to retain and those to be demolished from a partially constructed coal unit. (2002/2003)

BACKFIT AND BETTERMENT

Consumers Energy Company

- Project Manager for over 20 plant betterment projects. (1998 & 1999)

PacifiCorp

- Project Manager for over 120 plant betterment projects. (1992 to 1996)
- Project Manager for over 55 backfit and betterment projects under a two year Service Agreement (2004 to present)

Sierra Pacific Power

- Project Manager for alternate coal conveyor design project at Valmy Generating Station. (1993/1994)

TU Electric (TXU)
- Lake Creek 1 and 2, gas, 317 MW total.
Project Manager for makeup water system replacement. (1988 to 1990)
- Valley 1 and 2, gas, 725 MW total
Project manager for the extension of the control rooms for both units and the replacement of the Unit 1 control system and burner management system. (1988 to 1989)
- Valley 2, gas, 550 MW.
Project manager for modification to the steam seal supply system. (1988 to 1989)
- Valley 1-3, gas, 1100 MW total.
Project manager for the addition of a new auxiliary boiler. (1986 to 1987)
- Dallas 3 and 9, gas, 150 MW total
Project manager for addition of control room and air conditioning, replacement of boiler control system and main auxiliary transformer. (1987)
- Morgan Creek 4-6, gas, 745 MW total.
Project manager for adding an enclosure ground-level under control rooms. (1987)
- Northlake 1-3, gas, 700 MW total.
Project manager for the electronics room expansion project. (1987)
- Permian Basin 5, gas, 115 MW.
Project manager for the addition of super heat spray system. (1987)
- DeCordova 1, gas, 729 MW.
Mechanical project engineer for air system upgrade. (1986)
- Permian Basin 5 and 6, gas, 651 MW total.
Mechanical project engineer for turbine water induction prevention study and modifications. (1986)
- Various TU Electric stations. Budget item manager for conceptual engineering and cost studies to allow for following-year budgeting, covering over 350 budget items. (1986)
- Sandow 4, lignite, 591 MW (1985).
Mechanical project engineer for various backfit projects.
- Morgan Creek 2-6, 826 MW total; & North Main 4, gas, 75 MW.
Mechanical project engineer for demineralizer system backfits. (1985 to 1986)
- Lake Creek 2, gas, 236 MW.
Mechanical project engineer for air compressor replacement. (1985)

• **Electric Power Research Institute**
- Coordinator of EPRI's Second International Conference on Improved Coal-Fired Power Plants. (1988 to 1989)
- Coordinator of EPRI's Heat Rate Improvement Conference. (1987 to 1988)

• **Missouri Public Service**
- Sibley 1-3, coal, 460 MW total.
Mechanical project engineer for life extension study and modification work. Scope of work included turbine water induction prevention study and modifications. (1987)

Wisconsin Power & Light Company
- Edgewater 4 and 5, coal, 521 MW total.
Mechanical project engineer for glycol heater drain pump study. (1985)

Houston Lighting & Power Company
- Parish 7 and 8, coal, 551 MW each.

Mechanical project engineer for precipitator upgrade study. (1984)

Virginia Power
- Bremo 3 and 4, coal, 254 MW total;
- Chesterfield 3-6, coal and oil, 1,353 MW total;
- Mount Storm 1-3, coal, 1,662 MW total;
- Possum Point 1-4, coal and oil, 491 MW total;
- Yorktown 1-3, coal and oil, 491 MW total.

Mechanical project engineer for conceptual engineering and cost feasibility studies for approximately 100 miscellaneous plant betterment activities. (1983 to 1984)

WASTE-TO-ENERGY

- **American Energy Corporation**

- Oakland County, 1500 tons per day.

Engineering manager for the development of a conceptual design for the plant. Supervised discipline engineers in preparing P&IDs, obtaining vendor quotes, and preparing detailed cost estimate. (1988 to 1989)

Ogden-Martin Systems, Inc.
- Irwindale, 3000 tons per day.

Participated in the conceptual design, including the development of flow schematics and equipment specifications. (1984)

MEMBERSHIPS

American Society of Mechanical Engineers
Tau Beta Pi

PUBLICATIONS

"Bayside Power Station - Project of the Year 2003", Power Engineering Magazine, December 2003.

“Comparisons of U.S. Plant Designs to Those in the PRC”, American Power Conference 1996.

“Procurement Approaches for the Next Generation of Power Plants: Case Histories for Success” (co-author), Sargent & Lundy General Engineering Conference, Chicago, Illinois, Spring 1991.

“Feedwater Heater Cycle Configuration,” EPRI Feedwater Heater Technology Symposium, Winston-Salem, North Carolina, June 1988.

“Fossil Plant Upgrades,” 1984 Joint Power Generation Conference, Toronto, Canada, October 1984.

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.

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Exhibit ____ [CK-1]
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RESUME OF

CHRIS J. KLAUSNER

Senior Consultant **Black & Veatch**

Project Management, Technical and Financial Analyses, Project Contract Assessment, Financial Pro Forma Modeling

Education
BS, Mechanical Engineering, University of Kansas, 1990; Masters of Business Administration, Finance Concentration, University of Kansas, 2001

Professional Registration
1995, Kansas, 13719

Total Years Experience
15

Joined Black & Veatch
1993

Language Capabilities
English

Chris J. Klausner is a senior consultant and project manager in the Enterprise Management Solutions Division of Black & Veatch. He is responsible for performing independent engineering assessments for project lenders, developers, owners, and bidders trying to acquire generation assets. These reviews provide technical, financial, and economic analysis in the following areas: technology; environmental; plant overall design and performance; project contracts (power purchase, O&M, major maintenance, EPC, fuel supply, steam sales, etc.), including liquidated damages provisions; O&M expense projections; financial pro forma modeling; construction methods and schedule; and project capital costs. Additionally, he manages other engineering studies, need for power applications, integrated resource plans, power supply studies, project development support, and conducts power plant valuations. He has experience with simple cycle, combined cycle, cogeneration, CFB, pulverized coal, integrated gasification combined cycle, biomass, and wind technologies. He has also provided construction monitoring on behalf of lenders for more 15 power plant construction projects.

Representative Project Experience

Brazos Electric Cooperative Power Supply Study, Waco, Texas
2006
Project Manager. Responsible for directing Request for Proposal process for power supply, development of self-build generating alternatives cost and performance, evaluation of alternatives, and other technical support on behalf of Brazos Electric to complete a power supply study to determine future generating unit additions.

FirstReserve, Various
2006
Senior Consultant. Technical and financial due diligence on behalf of a potential investor a 460 MW blast furnace gas fired combined cycle project in Brazil. Assisted client in preliminary EPC Contract scope negotiations and development of financial model. Technical

and financial advisory services for equity investment in 660 MW pulverized coal project.

Confidential Sale Due Diligence, Various US
2006
Project Manager. Technical and financial due diligence on behalf of the owner for the potential sale of 13 combined heat and power plants located throughout the US and totaling about 730 MW.

Confidential Sale Due Diligence, Dighton, Massachusetts
2006
Project Manager. Technical and financial due diligence on behalf of a potential investor in the Dighton Power Associates 160 MW single shaft combined cycle project for sale as part of Calpine's bankruptcy reorganization.

JEA Integrated Resource Plan Study, Florida
2005-2006
Engineering Manager. Conducted a resource planning study for the JEA electric system in Jacksonville which has a system load of about 2800 MW. Developed supply side alternatives, provided model inputs, analyzed modeling results determined system needs, and completed study report.

JEA, FMPA, City of Tallahassee, and Reedy Creek Need Application, Florida
2005-2006
Senior Consultant. Team leader for JEA system for need for power application for an 765 MW coal and petroleum coke fired supercritical coal fired power plant located in Florida.

OUC Stanton B Need for Power Application, Florida
2005-2006
Senior Consultant. Technical lead for 283 MW integrated gasification combined cycle plant need for power application. Developed various application sections.

Intergen Acquisition Support, Mexico, Europe, Asia
2005
Senior Consultant. Technical and financial acquisition support for bidder in the Intergen generation plant auction. Team lead responsible for evaluating four European combined cycle plants.

Confidential Client, US
2005
Project Manager. Technical due diligence of a 55 MW turkey manure stoker fired biomass power plant under construction. Managed a multi-discipline team evaluating design, financial model inputs, and project contracts.

FMPA Treasure Coast Energy Center Need for Power Application, Florida
2004-2005
Senior Consultant. Coordinated development of the need for power application for a nominal 300 MW combined cycle project. Also, developed various application sections.

Boston Generating, Massachusetts
2000-2005
Senior Consultant. Technical and financial due diligence of a portfolio of generating assets including three 800 MW blocks of MHI 501G combined cycle units with air cooled condensers for project lenders. Also, assisted lenders in negotiating close out of EPC Contract after projects turned over to lender group.

Confidential Project
2004
Senior Consultant. Conducted a valuation analysis using replacement cost, comparable sales, and discounted cash flow for a natural gas and electric transmission and distribution company located in the Midwest.

AmerenCILCO, AEG, Illinois
2003
Senior Consultant. Conducted a valuation analysis using replacement cost, comparable sales, and discounted cash flow for three power generation stations to be transferred under a loan indenture. The plants included the coal-fired Edwards Duck Creek stations, and the Sterling Avenue peaking combustion turbine station.

Craig Unit 3 Valuation, Tri-State, Colorado
2002 and 2005
Project Manager. Conducted a valuation analysis for the Craig Unit 3 coal-fired, pulverized coal power station. Evaluation included on-site condition assessment, forecast of energy revenues and fuel prices, O&M expense forecast, and detailed discounted cash flow development and modeling. Analysis also evaluated replacement cost and comparable sales valuation approaches.

Miscellaneous Discounted Cash Flow Valuations, Various locations
2001-2003
Project Manager. Conducted discounted cash flow valuation analysis for a variety of power plant projects including Seabrook Nuclear station, 772 MW combined cycle power plant in Colombia, 250 MW combined cycle cogeneration plant in Canada, and 500 MW combined cycle in Philadelphia.

Wanapa Project, Diamond Generating Corporation, Oregon
2001-2003
Engineering Manager. Provided conceptual and detailed engineering, cost estimates, and schedule to support development of a 1200 MW combined cycle project. The project included two power blocks in a 2x1 configuration based on either SWPC 501F or GE 7FA turbines. Black & Veatch provided cost estimates, detailed performance heat balances, multi-point emissions rates, plant layout and rendering drawings, site elevation determination, and water discharge quality characterizations. Project development was started by Williams EM&T.

AES Granite Ridge, ABN AMRO Bank, New Hampshire
2000-2001
Engineering Manager. Coordination of multidiscipline technical and financial analysis of a 720 MW combined cycle project utilizing SWPC 501G combustion turbines for the project lenders. Lead reviewer of the financial pro forma and long term service agreement.

Rowan and Effingham Project, Progress Energy Services Company LLC, Georgia and South Carolina
2001-2002
Engineering Manager. Coordination of multidiscipline technical and financial analysis of a portfolio of four projects utilizing GE 7FA and SWPC 501F combustion turbines in a simple and combined cycle configurations. Total output is over 2000 MW and these plants are located in the southeastern US. Lead reviewer of the financial pro forma, long term service agreement, and other project agreements.

AES Puerto Rico Project, Goldman Sachs, ABN AMRO, TD Securities and Credit Lyonnais, Puerto Rico
2000-2006
Engineering Manager. Coordination of multidiscipline technical and financial analysis of a 454 MW circulating fluidized bed boiler cogeneration project for the project lenders. Lead reviewer of project contracts and financial pro forma. Provide quarterly operations review reports.

Channelview Cogeneration Project, Bank of America, Texas,
1999-2002
Engineering Manager. Coordination of multidiscipline technical and financial analysis of a 781 MW combined cycle cogeneration project utilizing SWPC 501FD2 turbines for project lenders. Lead reviewer of project contracts and financial pro forma.

FirstEnergy Bay Shore Project, Lehman Brothers, Ohio
1997-2006
Project Manager. Technical and financial analysis of 1,380,000 pph petroleum coke fired circulating fluidized bed boiler project. Steam produced by the project is sold to FirstEnergy and an adjacent refinery. Assessment was performed for bond offering and included multiple investor road shows.

Greenfield & Cogeneration Projects, Washington
1999 and 2001
Project Manager. Coordination of two feasibility studies involving the expansion of an existing cogeneration plant and development of a 250 to 500 MW merchant combined cycle project based on General Electric 7FA combustion turbines. Also, coordination of a feasibility study for the proposed development of a 240 MW project utilizing four GE LM6000 combustion turbines configured in a combined cycle arrangement at two potential sites. These projects included development of system descriptions, plant general arrangements, conceptual cost estimates, performance estimates, and evaluation of expected permitting requirements.

Bucharest CHP Study, USTDA, Romania
1998-1999
Engineering Manager. Coordination and development of conceptual design, site arrangement, cost estimates, and performance estimates. Also, responsible for financial modeling of various plant configurations.

NIMO, NYSEG, and GPU Acquisition Support, Northeast U.S.
Late 1990's
Mechanical Engineer. Technical and financial acquisition support for bidder in the NIMO, NYSEG, and GPU generation plant auctions. Provided O&M, capital expenditure, performance and staffing projections to support financial model.

Sarlux IGCC Project, Chase Investments, Italy
1995-1999
Senior Consultant. Technical and financial analysis of a 551 MW integrated gasification combined cycle plant. Assessment included project contracts, pro forma modeling, overall plant design, interconnections and supply arrangements between the refinery and the plant.

Termobarranquilla Project, BNP Paribas, OPIC, EXIM, Colombia
1994-2006
Senior Consultant. Provided initial due diligence of a new 750 MW combined cycle plant utilizing GT11N2 turbines and existing plant units to support financial closing including review of technology, environmental, permits, contracts, and financial model. Black & Veatch also provided construction monitoring and continues to provide operational support for the lender group.

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Exhibit ____ [CK-2]
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Generating Unit Alternatives for Selected Sites

Supply Alternatives	**FMPA**	**JEA**	**RCID**	**TALLAHASSEE**
Joint Development Alternatives$^{(1, 2)}$				
Three 1x1 train IGCC$^{(3)}$	Joint	Joint	Joint	Joint
3x1 GE 7FA combined cycle	Joint	Joint	Joint	Joint
Nuclear option$^{(3)}$	Joint	Joint	Joint	Joint
Existing Site--Individual Participant Options				
GE LM6000 simple cycle	Lake Worth	No	No	Hopkins$^{(5)}$/Purdom$^{(6)}$
GE LMS100 simple cycle$^{(3)}$	TCEC	Northside/Kennedy	No	Hopkins$^{(5)}$/Purdom$^{(6)}$
GE 7EA simple cycle	Lake Worth	No	No	Hopkins$^{(5)}$/Purdom$^{(6)}$
GE 7FA simple cycle	TCEC	Northside/Kennedy	No	Hopkins$^{(5)}$
1x1 GE LM6000 combined cycle	No	No	CEP	Hopkins$^{(5)}$
1x1 GE 7FA combined cycle	TCEC/Cane Island	Northside/Kennedy	No	Hopkins$^{(5)}$
250 MW CFB	No	Northside/Kennedy	No	Hopkins$^{(5,7)}$
Single 1x1 train IGCC	No	Kennedy	No	Hopkins$^{(5,7)}$
Greenfield--Individual Participant Options				
GE LM6000 simple cycle	Yes	No	No	Yes
GE LMS100 simple cycle$^{(3)}$	Yes	Yes	No	Yes
GE 7EA simple cycle	Yes	No	No	Yes
GE 7FA simple cycle	Yes	Yes	No	Yes
1x1 GE LM6000 combined cycle	No	No	No	Yes
1x1 GE 7FA combined cycle	Yes	Yes	No	Yes
250 MW CFB	Yes	Yes	No	Yes
Single 1x1 train IGCC	Yes	No$^{(4)}$	No	Yes

(1) All costs for joint development alternatives were developed assuming installation at a greenfield site.

(2) A joint development CFB option was not evaluated due to similarity with the TEC and higher capital cost resulting from multiple boiler units required for a 750 MW output.

(3) IGCC, nuclear, and the GE LMS100 are considered emerging technologies that are not commercially proven. Power producing IGCC plants are currently being considered by utilities and developers in the United States, but have yet to be demonstrated commercially. Although existing nuclear plants are considered proven, future plants will employ new designs and technologies. The first GE LMS100 entered commercial operation in the United States in July 2006 and, therefore, is not yet considered a commercially proven technology.

(4) Although JEA would consider a greenfield individual IGCC option, for purposes of this Application, a unit at Northside/Kennedy will offer a lower cost due to existing infrastructure and O&M savings.

(5) Not all combinations of individual options can be located at Hopkins. Transmission infrastructure improvements will be required to accommodate any additional generation at Hopkins.

(6) Not all combinations of individual options can be located at Purdom. The impact on the environmental signature of any additional combustion turbine installed at Purdom will require a limit on the maximum annual run hours of that unit and require the retrofit of SCR and CO catalyst on the existing Purdom 8 combined cycle unit.

(7) To locate a CFB, IGCC, or any other solid fuel alternative at Hopkins would require the purchase of additional land adjacent to the existing plant site and a citizen referendum (compliant with City of Tallahassee Code of Ordinances and Land Development Code) approving the project.

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 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 measures passed the Total Resource Test for residential and commercial rate classes combined, and 24 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.

Resume of
Bradley E. Kushner
Black & Veatch

Senior Consultant / Project Manager

Utility System Planning, Production Costing, and Economic Analysis

Education
Bachelors, Mechanical Engineering, University of Missouri at Columbia, 2000

Total Years Experience
6

Joined B&V
2000

Mr. Kushner is responsible for production costing associated with utility system expansion planning, as well as feasibility studies and demand-side management evaluation. He has also been involved in the issuance and evaluation of requests for proposals (RFPs).

Representative Project Experience

Taylor Energy Center Need for Power Application; Various Clients, Florida
2005 - Present
Study Manager. Provide production costing, economic analysis, and various other support to facilitate completion and filing of the Taylor Energy Center (TEC) Need for Power Application (NFP). Also includes preparation of testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the four separate utilities participating in the project. The analysis considered self-build and purchase power alternatives.

Integrated Resource Plan; City of Tallahassee; Tallahassee, Florida
2004 - Present
Study Manager. Analysis related to and preparation of the City of Tallahassee's (the City's) Integrated Resource Plan (IRP). The IRP will include consideration of the City's existing generating system and strategic planning to satisfy forecasted system requirements. The strategic planning process includes consideration of conventional supply-side options, demand-side management measures, renewable supply-side alternatives, and possible future environmental impacts.

Stanton Energy Center Unit B Need for Power Application; Orlando Utilities Commission; Orlando, Florida
2005 - 2006
Study Manager. Provided production costing, economic analysis, and various other support to facilitate completion and filing of the Stanton Energy Center Unit B (Stanton B) Need for Power Application (NFP). Also included preparation of testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the Orlando Utilities Commission. The FPSC approved the Stanton B NFP Application in May 2006, which represents the first coal-fired power plant approved in the State of Florida since 1991.

RFP Issuance and Evaluation; Western Farmers Electric Cooperative; Anadarko, Oklahoma
2002 - 2006
Project Analysis Engineer. Coordinated with Western Farmers Electric Cooperative (WFEC) to draft, issue, and evaluate a capacity solicitation (RFP) to secure forecast capacity requirements in most cost-effective and reliable manner. The RFP process was undertaken through coordination with Rural Utilities Services (RUS) in an effort to obtain low-cost RUS project financing. Involved evaluation of numerous conventional as well as renewable technology proposals and culminated in the issuance of a short-list and presentation to WFEC Board of Directors.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2006
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, EIA-860 and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2006
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2006 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. The EIA-860 collects data related to the specific utility's existing and planned generating units. The Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

RFP Issuance and Evaluation; City of Columbia, Water & Light Department; Columbia, Missouri
2005 - 2006
Study Manager. Coordinate with the City of Columbia, Water & Light Department (the City) to draft, issue, and evaluate a capacity solicitation (RFP) to secure forecast capacity requirements in most cost-effective and reliable manner. Involved evaluation of numerous conventional capacity options under consideration by the City, as well as options proposed by respondents to the RFP. Included continuous communication with City staff as well as presentations to the City's planning committee.

Treasure Coast Energy Center Need for Power Application; Florida Municipal Power Agency; Orlando, Florida
2004 - 2005
Project Analysis Engineer. Provided production costing, economic analysis, and various other support to facilitate completion and filing of the Florida Municipal

Power Agency's (FMPA) Need for Power Application (NFP). Also provided testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements. The analysis performed for FMPA considered self-build and purchase power alternatives. The NFP Application was approved by the FPSC in July, 2005, representing a critical step in the permitting and licensing process in the State of Florida.

Stock Island Combustion Turbine Evaluation; Florida Municipal Power Agency; Orlando, Florida
2004 - 2005
Project Analysis Engineer. Perform production costing and economic analysis to determine the most cost-effective capacity additions to be located at the Stock Island site. The analysis considered two different generating units from specific manufacturers, who responded to FMPA's request for bids.

Generation Expansion Study; Oman
2005
Project Analysis Engineer. Performed production costing and economic analysis to determine the most cost-effective capacity additions to satisfy forecast capacity requirements in the Country of Oman. The analysis considered seven different generating technologies.

Integrated Resource Plan; Golden Valley Electric Association; Fairbanks, Alaska
2005
Project Analysis Engineer. Economic analysis in support of the Golden Valley Electric Association's (GVEA) Integrated Resource Plan (IRP). The IRP will provide GVEA with recommendations of capacity additions which will satisfy forecasted capacity requirements in the most cost-effective manner.

Ten-Year Site Plan and FRCC Forms; Florida Municipal Power Agency; Orlando, Florida
2005
Engineering Manager. Provided assistance and support to the Florida Municipal Power Agency (FMPA) related to its 2005 Ten-Year Site Plan and subsequent submission to the Florida Public Service Commission (FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2005
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, EIA-860 and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2005
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2005 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. The EIA-860 collects data related to the specific utility's existing and planned generating units. The Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Due Diligence and Economic Analysis; Dairyland Power Cooperative; La Crosse, Wisconsin
2003-2005
Project Analysis Engineer. Performed due diligence review of the power supply planning efforts undertaken by Dairyland Power Cooperative (DPC). Included development of numerous capacity expansion plans and associated system production costing. Analysis was done in compliance with the requirements of the Rural Utilities Services (RUS) to potentially obtain low-cost RUS project financing. Also included was a presentation of the study's findings to the DPC Board of Directors. Following the issuance of a request for proposals (RFP) for capacity supplies, Black & Veatch was released to perform additional production costing and evaluations of the bids and self-build options was completed, with the results presented to DPC project personnel as well as RUS staff.

Numeric Conservation Goals Filing; JEA; Jacksonville, Florida
2004
Project Analysis Engineer. Analysis related to and preparation of the JEA 2004 Petition for Approval of Numeric Conservation Goals, as required by the Florida Public Service Commission (FPSC). The submittal included analysis of numerous demand-side management (DSM) measures to be considered by JEA in order to determine their cost-effectiveness. The process is required to be completed by JEA every five years, culminating in the eventual determination by the FPSC of the conservation goals JEA must satisfy each year.

Numeric Conservation Goals Filing; Orlando Utilities Commission; Orlando, Florida
2004
Project Analysis Engineer. Analysis related to and preparation of the Orlando Utilities Commission (OUC) 2004 Petition for Approval of Numeric Conservation Goals, as required by the Florida Public Service Commission (FPSC). The submittal included analysis of numerous demand-side management (DSM) measures to be considered by OUC in order to determine their cost-effectiveness. The process is required to be completed by OUC every five years, culminating in the eventual determination by the FPSC of the conservation goals OUC must satisfy each year.

Site Selection Study; Florida Municipal Power Agency; Orlando, Florida
2004
Project Analysis Engineer. Coordination and preparation of a site selection study related to the potential construction of a new combined cycle unit to be installed by the Florida Municipal Power Agency.

Ten-Year Site Plan; Florida Municipal Power Agency; Orlando, Florida
2004
Engineering Manager. Provided assistance and support to the Florida Municipal Power Agency (FMPA) related to its 2004 Ten-Year Site Plan and subsequent submission to the Florida Public Service Commission (FPSC).

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2004
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2004
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2004 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Due Diligence; City Utilities; Springfield, Missouri
2003
Project Analysis Engineer. Due diligence and economic analysis to determine the most cost-effective capacity additions to satisfy forecasted system requirements for City Utilities – Springfield. Two options were considered, consisting of constructing a second unit at an existing site and an independent developer's proposed construction of a unit at a new site.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2003
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Participation Agreement; Kissimmee Utility Authority; Orlando, Florida
2003
Engineering Manager. Development of a Participation Agreement between client (KUA) and another Florida utility governing ownership, construction, and operation of a new generating unit at a KUA site. Included meetings and coordination with clients and incorporation of various requirements to sufficiently complete the Agreement.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2003
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2003 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Capacity Planning Study; Western Farmers Electric Cooperative; Anadarko, Oklahoma
2001 - 2002
Project Analysis Engineer. Production costing and economic analysis to determine WFEC's most cost-effective expansion options to meet forecast capacity requirements. The capacity planning study was performed in support of the RFP issuance described above.

Feasibility Study; Kissimmee Utility Authority; Kissimmee, Florida
2002
Engineering Manager. Assisted in coordination and preparation of a preliminary study to evaluate the feasibility of constructing a new generating unit at an existing Kissimmee Utility Authority site.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2002
Project Analysis Engineer. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2002 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Capacity Planning Study; Braintree Electric Light Department; Braintree, Massachusetts
2002
Project Analysis Engineer. Production costing and economic analysis to determine Braintree Electric Light Department's most cost-effective expansion options to meet forecast capacity requirements.

Integrated Resource Plan; City of Tallahassee; Tallahassee, Florida
2001-2002
Project Analysis Engineer. Assisted in completion of the City of Tallahassee's Integrated Resource Plan (IRP), including evaluation of the City's demand-side management program alternatives.

Capacity Planning Study; Basin Electric Power Cooperative; Bismarck, North Dakota
2001
Project Analysis Engineer. Production costing and economic analysis necessary to provide Basin Electric Power Cooperative with recommendations as to which capacity additions would be most cost-effective to satisfy system requirements.

Ten-Year Site Plan; Lakeland Electric; Lakeland, Florida
2001
Project Analysis Engineer. Assisted in completion of Lakeland Electric's 2001 Ten-Year Site Plan, including consideration of Lakeland's capacity addition options.

Ten-Year Site Plan; Orlando Utilities Commission; Orlando, Florida
2001
Project Analysis Engineer. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2001 Ten-Year Site Plan and submit to the Florida Public Service Commission. Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff.

Need for Power Application; Various Clients; Florida
2001
Project Analysis Engineer. Production costing and economic analysis required in support of determination of most cost-effective expansion options to meet the individual needs of the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency. Also included preparation of corresponding application to be presented to the Florida Public Service Commission, as well as written testimony in support thereof.

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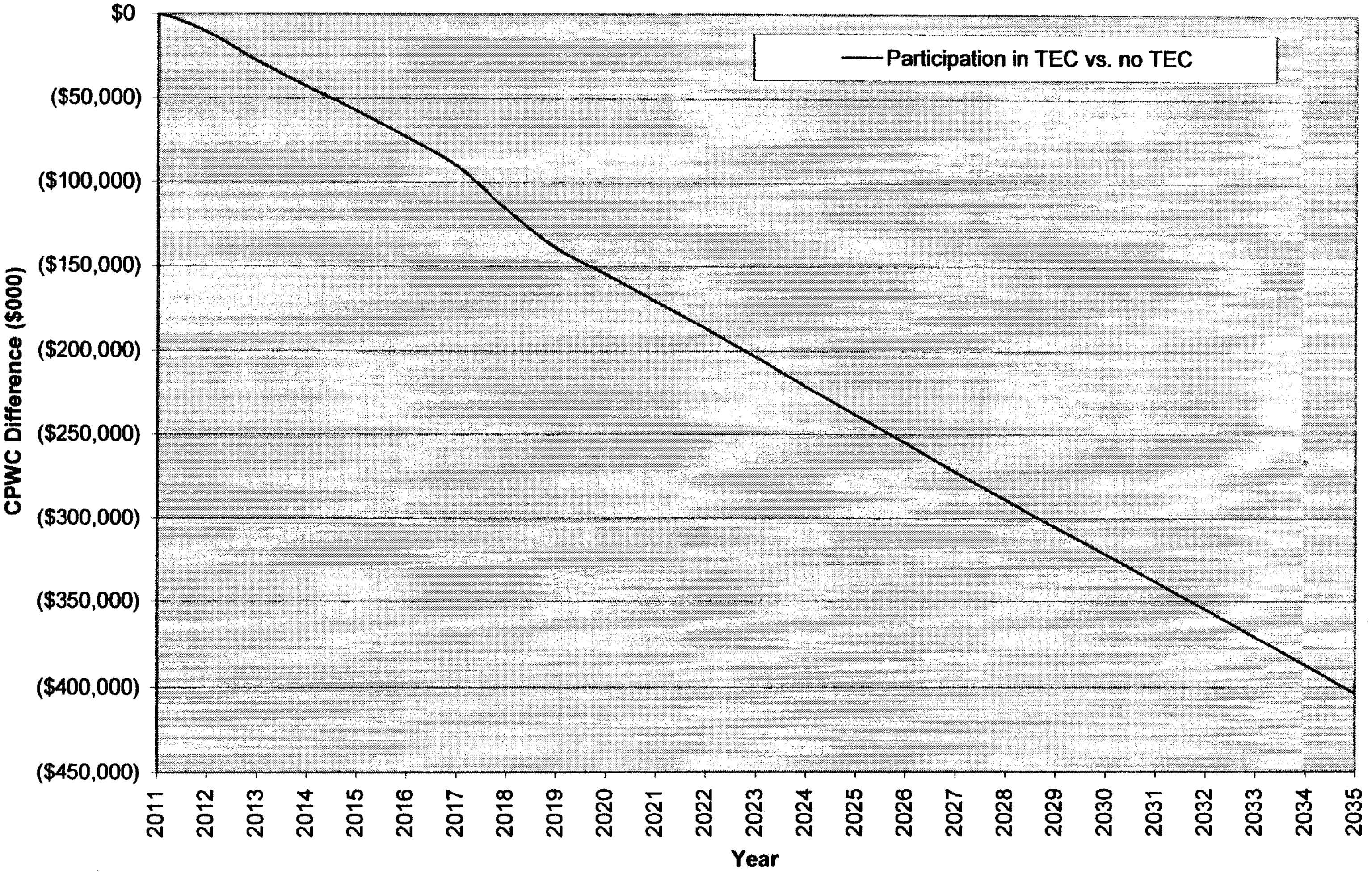

Figure 1. FMPA Cumulative Present Worth Cost (CPWC) Analysis

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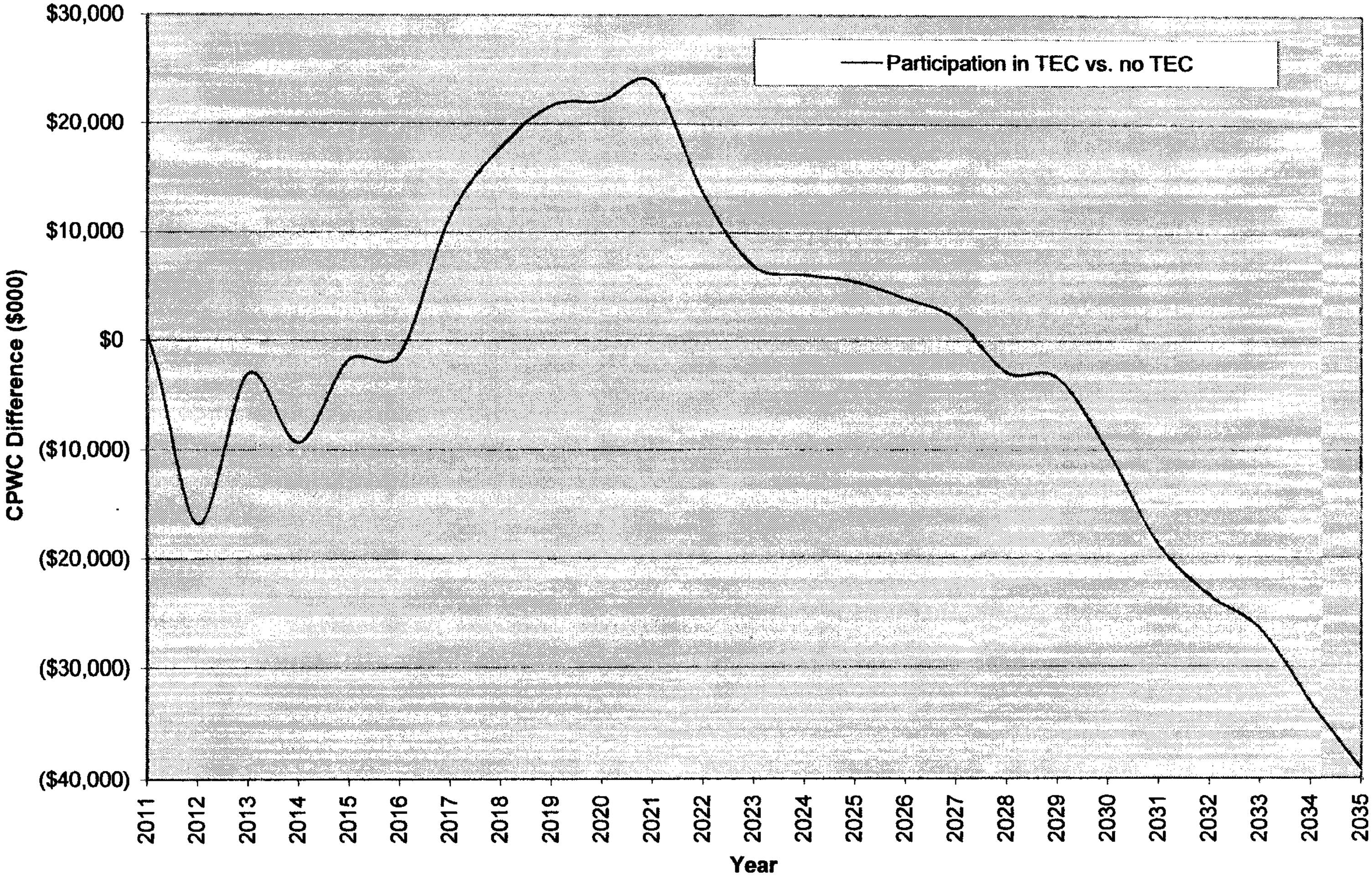

Figure 2. JEA Cumulative Present Worth Cost (CPWC) Analysis

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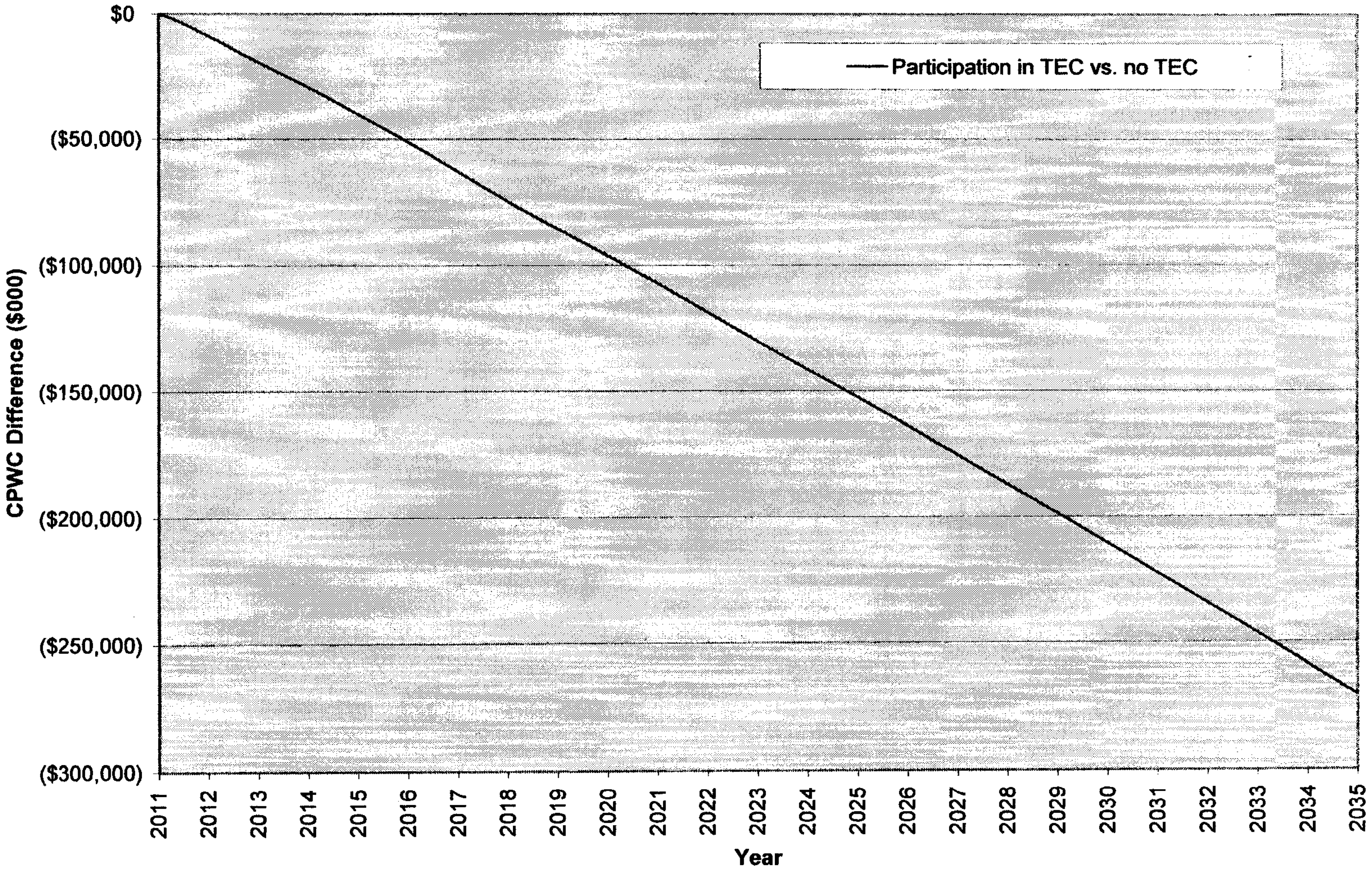

Figure 3. RCID Cumulative Present Worth Cost (CPWC) Analysis

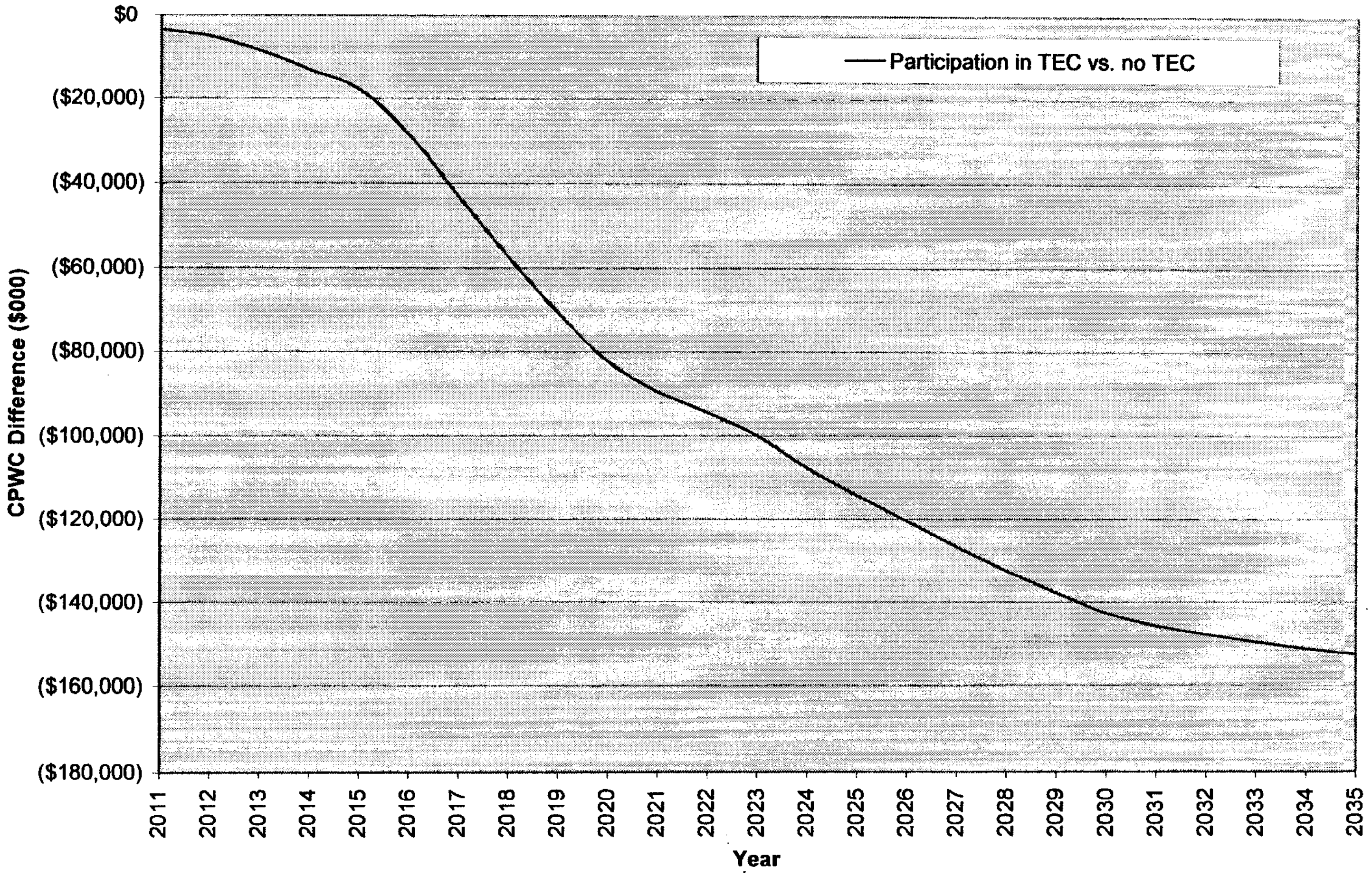

Figure 4. City of Tallahassee Cumulative Present Worth Cost (CPWC) Analysis

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Table 1
Summary of FMPA's Sensitivity Analyses
(Varying Base Case Input Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	With TEC	Without TEC	Differential CPWC Savings with TEC
Base Case	8,927.9	9,331.5	403.6
High Fuel Prices	9,979.6	10,343.1	363.5
Low Fuel Prices	7,890.9	8,265.5	374.6
High Load and Energy Growth	10,392.7	10,853.3	460.6
Low Load and Energy Growth	7,539.6	7,952.2	412.6
High Capital Cost	9,222.9	9,634.5	411.6
Low Capital Cost	8,632.6	9,024.0	391.4
High Emissions Allowances Costs	9,050.0	9,458.5	408.5
Low Emissions Allowances Costs	8,807.6	9,178.6	371.0
Regulated CO_2	9,427.7	9,798.1	370.4

Table 2
Summary of FMPA's Sensitivity Analyses
(Varying External Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
3x1 Combined Cycle Joint Development	9,571.9	8,927.9	644.0
Three-Train 1x1 IGCC Joint Development	9,127.7	8,927.9	199.8
Second Jointly Owned Pulverized Coal Unit	8,613.4	8,927.9	(314.5)
All Natural Gas Capacity Expansion Plan	10,014.0	8,927.9	1,086.1
Biomass Supply-Side Addition with TEC	9,007.7	8,927.9	79.8
Biomass Supply-Side Addition without TEC	9,409.0	8,927.9	481.1
PRB Coal for TEC	8,951.5	8,927.9	23.6

Table 3
Summary of FMPA's Share of Southern's Bids

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
Southern's Pulverized Coal Unit	9,502.9	8,927.9	575.0
Southern's 2x1 Combined Cycle Unit	9,619.1	8,927.9	691.2

Table 4
Summary of JEA's Sensitivity Analyses
(Varying Base Case Input Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	With TEC	Without TEC	Differential CPWC Savings with TEC
Base Case	$14,139.0	$14,178.1	$39.1
High Fuel Prices	$15,521.2	$15,580.9	$59.7
Low Fuel Prices	$12,650.7	$12,651.3	$0.6
High Load and Energy Growth	$17,591.0	$17,721.5	$130.5
Low Load and Energy Growth	$13,371.9	$13,427.3	$55.4
High Capital Cost	$14,465.4	$14,500.7	$35.3
Low Capital Cost	$13,788.2	$13,877.7	$89.5
High Emissions Allowance Costs	$14,427.7	$14,459.1	$31.4
Low Emissions Allowance Costs	$13,850.4	$13,896.7	$46.3
Regulated CO_2	$15,659.2	$15,712.6	$53.4

Table 5
Summary of JEA's Sensitivity Analyses
(Varying External Parameters)

	Expansion Plan CPWC Cost ($ million)		
Sensitivity Case	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
3x1 Combined Cycle Joint Development	$14,362.4	$14,139.0	$223.4
Three-Train 1x1 IGCC Joint Development	$14,176.1	$14,139.0	$37.1
Second Jointly Owned Pulverized Coal Unit	$14,109.2	$14,139.0	($29.8)
All Natural Gas Capacity Expansion Plan	$15,055.2	$14,139.0	$916.2
Biomass Supply-Side Addition with TEC	$14,218.3	$14,139.0	$79.3
Biomass Supply-Side Addition without TEC	$14,230.1	$14,139.0	$91.1
PRB Coal for TEC	$14,159.5	$14,139.0	$20.5

Table 6
Summary of JEA's Share of Southern's Bids

	Expansion Plan CPWC Cost ($ million)		
Sensitivity Case	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
Southern's Pulverized Coal Unit	$14,626.1	$14,139.0	$487.1
Southern's 2x1 Combined Cycle Unit	$14,446.7	$14,139.0	$307.7

Table 7
Summary of RCID's Sensitivity Analyses
(Varying Base Case Input Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million) With TEC	Without TEC	Differential CPWC Savings with TEC
Base Case	$1,771.2	$2,042.1	$270.9
High Fuel Prices	$1,923.6	$2,222.1	$298.5
Low Fuel Prices	$1,584.4	$1,774.2	$189.8
High Load and Energy Growth	$1,854.0	$2,111.9	$257.9
Low Load and Energy Growth	$1,713.1	$1,985.1	$272.0
High Capital Cost	$1,832.8	$2,091.9	$259.1
Low Capital Cost	$1,709.7	$1,992.2	$282.5
High Emissions Allowances Costs	$1,780.4	$2,043.4	$263.0
Low Emissions Allowances Costs	$1,762.0	$2,040.7	$278.7
Regulated CO_2	$1,825.3	$2,067.0	$241.7

Table 8
Summary of RCID's Sensitivity Analyses
(Varying External Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million) Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
3x1 Combined Cycle Joint Development	$1,914.4	$1,771.2	$143.2
Three-Train 1x1 IGCC Joint Development	$1,814.8	$1,771.2	$43.6
Second Jointly Owned Pulverized Coal Unit	$1,539.9	$1,771.2	($231.3)
Biomass Supply-Side Addition with TEC	$1,727.5	$1,771.2	($43.7)
Biomass Supply-Side Addition without TEC	$1,982.2	$1,771.2	$211.0
PRB Coal for TEC	$1,780.6	$1,771.2	$9.4

Table 9
Summary of RCID's Share of Southern's Bids

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
Southern's Pulverized Coal Unit	$1,872.4	$1,771.2	$101.2
Southern's 2x1 Combined Cycle Unit	$1,973.8	$1,771.2	$202.6

Table 10
Summary of the City's Sensitivity Analyses
(Varying Base Case Input Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	With TEC	Without TEC	Differential CPWC Savings with TEC
Base Case	$4,320.0	$4,472.6	$152.6
High Fuel Prices	$4,817.0	$4,996.6	$179.6
Low Fuel Prices	$3,502.7	$3,648.6	$145.9
High Load and Energy Growth	$4,670.3	$4,793.1	$122.8
Low Load and Energy Growth	$4,058.0	$4,234.9	$176.9
High Capital Cost	$4,388.6	$4,573.3	$184.7
Low Capital Cost	$4,187.9	$4,372.0	$184.1
High Emissions Allowance Costs	$4,344.5	$4,516.3	$171.8
Low Emissions Allowance Costs	$4,274.9	$4,431.7	$156.8
Regulated CO_2	$4,392.8	$4,508.4	$115.6

Table 11
Summary of the City's Sensitivity Analyses
(Varying External Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
3x1 Combined Cycle Joint Development	$4,598.0	$4,320.0	$278.0
Three-Train 1x1 IGCC Joint Development	$4,421.8	$4,320.0	$101.8
Second Jointly Owned Pulverized Coal Unit	$4,134.7	$4,320.0	($185.3)
All Natural Gas Capacity Expansion Plan	$4,619.8	$4,320.0	$299.8
Biomass Supply-Side Addition with TEC	$4,345.5	$4,320.0	$25.5
Biomass Supply-Side Addition without TEC	$4,514.5	$4,320.0	$194.5
PRB Coal for TEC	$4,334.5	$4,320.0	$14.5

Table 12
Summary of the City's Share of Southern's Bids

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
Southern's Pulverized Coal Unit	$4,576.3	$4,320.0	$256.3
Southern's 2x1 Combined Cycle Unit	$4,734.3	$4,320.0	$414.3

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MICHAEL NEILL LAWSON

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 address.

A. My name is Michael Neill Lawson. My business address is 21 West Church Street, Jacksonville, Florida 32202.

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

A. I am employed by JEA as a Project Manager.

Q. Please describe your responsibilities in that position.

A. I am responsible for all phases of project management from start of engineering through startup and commissioning for new projects.

Q. Please state your educational background and professional experience.

A. I have a Bachelor's degree in Mechanical Engineering from the University of Alabama in Huntsville. I am a registered Professional Engineer in the State of Florida.

I have worked for JEA since 1983 and my responsibilities have included serving as Lead Project Administrator and Contracts Administration Manager for the St. Johns River Power Park, Construction Site Manager for the Northside Repowering Project, Project Manager for the Brandy Branch Combined Cycle Project, and my current position as Project Manager for the proposed Taylor Energy Center (TEC). Prior to JEA, I worked in a variety of engineering positions including Startup Engineer, Lead Project Engineer, and Plant Engineer.

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

A. The purpose of my testimony is to discuss the proposed ownership structure of the TEC and discuss the decision not to pursue the bids received in response to the request for proposals (RFP).

Q. Gave you prepared any exhibits to your testimony?

A. Yes. Exhibit __[MNL-1] is a copy of my resume.

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

A. Yes, I am sponsoring Section A.3.1, which was prepared under my direct supervision.

Q. Please briefly describe the proposed ownership structure for TEC.

A. TEC is being proposed as a joint development project by four municipal utilities, including Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (City) (collectively referred to as the Participants). FMPA is a wholesale supplier to 15 city-owned electric utilities throughout Florida. JEA is a retail supplier in Jacksonville, Florida, and in parts of three adjacent counties. RCID is a retail supplier in parts of Orange and Osceola Counties. The City of Tallahassee is the principal retail supplier in Tallahassee, Florida.

All of TEC's capacity will be fully subscribed to and owned by the four Participants. FMPA will own 38.9 percent of TEC, JEA will own 31.5 percent of TEC, RCID will own 9.3 percent of TEC, and the City of Tallahassee will own the remaining 20.3 percent of TEC.

Q. How will the costs for TEC be allocated among the Participants?

A. Each Participant will be responsible for the costs associated with TEC in proportion to its individual ownership percentage.

Q. Why are the Participants interested in developing TEC?

A. The Participants are developing the proposed TEC to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant and to meet the forecast capacity requirements of each Participant. TEC will provide low cost, reliable baseload energy and fuel diversity for the Participants.

Q. Did the Participants conduct an RFP process to determine if other utilities or entities could provide capacity more cost-effectively than TEC?

A. Yes. JEA administered and issued the RFP on behalf of Participants on November 28, 2005. A summary of the RFP process and a discussion of the evaluation of the bids received in response to the RFP are discussed in the testimony of Paul Arsuaga from R.W. Beck, Inc. (Beck), the independent engineering firm retained by the Participants to evaluate the bids.

Q. What was the outcome of the RFP process?

A. The Participants received two bids (one for a coal fired power plant and one for a combined cycle power plant) from one bidder (Southern Power Company, or Southern). The Beck evaluation concluded that neither of Southern's bids received in response to the RFP would provide the Participants with capacity more cost-effectively than TEC.

Q. Does this conclude your testimony?

A. Yes.

EMPLOYMENT

02/05 – Present

JEA, Taylor Energy Center

Project Manager for 800 MW solid fuel fire electric generating plant. Project cost $1,200 million. Responsible for all phases of project management from start of engineering through start-up and commissioning for a multi-participant project.

02/02 – 02/05
FL

JEA, Brandy Branch Combined Cycle Project, Jacksonville,

Project Manager for the addition of a combined cycle plant on two 7FA GE CT's. Project cost $201 million. Responsible for all phases of project management from start of engineering through start-up and commissioning.

4/98 – 02/02

JEA, Northside Repowering Project, Jacksonville Fl.

Construction Site Manager for repowering two – 275 MW oil/gas fired units with two 300 MW solid fuel fired CFB boilers. Project cost $650 million. Responsible for all site construction activities including work scope delineation, change management, laydown coordination, security, safety program, owners providied insurance program, and budget responsibility.

8/83 – 4/98
Jacksonville, Fl.

Jacksonville Electric Authority, St Johns River Power Park,

Contracts Administration Manager: Responsible for all phases of major capital and maintenance projects ranging from power piping, boiler modifications, and major equipment installations to yard utilities. Heavy involvement with plant planned and forced outages. Duties include: development, biding and management of all site Contracts; review of engineering packages; daily interface and direction of contractors; project scheduling, budgeting, estimating, equipment procurement and cost controls; construction and maintenance field inspections; and direct supervision of up to 40 Contract Management employees.

Lead Project Administrator: Owner representative for boiler, coal handling, cooling tower and other various contracts on construction of two 624 megawatt coal fired electric generating units. Responsible for Owner inspections, budget control, preparation of change orders, payment approvals, contract interpretations, claims negotiations, and managing 38 million dollars of project force contract work.

11/82 - 8/83 **Tennessee Valley Authority,** Bellefonte Nuclear Plant, Hollywood, Al.

Start-up Engineer: Group leader of four engineers. Prepared flush procedures; prepared construction operating instructions; coordinated start-up of various plant systems; maintained construction schedules; and prepared turnover packages for plant systems .

4/79 - 7/82 **Gardinier, Inc.,** Ft. Meade Mine, Ft. Meade, Florida

Lead Project Engineer: Concept, design and control of $40 million slimes thickening project. Supervised six person engineering staff.

Plant Engineer: Phosphate mining and beneficiation; full control of various plant modifications and additions such as slurry pumps, conveyor stackers, classifiers, log washers, hydraulic stations, and thickeners from concept through design and construction. Lead Project Engineer for new $3.5 million matrix pumping system. Was on design team for $25 million major plant expansion. All projects involved concept, design, equipment selection, procurement, and construction.

3/78 - 4/79 **Gulf States Utilities Company,** Sabine Station, Bridge City, Texas

Engineer: Power Plant maintenance planning; boiler, pump, and turbine maintenance supervision; specification preparation, bidding, and procurement. Major projects: Outage Coordinator for a 380 megawatt steam turbine generator; boiler inspections and maintenance on four boilers including leak records and supervision of repair crews.

12/76 - 3/78 **United Parcel Service,** Huntsville, Alabama

Pre-load Splitter: Sorted packages into driver routes, loaded package trucks.

9/75 - 12/76 **Montgomery Ward and Company,** Huntsville, Alabama

Salesman: Sales in hardware department. 30 - 40 hours per week.

71 - 75 **Ala-Tenn Natural Gas Company,** Muscle Shoals, Alabama

Summer Crew Foreman: Supervised six to eight men on general pipeline maintenance. Summers 40 hours per week.

EDUCATION

1974 - 1978 University of Alabama in Huntsville

Mechanical Engineering Degree obtained in 1978.

1973 - 1974 University of North Alabama, Florence, Alabama

1969 - 1973 Bradshaw High School, Florence, Alabama

PERSONAL

Born: December 7, 1954, Jackson, Tennessee.
Married: Two sons.
Appearance: Height: 6'0"; Weight: 205 lbs.
Hobbies: Golf, SCUBA diving, photography, hunting, fishing.
Licensing: **Professional Engineer,** State of Florida, certificate #32619.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF WILLIAM S. MAY

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _______

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is William S. May. My business address is 8553 Commodity Circle, Orlando, Florida 32819.

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

A. I am employed by Florida Municipal Power Agency (FMPA) as the Manager of the Planning and Contracts Department.

Q. Please describe your responsibilities in that position.

A. As the Manager of the Planning and Contracts Department for FMPA, I have responsibility for managing the planning functions for its expanding All-Requirements Power (ARP) Supply Project including production of annual load forecasts, annual reporting to regulatory bodies, transmission planning and load-flow studies, demand-side planning, and generation expansion planning. I manage the development, issuance, and evaluation of requests for proposals involving both short-term and long-term purchases and generation construction options. I am also responsible for negotiation and implementation of purchase power contracts. I direct the analysis and implementation of integrated resource plans and review analysis results. I represent FMPA on the Florida Reliability Coordinating Council (FRCC) Planning Committee and oversee FMPA representation on the FRCC Load and Resource Working Group, Transmission Working Group, and Stability Working Group. In addition, I am a member of the FMPA Risk Management Group.

Q. Please state your educational background and professional experience.

A. I received Bachelor of Science degrees in Electrical Engineering and Applied Mathematics from North Carolina State University, Raleigh, North Carolina, and a Master of Science degree in Electrical Engineering with emphasis in power systems modeling from Georgia Institute of Technology, Atlanta, Georgia. I am a member of the Institute for Electronic & Electrical Engineers (IEEE). My 31 years in the electric utility industry have encompassed many facets of the business, including experience as a consultant to the power industry, a power systems engineer, an energy market price forecaster, a transmission planning engineer, a substation design engineer, and a designer of simulation software. Before joining FMPA, I was a self-employed entrepreneur in the field of electric power supply systems modeling, power plant value analysis, and litigation consulting.

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

A. The purpose of my testimony is to provide a description of FMPA and its ARP. I will summarize FMPA's existing generation system as well as available purchase power resources. I will discuss FMPA's expected need for capacity and provide an overview of the demand-side management (DSM) programs currently offered by FMPA's members. I also will discuss strategic considerations that support FMPA's decision to participate in the Taylor Energy Center (TEC). Finally, I will discuss FMPA's ability to finance its ownership share of TEC.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. I am sponsoring Exhibit __ [WSM-1], entitled "ARP Member Cities," Exhibit __ [WSM-2], entitled "Percentages of ARP, Member, Nuclear, and Purchase Power Capacity," Exhibit __ [WSM-3], entitled "ARP's Existing Resource Capacity," and Exhibit __ [WSM-4], which is a copy of my resume. 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 Sections B.1.0, B.2.0, B.4.0, B.7.1, B.8.0, and B.10, all of which were either prepared by me or under my direct supervision.

Q. Please describe the purpose and structure of FMPA.

A. FMPA is a wholesale power company composed of 30 municipal electric utilities. FMPA provides economies of scale in power generation and related services to support community-owned electric utilities. FMPA was created on February 24, 1978, under the provisions of the Florida Constitution, the Joint

Power Act, and the Florida Interlocal Cooperation Act of 1969. FMPA was formed to allow its members to cooperate with each other, on the basis of mutual advantage, to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities. Specifically, FMPA is involved in the joint financing, constructing, acquiring, managing, operating, utilizing, and owning of electric power plants for its municipal members. FMPA is governed by a Board of Directors consisting of one representative from each of the 30 municipal members.

As a joint operating agency engaged in the business of generating and transmitting electric energy, the FMPA is an "Electric Utility" under 403.503(14), Florida Statutes, and, therefore, is an "applicant" as defined by Section 403.503(4), Florida Statutes. The Public Service Commission previously has held that FMPA is a proper applicant for a determination of need pursuant to Section 403.519, Florida Statutes.

Q. Please describe the ARP.

A. The ARP was formed on May 1, 1986, initially with five municipal participants. The purpose of ARP is to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the entire needs of the ARP Members.

Several other municipals have joined over time. The 15 current ARP participants include the following:

- City of Bushnell
- City of Clewiston
- City of Fort Meade
- Fort Pierce Utilities Authority
- City of Green Cove Springs
- Town of Havana
- City of Jacksonville Beach
- City of Key West
- City of Leesburg
- City of Newberry
- Ocala Electric Utility
- City of Starke
- City of Vero Beach
- City of Lake Worth
- City of Kissimmee

The Members of ARP are shown in Exhibit __ [WSM-1], which is attached to and included in my pre-filed testimony. ARP Members are classified as either generating or non-generating members. All ARP Members are required to purchase all of their capacity and energy from the ARP with the exception of excluded resources that are the Members' ownership share of Crystal River 3 and St. Lucie 2. Generating Members get reimbursements in the form of credits for their capacity contributions to the ARP. Once a municipal utility has joined the ARP, a contract is signed for a term of approximately 30 years, and this contract is automatically renewed unless the member elects otherwise. Exhibit __ [WSM-2] displays the percentage of existing ARP power supply resources that are owned, purchased from ARP Members, and purchased under other contracts.

Q. Please summarize the capacity resources currently available to FMPA's ARP.

A. The ARP's existing capacity resources (summer rating) are presented in Exhibit __ [WSM-3]. The exhibit illustrates that the ARP's capacity resources decrease as many of the ARP's purchase power contracts will expire in the near-term.

Q. What reserve margin does FMPA use for planning purposes?

A. FMPA has established a 15 percent minimum planned reserve margin criteria for the winter period and an 18 percent reserve margin criteria for the summer period for planning purposes.

Q. Please describe FMPA's expected need for additional capacity to satisfy reserve margin requirements under the base case load forecast.

A. Considering the base case load forecast summarized in the testimony of Jonathan Nunes of R.W. Beck, Inc., and the ARP capacity resources discussed previously in my testimony, winter reserve margins are expected to fall below the required 15 percent minimum in the winter of 2012/13. At this time, FMPA's reserve margin is projected to fall to 11.4 percent, or 52 MW below the capacity required to maintain a 15 percent reserve margin. In the following winter season, 2013/14, FMPA's reserve margin is projected to fall to a negative 0.2 percent (net capacity less than projected load), or 227 MW below the capacity required to maintain a 15 percent reserve margin. Projected winter capacity deficits continue to increase beyond 2013/14.

Summer reserve margins are forecast to fall below the 18 percent level in the summer of 2007. At this time, FMPA's reserve margin is projected to fall to 16.6 percent, or 20 MW below the capacity required to maintain an 18 percent reserve margin. FMPA would likely enter into a short-term seasonal purchase to maintain its reserve margin in 2007. The addition of the 296 MW Treasure Coast Energy Center combined cycle unit in June 2008 raises FMPA's projected reserve margin above 18 percent in 2008 and 2009. The addition of simple cycle combustion turbines in the summer of 2010 will satisfy forecast capacity requirements for FMPA until the summer of 2011. In the summer of 2011, FMPA's reserve margin is projected to decrease to 13.9 percent, or 59 MW below the capacity required to maintain an 18 percent reserve margin. Projected summer capacity deficits continue to increase beyond 2011.

Tables B.4-1 and B.4-2 of Exhibit __ [TEC-1] present the projected reliability levels for the winter and summer seasons, respectively, under the base case load forecast.

Q. Please explain how DSM is conducted by FMPA.

A. FMPA is a wholesale supplier of electricity to the ARP Members. As such, FMPA does not directly implement DSM to retail customers. The individual ARP Members actually provide the DSM programs to their customers. FMPA fully supports DSM and provides assistance to ARP Members implementing DSM programs.

Q. Are ARP Members offering any DSM programs currently?

A. Yes. Several ARP members offer various DSM programs, including the following:

- Energy Audits
- High Pressure Sodium Outdoor Lighting Conversions
- Energy Star® Programs
- Energy Services for Energy Upgrades
- Green Energy Programs
- Load Profiling for Commercial Customers
- Fix-Up Program for the Elderly and Handicapped

Q. Did FMPA consider new DSM measures as alternatives to participation in TEC in this Application?

A. Yes. FMPA's analysis of potentially cost-effective new DSM measures is discussed in the testimony of Bradley Kushner of Black & Veatch.

Q. Are there any advantages that the installation of TEC will have on fuel diversity?

A. Yes. TEC will increase fuel diversity for FMPA and the State of Florida as a whole. The project will have the ability to source solid fuels from both domestic and international coal producing regions including the Powder River Basin (PRB), Central Appalachia, Latin American, and other regions, as well as petroleum coke from the Gulf Coast region and the Caribbean. Historically, coals from these regions and petroleum coke have experienced significantly lower prices on a $/MBtu basis than oil and natural gas. As a result, TEC will not only provide solid fuel capacity for FMPA and the State of Florida, but it will also provide further fuel diversification through the capability to source coal and petroleum coke from numerous different regions, which will help mitigate exposure to high natural gas and fuel oil prices. The low cost baseload energy from TEC will help FMPA and the State of Florida reduce dependence on higher cost energy from natural gas and oil.

Q. Are there any advantages that the installation of TEC will have on fuel reliability?

A. Yes. The addition of solid fueled generation increases the reliability of FMPA's fuel supply. Coal and petroleum coke inventory for up to approximately 90 days of operation can be stored onsite at TEC, reducing the potential supply disruptions associated with natural gas like those resulting from hurricanes in the Gulf Coast. Furthermore, the ability to store up to approximately 90 days of fuel mitigates potential transportation disruption.

Q. Are there any advantages that the installation of TEC will have on the stability of FMPA's electric rates?

A. Yes. TEC will help to satisfy the need for low cost, baseload energy within FMPA's service territory and the State of Florida as a whole. Additional low cost, baseload energy from TEC will help to limit electric rate increases for consumers and businesses. Electric rate stability will be beneficial in long-term planning, and should also help facilitate more stable growth within the economy.

Q. Will the economic advantages of TEC end after 2035?

A. No. Although economic evaluations have been conducted through 2035 for this TEC Need for Power Application (Exhibit __ [TEC-1]), TEC will be designed for, and is expected to have, a service life significantly greater than the 23 years of operation captured by the analysis period. The benefits of TEC's expected actual service life of 35 to 50 years or more have not been captured in the economic analysis, but are expected to be realized by FMPA and the other project participants. Therefore, the total cost savings and benefits of TEC are understated in the economic analysis.

Q. Are there any advantages that the installation of TEC will have on geographic diversity?

A. Yes. For FMPA, the other project participants, and the State of Florida as a whole, TEC will provide geographic diversity because it will be constructed on a greenfield site. The greenfield site provides FMPA with additional baseload generation without increasing the concentration of its generation resources at one location. This diversity should increase reliability and availability of generating resources, particularly if a hurricane or other extreme condition causes forced outages in a localized area.

Q. Are there other important factors that FMPA considered in its decision to participate in TEC?

A. Yes. As discussed in the testimony of Paul Hoornaert, TEC will utilize proven supercritical technology and include the Best Available Control Technology to minimize plant emissions. It was important to FMPA that TEC utilize proven and reliable technology, and also minimize impacts to the environment.

Q. How does FMPA intend to finance the construction of TEC?

A. FMPA has several funding sources available that may be used to finance the development and construction of TEC. These sources include internal funds, pooled loans, and new long-term debt issuances. During preliminary design, engineering, and permitting, FMPA may draw on its working capital within the ARP fund. As the initial development concludes and construction commences, FMPA may rely on its pooled loan commercial paper to get the construction process under way. The pooled loans could be expected to be used for financing up to the first $100 million of costs. Once the project is well defined and construction under way, FMPA would need to initiate a revenue bond issuance for long-term project funding. For large projects such as a coal fired power plant, FMPA would expect to issue either fixed or floating rate revenue bonds with a term of 30 years. FMPA has a credit rating of A+ from Fitch and an A1 from Moody's Investors Service. Typically, FMPA purchases bond insurance on its long-term bonds to increase its rating to AAA and Aaa, respectively. In addition, to protect against fluctuations in the interest rate, FMPA employs interest rate swap contracts based on well established indices for its floating rate debt.

Q. Will FMPA be able to obtain the financing for the construction of TEC?

A. Yes. Based on the project's favorable economics and its excellent credit rating, FMPA believes there will be no problems issuing debt to cover its share of the TEC project costs. FMPA has recently initiated bond offerings with tax-exempt interest rates well below the rates assumed for the economic analysis.

Q. Does this conclude your testimony?

A. Yes.

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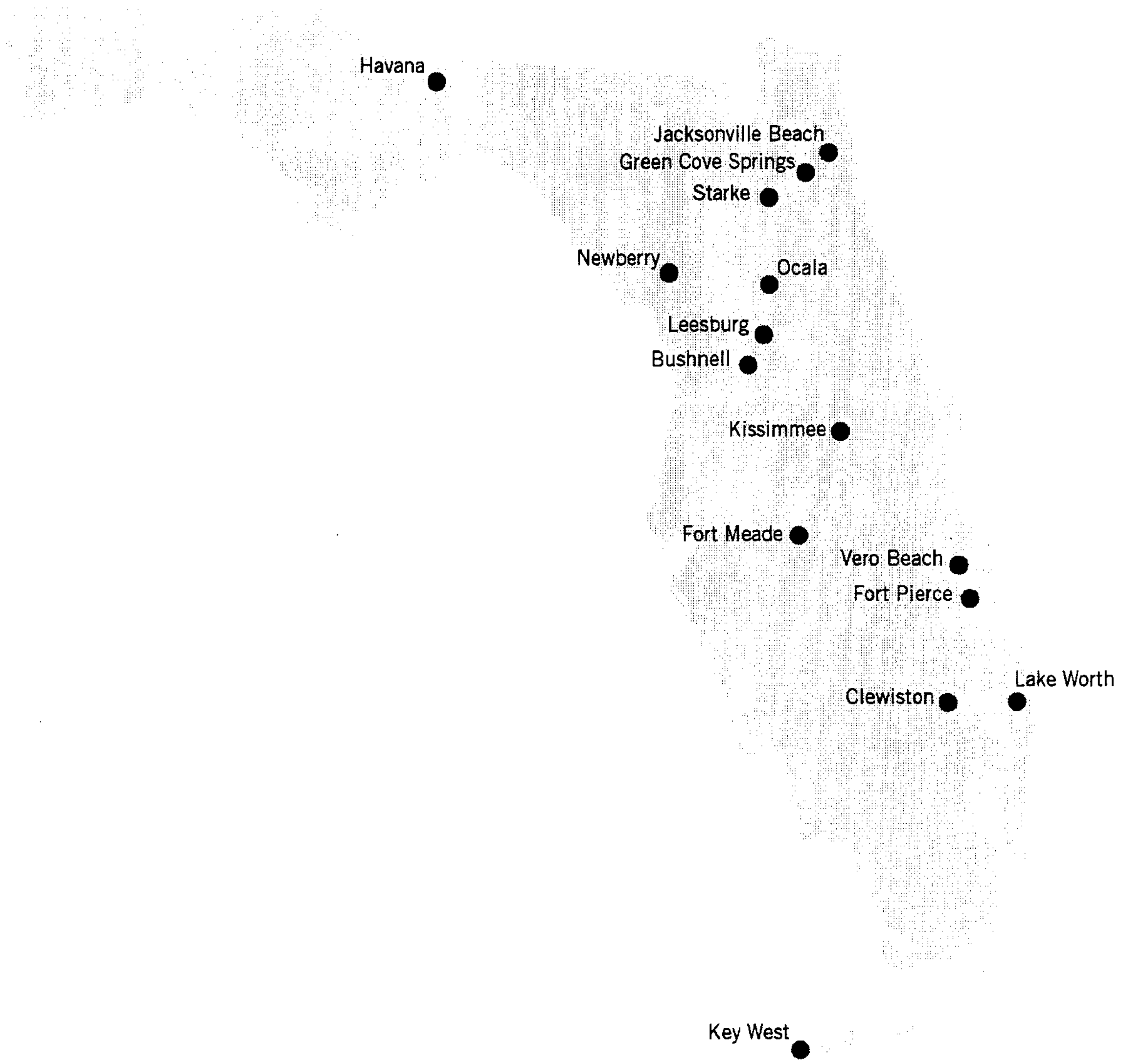
Taylor Energy Center
William May
Exhibit ____ [WSM-1]
Page 1 of 1

ARP Members

The figure below shows the ARP Member city locations.



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William May
Exhibit ____ [WSM-2]
Page 1 of 1

Percentages of ARP, Member, Nuclear, and Purchase Power Capacity

Type	Capacity Summary Unit	2007 MW Summer	2007 % Summer
Jointly Owned Nuclear Capacity	CR3	23	1.3
	St. Lucie Project	60	3.4
	Total Nuclear	83	4.8
Owned Capacity	Stanton Coal Plant	203	11.7
	Stanton CC Unit A	21	1.2
	Cane Island 1-3	194	11.1
	Indian River CTs	72	4.1
	Key West CTs 2 and 3	31	1.8
	Stock Island CT 4	42	2.4
	Total Owned	562	32.3
Member Generation	Ft. Pierce	110	6.3
	Key West	41	2.4
	KUA/Hansel	48	2.8
	Lake Worth	87	5.0
	Vero Beach	137	7.9
	Cane Island 1,2,3	194	11.1
	Stanton CC	21	1.2
	KUA Stanton 1	21	1.2
	KUA Indian River CTs	10	0.6
	Total Member	668	38.3
Purchased Power	PEF PR	30	1.7
	FPL LT	45	2.6
	FPL PR	75	4.3
	Lakeland Purchase	100	5.7
	Calpine Purchase	100	5.7
	Stanton A Purchase	80	4.6
	Total Purchase Power	430	24.7
Total Capacity	Total Capacity	1,742	100.0

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Taylor Energy Center
William May
Exhibit ____ [WSM-3]
Page 1 of 1

ARP's Existing and Approved/Planned Resource Capacity(1)

	Summer Rating								
Generating Resources	2006	2007	2008	2009	2010	2011	2012	2013	2014-2035
Excluded Resources (Nuclear) (2)	84	83	83	83	72	72	72	72	72
Stanton Coal Plant(2)	224	224	224	224	186	186	186	186	186
Stanton CC Unit A(3)	42	42	42	42	42	42	42	42	42
Cane Island 1-3	388	388	388	388	388	388	388	388	388
Indian River CTs	82	82	82	82	82	82	82	82	82
Key West Units 2&3	31	31	31	31	31	31	31	31	31
Ft. Pierce Native Generation	110	110	0	0	0	0	0	0	0
Key West Native Generation	41	41	41	41	41	41	41	41	41
Kissimmee Native Generation	48	48	48	48	48	48	0	0	0
Lake Worth Native Generation	87	87	87	87	87	87	0	0	0
Vero Beach Native Generation	137	137	137	137	0	0	0	0	0
Stock Island Unit 4	42	42	42	42	42	42	42	42	42
Treasure Coast Energy Center	0	0	296	296	296	296	296	296	296
New Peaking Capacity	0	0	0	0	84	84	84	84	84
Total Generating Capacity(4)	1,313	1,313	1,499	1,499	1,397	1,397	1,264	1,264	1,264
Purchased Power									
PEF Partial Requirements	40	30	30	60	40	0	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	45	45	0	0
FPL Partial Requirements	75	75	0	0	0	0	0	0	0
OUC Indian River Purchase	22	0	0	0	0	0	0	0	0
Starke (GRU)	3	0	0	0	0	0	0	0	0
Lakeland Purchase	100	100	0	0	0	0	0	0	0
Calpine Purchase	75	100	100	100	0	0	0	0	0
Stanton A Purchase(5)	80	80	80	80	80	80	80	80	0
SPC PPA	0	0	157	157	157	157	157	157	157
Total Purchased Power Resources(4)	439	430	412	442	322	282	282	237	157
Total Resources(4)	1,753	1,742	1,910	1,940	1,719	1,679	1,545	1,500	1,421

(1) Planned capacity prior to commercial operation of Taylor Energy Center.

(2) Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP.

(3) Includes FMPA and KUA ownership capacity.

(4) Sums may not match totals due to rounding.

(5) Includes FMPA and KUA capacity purchased from Southern Company Florida, LLC.

Docket No. ________
Taylor Energy Center
William May
Exhibit ____ [WSM-4]

RESUME OF

William S. May,

Manager of the Planning and Contracts Department

Florida Municipal Power Agency (FMPA)

Qualifications and Experience:

Since December of 2004, Mr. May has served as the Manager of the Planning and Contracts Department of FMPA. Mr. May has used his management, organizational, simulation software knowledge, and planning skills, and electric utility experience to direct the evaluation, negotiation, and execution of power supply contracts, load forecasting, and generation and transmission planning activities. Mr. May has negotiated contracts for software licenses and consulting engagements with electric utilities, independent power producers, and law firms representing electric providers. He has made presentations to a wide range of audiences including peers, company management, executive committees, the Board of directors, and the Florida PSC. From January 2003 to December 2004, Mr. May supervised and participated in the generation and transmission planning and load forecasting activities of FMPA. In the prior seven years Mr. May was a self-employed entrepreneur in the field of electric power supply systems modeling, power plant value analysis, and litigation consulting. Altogether, he has over 30 years experience as a consultant to the power industry, a power systems engineer, an energy market price forecaster, a transmission planning engineer, a substation design engineer, and a designer of simulation software.

Mr. May has negotiated contracts for software licenses and consulting engagements with electric utilities, independent power producers, and law firms representing electric providers. He has communicated with all levels of company employees through marketing activities, contract negotiations, and product support efforts. Mr. May has acted as an expert witness in confidential litigation activities. He has also performed transmission studies using power flow simulations and has designed transmission substations.

Mr. May has Bachelor of Science degrees in Electrical Engineering and Applied Mathematics from North Carolina State University, Raleigh, NC. and a Master of Science degree in Electrical Engineering with emphasis in Power Systems Simulation from Georgia Institute of Technology, Atlanta, GA.

Electric Utility Planning

Mr. May has been involved in many aspects of electric utility planning, including:

- directing the development, issuance, and analysis of requests for proposals and the negotiation and implementation of purchased power agreements.
- directing the analysis and implementation of integrated resource plans and review of analysis results.
- directing the development of the long term load forecast for member cities and FMPA.
- directing the development of software tools that are used in conjunction with other software models to facilitate load forecasts, generation planning analysis, and reporting.

- directing transmission network studies as they involve business activities of FMPA.
- representing FMPA on the FRCC Planning Committee.
- overseeing FMPA representation on the FRCC Load and Resource Working Group, Transmission Working Group, and Stability Working Group.
- participating as a member of the FMPA Risk Management Group.
- directing participants from member cities, consulting firms, and FMPA to produce an Integrated Resource Plan involving load, fuel price, market price, and capacity cost forecasts which were used to evaluate expansion scenarios based on risk factors, transmission impact, net present value of benefits, location marginal pricing, and rate impact.
- composing an RFP for short-term power purchases and evaluated the proposals.
- using and directing the use of the PROSYM production costing model to evaluate multiple purchased power and expansion alternatives.
- conducting consulting studies including studies using the PROMOD III multi-area transmission and production costing model
- serving as an expert witness providing written testimony; reviewing data, analytical processes, and generation and transmission contracts; participating in depositions; and testified under direct and cross-examination.
- preparing numerous market price forecasts.
- developing cost/benefit analysis studies for existing and new generation.
- preparing investment risk assessments of future generating capacity.
- providing training in market-based methodologies.

Electric Utility Planning Software Development

Mr. May directed the development of the PROMOD IV hourly transmission and generation dispatch model including organization, design, and implementation. He was also involved in sales presentations and product training. Mr. May also directed the development of the FUELPLAN optimal fuel contract and dispatch model including market research, preparation of requirements specification, implementation, client training, and support.

Transmission Planning Engineer

Mr. May prepared operational and long-term transmission load-flow studies including system voltage drop, system security, new-capacity connection, and loss of load probability analysis. He also has designed lightning and fire protection systems for substations and performed reliability studies of transmission interconnections. Mr. May has engineered design drawings for the construction of new substations and additions to existing substations.

Employment History:	2003-Present	FMPA
	1996-2003	Utility Systems Associates
	1980-1996	EDS/Energy Management Associates
	1975-1980	Georgia Power Company
Education:	M.S.	Electrical Engineering, Georgia Institute of Technology, Atlanta, GA
	B.S.	Electrical Engineering, North Carolina State University, Raleigh, NC.
	B.S.	Applied Mathematics, North Carolina State University, Raleigh, NC.

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.

Docket No. ________
Taylor Energy Center
Jim Myers
Exhibit ____ [JM-1]
Page 1 of 2

JAMES T. MYERS

Director, Fuel Management Services
JEA
21 West Church Street
Jacksonville, FL 32202
904-665-6224
Email: myerjt@jea.com

SUMMARY

Over twenty-four years experience in fuel procurement, generation planning, and related activities at JEA including three years in current position as Director, Fuel Management Services.

PROFESSIONAL EXPERIENCE

FUEL MANAGEMENT SERVICES 1995-Present

Team member and, since 2003, Director of group responsible for design and implementation of fuel management processes including fuel supply planning, procurement and scheduling, and reporting. Developed fuel acquisition strategies and market forecasts for JEA Electric System, negotiated agreements, and maintained documentation supporting fuel purchases.

Selected Accomplishments

- Directly responsible for approximately $300 million of current annual JEA fuel and purchased power budget including the procurement of all petroleum coke, coal, natural gas, #6 fuel oil, #2 fuel oil, and limestone for JEA Electric System.
- JEA representative on St. John's River Power Park and Plant Scherer Fuel Committees.
- Chairman, Taylor Energy Center Fuel Committee.
- Maintained sufficient economic supply of fuel during various recent storm events and 2003 Venezuelan worker strike.
- Acquired delivered gas supplies at below market rate to support long term JEA needs.
- Negotiated natural gas agreements that provide flexible gas volumes and the construction of laterals serving JEA's Brandy Branch Generating Station.
- Coordinated the transfer of daily gas procurement activity to The Energy Authority's natural gas trading group.
- Achieved "Six Sigma Green Belt" designation in reducing JEA's #6 oil procurement by over $2 million since June 2004.
- Developed fuel price forecasts to support budget analysis, Ten Year Site Plans and Integrated Resource Planning Studies.

ENERGY RESOURCE PLANNING **1987-1995**

Responsible for long range planning. This effort included the development of corporate financial models and preparation of Official Statements to support bond issues. Prepared and submitted various regulatory filings such as the Ten Year Site Plan required by the Florida Public Utilities Commission.

Selected Accomplishments

- Participated in JEA's first IRP study in 1994/95.
- Developed economic analysis supporting Scherer 4 capacity purchase in 1991.
- Served as Chairman (1991-92) and Vice-Chairman (1990-91) of the Florida Electric Power Coordinating Group's Generation Task Force.
    - Presented the Florida Ten Year Plan and JEA Ten Year Site Plan to FPSC staff.
    - Represented Florida subregion before NERC Reliability Assessment subcommittee.
- Evaluated various computer models for load research/forecasting and generation planning.

LOAD AND ENERGY FORECASTING / LOAD RESEARCH **1981-1986**

Developed economic, energy, and peak demand models and produced load and energy forecasts for generation planning.

Selected Accomplishments

- Reduced expenses by bringing the forecast process in-house in 1983.
- Developed annual forecast documents.
- Produced statistically valid estimates of residential appliance use and developed annual residential customer survey documents.

EDUCATION

Bachelor of Industrial Engineering, Georgia Institute of Technology - 1981
Numerous Professional Seminars
"Six Sigma Green Belt" training and designation
Working knowledge of Excel, Word, and Power Point

ACCREDITATION

Registered Professional Engineer in Florida, February 1986

Docket No. ________
Taylor Energy Center
Jim Myers
Exhibit ____ [JM-2]
Page 1 of 1

CURRENT YEAR $ DOLLARS PER MMBTU (DELIVERED) - BASE CASE

		MODELED QUALITY																												
SUB-REGION	FLAVOR	Btu/lb.	% SULFUR	Lbs. SO2/ mmBtu	Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS																														
WEST. PA	MID-SULFUR	13,000	1.95	3.00		$ 3.10	$ 2.95	$ 2.83	$ 2.71	$ 2.73	$ 2.77	$ 2.96	$ 2.92	$ 2.97	$ 3.01	$ 3.10	$ 3.17	$ 3.33	$ 3.43	$ 3.48	$ 3.59	$ 3.67	$ 3.82	$ 3.92	$ 4.02	$ 4.10	$ 4.24	$ 4.38	$ 4.48	$ 4.61
WEST. PA	HIGH-SULFUR	12,200	3.34	5.48		$ 3.23	$ 3.03	$ 2.80	$ 2.71	$ 2.73	$ 2.75	$ 2.84	$ 2.90	$ 2.98	$ 3.01	$ 3.09	$ 3.16	$ 3.33	$ 3.45	$ 3.47	$ 3.58	$ 3.66	$ 3.81	$ 3.92	$ 4.01	$ 4.13	$ 4.26	$ 4.39	$ 4.52	$ 4.66
OHIO	MID-SULFUR	12,150	2.20	3.62		$ 3.03	$ 2.77	$ 2.58	$ 2.74	$ 2.79	$ 2.82	$ 2.91	$ 2.99	$ 3.03	$ 3.09	$ 3.21	$ 3.29	$ 3.55	$ 3.64	$ 3.69	$ 3.81	$ 3.88	$ 4.06	$ 4.21	$ 4.35	$ 4.43	$ 4.62	$ 4.77	$ 4.93	$ 5.10
OHIO	HIGH-SULFUR	11,750	3.60	6.13		$ 2.92	$ 2.68	$ 2.89	$ 2.74	$ 2.76	$ 2.80	$ 2.89	$ 2.97	$ 3.00	$ 3.06	$ 3.16	$ 3.23	$ 3.50	$ 3.58	$ 3.79	$ 3.86	$ 3.95	$ 4.13	$ 4.28	$ 4.38	$ 4.47	$ 4.64	$ 4.79	$ 4.94	$ 5.09
N. WV	MID-SULFUR	12,900	2.10	3.28		$ 3.20	$ 2.87	$ 2.71	$ 2.68	$ 2.71	$ 2.75	$ 2.83	$ 2.92	$ 2.98	$ 3.01	$ 3.13	$ 3.21	$ 3.36	$ 3.45	$ 3.49	$ 3.61	$ 3.68	$ 3.65	$ 3.94	$ 4.05	$ 4.12	$ 4.27	$ 4.39	$ 4.51	$ 4.64
N. WV	HIGH-SULFUR	12,350	3.60	5.83		$ 3.20	$ 2.94	$ 2.73	$ 2.77	$ 2.79	$ 2.84	$ 2.92	$ 2.98	$ 3.03	$ 3.07	$ 3.14	$ 3.21	$ 3.35	$ 3.46	$ 3.49	$ 3.61	$ 3.70	$ 3.82	$ 3.90	$ 3.98	$ 4.08	$ 4.18	$ 4.28	$ 4.38	$ 4.49
CENTRAL APPALACHIA REGION SELECTED COALS																														
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		$ 3.56	$ 3.19	$ 2.69	$ 2.49	$ 2.52	$ 2.57	$ 2.65	$ 2.72	$ 2.79	$ 2.86	$ 2.97	$ 3.04	$ 3.15	$ 3.20	$ 3.29	$ 3.43	$ 3.49	$ 3.64	$ 3.70	$ 3.86	$ 3.95	$ 4.08	$ 4.21	$ 4.33	$ 4.47
S. WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.99		$ 3.54	$ 3.27	$ 2.82	$ 2.48	$ 2.56	$ 2.60	$ 2.69	$ 2.77	$ 2.81	$ 2.86	$ 3.00	$ 3.07	$ 3.16	$ 3.20	$ 3.30	$ 3.43	$ 3.50	$ 3.63	$ 3.74	$ 3.84	$ 3.94	$ 4.07	$ 4.19	$ 4.31	$ 4.44
S. WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		$ 3.60	$ 3.36	$ 2.80	$ 2.49	$ 2.51	$ 2.54	$ 2.63	$ 2.70	$ 2.76	$ 2.84	$ 2.91	$ 2.98	$ 3.08	$ 3.15	$ 3.21	$ 3.33	$ 3.40	$ 3.53	$ 3.62	$ 3.71	$ 3.80	$ 3.92	$ 4.03	$ 4.14	$ 4.25
S. WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		$ 3.64	$ 3.26	$ 2.85	$ 2.50	$ 2.57	$ 2.59	$ 2.67	$ 2.76	$ 2.78	$ 2.85	$ 2.96	$ 3.01	$ 3.10	$ 3.17	$ 3.23	$ 3.36	$ 3.45	$ 3.60	$ 3.73	$ 3.83	$ 3.91	$ 4.07	$ 4.20	$ 4.33	$ 4.47
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		$ 3.33	$ 2.93	$ 2.71	$ 2.40	$ 2.42	$ 2.46	$ 2.54	$ 2.61	$ 2.66	$ 2.73	$ 2.84	$ 2.90	$ 3.00	$ 3.07	$ 3.13	$ 3.23	$ 3.30	$ 3.43	$ 3.52	$ 3.61	$ 3.68	$ 3.80	$ 3.90	$ 4.01	$ 4.11
S. WV-MID BTU-NS	NEAR-COMPLIANCE	12,250	0.98	1.60		$ 3.44	$ 3.00	$ 2.78	$ 2.42	$ 2.47	$ 2.53	$ 2.60	$ 2.70	$ 2.73	$ 2.78	$ 2.89	$ 2.95	$ 3.04	$ 3.10	$ 3.15	$ 3.29	$ 3.37	$ 3.52	$ 3.64	$ 3.74	$ 3.81	$ 3.96	$ 4.08	$ 4.21	$ 4.34
S. WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		$ 3.10	$ 2.83	$ 2.63	$ 2.39	$ 2.43	$ 2.48	$ 2.53	$ 2.61	$ 2.67	$ 2.74	$ 2.83	$ 2.89	$ 2.99	$ 3.06	$ 3.11	$ 3.22	$ 3.28	$ 3.43	$ 3.55	$ 3.64	$ 3.71	$ 3.86	$ 3.98	$ 4.10	$ 4.23
S. WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		$ 2.46	$ 2.39	$ 2.38	$ 2.42	$ 2.46	$ 2.54	$ 2.59	$ 2.69	$ 2.72	$ 2.77	$ 2.88	$ 2.95	$ 3.05	$ 3.11	$ 3.16	$ 3.30	$ 3.38	$ 3.53	$ 3.66	$ 3.75	$ 3.82	$ 3.97	$ 4.09	$ 4.22	$ 4.35
E. KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		$ 3.58	$ 3.26	$ 2.76	$ 2.48	$ 2.51	$ 2.56	$ 2.64	$ 2.71	$ 2.78	$ 2.85	$ 2.94	$ 3.01	$ 3.13	$ 3.18	$ 3.25	$ 3.38	$ 3.44	$ 3.59	$ 3.68	$ 3.80	$ 3.89	$ 4.02	$ 4.15	$ 4.27	$ 4.40
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		$ 2.91	$ 2.77	$ 2.88	$ 2.47	$ 2.54	$ 2.58	$ 2.66	$ 2.75	$ 2.78	$ 2.85	$ 2.98	$ 3.05	$ 3.14	$ 3.18	$ 3.28	$ 3.40	$ 3.48	$ 3.60	$ 3.71	$ 3.81	$ 3.91	$ 4.04	$ 4.16	$ 4.28	$ 4.41
E. KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		$ 3.43	$ 3.12	$ 2.70	$ 2.40	$ 2.42	$ 2.45	$ 2.52	$ 2.59	$ 2.65	$ 2.73	$ 2.80	$ 2.86	$ 2.95	$ 3.03	$ 3.08	$ 3.19	$ 3.26	$ 3.39	$ 3.48	$ 3.60	$ 3.66	$ 3.79	$ 3.90	$ 4.02	$ 4.14
E. KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		$ 3.61	$ 3.11	$ 2.74	$ 2.47	$ 2.53	$ 2.55	$ 2.64	$ 2.72	$ 2.76	$ 2.81	$ 2.92	$ 2.97	$ 3.06	$ 3.13	$ 3.18	$ 3.32	$ 3.41	$ 3.56	$ 3.69	$ 3.78	$ 3.87	$ 4.02	$ 4.15	$ 4.29	$ 4.42
E. KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		$ 3.26	$ 2.84	$ 2.57	$ 2.36	$ 2.40	$ 2.46	$ 2.53	$ 2.61	$ 2.67	$ 2.74	$ 2.84	$ 2.89	$ 2.99	$ 3.07	$ 3.12	$ 3.20	$ 3.28	$ 3.41	$ 3.51	$ 3.61	$ 3.68	$ 3.81	$ 3.92	$ 4.04	$ 4.16
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		$ 3.32	$ 2.88	$ 2.69	$ 2.33	$ 2.37	$ 2.44	$ 2.51	$ 2.60	$ 2.64	$ 2.68	$ 2.79	$ 2.84	$ 2.93	$ 2.99	$ 3.05	$ 3.18	$ 3.26	$ 3.40	$ 3.52	$ 3.62	$ 3.70	$ 3.84	$ 3.97	$ 4.09	$ 4.22
E. KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		$ 2.59	$ 2.49	$ 2.41	$ 2.43	$ 2.47	$ 2.52	$ 2.60	$ 2.68	$ 2.74	$ 2.81	$ 2.91	$ 2.96	$ 3.07	$ 3.14	$ 3.19	$ 3.27	$ 3.35	$ 3.48	$ 3.59	$ 3.69	$ 3.76	$ 3.89	$ 4.00	$ 4.12	$ 4.24
E. KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		$ 2.54	$ 2.46	$ 2.41	$ 2.37	$ 2.41	$ 2.47	$ 2.54	$ 2.64	$ 2.67	$ 2.72	$ 2.84	$ 2.90	$ 3.00	$ 3.07	$ 3.12	$ 3.25	$ 3.33	$ 3.48	$ 3.59	$ 3.68	$ 3.76	$ 3.90	$ 4.01	$ 4.14	$ 4.26
ILLINOIS BASIN SELECTED COALS																														
INDIANA	COMPLIANCE	11,100	0.58	1.05		$ 4.15	$ 3.78	$ 3.41	$ 2.85	$ 2.90	$ 2.93	$ 2.97	$ 3.06	$ 3.12	$ 3.17	$ 3.23	$ 3.27	$ 3.34	$ 3.41	$ 3.47	$ 3.55	$ 3.60	$ 3.72	$ 3.81	$ 3.87	$ 3.92	$ 4.03	$ 4.11	$ 4.20	$ 4.29
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		$ 3.37	$ 3.02	$ 2.86	$ 2.72	$ 2.74	$ 2.79	$ 2.84	$ 2.91	$ 2.96	$ 3.02	$ 3.13	$ 3.17	$ 3.27	$ 3.44	$ 3.53	$ 3.60	$ 3.63	$ 3.75	$ 3.86	$ 3.91	$ 3.95	$ 4.07	$ 4.15	$ 4.24	$ 4.33
INDIANA	MID-SULFUR	11,000	1.70	3.09		$ 3.29	$ 3.01	$ 2.78	$ 2.70	$ 2.73	$ 2.82	$ 2.90	$ 2.96	$ 2.97	$ 3.02	$ 3.12	$ 3.20	$ 3.28	$ 3.40	$ 3.46	$ 3.51	$ 3.54	$ 3.67	$ 3.76	$ 3.84	$ 3.91	$ 4.02	$ 4.12	$ 4.22	$ 4.32
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		$ 2.93	$ 2.73	$ 2.60	$ 2.65	$ 2.66	$ 2.73	$ 2.78	$ 2.83	$ 2.88	$ 2.91	$ 3.00	$ 3.05	$ 3.17	$ 3.27	$ 3.29	$ 3.37	$ 3.42	$ 3.54	$ 3.62	$ 3.69	$ 3.75	$ 3.86	$ 3.95	$ 4.04	$ 4.13
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		$ 3.10	$ 2.83	$ 2.68	$ 2.55	$ 2.58	$ 2.62	$ 2.67	$ 2.74	$ 2.79	$ 2.86	$ 2.96	$ 3.01	$ 3.14	$ 3.20	$ 3.24	$ 3.34	$ 3.40	$ 3.54	$ 3.62	$ 3.72	$ 3.78	$ 3.90	$ 4.00	$ 4.11	$ 4.22
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		$ 3.12	$ 2.84	$ 2.66	$ 2.63	$ 2.65	$ 2.70	$ 2.74	$ 2.81	$ 2.86	$ 2.92	$ 3.01	$ 3.05	$ 3.14	$ 3.21	$ 3.25	$ 3.33	$ 3.39	$ 3.52	$ 3.62	$ 3.70	$ 3.77	$ 3.89	$ 3.99	$ 4.10	$ 4.20
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		$ 3.03	$ 2.73	$ 2.62	$ 2.62	$ 2.64	$ 2.70	$ 2.74	$ 2.79	$ 2.82	$ 2.88	$ 2.95	$ 2.98	$ 3.06	$ 3.14	$ 3.16	$ 3.23	$ 3.30	$ 3.42	$ 3.51	$ 3.65	$ 3.67	$ 3.81	$ 3.92	$ 4.03	$ 4.15
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		$ 3.11	$ 2.97	$ 2.96	$ 2.81	$ 2.76	$ 2.82	$ 2.89	$ 2.93	$ 2.95	$ 3.01	$ 3.08	$ 3.13	$ 3.21	$ 3.28	$ 3.33	$ 3.44	$ 3.47	$ 3.61	$ 3.70	$ 3.78	$ 3.83	$ 3.95	$ 4.05	$ 4.15	$ 4.25
W. KY	HIGH-SULFUR	11,600	3.19	5.50		$ 2.80	$ 2.46	$ 2.46	$ 2.53	$ 2.56	$ 2.61	$ 2.66	$ 2.70	$ 2.75	$ 2.80	$ 2.86	$ 2.90	$ 2.97	$ 3.05	$ 3.07	$ 3.15	$ 3.19	$ 3.31	$ 3.37	$ 3.43	$ 3.49	$ 3.59	$ 3.67	$ 3.75	$ 3.83
WYOMING POWDER RIVER BASIN																														
PRB-N.GILLETTE	COMPLIANCE	8,350	0.44	1.05		$ 2.87	$ 2.81	$ 2.44	$ 2.45	$ 2.50	$ 2.51	$ 2.54	$ 2.60	$ 2.62	$ 2.66	$ 2.75	$ 2.80	$ 2.84	$ 2.89	$ 2.83	$ 3.11	$ 3.16	$ 3.41	$ 3.47	$ 3.54	$ 3.58	$ 3.74	$ 3.85	$ 3.96	$ 4.08
PRB-S.GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		$ 2.94	$ 2.87	$ 2.51	$ 2.47	$ 2.51	$ 2.53	$ 2.56	$ 2.60	$ 2.62	$ 2.66	$ 2.76	$ 2.80	$ 2.85	$ 2.89	$ 2.94	$ 3.12	$ 3.17	$ 3.41	$ 3.47	$ 3.55	$ 3.59	$ 3.74	$ 3.85	$ 3.97	$ 4.08
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,800	0.35	0.80		$ 2.91	$ 2.84	$ 2.48	$ 2.43	$ 2.47	$ 2.48	$ 2.51	$ 2.56	$ 2.58	$ 2.62	$ 2.71	$ 2.76	$ 2.80	$ 2.84	$ 2.89	$ 3.07	$ 3.12	$ 3.37	$ 3.43	$ 3.50	$ 3.54	$ 3.70	$ 3.81	$ 3.92	$ 4.04
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		$ 3.04	$ 2.98	$ 2.61	$ 2.48	$ 2.53	$ 2.53	$ 2.56	$ 2.62	$ 2.64	$ 2.69	$ 2.82	$ 2.87	$ 2.91	$ 2.92	$ 3.00	$ 3.11	$ 3.16	$ 3.39	$ 3.44	$ 3.52	$ 3.56	$ 3.71	$ 3.81	$ 3.92	$ 4.03
LATIN AMERICA																														
LATIN AMER	HI BTU PANAMAX/JAX	13,000	0.6	0.92		$ 2.73	$ 2.86	$ 2.99	$ 3.06	$ 3.10	$ 3.06	$ 2.99	$ 2.94	$ 3.06	$ 3.09	$ 3.11	$ 3.02	$ 2.92	$ 2.97	$ 3.09	$ 3.14	$ 3.11	$ 3.10	$ 3.24	$ 3.26	$ 3.33	$ 3.24	$ 3.36	$ 3.40	$ 3.44
LATIN AMER	MID BTU PANANMAX/JAX	12,000	1.17	1.95		$ 2.66	$ 2.88	$ 3.01	$ 3.08	$ 3.14	$ 3.12	$ 3.05	$ 2.99	$ 3.12	$ 3.17	$ 3.19	$ 3.10	$ 3.00	$ 3.05	$ 3.18	$ 3.23	$ 3.20	$ 3.19	$ 3.34	$ 3.36	$ 3.43	$ 3.34	$ 3.47	$ 3.52	$ 3.55
PETROLEUM COKE																														
Pet Coke	Low Sulfur, High Grind	14,000				$ 1.56	$ 1.51	$ 1.65	$ 1.74	$ 1.74	$ 1.75	$ 1.68	$ 1.70	$ 1.77	$ 1.91	$ 1.97	$ 2.00	$ 2.00	$ 2.10	$ 2.17	$ 2.24	$ 2.26	$ 2.25	$ 2.40	$ 2.51	$ 2.53	$ 2.52	$ 2.61	$ 2.74	$ 2.83
	Low Sulfur, Low Grind	14,000				$ 1.51	$ 1.46	$ 1.60	$ 1.69	$ 1.69	$ 1.69	$ 1.63	$ 1.65	$ 1.71	$ 1.85	$ 1.91	$ 1.94	$ 1.93	$ 2.03	$ 2.10	$ 2.17	$ 2.18	$ 2.17	$ 2.32	$ 2.43	$ 2.45	$ 2.44	$ 2.52	$ 2.65	$ 2.74
Pet Coke	High Sulfur, High Grind	14,000				$ 1.38	$ 1.33	$ 1.46	$ 1.55	$ 1.55	$ 1.54	$ 1.48	$ 1.49	$ 1.55	$ 1.69	$ 1.74	$ 1.77	$ 1.75	$ 1.85	$ 1.91	$ 1.98	$ 1.99	$ 1.98	$ 2.12	$ 2.22	$ 2.23	$ 2.22	$ 2.30	$ 2.42	$ 2.51
	High Sulfur, Low Grind	14,000				$ 1.33	$ 1.28	$ 1.41	$ 1.49	$ 1.49	$ 1.49	$ 1.42	$ 1.43	$ 1.49	$ 1.63	$ 1.68	$ 1.70	$ 1.69	$ 1.78	$ 1.84	$ 1.91	$ 1.92	$ 1.90	$ 2.04	$ 2.14	$ 2.15	$ 2.13	$ 2.21	$ 2.33	$ 2.42
NATURAL GAS																														
Commodity						$ 9.25	$ 8.77	$ 7.75	$ 6.76	$ 6.06	$ 5.91	$ 6.18	$ 6.47	$ 6.76	$ 7.07	$ 7.39	$ 7.72	$ 8.08	$ 8.45	$ 8.82	$ 9.23	$ 9.65	$ 10.09	$ 10.55	$ 11.03	$ 11.52	$ 12.05	$ 12.60	$ 13.17	$ 13.77
Commodity+Variable Charges						$ 9.58	$ 9.10	$ 8.05	$ 7.02	$ 6.31	$ 6.16	$ 6.43	$ 6.73	$ 7.03	$ 7.35	$ 7.68	$ 8.03	$ 8.40	$ 8.78	$ 9.17	$ 9.59	$ 10.02	$ 10.48	$ 10.96	$ 11.45	$ 11.96	$ 12.51	$ 13.08	$ 13.67	$ 14.29
RESIDUAL FUEL OIL AND DIESEL																														
GC #6 1%						$ 7.42	$ 7.02	$ 6.93	$ 6.84	$ 6.69	$ 6.62	$ 6.74	$ 6.91	$ 7.08	$ 7.27	$ 7.52	$ 7.80	$ 8.09	$ 8.39	$ 8.70	$ 9.03	$ 9.36	$ 9.70	$ 10.05	$ 10.54	$ 10.80	$ 11.19	$ 11.60	$ 12.02	$ 12.45
GC #6 3%						$ 6.11	$ 5.84	$ 5.79	$ 5.74	$ 5.64	$ 5.59	$ 5.69	$ 5.84	$ 5.98	$ 6.14	$ 6.35	$ 6.58	$ 6.82	$ 7.06	$ 7.32	$ 7.58	$ 7.85	$ 8.13	$ 8.42	$ 8.81	$ 9.03	$ 9.35	$ 9.67	$ 10.01	$ 10.36
GC #2 0.5%						$ 13.96	$ 12.59	$ 12.31	$ 12.06	$ 11.70	$ 11.52	$ 11.71	$ 12.00	$ 12.30	$ 12.63	$ 13.09	$ 13.60	$ 14.13	$ 14.68	$ 15.25	$ 15.85	$ 16.47	$ 17.11	$ 17.78	$ 18.47	$ 19.19	$ 19.95	$ 20.73	$ 21.53	$ 22.38
GC #2 0.05%						$ 14.19	$ 12.78	$ 12.49	$ 12.23	$ 11.86	$ 11.66	$ 11.86	$ 12.15	$ 12.45	$ 12.78	$ 13.26	$ 13.77	$ 14.31	$ 14.87	$ 15.46	$ 16.06	$ 16.70	$ 17.35	$ 18.03	$ 18.74	$ 19.47	$ 20.24	$ 21.04	$ 21.86	$ 22.72
GC #2 0.0015%						$ 14.64	$ 13.54	$ 13.24	$ 12.99	$ 12.66	$ 12.69	$ 12.79	$ 13.01	$ 13.24	$ 13.50	$ 13.99	$ 14.53	$ 15.09	$ 15.67	$ 16.27	$ 16.90	$ 17.55	$ 18.22	$ 18.93	$ 19.65	$ 20.41	$ 21.21	$ 22.03	$ 22.88	$ 23.76

Docket No. ________
Taylor Energy Center
Jim Myers
Exhibit ____ [JM-3]
Page 1 of 1

CURRENT YEAR $ DOLLARS PER MMBTU (DELIVERED) - HIGH CASE

		MODELED QUALITY																												
SUB-REGION	FLAVOR	Btu/lb.	% SULFUR	Lbs. SO2/ mmBtu	Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS																														
WEST. PA	MID-SULFUR	13,000	1.95	3.00		$ 3.18	$ 2.89	$ 2.64	$ 2.84	$ 2.82	$ 2.88	$ 3.00	$ 3.05	$ 3.09	$ 3.18	$ 3.28	$ 3.35	$ 3.50	$ 3.57	$ 3.64	$ 3.60	$ 3.90	$ 4.01	$ 4.14	$ 4.33	$ 4.47	$ 4.62	$ 4.77	$ 4.93	$ 5.09
WEST. PA	HIGH-SULFUR	12,200	3.34	5.48		$ 3.28	$ 3.03	$ 2.60	$ 2.83	$ 2.81	$ 2.85	$ 2.98	$ 3.03	$ 3.07	$ 3.16	$ 3.28	$ 3.34	$ 3.50	$ 3.58	$ 3.64	$ 3.78	$ 3.87	$ 3.57	$ 4.13	$ 4.24	$ 4.37	$ 4.51	$ 4.65	$ 4.79	$ 4.94
OHIO	MID-SULFUR	12,150	2.20	3.62		$ 3.11	$ 2.80	$ 2.58	$ 2.87	$ 2.88	$ 2.93	$ 3.05	$ 3.12	$ 3.17	$ 3.26	$ 3.38	$ 3.47	$ 3.71	$ 3.79	$ 3.88	$ 4.01	$ 4.12	$ 4.27	$ 4.41	$ 4.53	$ 4.68	$ 4.83	$ 4.99	$ 5.15	$ 5.32
OHIO	HIGH-SULFUR	11,750	3.60	6.13		$ 2.98	$ 2.70	$ 2.69	$ 2.87	$ 2.85	$ 2.82	$ 3.03	$ 3.10	$ 3.14	$ 3.22	$ 3.33	$ 3.41	$ 3.65	$ 3.88	$ 3.95	$ 4.04	$ 4.13	$ 4.31	$ 4.47	$ 4.57	$ 4.67	$ 4.92	$ 5.08	$ 5.25	$ 5.43
N. WV	MID-SULFUR	12,900	2.10	3.28		$ 3.28	$ 3.01	$ 2.72	$ 2.81	$ 2.80	$ 2.86	$ 2.97	$ 3.04	$ 3.07	$ 3.18	$ 3.30	$ 3.37	$ 3.53	$ 3.59	$ 3.66	$ 3.81	$ 3.91	$ 4.02	$ 4.16	$ 4.28	$ 4.41	$ 4.55	$ 4.69	$ 4.84	$ 4.99
N. WV	HIGH-SULFUR	12,350	3.60	5.83		$ 3.26	$ 2.97	$ 2.74	$ 2.89	$ 2.88	$ 2.94	$ 3.05	$ 3.11	$ 3.14	$ 3.23	$ 3.32	$ 3.38	$ 3.53	$ 3.60	$ 3.67	$ 3.83	$ 3.93	$ 4.01	$ 4.14	$ 4.28	$ 4.38	$ 4.51	$ 4.65	$ 4.78	$ 4.93
CENTRAL APPALACHIA REGION SELECTED COALS																														
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		$ 3.70	$ 3.33	$ 2.80	$ 2.56	$ 2.59	$ 2.67	$ 2.76	$ 2.84	$ 2.86	$ 2.99	$ 3.12	$ 3.19	$ 3.30	$ 3.36	$ 3.47	$ 3.62	$ 3.77	$ 3.83	$ 3.93	$ 4.06	$ 4.18	$ 4.31	$ 4.44	$ 4.57	$ 4.71
S. WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.99		$ 3.65	$ 3.39	$ 2.91	$ 2.54	$ 2.60	$ 2.69	$ 2.78	$ 2.86	$ 2.90	$ 2.99	$ 3.26	$ 3.17	$ 3.38	$ 3.35	$ 3.45	$ 3.63	$ 3.70	$ 3.86	$ 3.99	$ 4.10	$ 4.23	$ 4.37	$ 4.51	$ 4.65	$ 4.80
S. WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		$ 3.74	$ 3.45	$ 3.00	$ 2.55	$ 2.58	$ 2.64	$ 2.75	$ 2.82	$ 2.84	$ 2.96	$ 3.05	$ 3.11	$ 3.23	$ 3.31	$ 3.38	$ 3.54	$ 3.66	$ 3.75	$ 3.86	$ 4.00	$ 4.13	$ 4.27	$ 4.41	$ 4.55	$ 4.70
S. WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		$ 3.67	$ 3.38	$ 2.93	$ 2.56	$ 2.81	$ 2.68	$ 2.76	$ 2.85	$ 2.89	$ 2.97	$ 3.09	$ 3.13	$ 3.21	$ 3.30	$ 3.39	$ 3.58	$ 3.69	$ 3.86	$ 3.98	$ 4.15	$ 4.31	$ 4.48	$ 4.66	$ 4.84	$ 5.03
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		$ 3.35	$ 2.99	$ 2.78	$ 2.46	$ 2.49	$ 2.55	$ 2.65	$ 2.71	$ 2.74	$ 2.85	$ 2.95	$ 3.01	$ 3.14	$ 3.22	$ 3.29	$ 3.44	$ 3.56	$ 3.65	$ 3.75	$ 3.89	$ 4.01	$ 4.15	$ 4.28	$ 4.42	$ 4.57
S. WV-MID BTU-NS	NEAR-COMPLIANCE	12,250	0.98	1.60		$ 3.42	$ 3.03	$ 2.84	$ 2.46	$ 2.51	$ 2.62	$ 2.69	$ 2.78	$ 2.80	$ 2.90	$ 3.02	$ 3.06	$ 3.14	$ 3.23	$ 3.30	$ 3.50	$ 3.61	$ 3.77	$ 3.89	$ 4.05	$ 4.21	$ 4.37	$ 4.54	$ 4.72	$ 4.90
S. WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		$ 3.13	$ 2.83	$ 2.63	$ 2.44	$ 2.47	$ 2.55	$ 2.64	$ 2.70	$ 2.74	$ 2.86	$ 2.94	$ 3.00	$ 3.13	$ 3.20	$ 3.27	$ 3.43	$ 3.54	$ 3.64	$ 3.75	$ 3.89	$ 4.02	$ 4.16	$ 4.30	$ 4.45	$ 4.60
S. WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		$ 2.48	$ 2.41	$ 2.40	$ 2.47	$ 2.50	$ 2.61	$ 2.68	$ 2.75	$ 2.79	$ 2.89	$ 3.01	$ 3.07	$ 3.16	$ 3.24	$ 3.31	$ 3.50	$ 3.62	$ 3.77	$ 3.88	$ 4.04	$ 4.19	$ 4.35	$ 4.51	$ 4.68	$ 4.86
E. KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		$ 3.70	$ 3.38	$ 2.86	$ 2.53	$ 2.57	$ 2.65	$ 2.74	$ 2.81	$ 2.84	$ 2.98	$ 3.08	$ 3.15	$ 3.26	$ 3.35	$ 3.43	$ 3.57	$ 3.71	$ 3.78	$ 3.88	$ 4.00	$ 4.13	$ 4.25	$ 4.38	$ 4.51	$ 4.65
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		$ 3.05	$ 2.93	$ 2.98	$ 2.53	$ 2.58	$ 2.67	$ 2.75	$ 2.83	$ 2.87	$ 2.96	$ 3.10	$ 3.15	$ 3.25	$ 3.32	$ 3.42	$ 3.64	$ 3.68	$ 3.88	$ 3.99	$ 4.11	$ 4.25	$ 4.39	$ 4.54	$ 4.70	$ 4.86
E. KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		$ 3.50	$ 3.21	$ 2.80	$ 2.44	$ 2.47	$ 2.54	$ 2.62	$ 2.69	$ 2.71	$ 2.83	$ 2.93	$ 2.99	$ 3.10	$ 3.18	$ 3.25	$ 3.39	$ 3.51	$ 3.61	$ 3.73	$ 3.86	$ 3.99	$ 4.12	$ 4.26	$ 4.41	$ 4.56
E. KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		$ 3.65	$ 3.22	$ 2.83	$ 2.52	$ 2.57	$ 2.64	$ 2.72	$ 2.81	$ 2.85	$ 2.93	$ 3.04	$ 3.09	$ 3.17	$ 3.26	$ 3.33	$ 3.53	$ 3.65	$ 3.81	$ 3.94	$ 4.10	$ 4.27	$ 4.44	$ 4.61	$ 4.79	$ 4.98
E. KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		$ 3.15	$ 2.84	$ 2.58	$ 2.41	$ 2.46	$ 2.53	$ 2.62	$ 2.68	$ 2.72	$ 2.84	$ 2.94	$ 3.00	$ 3.10	$ 3.19	$ 3.25	$ 3.40	$ 3.54	$ 3.64	$ 3.76	$ 3.89	$ 4.02	$ 4.16	$ 4.30	$ 4.45	$ 4.60
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		$ 3.29	$ 2.90	$ 2.72	$ 2.37	$ 2.41	$ 2.52	$ 2.60	$ 2.66	$ 2.70	$ 2.79	$ 2.91	$ 2.95	$ 3.03	$ 3.12	$ 3.19	$ 3.38	$ 3.49	$ 3.55	$ 3.76	$ 3.92	$ 4.08	$ 4.24	$ 4.40	$ 4.58	$ 4.76
E. KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		$ 2.59	$ 2.49	$ 2.42	$ 2.48	$ 2.52	$ 2.59	$ 2.69	$ 2.75	$ 2.79	$ 2.92	$ 3.01	$ 3.07	$ 3.18	$ 3.27	$ 3.32	$ 3.48	$ 3.62	$ 3.72	$ 3.84	$ 3.98	$ 4.11	$ 4.26	$ 4.40	$ 4.55	$ 4.71
E. KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		$ 2.57	$ 2.48	$ 2.43	$ 2.42	$ 2.45	$ 2.56	$ 2.63	$ 2.70	$ 2.74	$ 2.84	$ 2.97	$ 3.03	$ 3.11	$ 3.19	$ 3.27	$ 3.45	$ 3.57	$ 3.71	$ 3.82	$ 3.97	$ 4.12	$ 4.27	$ 4.43	$ 4.60	$ 4.77
ILLINOIS BASIN SELECTED COALS																														
INDIANA	COMPLIANCE	11,100	0.58	1.05		$ 4.30	$ 3.90	$ 3.55	$ 2.98	$ 2.95	$ 3.02	$ 3.11	$ 3.21	$ 3.23	$ 3.33	$ 3.38	$ 3.43	$ 3.55	$ 3.59	$ 3.67	$ 3.84	$ 3.96	$ 4.07	$ 4.15	$ 4.32	$ 4.46	$ 4.60	$ 4.74	$ 4.90	$ 5.05
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		$ 3.39	$ 3.10	$ 2.98	$ 2.88	$ 2.86	$ 2.95	$ 3.05	$ 3.12	$ 3.18	$ 3.26	$ 3.36	$ 3.40	$ 3.52	$ 3.57	$ 3.62	$ 3.77	$ 3.97	$ 4.11	$ 4.20	$ 4.40	$ 4.57	$ 4.75	$ 4.93	$ 5.12	$ 5.31
INDIANA	MID-SULFUR	11,000	1.70	3.09		$ 3.40	$ 3.11	$ 2.82	$ 2.87	$ 2.85	$ 2.96	$ 3.04	$ 3.13	$ 3.17	$ 3.25	$ 3.48	$ 3.56	$ 3.67	$ 3.78	$ 3.77	$ 3.84	$ 3.95	$ 3.99	$ 4.09	$ 4.18	$ 4.27	$ 4.36	$ 4.45	$ 4.55	$ 4.64
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		$ 3.00	$ 2.78	$ 2.61	$ 2.80	$ 2.78	$ 2.87	$ 2.96	$ 3.03	$ 3.08	$ 3.15	$ 3.21	$ 3.27	$ 3.38	$ 3.43	$ 3.49	$ 3.62	$ 3.72	$ 3.79	$ 3.89	$ 3.99	$ 4.10	$ 4.21	$ 4.33	$ 4.44	$ 4.56
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		$ 3.09	$ 2.83	$ 2.67	$ 2.70	$ 2.67	$ 2.76	$ 2.85	$ 2.95	$ 2.98	$ 3.08	$ 3.17	$ 3.23	$ 3.35	$ 3.40	$ 3.46	$ 3.60	$ 3.76	$ 3.83	$ 3.91	$ 4.05	$ 4.16	$ 4.29	$ 4.41	$ 4.54	$ 4.67
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		$ 3.17	$ 2.90	$ 2.71	$ 2.79	$ 2.77	$ 2.88	$ 2.95	$ 3.02	$ 3.07	$ 3.15	$ 3.24	$ 3.27	$ 3.37	$ 3.40	$ 3.48	$ 3.61	$ 3.75	$ 3.81	$ 3.89	$ 4.03	$ 4.15	$ 4.27	$ 4.40	$ 4.53	$ 4.66
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		$ 3.07	$ 2.88	$ 2.66	$ 2.78	$ 2.76	$ 2.85	$ 2.93	$ 3.00	$ 3.02	$ 3.09	$ 3.17	$ 3.20	$ 3.29	$ 3.31	$ 3.37	$ 3.50	$ 3.63	$ 3.69	$ 3.77	$ 3.91	$ 4.03	$ 4.15	$ 4.27	$ 4.39	$ 4.52
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		$ 3.13	$ 3.01	$ 3.00	$ 2.97	$ 2.85	$ 2.94	$ 3.04	$ 3.11	$ 3.15	$ 3.24	$ 3.31	$ 3.36	$ 3.45	$ 3.51	$ 3.58	$ 3.75	$ 3.84	$ 3.91	$ 3.98	$ 4.10	$ 4.21	$ 4.32	$ 4.43	$ 4.54	$ 4.66
W. KY	HIGH-SULFUR	11,600	3.19	5.50		$ 2.86	$ 2.51	$ 2.51	$ 2.69	$ 2.68	$ 2.76	$ 2.85	$ 2.91	$ 2.96	$ 3.01	$ 3.07	$ 3.12	$ 3.19	$ 3.25	$ 3.31	$ 3.43	$ 3.50	$ 3.56	$ 3.64	$ 3.74	$ 3.83	$ 3.93	$ 4.03	$ 4.13	$ 4.23
WYOMING POWDER RIVER BASIN																														
PRB-N.GILLETTE	COMPLIANCE	8,350	0.44	1.05		$ 3.00	$ 2.91	$ 2.55	$ 2.50	$ 2.51	$ 2.55	$ 2.59	$ 2.63	$ 2.67	$ 2.71	$ 2.77	$ 2.83	$ 2.88	$ 3.01	$ 3.24	$ 3.49	$ 3.56	$ 3.52	$ 3.68	$ 3.86	$ 3.98	$ 4.11	$ 4.24	$ 4.38	$ 4.52
PRB-S.GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		$ 3.08	$ 2.96	$ 2.64	$ 2.51	$ 2.51	$ 2.55	$ 2.59	$ 2.63	$ 2.67	$ 2.72	$ 2.78	$ 2.83	$ 2.88	$ 3.01	$ 3.25	$ 3.50	$ 3.57	$ 3.63	$ 3.69	$ 3.87	$ 3.99	$ 4.12	$ 4.25	$ 4.39	$ 4.53
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,800	0.35	0.80		$ 3.06	$ 2.95	$ 2.62	$ 2.47	$ 2.47	$ 2.51	$ 2.55	$ 2.59	$ 2.63	$ 2.67	$ 2.73	$ 2.79	$ 2.84	$ 2.97	$ 3.21	$ 3.45	$ 3.52	$ 3.59	$ 3.65	$ 3.83	$ 3.95	$ 4.08	$ 4.21	$ 4.35	$ 4.49
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		$ 3.22	$ 3.10	$ 2.78	$ 2.52	$ 2.53	$ 2.56	$ 2.61	$ 2.65	$ 2.70	$ 2.76	$ 2.85	$ 2.90	$ 2.95	$ 3.04	$ 3.24	$ 3.48	$ 3.54	$ 3.60	$ 3.66	$ 3.83	$ 3.95	$ 4.07	$ 4.20	$ 4.33	$ 4.46
LATIN AMERICA																														
LATIN AMER	HI BTU PANAMAX/JAX	13,000	0.6	0.92		$ 2.80	$ 2.91	$ 3.02	$ 3.08	$ 3.14	$ 3.08	$ 3.01	$ 2.99	$ 3.13	$ 3.26	$ 3.41	$ 3.44	$ 3.51	$ 3.64	$ 3.81	$ 3.92	$ 3.96	$ 4.03	$ 4.26	$ 4.39	$ 4.50	$ 4.53	$ 4.74	$ 4.89	$ 5.04
LATIN AMER	MID BTU PANANMAX/JAX	12,000	1.17	1.95		$ 2.70	$ 2.90	$ 3.03	$ 3.09	$ 3.16	$ 3.13	$ 3.07	$ 3.10	$ 3.25	$ 3.39	$ 3.54	$ 3.57	$ 3.64	$ 3.77	$ 3.96	$ 4.07	$ 4.11	$ 4.18	$ 4.42	$ 4.55	$ 4.67	$ 4.69	$ 4.92	$ 5.08	$ 5.22
PETROLEUM COKE																														
Pet Coke	Low Sulfur, High Grind	14,000				$ 1.68	$ 1.64	$ 1.78	$ 1.87	$ 1.88	$ 1.89	$ 1.83	$ 1.85	$ 1.92	$ 2.07	$ 2.13	$ 2.16	$ 2.16	$ 2.27	$ 2.34	$ 2.42	$ 2.44	$ 2.44	$ 2.59	$ 2.71	$ 2.73	$ 2.73	$ 2.82	$ 2.95	$ 3.05
	Low Sulfur, Low Grind	14,000				$ 1.63	$ 1.59	$ 1.73	$ 1.82	$ 1.82	$ 1.83	$ 1.77	$ 1.79	$ 1.86	$ 2.01	$ 2.06	$ 2.10	$ 2.09	$ 2.20	$ 2.27	$ 2.35	$ 2.37	$ 2.36	$ 2.52	$ 2.63	$ 2.65	$ 2.64	$ 2.73	$ 2.87	$ 2.96
Pet Coke	High Sulfur, High Grind	14,000				$ 1.49	$ 1.44	$ 1.58	$ 1.67	$ 1.67	$ 1.67	$ 1.61	$ 1.62	$ 1.69	$ 1.83	$ 1.88	$ 1.91	$ 1.90	$ 2.00	$ 2.07	$ 2.14	$ 2.16	$ 2.15	$ 2.30	$ 2.40	$ 2.42	$ 2.41	$ 2.49	$ 2.62	$ 2.71
	High Sulfur, Low Grind	14,000				$ 1.45	$ 1.40	$ 1.53	$ 1.62	$ 1.62	$ 1.62	$ 1.55	$ 1.57	$ 1.64	$ 1.77	$ 1.83	$ 1.86	$ 1.84	$ 1.94	$ 2.01	$ 2.08	$ 2.09	$ 2.08	$ 2.23	$ 2.33	$ 2.34	$ 2.33	$ 2.41	$ 2.54	$ 2.63
NATURAL GAS																														
Commodity						$ 11.09	$ 9.62	$ 9.30	$ 8.11	$ 7.28	$ 7.10	$ 7.42	$ 7.76	$ 8.11	$ 8.48	$ 8.86	$ 9.26	$ 9.69	$ 10.14	$ 10.58	$ 11.08	$ 11.58	$ 12.11	$ 12.66	$ 13.23	$ 13.83	$ 14.46	$ 15.12	$ 15.80	$ 16.53
Commodity+Variable Charges						$ 11.49	$ 9.97	$ 9.65	$ 8.41	$ 7.56	$ 7.37	$ 7.71	$ 8.06	$ 8.42	$ 8.81	$ 9.20	$ 9.62	$ 10.06	$ 10.52	$ 10.98	$ 11.50	$ 12.01	$ 12.56	$ 13.13	$ 13.72	$ 14.34	$ 14.99	$ 15.68	$ 16.38	$ 17.13
RESIDUAL FUEL OIL AND DIESEL																														
GC #6 1%						$ 8.91	$ 8.42	$ 8.31	$ 8.21	$ 8.03	$ 7.95	$ 8.09	$ 8.29	$ 8.50	$ 8.72	$ 9.03	$ 9.36	$ 9.71	$ 10.07	$ 10.44	$ 10.83	$ 11.23	$ 11.64	$ 12.07	$ 12.65	$ 12.96	$ 13.43	$ 13.92	$ 14.42	$ 14.94
GC #6 3%						$ 7.34	$ 7.01	$ 6.95	$ 6.89	$ 6.76	$ 6.71	$ 6.83	$ 7.00	$ 7.18	$ 7.36	$ 7.62	$ 7.90	$ 8.18	$ 8.48	$ 8.78	$ 9.10	$ 9.42	$ 9.76	$ 10.11	$ 10.57	$ 10.83	$ 11.22	$ 11.61	$ 12.02	$ 12.44
GC #2 0.5%						$ 16.57	$ 14.92	$ 14.59	$ 14.28	$ 13.85	$ 13.62	$ 13.85	$ 14.19	$ 14.55	$ 14.93	$ 15.48	$ 16.09	$ 16.72	$ 17.37	$ 18.05	$ 18.76	$ 19.50	$ 20.26	$ 21.06	$ 21.88	$ 22.74	$ 23.64	$ 24.57	$ 25.53	$ 26.53
GC #2 0.05%						$ 16.86	$ 15.15	$ 14.81	$ 14.48	$ 14.03	$ 13.79	$ 14.02	$ 14.37	$ 14.73	$ 15.12	$ 15.68	$ 16.29	$ 16.94	$ 17.60	$ 18.30	$ 19.02	$ 19.77	$ 20.55	$ 21.36	$ 22.20	$ 23.08	$ 23.99	$ 24.94	$ 25.92	$ 26.94
GC #2 0.0015%						$ 17.39	$ 16.07	$ 15.70	$ 15.40	$ 14.99	$ 15.02	$ 15.15	$ 15.40	$ 15.67	$ 15.98	$ 16.56	$ 17.20	$ 17.86	$ 18.55	$ 19.27	$ 20.02	$ 20.79	$ 21.60	$ 22.44	$ 23.30	$ 24.21	$ 25.15	$ 26.12	$ 27.14	$ 28.19

Docket No. ________
Taylor Energy Center
Jim Myers
Exhibit ____ [JM-4]
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CURRENT YEAR $ DOLLARS PER MMBTU (DELIVERED) - LOW CASE

		MODELED QUALITY																												
SUB-REGION	FLAVOR	Btu/lb.	% SULFUR	Lbs. SO2/ mmBtu	Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS																														
WEST. PA	MID-SULFUR	13,000	1.85	3.00		$ 3.15	$ 2.85	$ 2.63	$ 2.70	$ 2.70	$ 2.72	$ 2.76	$ 2.84	$ 2.88	$ 2.93	$ 3.03	$ 3.10	$ 3.26	$ 3.37	$ 3.43	$ 3.49	$ 3.56	$ 3.70	$ 3.76	$ 3.86	$ 3.93	$ 4.13	$ 4.24	$ 4.36	$ 4.49
WEST. PA	HIGH-SULFUR	12,200	3.34	5.48		$ 3.27	$ 3.03	$ 2.61	$ 2.70	$ 2.70	$ 2.70	$ 2.76	$ 2.84	$ 2.88	$ 2.93	$ 3.02	$ 3.10	$ 3.27	$ 3.38	$ 3.44	$ 3.49	$ 3.55	$ 3.69	$ 3.77	$ 3.88	$ 3.94	$ 4.06	$ 4.16	$ 4.27	$ 4.38
OHIO	MID-SULFUR	12,150	2.20	3.62		$ 3.08	$ 2.77	$ 2.59	$ 2.73	$ 2.78	$ 2.78	$ 2.83	$ 2.93	$ 2.98	$ 3.04	$ 3.13	$ 3.23	$ 3.48	$ 3.58	$ 3.64	$ 3.70	$ 3.75	$ 3.97	$ 4.05	$ 4.16	$ 4.21	$ 4.38	$ 4.50	$ 4.63	$ 4.76
OHIO	HIGH-SULFUR	11,750	3.60	6.13		$ 2.95	$ 2.69	$ 2.70	$ 2.74	$ 2.75	$ 2.77	$ 2.82	$ 2.90	$ 2.95	$ 3.00	$ 3.09	$ 3.17	$ 3.43	$ 3.55	$ 3.75	$ 3.82	$ 3.91	$ 4.09	$ 4.24	$ 4.33	$ 4.43	$ 4.60	$ 4.74	$ 4.89	$ 5.04
N. WV	MID-SULFUR	12,900	2.10	3.26		$ 3.22	$ 2.98	$ 2.71	$ 2.67	$ 2.68	$ 2.70	$ 2.74	$ 2.83	$ 2.91	$ 2.98	$ 3.05	$ 3.14	$ 3.30	$ 3.39	$ 3.44	$ 3.49	$ 3.55	$ 3.71	$ 3.78	$ 3.89	$ 3.94	$ 4.06	$ 4.17	$ 4.28	$ 4.39
N. WV	HIGH-SULFUR	12,350	3.60	5.83		$ 3.23	$ 2.95	$ 2.73	$ 2.76	$ 2.77	$ 2.79	$ 2.83	$ 2.90	$ 2.94	$ 2.99	$ 3.09	$ 3.15	$ 3.30	$ 3.40	$ 3.48	$ 3.54	$ 3.61	$ 3.71	$ 3.76	$ 3.85	$ 3.93	$ 4.00	$ 4.09	$ 4.17	$ 4.26
CENTRAL APPALACHIA REGION SELECTED COALS																														
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		$ 3.42	$ 3.09	$ 2.66	$ 2.48	$ 2.48	$ 2.53	$ 2.59	$ 2.67	$ 2.74	$ 2.82	$ 2.92	$ 3.01	$ 3.11	$ 3.15	$ 3.23	$ 3.29	$ 3.40	$ 3.51	$ 3.59	$ 3.69	$ 3.78	$ 3.87	$ 3.97	$ 4.07	$ 4.17
S. WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.98		$ 3.41	$ 3.18	$ 2.79	$ 2.49	$ 2.53	$ 2.59	$ 2.64	$ 2.72	$ 2.78	$ 2.83	$ 2.96	$ 2.96	$ 3.11	$ 3.15	$ 3.23	$ 3.38	$ 3.40	$ 3.58	$ 3.63	$ 3.76	$ 3.93	$ 4.03	$ 4.16	$ 4.30	$ 4.44
S. WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		$ 3.56	$ 3.28	$ 2.87	$ 2.48	$ 2.48	$ 2.52	$ 2.57	$ 2.66	$ 2.72	$ 2.81	$ 2.87	$ 2.85	$ 3.04	$ 3.10	$ 3.16	$ 3.22	$ 3.31	$ 3.43	$ 3.50	$ 3.57	$ 3.65	$ 3.74	$ 3.82	$ 3.91	$ 4.00
S. WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		$ 3.63	$ 3.18	$ 2.82	$ 2.50	$ 2.54	$ 2.58	$ 2.63	$ 2.72	$ 2.77	$ 2.83	$ 2.91	$ 2.97	$ 3.05	$ 3.11	$ 3.17	$ 3.24	$ 3.34	$ 3.47	$ 3.57	$ 3.65	$ 3.71	$ 3.82	$ 3.92	$ 4.02	$ 4.13
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		$ 3.23	$ 2.89	$ 2.69	$ 2.39	$ 2.40	$ 2.43	$ 2.49	$ 2.58	$ 2.62	$ 2.70	$ 2.78	$ 2.85	$ 2.96	$ 3.01	$ 3.07	$ 3.13	$ 3.21	$ 3.33	$ 3.40	$ 3.47	$ 3.54	$ 3.63	$ 3.71	$ 3.80	$ 3.89
S. WV-MID BTU-NS	NEAR-COMPLIANCE	12,250	0.98	1.60		$ 3.37	$ 2.99	$ 2.79	$ 2.41	$ 2.45	$ 2.52	$ 2.57	$ 2.63	$ 2.68	$ 2.75	$ 2.84	$ 2.91	$ 2.99	$ 3.04	$ 3.10	$ 3.17	$ 3.27	$ 3.39	$ 3.49	$ 3.56	$ 3.62	$ 3.72	$ 3.81	$ 3.91	$ 4.01
S. WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		$ 3.10	$ 2.83	$ 2.83	$ 2.38	$ 2.40	$ 2.47	$ 2.52	$ 2.57	$ 2.63	$ 2.71	$ 2.78	$ 2.84	$ 2.95	$ 3.00	$ 3.06	$ 3.12	$ 3.20	$ 3.31	$ 3.41	$ 3.47	$ 3.53	$ 3.63	$ 3.73	$ 3.82	$ 3.92
S. WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		$ 2.46	$ 2.38	$ 2.37	$ 2.42	$ 2.45	$ 2.54	$ 2.59	$ 2.64	$ 2.69	$ 2.74	$ 2.83	$ 2.90	$ 3.00	$ 3.05	$ 3.11	$ 3.19	$ 3.28	$ 3.40	$ 3.49	$ 3.58	$ 3.64	$ 3.75	$ 3.85	$ 3.95	$ 4.05
E. KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		$ 3.45	$ 3.17	$ 2.72	$ 2.47	$ 2.48	$ 2.54	$ 2.59	$ 2.67	$ 2.73	$ 2.83	$ 2.92	$ 2.97	$ 3.09	$ 3.13	$ 3.20	$ 3.28	$ 3.39	$ 3.50	$ 3.59	$ 3.68	$ 3.77	$ 3.86	$ 3.96	$ 4.06	$ 4.16
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		$ 2.75	$ 2.66	$ 2.84	$ 2.47	$ 2.51	$ 2.57	$ 2.62	$ 2.70	$ 2.75	$ 2.81	$ 2.91	$ 2.98	$ 3.08	$ 3.13	$ 3.20	$ 3.29	$ 3.39	$ 3.51	$ 3.62	$ 3.70	$ 3.79	$ 3.89	$ 3.99	$ 4.10	$ 4.21
E. KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		$ 3.34	$ 3.05	$ 2.67	$ 2.39	$ 2.39	$ 2.43	$ 2.47	$ 2.55	$ 2.61	$ 2.71	$ 2.78	$ 2.83	$ 2.92	$ 2.97	$ 3.04	$ 3.12	$ 3.22	$ 3.33	$ 3.40	$ 3.48	$ 3.56	$ 3.64	$ 3.73	$ 3.82	$ 3.91
E. KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		$ 3.43	$ 3.03	$ 2.71	$ 2.47	$ 2.51	$ 2.54	$ 2.60	$ 2.68	$ 2.73	$ 2.79	$ 2.87	$ 2.93	$ 3.01	$ 3.08	$ 3.13	$ 3.21	$ 3.31	$ 3.43	$ 3.53	$ 3.61	$ 3.68	$ 3.79	$ 3.89	$ 3.99	$ 4.10
E. KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		$ 3.13	$ 2.84	$ 2.56	$ 2.36	$ 2.39	$ 2.44	$ 2.50	$ 2.57	$ 2.63	$ 2.71	$ 2.79	$ 2.85	$ 2.95	$ 3.01	$ 3.07	$ 3.13	$ 3.21	$ 3.30	$ 3.37	$ 3.43	$ 3.52	$ 3.60	$ 3.68	$ 3.76	$ 3.85
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		$ 3.24	$ 2.87	$ 2.69	$ 2.32	$ 2.36	$ 2.43	$ 2.48	$ 2.53	$ 2.58	$ 2.65	$ 2.74	$ 2.80	$ 2.88	$ 2.94	$ 2.99	$ 3.06	$ 3.16	$ 3.27	$ 3.37	$ 3.44	$ 3.51	$ 3.61	$ 3.70	$ 3.80	$ 3.90
E. KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		$ 2.58	$ 2.49	$ 2.41	$ 2.42	$ 2.46	$ 2.50	$ 2.56	$ 2.64	$ 2.70	$ 2.76	$ 2.85	$ 2.92	$ 3.02	$ 3.08	$ 3.14	$ 3.20	$ 3.29	$ 3.38	$ 3.44	$ 3.50	$ 3.59	$ 3.66	$ 3.74	$ 3.82	$ 3.90
E. KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		$ 2.54	$ 2.45	$ 2.40	$ 2.37	$ 2.39	$ 2.46	$ 2.51	$ 2.57	$ 2.62	$ 2.69	$ 2.78	$ 2.86	$ 2.96	$ 3.01	$ 3.07	$ 3.14	$ 3.24	$ 3.36	$ 3.42	$ 3.52	$ 3.58	$ 3.68	$ 3.78	$ 3.87	$ 3.97
ILLINOIS BASIN SELECTED COALS																														
INDIANA	COMPLIANCE	11,100	0.58	1.05		$ 4.03	$ 3.68	$ 3.37	$ 2.84	$ 2.85	$ 2.85	$ 2.89	$ 3.00	$ 3.06	$ 3.14	$ 3.23	$ 3.26	$ 3.29	$ 3.38	$ 3.40	$ 3.44	$ 3.54	$ 3.34	$ 3.69	$ 3.75	$ 3.85	$ 3.92	$ 4.00	$ 4.08	$ 4.16
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		$ 3.35	$ 3.03	$ 2.86	$ 2.71	$ 2.70	$ 2.73	$ 2.78	$ 2.86	$ 2.91	$ 2.97	$ 3.07	$ 3.12	$ 3.22	$ 3.41	$ 3.47	$ 3.48	$ 3.55	$ 3.62	$ 3.70	$ 3.79	$ 3.86	$ 3.95	$ 4.03	$ 4.12	$ 4.21
INDIANA	MID-SULFUR	11,000	1.70	3.09		$ 3.26	$ 2.99	$ 2.77	$ 2.70	$ 2.70	$ 2.76	$ 2.81	$ 2.92	$ 2.93	$ 2.97	$ 3.06	$ 3.11	$ 3.23	$ 3.36	$ 3.41	$ 3.43	$ 3.49	$ 3.56	$ 3.63	$ 3.72	$ 3.78	$ 3.87	$ 3.94	$ 4.03	$ 4.11
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		$ 2.95	$ 2.74	$ 2.60	$ 2.65	$ 2.63	$ 2.68	$ 2.73	$ 2.79	$ 2.84	$ 2.88	$ 2.95	$ 3.01	$ 3.12	$ 3.23	$ 3.27	$ 3.31	$ 3.37	$ 3.44	$ 3.50	$ 3.56	$ 3.63	$ 3.69	$ 3.76	$ 3.83	$ 3.90
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		$ 3.10	$ 2.82	$ 2.67	$ 2.55	$ 2.53	$ 2.59	$ 2.63	$ 2.69	$ 2.75	$ 2.83	$ 2.89	$ 2.96	$ 3.08	$ 3.14	$ 3.18	$ 3.25	$ 3.32	$ 3.40	$ 3.46	$ 3.52	$ 3.62	$ 3.69	$ 3.77	$ 3.85	$ 3.93
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		$ 3.11	$ 2.82	$ 2.65	$ 2.62	$ 2.61	$ 2.64	$ 2.69	$ 2.76	$ 2.81	$ 2.87	$ 2.95	$ 2.98	$ 3.09	$ 3.15	$ 3.19	$ 3.24	$ 3.31	$ 3.39	$ 3.48	$ 3.53	$ 3.60	$ 3.69	$ 3.77	$ 3.85	$ 3.93
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		$ 2.98	$ 2.70	$ 2.62	$ 2.62	$ 2.61	$ 2.64	$ 2.69	$ 2.73	$ 2.77	$ 2.82	$ 2.89	$ 2.93	$ 3.01	$ 3.07	$ 3.11	$ 3.17	$ 3.23	$ 3.31	$ 3.40	$ 3.50	$ 3.52	$ 3.64	$ 3.73	$ 3.82	$ 3.91
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		$ 3.08	$ 2.93	$ 2.94	$ 2.81	$ 2.75	$ 2.80	$ 2.84	$ 2.91	$ 3.02	$ 3.06	$ 3.05	$ 3.09	$ 3.16	$ 3.24	$ 3.30	$ 3.33	$ 3.39	$ 3.46	$ 3.54	$ 3.60	$ 3.66	$ 3.74	$ 3.81	$ 3.89	$ 3.97
W. KY	HIGH-SULFUR	11,600	3.19	5.50		$ 2.81	$ 2.43	$ 2.46	$ 2.53	$ 2.53	$ 2.55	$ 2.63	$ 2.67	$ 2.72	$ 2.77	$ 2.82	$ 2.87	$ 2.93	$ 3.01	$ 3.05	$ 3.09	$ 3.15	$ 3.21	$ 3.26	$ 3.32	$ 3.37	$ 3.44	$ 3.50	$ 3.56	$ 3.62
WYOMING POWDER RIVER BASIN																														
PRB-N.GILLETTE	COMPLIANCE	8,350	0.44	1.05		$ 2.78	$ 2.48	$ 2.39	$ 2.45	$ 2.47	$ 2.49	$ 2.53	$ 2.57	$ 2.61	$ 2.65	$ 2.70	$ 2.74	$ 2.79	$ 2.83	$ 2.88	$ 2.98	$ 3.10	$ 3.15	$ 3.21	$ 3.23	$ 3.31	$ 3.34	$ 3.39	$ 3.44	$ 3.49
PRB-S.GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		$ 2.83	$ 2.80	$ 2.47	$ 2.47	$ 2.49	$ 2.50	$ 2.54	$ 2.58	$ 2.62	$ 2.66	$ 2.71	$ 2.75	$ 2.79	$ 2.83	$ 2.88	$ 2.98	$ 3.10	$ 3.15	$ 3.21	$ 3.23	$ 3.31	$ 3.34	$ 3.39	$ 3.44	$ 3.49
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,800	0.35	0.80		$ 2.80	$ 2.77	$ 2.44	$ 2.43	$ 2.45	$ 2.46	$ 2.49	$ 2.53	$ 2.57	$ 2.62	$ 2.66	$ 2.70	$ 2.74	$ 2.79	$ 2.84	$ 2.94	$ 3.06	$ 3.11	$ 3.17	$ 3.19	$ 3.27	$ 3.30	$ 3.35	$ 3.40	$ 3.45
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		$ 2.90	$ 2.62	$ 2.56	$ 2.48	$ 2.50	$ 2.50	$ 2.54	$ 2.59	$ 2.62	$ 2.68	$ 2.76	$ 2.81	$ 2.86	$ 2.89	$ 2.95	$ 3.05	$ 3.18	$ 3.22	$ 3.27	$ 3.28	$ 3.29	$ 3.32	$ 3.34	$ 3.37	$ 3.40
LATIN AMERICA																														
LATIN AMER	HI BTU PANAMAX/JAX	13,000	0.6	0.92		$ 2.70	$ 2.58	$ 2.72	$ 2.49	$ 2.48	$ 2.47	$ 2.53	$ 2.67	$ 2.84	$ 2.88	$ 2.98	$ 2.99	$ 2.90	$ 2.94	$ 3.06	$ 3.11	$ 3.08	$ 3.07	$ 3.21	$ 3.23	$ 3.30	$ 3.21	$ 3.32	$ 3.37	$ 3.40
LATIN AMER	MID BTU PANANMAX/JAX	12,000	1.17	1.95		$ 2.64	$ 2.56	$ 2.66	$ 2.47	$ 2.45	$ 2.45	$ 2.51	$ 2.65	$ 2.83	$ 2.85	$ 2.96	$ 2.88	$ 2.97	$ 3.02	$ 3.15	$ 3.20	$ 3.17	$ 3.16	$ 3.31	$ 3.33	$ 3.40	$ 3.30	$ 3.43	$ 3.48	$ 3.51
PETROLEUM COKE																														
Pet Coke	Low Sulfur, High Grind	14,000				$ 1.44	$ 1.39	$ 1.52	$ 1.61	$ 1.61	$ 1.61	$ 1.54	$ 1.56	$ 1.62	$ 1.76	$ 1.81	$ 1.84	$ 1.83	$ 1.93	$ 1.99	$ 2.06	$ 2.08	$ 2.06	$ 2.21	$ 2.31	$ 2.33	$ 2.31	$ 2.39	$ 2.52	$ 2.61
	Low Sulfur, Low Grind	14,000				$ 1.39	$ 1.34	$ 1.47	$ 1.55	$ 1.55	$ 1.55	$ 1.48	$ 1.50	$ 1.56	$ 1.70	$ 1.75	$ 1.78	$ 1.76	$ 1.86	$ 1.92	$ 1.99	$ 2.00	$ 1.99	$ 2.13	$ 2.23	$ 2.25	$ 2.23	$ 2.31	$ 2.43	$ 2.52
Pet Coke	High Sulfur, High Grind	14,000				$ 1.27	$ 1.21	$ 1.34	$ 1.43	$ 1.42	$ 1.42	$ 1.35	$ 1.36	$ 1.42	$ 1.55	$ 1.60	$ 1.62	$ 1.60	$ 1.70	$ 1.76	$ 1.82	$ 1.83	$ 1.81	$ 1.95	$ 2.04	$ 2.05	$ 2.03	$ 2.11	$ 2.22	$ 2.30
	High Sulfur, Low Grind	14,000				$ 1.21	$ 1.16	$ 1.29	$ 1.37	$ 1.36	$ 1.36	$ 1.28	$ 1.29	$ 1.35	$ 1.48	$ 1.53	$ 1.55	$ 1.53	$ 1.62	$ 1.68	$ 1.74	$ 1.75	$ 1.72	$ 1.86	$ 1.96	$ 1.96	$ 1.94	$ 2.01	$ 2.13	$ 2.21
NATURAL GAS																														
Commodity						$ 7.40	$ 6.41	$ 6.20	$ 5.40	$ 4.85	$ 4.73	$ 4.94	$ 5.18	$ 5.41	$ 5.65	$ 5.91	$ 6.18	$ 6.46	$ 6.76	$ 7.06	$ 7.39	$ 7.72	$ 8.07	$ 8.44	$ 8.82	$ 9.22	$ 9.64	$ 10.08	$ 10.53	$ 11.02
Commodity+Variable Charges						$ 7.68	$ 6.66	$ 6.45	$ 5.63	$ 5.06	$ 4.94	$ 5.16	$ 5.40	$ 5.63	$ 5.89	$ 6.16	$ 6.43	$ 6.73	$ 7.04	$ 7.35	$ 7.69	$ 8.03	$ 8.40	$ 8.78	$ 9.18	$ 9.59	$ 10.03	$ 10.48	$ 10.95	$ 11.45
RESIDUAL FUEL OIL AND DIESEL																														
GC #6 1%						$ 5.94	$ 5.61	$ 5.54	$ 5.47	$ 5.36	$ 5.30	$ 5.39	$ 5.53	$ 5.66	$ 5.81	$ 6.02	$ 6.24	$ 6.47	$ 6.72	$ 6.96	$ 7.22	$ 7.49	$ 7.76	$ 8.04	$ 8.43	$ 8.64	$ 8.96	$ 9.28	$ 9.62	$ 9.96
GC #6 3%						$ 4.89	$ 4.67	$ 4.63	$ 4.59	$ 4.51	$ 4.47	$ 4.56	$ 4.67	$ 4.78	$ 4.91	$ 5.08	$ 5.26	$ 5.46	$ 5.65	$ 5.85	$ 6.07	$ 6.28	$ 6.51	$ 6.74	$ 7.05	$ 7.22	$ 7.48	$ 7.74	$ 8.01	$ 8.29
GC #2 0.5%						$ 11.35	$ 10.25	$ 10.04	$ 9.84	$ 9.56	$ 9.42	$ 9.58	$ 9.81	$ 10.06	$ 10.32	$ 10.70	$ 11.11	$ 11.55	$ 11.99	$ 12.45	$ 12.94	$ 13.44	$ 13.96	$ 14.50	$ 15.06	$ 15.65	$ 16.26	$ 16.89	$ 17.54	$ 18.22
GC #2 0.05%						$ 11.53	$ 10.41	$ 10.18	$ 9.98	$ 9.68	$ 9.53	$ 9.69	$ 9.93	$ 10.18	$ 10.45	$ 10.83	$ 11.25	$ 11.69	$ 12.15	$ 12.62	$ 13.11	$ 13.62	$ 14.15	$ 14.70	$ 15.27	$ 15.87	$ 16.49	$ 17.14	$ 17.80	$ 18.50
GC #2 0.0015%						$ 11.89	$ 11.02	$ 10.78	$ 10.59	$ 10.32	$ 10.35	$ 10.44	$ 10.62	$ 10.81	$ 11.02	$ 11.42	$ 11.86	$ 12.31	$ 12.78	$ 13.27	$ 13.78	$ 14.30	$ 14.85	$ 15.42	$ 16.01	$ 16.62	$ 17.26	$ 17.93	$ 18.62	$ 19.33

Docket No. ________
Taylor Energy Center
Jim Myers
Exhibit ____ [JM-5]
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CURRENT YEAR $ DOLLARS PER MMBTU (DELIVERED) - REGULATED-CO$_2$ FUEL PRICE ANALYSIS

		MODELED QUALITY																												
SUB-REGION	FLAVOR	Btu/lb.	% SULFUR	Lbs. SO2/ mmBtu	Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS																														
WEST.PA	MID-SULFUR	13,000	1.95	3.00		$ 3.10	$ 2.85	$ 2.63	$ 2.71	$ 2.68	$ 2.74	$ 2.83	$ 2.90	$ 2.90	$ 2.86	$ 2.87	$ 2.92	$ 3.08	$ 3.17	$ 3.19	$ 3.32	$ 3.40	$ 3.48	$ 3.50	$ 3.39	$ 3.31	$ 3.41	$ 3.50	$ 3.59	$ 3.68
WEST.PA	HIGH-SULFUR	12,200	3.34	5.48		$ 3.23	$ 3.03	$ 2.60	$ 2.71	$ 2.66	$ 2.72	$ 2.82	$ 2.89	$ 2.91	$ 2.88	$ 2.89	$ 2.94	$ 3.11	$ 3.19	$ 3.22	$ 3.33	$ 3.41	$ 3.49	$ 3.51	$ 3.39	$ 3.34	$ 3.44	$ 3.54	$ 3.64	$ 3.74
OHIO	MID-SULFUR	12,150	2.20	3.62		$ 3.03	$ 2.77	$ 2.58	$ 2.74	$ 2.72	$ 2.79	$ 2.87	$ 2.97	$ 2.98	$ 2.98	$ 3.02	$ 3.10	$ 3.35	$ 3.41	$ 3.46	$ 3.59	$ 3.67	$ 3.76	$ 3.83	$ 3.72	$ 3.61	$ 3.76	$ 3.87	$ 4.00	$ 4.12
OHIO	HIGH-SULFUR	11,750	3.60	6.13		$ 2.92	$ 2.68	$ 2.69	$ 2.74	$ 2.70	$ 2.77	$ 2.87	$ 2.95	$ 2.95	$ 2.82	$ 2.96	$ 3.05	$ 3.31	$ 3.35	$ 3.54	$ 3.62	$ 3.71	$ 3.80	$ 3.87	$ 3.71	$ 3.62	$ 3.75	$ 3.66	$ 3.97	$ 4.08
N.WV	MID-SULFUR	12,900	2.10	3.26		$ 3.20	$ 2.97	$ 2.71	$ 2.68	$ 2.69	$ 2.71	$ 2.80	$ 2.90	$ 2.93	$ 2.87	$ 2.90	$ 2.96	$ 3.12	$ 3.19	$ 3.22	$ 3.35	$ 3.42	$ 3.52	$ 3.54	$ 3.43	$ 3.34	$ 3.45	$ 3.55	$ 3.64	$ 3.74
N.WV	HIGH-SULFUR	12,350	3.60	5.83		$ 3.20	$ 2.94	$ 2.73	$ 2.77	$ 2.72	$ 2.80	$ 2.89	$ 2.96	$ 2.98	$ 3.00	$ 3.01	$ 3.05	$ 3.16	$ 3.23	$ 3.27	$ 3.40	$ 3.49	$ 3.54	$ 3.54	$ 3.40	$ 3.34	$ 3.42	$ 3.50	$ 3.58	$ 3.67
CENTRAL APPALACHIA REGION SELECTED COALS																														
S.WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		$ 3.56	$ 3.19	$ 2.69	$ 2.49	$ 2.41	$ 2.48	$ 2.55	$ 2.58	$ 2.67	$ 2.72	$ 2.73	$ 2.82	$ 2.95	$ 2.97	$ 3.05	$ 3.18	$ 3.23	$ 3.09	$ 3.18	$ 3.30	$ 3.22	$ 3.33	$ 3.43	$ 3.53	$ 3.63
S.WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.99		$ 3.54	$ 3.27	$ 2.82	$ 2.49	$ 2.42	$ 2.49	$ 2.58	$ 2.64	$ 2.89	$ 2.74	$ 2.83	$ 2.89	$ 2.97	$ 2.97	$ 3.05	$ 3.21	$ 3.29	$ 3.39	$ 3.38	$ 3.32	$ 3.25	$ 3.35	$ 3.45	$ 3.55	$ 3.65
S.WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		$ 3.64	$ 3.36	$ 2.90	$ 2.49	$ 2.40	$ 2.46	$ 2.53	$ 2.58	$ 2.65	$ 2.73	$ 2.74	$ 2.80	$ 2.91	$ 2.94	$ 3.02	$ 3.14	$ 3.20	$ 3.28	$ 3.31	$ 3.22	$ 3.15	$ 3.24	$ 3.33	$ 3.42	$ 3.51
S.WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		$ 3.64	$ 3.26	$ 2.85	$ 2.50	$ 2.43	$ 2.48	$ 2.57	$ 2.62	$ 2.68	$ 2.73	$ 2.79	$ 2.84	$ 2.92	$ 2.95	$ 3.00	$ 3.15	$ 3.25	$ 3.38	$ 3.39	$ 3.32	$ 3.24	$ 3.36	$ 3.46	$ 3.57	$ 3.68
S.WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		$ 3.28	$ 2.93	$ 2.71	$ 2.40	$ 2.33	$ 2.38	$ 2.45	$ 2.50	$ 2.56	$ 2.63	$ 2.67	$ 2.72	$ 2.81	$ 2.85	$ 2.90	$ 3.02	$ 3.08	$ 3.19	$ 3.18	$ 3.10	$ 3.03	$ 3.12	$ 3.20	$ 3.29	$ 3.37
S.WV-MID BTU-NS	NEAR-COMPLIANCE	12,250	0.98	1.60		$ 3.39	$ 3.00	$ 2.79	$ 2.42	$ 2.36	$ 2.42	$ 2.51	$ 2.57	$ 2.62	$ 2.67	$ 2.73	$ 2.78	$ 2.88	$ 2.88	$ 2.94	$ 3.09	$ 3.16	$ 3.28	$ 3.29	$ 3.22	$ 3.14	$ 3.26	$ 3.35	$ 3.45	$ 3.56
S.WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		$ 3.10	$ 2.83	$ 2.63	$ 2.39	$ 2.35	$ 2.40	$ 2.44	$ 2.49	$ 2.56	$ 2.63	$ 2.66	$ 2.71	$ 2.81	$ 2.83	$ 2.85	$ 2.99	$ 3.06	$ 3.18	$ 3.22	$ 3.11	$ 3.03	$ 3.15	$ 3.24	$ 3.34	$ 3.44
S.WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		$ 2.46	$ 2.39	$ 2.38	$ 2.42	$ 2.35	$ 2.43	$ 2.50	$ 2.56	$ 2.61	$ 2.66	$ 2.72	$ 2.77	$ 2.86	$ 2.82	$ 2.96	$ 3.09	$ 3.18	$ 3.30	$ 3.42	$ 3.50	$ 3.57	$ 3.71	$ 3.82	$ 3.84	$ 4.06
E.KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		$ 3.58	$ 3.26	$ 2.76	$ 2.48	$ 2.41	$ 2.40	$ 2.55	$ 2.58	$ 2.65	$ 2.70	$ 2.72	$ 2.79	$ 2.90	$ 2.93	$ 2.96	$ 3.12	$ 3.17	$ 3.28	$ 3.32	$ 3.25	$ 3.16	$ 3.27	$ 3.36	$ 3.46	$ 3.56
E.KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		$ 2.91	$ 2.77	$ 2.88	$ 2.47	$ 2.40	$ 2.47	$ 2.57	$ 2.62	$ 2.66	$ 2.70	$ 2.77	$ 2.84	$ 2.93	$ 2.95	$ 3.01	$ 3.16	$ 3.24	$ 3.34	$ 3.34	$ 3.29	$ 3.21	$ 3.31	$ 3.41	$ 3.51	$ 3.61
E.KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		$ 3.41	$ 3.12	$ 2.70	$ 2.40	$ 2.32	$ 2.37	$ 2.43	$ 2.47	$ 2.53	$ 2.60	$ 2.60	$ 2.66	$ 2.74	$ 2.79	$ 2.82	$ 2.97	$ 3.02	$ 3.11	$ 3.16	$ 3.08	$ 2.99	$ 3.09	$ 3.18	$ 3.27	$ 3.36
E.KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		$ 3.54	$ 3.11	$ 2.74	$ 2.47	$ 2.40	$ 2.45	$ 2.54	$ 2.59	$ 2.64	$ 2.70	$ 2.75	$ 2.80	$ 2.88	$ 2.81	$ 2.94	$ 3.11	$ 3.19	$ 3.32	$ 3.45	$ 3.53	$ 3.62	$ 3.76	$ 3.87	$ 4.00	$ 4.12
E.KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		$ 3.14	$ 2.84	$ 2.57	$ 2.36	$ 2.34	$ 2.39	$ 2.45	$ 2.50	$ 2.55	$ 2.62	$ 2.66	$ 2.71	$ 2.79	$ 2.82	$ 2.87	$ 2.97	$ 3.06	$ 3.14	$ 3.16	$ 3.07	$ 3.01	$ 3.11	$ 3.20	$ 3.29	$ 3.38
E.KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		$ 3.26	$ 2.88	$ 2.69	$ 2.33	$ 2.27	$ 2.34	$ 2.42	$ 2.48	$ 2.53	$ 2.57	$ 2.63	$ 2.68	$ 2.75	$ 2.78	$ 2.83	$ 2.98	$ 3.05	$ 3.16	$ 3.22	$ 3.23	$ 3.27	$ 3.40	$ 3.50	$ 3.61	$ 3.72
E KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		$ 2.59	$ 2.49	$ 2.41	$ 2.43	$ 2.41	$ 2.46	$ 2.53	$ 2.57	$ 2.62	$ 2.69	$ 2.73	$ 2.78	$ 2.86	$ 2.89	$ 2.94	$ 3.03	$ 3.13	$ 3.21	$ 3.23	$ 3.13	$ 3.06	$ 3.16	$ 3.25	$ 3.34	$ 3.43
E.KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		$ 2.54	$ 2.46	$ 2.41	$ 2.37	$ 2.30	$ 2.36	$ 2.45	$ 2.51	$ 2.56	$ 2.61	$ 2.68	$ 2.73	$ 2.82	$ 2.85	$ 2.89	$ 3.04	$ 3.12	$ 3.24	$ 3.22	$ 3.16	$ 3.09	$ 3.20	$ 3.29	$ 3.38	$ 3.48
ILLINOIS BASIN SELECTED COALS																														
INDIANA	COMPLIANCE	11,100	0.58	1.05		$ 4.15	$ 3.78	$ 3.41	$ 2.85	$ 2.79	$ 2.85	$ 2.83	$ 2.93	$ 3.01	$ 3.05	$ 3.08	$ 3.16	$ 3.24	$ 3.29	$ 3.29	$ 3.38	$ 3.43	$ 3.49	$ 3.50	$ 3.37	$ 3.26	$ 3.34	$ 3.41	$ 3.48	$ 3.55
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		$ 3.37	$ 3.02	$ 2.86	$ 2.72	$ 2.64	$ 2.72	$ 2.78	$ 2.83	$ 2.87	$ 2.91	$ 2.95	$ 2.98	$ 3.08	$ 3.21	$ 3.24	$ 3.32	$ 3.35	$ 3.44	$ 3.47	$ 3.32	$ 3.24	$ 3.33	$ 3.40	$ 3.47	$ 3.54
INDIANA	MID-SULFUR	11,000	1.70	3.09		$ 3.29	$ 3.01	$ 2.78	$ 2.70	$ 2.63	$ 2.75	$ 2.85	$ 2.89	$ 2.90	$ 2.92	$ 2.98	$ 3.04	$ 3.08	$ 3.17	$ 3.23	$ 3.29	$ 3.33	$ 3.39	$ 3.40	$ 3.30	$ 3.23	$ 3.32	$ 3.40	$ 3.47	$ 3.55
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		$ 2.93	$ 2.73	$ 2.60	$ 2.65	$ 2.61	$ 2.70	$ 2.75	$ 2.80	$ 2.84	$ 2.85	$ 2.87	$ 2.91	$ 2.98	$ 3.05	$ 3.07	$ 3.17	$ 3.22	$ 3.28	$ 3.28	$ 3.16	$ 3.10	$ 3.18	$ 3.25	$ 3.33	$ 3.40
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		$ 3.10	$ 2.83	$ 2.68	$ 2.55	$ 2.46	$ 2.57	$ 2.62	$ 2.67	$ 2.73	$ 2.75	$ 2.79	$ 2.83	$ 2.94	$ 2.98	$ 2.99	$ 3.10	$ 3.17	$ 3.25	$ 3.26	$ 3.16	$ 3.09	$ 3.18	$ 3.26	$ 3.34	$ 3.42
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		$ 3.12	$ 2.84	$ 2.66	$ 2.63	$ 2.54	$ 2.64	$ 2.69	$ 2.75	$ 2.80	$ 2.80	$ 2.85	$ 2.88	$ 2.95	$ 2.99	$ 3.01	$ 3.09	$ 3.16	$ 3.24	$ 3.26	$ 3.15	$ 3.09	$ 3.18	$ 3.26	$ 3.34	$ 3.42
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		$ 3.03	$ 2.73	$ 2.62	$ 2.62	$ 2.58	$ 2.62	$ 2.67	$ 2.71	$ 2.73	$ 2.76	$ 2.77	$ 2.79	$ 2.85	$ 2.90	$ 2.91	$ 3.00	$ 3.05	$ 3.15	$ 3.16	$ 3.11	$ 3.02	$ 3.12	$ 3.21	$ 3.29	$ 3.38
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		$ 3.11	$ 2.97	$ 2.96	$ 2.81	$ 2.61	$ 2.72	$ 2.84	$ 2.84	$ 2.87	$ 2.97	$ 2.98	$ 2.96	$ 3.01	$ 3.08	$ 3.11	$ 3.21	$ 3.26	$ 3.33	$ 3.35	$ 3.43	$ 3.48	$ 3.59	$ 3.67	$ 3.76	$ 3.85
W. KY	HIGH-SULFUR	11,600	3.19	5.50		$ 2.80	$ 2.46	$ 2.46	$ 2.53	$ 2.50	$ 2.57	$ 2.65	$ 2.68	$ 2.70	$ 2.74	$ 2.73	$ 2.77	$ 2.80	$ 2.84	$ 2.85	$ 2.95	$ 2.98	$ 3.04	$ 3.04	$ 2.94	$ 2.88	$ 2.95	$ 3.01	$ 3.08	$ 3.14
WYOMING POWDER RIVER BASIN																														
PRB-N.GILLETTE	COMPLIANCE	8,350	0.44	1.05		$ 2.87	$ 2.81	$ 2.44	$ 2.45	$ 2.44	$ 2.44	$ 2.50	$ 2.55	$ 2.57	$ 2.61	$ 2.66	$ 2.69	$ 2.75	$ 2.78	$ 2.82	$ 2.96	$ 3.01	$ 3.21	$ 3.26	$ 3.33	$ 3.37	$ 3.49	$ 3.59	$ 3.68	$ 3.78
PRB-S.GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		$ 2.94	$ 2.87	$ 2.51	$ 2.47	$ 2.44	$ 2.46	$ 2.51	$ 2.55	$ 2.58	$ 2.63	$ 2.70	$ 2.73	$ 2.79	$ 2.78	$ 2.82	$ 2.96	$ 3.02	$ 3.21	$ 3.26	$ 3.33	$ 3.37	$ 3.49	$ 3.59	$ 3.68	$ 3.78
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,800	0.35	0.80		$ 2.91	$ 2.84	$ 2.48	$ 2.43	$ 2.40	$ 2.41	$ 2.46	$ 2.50	$ 2.53	$ 2.57	$ 2.62	$ 2.66	$ 2.71	$ 2.72	$ 2.76	$ 2.90	$ 2.95	$ 3.14	$ 3.20	$ 3.26	$ 3.30	$ 3.43	$ 3.52	$ 3.61	$ 3.71
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		$ 3.04	$ 2.98	$ 2.61	$ 2.48	$ 2.44	$ 2.45	$ 2.51	$ 2.54	$ 2.58	$ 2.61	$ 2.68	$ 2.72	$ 2.79	$ 2.78	$ 2.84	$ 2.93	$ 2.98	$ 3.16	$ 3.21	$ 3.28	$ 3.31	$ 3.43	$ 3.52	$ 3.61	$ 3.71
LATIN AMERICA																														
LATIN AMER	HI BTU PANAMAX/JAX	13,000	0.6	0.92		$ 2.73	$ 2.86	$ 2.99	$ 3.06	$ 2.93	$ 2.92	$ 2.84	$ 2.74	$ 2.91	$ 2.93	$ 2.89	$ 2.82	$ 2.72	$ 2.74	$ 2.82	$ 2.89	$ 2.87	$ 2.81	$ 2.88	$ 2.76	$ 2.67	$ 2.58	$ 2.70	$ 2.74	$ 2.78
LATIN AMER	MID BTU PANANMAX/JAX	12,000	1.17	1.95		$ 2.66	$ 2.88	$ 3.01	$ 3.08	$ 2.96	$ 2.99	$ 2.89	$ 2.80	$ 2.98	$ 3.01	$ 2.97	$ 2.88	$ 2.77	$ 2.80	$ 2.90	$ 2.95	$ 2.91	$ 2.85	$ 2.93	$ 2.81	$ 2.72	$ 2.63	$ 2.76	$ 2.81	$ 2.85
PETROLEUM COKE																														
Pet Coke	Low Sulfur, High Grind	14,000				$ 1.56	$ 1.51	$ 1.65	$ 1.74	$ 1.74	$ 1.75	$ 1.68	$ 1.70	$ 1.77	$ 1.91	$ 1.97	$ 2.00	$ 2.00	$ 2.10	$ 2.17	$ 2.24	$ 2.26	$ 2.25	$ 2.40	$ 2.51	$ 2.53	$ 2.52	$ 2.61	$ 2.74	$ 2.83
	Low Sulfur, Low Grind	14,000				$ 1.51	$ 1.46	$ 1.60	$ 1.69	$ 1.69	$ 1.69	$ 1.63	$ 1.65	$ 1.71	$ 1.85	$ 1.91	$ 1.94	$ 1.93	$ 2.03	$ 2.10	$ 2.17	$ 2.18	$ 2.17	$ 2.32	$ 2.43	$ 2.45	$ 2.44	$ 2.52	$ 2.65	$ 2.74
Pet Coke	High Sulfur, High Grind	14,000				$ 1.38	$ 1.33	$ 1.46	$ 1.55	$ 1.55	$ 1.54	$ 1.48	$ 1.49	$ 1.55	$ 1.69	$ 1.74	$ 1.77	$ 1.75	$ 1.85	$ 1.91	$ 1.98	$ 1.99	$ 1.98	$ 2.12	$ 2.22	$ 2.23	$ 2.22	$ 2.30	$ 2.42	$ 2.51
	High Sulfur, Low Grind	14,000				$ 1.33	$ 1.28	$ 1.41	$ 1.49	$ 1.49	$ 1.49	$ 1.42	$ 1.43	$ 1.49	$ 1.63	$ 1.68	$ 1.70	$ 1.69	$ 1.78	$ 1.84	$ 1.91	$ 1.92	$ 1.90	$ 2.04	$ 2.14	$ 2.15	$ 2.13	$ 2.21	$ 2.33	$ 2.42
NATURAL GAS																														
Commodity						*$ 9.25*	*$ 8.02*	*$ 7.75*	*$ 6.76*	*$ 6.05*	*$ 5.91*	*$ 6.18*	*$ 6.47*	*$ 6.76*	*$ 7.07*	*$ 7.39*	*$ 7.72*	*$ 8.08*	*$ 8.45*	*$ 8.82*	*$ 9.23*	*$ 9.65*	*$ 10.09*	*$ 10.55*	*$ 11.03*	*$ 11.52*	*$ 12.05*	*$ 12.60*	*$ 13.17*	*$ 13.77*
Commodity+Variable Charges						$ 9.58	$ 8.32	$ 8.05	$ 7.02	$ 6.31	$ 6.16	$ 6.43	$ 6.73	$ 7.03	$ 7.35	$ 7.68	$ 8.03	$ 8.40	$ 8.78	$ 9.17	$ 9.59	$ 10.02	$ 10.48	$ 10.96	$ 11.45	$ 11.96	$ 12.51	$ 13.08	$ 13.67	$ 14.29
RESIDUAL FUEL OIL AND DIESEL																														
GC #6 1%						$ 7.42	$ 7.02	$ 6.93	$ 6.84	$ 6.69	$ 6.62	$ 6.74	$ 6.91	$ 7.08	$ 7.27	$ 7.52	$ 7.80	$ 8.09	$ 8.39	$ 8.70	$ 9.03	$ 9.36	$ 9.70	$ 10.05	$ 10.54	$ 10.80	$ 11.19	$ 11.60	$ 12.02	$ 12.45
GC #6 3%						$ 6.11	$ 5.84	$ 5.79	$ 5.74	$ 5.64	$ 5.59	$ 5.69	$ 5.94	$ 5.98	$ 6.14	$ 6.35	$ 6.58	$ 6.82	$ 7.06	$ 7.32	$ 7.58	$ 7.85	$ 8.13	$ 8.42	$ 8.81	$ 9.03	$ 9.35	$ 9.67	$ 10.01	$ 10.36
GC #2 0.5%						$ 13.96	$ 12.59	$ 12.31	$ 12.06	$ 11.70	$ 11.52	$ 11.71	$ 12.00	$ 12.30	$ 12.63	$ 13.09	$ 13.60	$ 14.13	$ 14.68	$ 15.25	$ 15.85	$ 16.47	$ 17.11	$ 17.78	$ 18.47	$ 19.19	$ 19.95	$ 20.73	$ 21.53	$ 22.38
GC #2 0.05%						$ 14.19	$ 12.78	$ 12.49	$ 12.23	$ 11.86	$ 11.66	$ 11.86	$ 12.15	$ 12.45	$ 12.78	$ 13.26	$ 13.77	$ 14.31	$ 14.87	$ 15.46	$ 16.06	$ 16.70	$ 17.35	$ 18.03	$ 18.74	$ 19.47	$ 20.24	$ 21.04	$ 21.86	$ 22.72
GC #2 0.0015%						$ 14.64	$ 13.54	$ 13.24	$ 12.99	$ 12.66	$ 12.69	$ 12.79	$ 13.01	$ 13.24	$ 13.50	$ 13.99	$ 14.53	$ 15.09	$ 15.67	$ 16.27	$ 16.90	$ 17.55	$ 18.22	$ 18.93	$ 19.65	$ 20.41	$ 21.21	$ 22.03	$ 22.88	$ 23.76

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF PETER NORFOLK

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 Peter Norfolk. My business address is Lloyds Chambers, 1 Portsoken Street, London, E1 8PH, United Kingdom.

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

A. I am employed by Simpson, Spence & Young Consultancy & Research Ltd, where I am a director.

Q. Please describe Simpson, Spence & Young Consultancy & Research Ltd.

A. Simpson, Spence & Young Consultancy & Research Ltd (SSY) is the world's largest independent ship brokering group. SSY has established an organic and dynamic organization over the last 125 years that delivers traditional brokering expertise with technological sophistication and innovation. We have taken a proactive approach to brokering and advise our clients of future market trends, developments, and opportunities, as well as anticipating their own growing and changing requirements. SSY provides global coverage to our clients through our offices in 11 countries. We provide a broad range of shipping services to our customers. The services we provide focus in the following areas:

- Dry cargo chartering.
- Tanker chartering.
- Sale and purchase.
- Freight futures.
- Agency and towage.
- Consulting services and research.

Q. Please describe your educational background and experience.

A. After gaining my degree at Oxford University, I worked in shipping journalism for 5 years, and then joined SSY as an analyst in the summer of 2002.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit __ [PN-1] is a copy of my résumé. Exhibit __ [PN-2] is the dry bulk carrier freight rate projections for coal imports into Florida developed by SSY.

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.4.6.7, which was prepared under my direct supervision.

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

A. The purpose of my testimony is to present the projections of dry bulk carrier freight rates for coal imports into Florida. Projections were developed for coal deliveries originating in Bolivar, Colombia (which is also representative of coal deliveries from Venezuela) and terminating at facilities in both Tampa and Jacksonville, Florida. Panamax bulk vessels lift approximately 65,000 tons with a draft of about 12.9 meters, and Handymax bulk vessels lift approximately 45,000 tons per shipment with a draft of about 10.7 meters. Forecasts were developed for both Panamax and Handymax vessels for delivery to Jacksonville and for Handymax vessels only for delivery to Tampa due to the lower draft capability in Tampa (10.2 meters at high tide).

Q. How did you become involved in this proceeding?

A. Hill & Associates retained SSY to provide a forecast of dry bulk carrier freight rates. I was responsible for developing the forecast, which is presented in Exhibit__ [PN-2].

Q. Describe the approach you took in developing the projections of dry bulk carrier freight rates for coal imports into Florida.

A. The analysis was conducted by using the spot charter basis for applicable types of vessels. The Florida ports being considered were analyzed for types of vessels they could accommodate and discharge capacity. Additionally, SSY considered the global seaborne shipping demand, as well as the life cycle of existing vessels and construction of new vessels.

Q. Please describe how global seaborne shipping demand was factored into your analysis.

A. The continued industrialization and commercialization in China is the primary driver in the expected growth in dry bulk trade. China's port and rail infrastructure had difficulty handling the volume resulting from the growth in the country's dry cargo imports in 2004. Together with the economic slowdown measures introduced by the Chinese government at the end of April 2004, growth in China's imports of raw materials was temporarily moderated. Further measures were introduced in 2005, signaling the Chinese government's determination to prevent certain sectors of the economy from growing at an unsustainable rate. However, SSY believes that China is expected to remain a strong influence in the growth of dry bulk trade, estimating that annual imports of iron ore will increase substantially through at least 2010.

World trade in key industrial cargos (for example, iron ore and coal) is expected to increase, including the prospect of increased Asian steam coal imports, because of the introduction of new coal fired power generating capacity, plus expansion in the steel industry of India and upside potential for China's grain imports. Combined, these factors will likely ensure that dry bulk trade over the balance of the decade remains above historical averages.

Beyond 2010, SSY assumes that the rate of demand growth will slow and gradually return to the long-term annual average growth rate of between 2.5 and 3.0 percent per year, compared to the 6.0 to 8.0 percent per year growth experienced over the past 3 years. The expected easing of demand growth is a result of assumed development in the Chinese economy towards more consumption rather than investment-led growth, which would be less steel-intensive.

Q. You mentioned China and India as influencing global seaborne shipping demand. What other international influences are factored into your analysis?

A. Increasing environmental concerns and legislation, such as the Kyoto Treaty, will slow the worldwide rate of steam coal demand growth. Additionally, in more industrialized economies, such as Europe, North America, and Japan, there is relatively limited growth in the demand for steel.

Q. How has dry bulk carrier vessel supply reacted to the recent increases in seaborne shipping vessel demand?

A. Record volumes of new vessels have entered the seaborne shipping fleet in recent years. A large number of those vessels are alternative vessel types, such as oil tankers, containerships, and gas carriers. Consequently, shipyards' abilities to build dry bulk carrier vessels has been somewhat constrained.

New capacity is, however, coming on stream in China, and over the medium to longer term, it is assumed that this will raise the underlying rate of dry bulk carrier new building additions. After 2010, the potential for a period of bulk carrier oversupply becomes more pronounced for three primary reasons:

- Regulatory requirements for the replacement of the single-hulled oil tanker fleet will be complete.
- Adequate fleet supply will be available to meet known liquefied natural gas (LNG) projects.
- As a result of the above factors there is likely to be a significant overhang of surplus shipbuilding capacity.

Q. Please describe the life cycle of existing dry bulk carrier vessels.

A. In response to the current demand for dry bulk carriers, relatively older vessels have remained in service and profitable. The rate of vessel demolition is extremely responsive to the freight market cycle. Typically, dry bulk carriers are scrapped after 25 to 30 years of age. Currently, over 10 percent of the dry bulk vessels (on a tonnage basis) are older than 25 years, and an additional 20 percent (on a tonnage basis) are between 20 to 24 years old, providing a large potential for accelerated demolition once the freight markets enter a period of severe downsizing.

Q. What effect does this have on your analysis?

A. The large number of demolition candidates can act as an automatic stabilizer for the dry bulk markets. Although the situation cannot in and of itself prevent a fall in freight rates, their eventual removal from service can ensure that supply and demand remain balanced. As a result, it is unlikely that very weak freight markets would exist for prolonged periods of time.

Q. What is SSY's assumption related to the future supply and demand balance for dry bulk carrier vessels?

A. SSY believes that growth in vessel supply will increase faster than demand during 2006 and 2007. However, we do not expect a major increase in surplus tonnage.

Q. How does SSY's forecast reflect these trends?

A. Once fleet supply increases are constrained by resumption of demolition, and with a sustained upward trend in iron ore and coal shipments, we expect a quick turnaround in the market resulting in a sharp increase in rates in 2008. SSY expects that freight rates for dry bulk vessels over the next 4 to 5 years will, on average, be higher than those over the last 10 years.

We also expect that the freight markets will be extremely volatile. The potential for shipbuilding overcapacity described previously in my testimony will likely lead to a relative decrease in rates during the first half of the next decade.

Beyond 2015, SSY expects that freight markets will maintain a cyclical pattern as demand growth rates return to their historic long-term average. We do not expect a continuous upward trend in rates.

Q. Does this conclude your testimony?

A. Yes.

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Exhibit ____ [PN-1]
Page 1 of 2

Curriculum Vitae - Peter Andrew Norfolk (BA Hons Oxon)

DOB 5/8/76
Address Basement Flat
165 Percy Road
London
W12 9QJ

Employment

Jan 2006 - date	Director
Sept 2002 – Dec 2005	Market Analyst

Simpson, Spence & Young Consultancy & Research Ltd
Lloyds Chambers, 1 Portsoken St, London E1 8PH

Nov 2001 – Aug 2002	Editor, *International Bulk Journal*
Jan 2000 – Sep 2001	Deputy Editor, Hazardous Cargo Bulletin

Informa Maritime & Transport, London

Jan 1999 – Dec 1999	Editor, *Bulk Distributor*
July 1998 – Dec 1999	Deputy Editor, Container Management
Jan 1998 – July 1998	Reporter, *Container Management*

Baltic Publishing, London

Education

Sept 1994 – Jun 1997	Bachelor of Arts Degree, English

Christ Church, University of Oxford

Sept 1992 – July 1994	3 A-Levels (English, History, French - 2 A's, 1 B)
Sept 1990 – July 1992	10 GCSEs (10 A's)

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Sept 1987 – July 1994
Robert Pattinson School, North Hykeham, Lincoln

Sept 1981 – July 1987
St Lawrence's CE School, Skellingthorpe, Lincoln

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Exhibit ____ [PN-2]
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Dry Bulk Carrier Freight Rate Projections

	Constant 2005 US$/short ton		
	Handymax	Handymax	Panamax
Year	Bolivar/Jacksonville	Bolivar/Tampa	Bolivar/Jacksonville
2006	$11.34	$12.02	$7.26
2007	$9.07	$9.53	$6.35
2008	$11.79	$12.47	$8.62
2009	$13.15	$14.29	$8.85
2010	$12.25	$13.15	$8.71
2011	$11.34	$12.02	$7.26
2012	$8.85	$9.30	$5.90
2013	$8.89	$8.85	$5.22
2014	$9.07	$9.53	$6.35
2015	$11.34	$12.02	$7.26
2016	$11.61	$12.38	$8.39
2017	$11.34	$12.02	$7.26
2018	$10.21	$10.89	$6.71
2019	$11.34	$12.02	$7.26
2020	$11.79	$12.70	$8.62
2021	$12.25	$13.15	$8.71
2022	$11.57	$12.25	$7.44
2023	$10.43	$11.11	$6.80
2024	$12.25	$13.15	$8.71
2025	$13.15	$14.29	$8.85
2026	$12.47	$13.38	$8.75
2027	$11.34	$12.02	$7.26
2028	$11.79	$12.70	$8.62
2029	$12.93	$13.83	$8.85
2030	$13.38	$14.29	$8.94

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JONATHAN P. NUNES

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _______

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Jonathan P. Nunes. My business address is 1000 Legion Place, Suite 1100, Orlando, Florida 32801.

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

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

Q. Please describe your responsibilities in that position.

A. As a Senior Economist in R. W. Beck's Generation Planning and Analysis practice, I am responsible for providing consulting services in the areas of power supply planning, financial planning and analysis, and modeling and systems analysis. In particular, I have been responsible for numerous load forecasts in support of power supply decisions, certificate of need filings, wholesale and retail rate planning, and budgeting for a variety of municipal and cooperative utilities throughout the United States.

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 state your educational background and professional experience.

A. I received a Bachelor of Science degree in Business Administration, Economics from the University of Central Florida. I also received a Master of Arts degree in Applied Economics from the University of Central Florida. I have over 12 years of experience in the utility industry.

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

A. The purpose of my testimony in this proceeding is to summarize the forecast of electrical power demand and energy consumption for the Florida Municipal Power Agency (FMPA) All-Requirements Project (ARP) developed by R. W. Beck. This summary will include a brief description of the methodology of the forecast, as well as the projected annual growth rates for summer and winter peak demand and net energy for load.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit __ [JPN-1] is a copy of my résumé.

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

A. Yes. I am sponsoring Section B.3.0, which was prepared under my direct supervision.

Q. Please briefly describe the methodology used to develop the load forecasts for the All-Requirements Project.

A. The FMPA 2005 Load Forecast relies on an econometric approach to project electric sales by major rate classification in the service territories of the ARP Members. Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience. These historical models are evaluated and selected on their statistical ability to explain variations in energy usage. The resulting models are then simulated using projections of the explanatory variables to produce forecasts of energy sales. Forecasts of net energy for load and peak demand are then derived from the energy sales forecast based on assumed loss and load factors, generally based on recent historical averages of these factors. Finally, the total ARP energy requirements and peak demand are based on summations of these load determinants across the Members supplied by the ARP and, in the case of coincident peak demand, assumed coincidence factors generally based on recent historical averages. Sections B.3.4 through B.3.7 of Exhibit__ [TEC-1] summarize the general methodology used to forecast load for each rate classification.

Q. Are there any changes to the ARP Members during the forecast period?

A. Yes. The City of Vero Beach has provided FMPA with its *Notice of Establishment of Contract Rate of Delivery* (CROD). The load forecast was developed assuming that Vero Beach's CROD becomes effective January 1, 2010. The effect of the notice on the forecast is that Vero Beach's load will no longer be included in the ARP load forecast once Vero Beach's CROD becomes effective. Also, the City of Fort Meade is included in the forecast beginning January 2009, at which time its load will begin being supplied by the ARP.

Q. Please summarize the All-Requirements Project's forecasted energy and demand?

A. The Base Case 2007 forecast winter peak demand is 1,458 MW, forecast summer peak demand is 1,499 MW, and forecast annual net energy for load is 7,480 GWh. The winter peak demand is projected to grow at an average annual growth rate of 2.6 percent from 2007 through 2009 (from 1,458 to 1,535 MW), and then grow at an annual rate of 2.1 percent from 2010 through 2024 (from 1,366 to 1,821 MW). The summer peak demand is projected to grow at an average annual growth rate of 2.5 percent from 2007 through 2009 (from 1,499 to 1,576 MW), and then grow at an annual rate of 2.1 percent from 2010 through 2024 (from 1,435 to 1,909 MW). Net energy for load is expected to grow at an annual average growth rate of 2.5 percent from 2007 through 2009 (from 7,480 to 7,858 GWh), and then grow at an annual average rate of 2.0 percent from 2010 through 2024 (from 7,157 to 9,456 GWh). Note that these growth rates reflect the addition of one ARP Member in January 2009.

Q. Were any alternative load forecasts developed?

A. Yes. In addition to the Base Case forecast that I just described, high and low case projections were developed to reflect various assumptions regarding future levels of population and economic activity. These high and low case forecasts are intended to capture 90 percent of the uncertainty in these long-term driving variables (1.7 standard deviations). Summaries of the results of the high case and low case forecasts are presented in Tables B.3-4 and B.3-5, respectively, of Exhibit__ [TEC-1].

Q. In your opinion are the assumptions used in the load forecasts reasonable for planning purposes?

A. Yes. The methodology used to estimate and simulate the forecasting equations is commonly accepted and widely used in the utility industry. The estimated parameters of the forecasting equations benchmark well against economic theory and the results of similar analyses done elsewhere. Historical data for ARP Members was provided by FMPA and are assumed to be accurate. Economic data was provided by Economy.com, a nationally-recognized provider of such data. Historical and normal weather data, on which the load forecast is based, were provided by the National Oceanic and Atmospheric Administration, a widely used source for weather data.

Q. Does this conclude your testimony?

A. Yes.

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Taylor Energy Center
Jonathan Nunes
Exhibit ____ [JPN-1]
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RESUME OF

Jonathan P. Nunes, Senior Economist

R. W. Beck, Inc.

Qualifications and Experience:

Mr. Nunes has been with R. W. Beck since 1993. Since joining the firm, he has provided consulting services in the areas of power supply planning, financial planning and analysis, and modeling and systems analysis. Although his work has focused on municipal and cooperative utilities and joint action agencies in the Southeast United States, Mr. Nunes has also provided consulting services to merchant power plant developers, solid waste collection agencies, local governments, and large industrial manufacturers.

Mr. Nunes has a Master of Arts degree in Applied Economics from the University of Central Florida and a Bachelor of Science degree in Business Administration, Economics from the University of Central Florida.

Power Supply Planning and Analysis

- Long-term Load Forecasting
- Hourly Load Forecasting
- Power Supply Analyses
- Energy Risk Management

Mr. Nunes has been responsible for numerous long-term electric load forecasts and related analyses for various municipal utilities, joint-action agencies, and cooperatives. These efforts have included the development of forecasting processes from the ground up and the supervision of other staff, including client staff, in prosecuting portions of the analytical work. Mr. Nunes has taken a lead role in the development of forecasting techniques and historical data analyses to develop base-line forecasts and the sensitivity of those forecasts to varying economic and weather assumptions.

Mr. Nunes has also been responsible for the development of hourly load forecasting models for various clients to facilitate the scheduling of power supply resources and forward sales. These models have relied on a combination of econometric and univariate techniques to maximize the accuracy of the resulting forecast.

Mr. Nunes has also been involved in the evaluation of power supply options, including joint power supply arrangements, and the negotiation of power supply contracts. This work has incorporated the simulation of the utilities' power supply arrangements and typically utilizes scenario planning and probabilistic analytical techniques to assess the range of potential results and clients' risk exposure.

Financial Planning and Analysis

- Utility Cost of Service
- Rate Design
- Stranded Cost Analysis
- Asset Valuation

Mr. Nunes has been involved in numerous analyses and reports related to energy sector clients' cost of service, wholesale and retail rates, and annual budgets. His responsibilities have included the projection of utility cost of service and associated wholesale and retail electric rates, including the investigation of alternative financing options, rate stabilization strategies, and rate structures. In addition, Mr. Nunes has been involved in the preparation of Consulting Engineer's reports for Official Statements and annual reports as required by bond resolutions.

Mr. Nunes has been involved in various studies to assist clients in preparing for increased competition in power supply. In particular, he has been involved in the development of stranded cost estimates for various utilities and associated impact on competitive rates of various recovery methodologies. Mr. Nunes has also been involved in the development of a computer model to assist municipal clients in analyzing the benefits of the ownership of their distribution system and the impact of deregulation on their system and customers. In addition, Mr. Nunes has assisted clients in the development of pricing and service strategies aimed at customer retention and securing long-term retail power supply contracts.

Modeling and Systems Analysis

- Econometric Analysis
- System Dynamics

Mr. Nunes has been responsible for numerous modeling assignments for clients in the energy and solid waste industries. These models have primarily involved the use of econometric analysis to establish the influence of various factors on important decision variables. In the energy sector, this work has included the estimation of power plant output at critical temperatures and pressures, the influence of weather on energy consumption and peak demand, and the future demand for primary and after-market power plant equipment based on electricity demand, the size of the fleet, and operating characteristics.

In the solid waste industry, Mr. Nunes was responsible for the gathering, management, and analysis of waste composition and building characteristics data to determine the factors that influence recycling success. This was part of a larger project to assist the strategic planning efforts of a major city in the Northeast United States. Mr. Nunes was also involved in the development of a solid waste characterization model that estimates the composition of a community's solid waste based on the characteristics of the community. The estimate relies on a series of regression models that take into account economic and demographic variables and recycling penetration.

Mr. Nunes has been involved in the development of simulation models relying on the system dynamics discipline in both the electric and solid waste industries. The system dynamics discipline involves visual mapping and simulation modeling to help decision-makers understand the systems underlying problems or challenges. Mr. Nunes has been involved in assignments regarding the projection of market prices for electricity and power plant development activity in a competitive market. He was also involved in the development of a dynamic model of solid waste collection operations that has been used to help clients make capital decisions to improve the efficiency of their operations.

Employment History:	1993-Present	R. W. Beck, Inc.
Education:	M.A.	Applied Economics, University of Central Florida
	B.S.	Business Administration/Economics, University of Central Florida

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF RYAN J. PLETKA

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 Ryan J. Pletka. 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 Project Manager.

Q. Please describe your responsibilities in that position.

A. As a Project Manager in Black & Veatch's renewable energy group, I am active in assessments of advanced, distributed, and renewable energy technologies. I have participated in Black & Veatch assessments of over 70 renewable energy projects and technologies. Project types have included strategic planning, policy advisory, feasibility studies, due diligence investigations, new technology evaluations, engineering and financial analyses, critical flaw reviews, market analyses, and project proposal evaluation. This experience includes evaluation of around 200 project proposals from developers of all types of renewable energy projects.

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 describe your educational background and professional experience.

A. I have a Bachelors and a Masters of Science degree in mechanical engineering from Iowa State University.

I have been involved in projects representing a wide variety of generation technologies including wind, biomass and waste, energy storage (batteries, compressed air energy storage, ultra-capacitors), cogeneration, microturbines, fuel cells, Stirling engines, solar photovoltaic, solar thermal, geothermal, hydroelectric, ocean energy, zero-point (free energy), and gasification, in addition to various conventional technologies. I am Black & Veatch's lead analyst of government incentives and regulatory policies for renewable energy. I have evaluated projects involving the production tax credit, accelerated depreciation, investment tax credit, renewable energy production incentive, unconventional fuels credit, net metering, green pricing, renewable energy credits, Clean Renewable Energy Bonds, renewable portfolio standards, and various state-specific grants, rebates, and other programs. A special area of emphasis is biomass technologies. I am knowledgeable about technologies for biomass gasification, combustion, pyrolysis, cofiring, landfill gas (LFG), and production of biofuels (ethanol and biodiesel).

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 renewable technologies evaluated as supply-side alternatives to meet each Participant's capacity needs. I will also describe the advanced technologies, energy storage technologies, and distributed technologies considered.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit __ [RJP-1] is a copy of my résumé.

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.6.1, A.6.3, A.6.4, and A.6.5, all of which were either prepared by me or under my direct supervision.

Q. What renewable technologies were considered as alternatives to TEC?

A. There were several renewable technologies analyzed to determine whether renewable energy was a viable alternative to TEC. The renewable technologies considered include solid biomass (direct-fired, gasification, and integrated gasification combined cycle [IGCC], and co-fired), biogas (anaerobic digestion and LFG), waste-to-energy (WTE, including mass burn and refuse derived fuel [RDF]), wind (onshore and offshore), solar (solar thermal and solar photovoltaic [PV]), geothermal, hydroelectric, and ocean energy (ocean thermal energy conversion, wave, marine, current, and tidal) technologies.

Q. What are advanced technologies?

A. Advanced technologies include developmental technologies approaching commercial status that may offer the potential for cost and efficiency improvements over conventional technologies.

Q. What were the advanced technologies considered as alternatives to TEC?

A. The technologies evaluated include advanced combustion turbines, fuel cells, and advanced coal.

Q. What are energy storage technologies?

A. Energy storage technologies convert and store electricity, increasing the value of power by allowing better utilization of off-peak baseload generation and the mitigation of instantaneous power fluctuations. Different types of technologies are available that provide a variety of storage durations. Storage durations range from microseconds (superconducting magnets, flywheels, and batteries), to minutes (flywheels and batteries), to hours and seasonal storage (pumped hydroelectric, batteries, and compressed air).

Q. What energy storage technologies were considered as alternatives to TEC?

A. Energy storage technologies evaluated include pumped hydroelectric, battery storage, and compressed air energy storage (CAES).

Q. What are distributed generation technologies?

A. In general, distributed generation options are small, modular units that are placed near customer load points and, when operated, can reduce a utility's demand. Distributed generation alternatives can also be used to provide baseload for smaller utilities.

Q. What distributed technologies were considered as alternatives to TEC?

A. Two types of distributed generation technologies that were analyzed are reciprocating engines and microturbines. In addition, fuel cells were considered under advanced technologies, and solar photovoltaic was considered under renewable technologies.

Q. Please describe how the costs and performance parameters of the nonconventional (renewable, advanced, energy storage, and distributed generation) technologies were developed.

A. Estimates for costs and performance parameters were based on Black & Veatch project experience, vendor inquiries, and literature reviews. Capital costs are in 2006 dollars and reflect the total project cost, including direct and indirect costs. Levelized costs are based on the municipal tax exempt bond rates presented in Section A.4 of Exhibit __[TEC-1]. Owner's costs were not included in the total project cost because such costs vary significantly for nonconventional (renewable, advanced, energy storage, and distributed generation) technologies. The inclusion of these owner's costs would further increase the cost of the non-conventional (renewable, advanced, energy storage, and distributed generation) technologies and decrease their competitiveness. When appropriate, ranges of costs and performance estimates for each nonconventional (renewable, advanced, energy storage, and distributed generation) technology were developed to create best and worst case scenarios for capital cost, net plant output, net plant heat rate, fixed and variable operations and maintenance (O&M) costs, and operating capacity factor. These ranges of costs and performance create a band that helps to provide more reasonable analyses considering the many uncertainties associated with nonconventional (renewable, advanced, energy storage, and distributed generation) technologies.

Q. Have renewable energy incentives for private developers been considered?

A. Yes. Examples of renewable energy incentives include production tax credits, accelerated depreciation, and miscellaneous grant and loan programs. However, there is uncertainty related to the applicability and renewal of these incentives.

Q. What is the current applicability of the federal production tax credit incentive?

A. The production tax credit (PTC) is currently in effect for projects that enter commercial operation by December 31, 2007. Projects that may benefit from the PTC include wind, biomass, geothermal, solar, municipal solid waste, some types of hydro, and landfill gas. Unless the PTC is renewed, renewable energy projects that enter commercial operation after the current deadline of December 31, 2007, will not be eligible for the PTC. In addition, the project owner must be a taxable entity, unlike the Participants, to directly receive the benefits of the PTC.

Q. How do these incentives influence a project's cost of energy?

A. Qualification for incentives has the potential to decrease the costs of renewable energy supply-side alternatives for independent power producers, investor-owned utilities, and other tax-paying entities.

Q. Are these incentives available to the Participants directly?

A. No. Most renewable energy incentives are designed as tax credits and would not be applicable to the Participants in a conventional municipal ownership structure. A taxable entity may be able to utilize these tax credits and thereby offer a lower net energy price to potential energy purchasers.

Q. What factors are important when evaluating nonconventional (renewable, advanced, energy storage, and distributed generation) alternatives other than economic or cost factors?

A. There are a number of noneconomic aspects of nonconventional (renewable, advanced, energy storage, and distributed generation) alternatives that should be considered. These include the technology's developmental status, fuel availability or resource availability to generate electric energy, reliability, feasibility, and the technology's overall ability to meet each Participant's forecast capacity needs.

Q. Have all nonconventional (renewable, advanced, energy storage, and distributed generation) technologies considered achieved commercial operation status?

A. No. Several of the nonconventional (renewable, advanced, energy storage, and distributed generation) technologies considered are still in the research and development stage. These technologies are either conceptual or are still operating only in pilot or demonstration facilities and are not developed enough to be considered commercially available. Technologies that are not considered commercial include biomass gasification with IGCC, parabolic dish, central receiver, solar chimney, ocean thermal, and marine current technologies.

Q. **Do all the nonconventional technologies have adequate resources available within the State of Florida?**

A. No. Several renewable technologies do not have adequate resources available for cost-effective electric power production in Florida. Because of transmission system limitations, nonconventional technology alternatives considered in this analysis were geographically limited to the state of Florida. As a result, if adequate resources are not available within Florida, several renewable alternatives are not viable for electric generation in Florida. The technologies with insufficient resource availability in Florida include wind energy, solar parabolic trough, geothermal, and hydroelectric technologies.

Q. **Is LFG a viable renewable alternative within Florida?**

A. Yes. However, while LFG is available at various sites throughout Florida, many of the most promising potential projects are already being utilized by other utilities, including JEA. Additionally, the amount of LFG available is not sufficient to mitigate the need for additional capacity for any of the Participants.

Q. **Are solid waste technologies such as municipal solid waste (MSW) and RDF available within Florida?**

A. Yes. Excluding cost and environmental factors, there is some availability of MSW and RDF resources within Florida.

Q. Is solar PV available within Florida?

A. Yes. Excluding cost factors, there is substantial availability of solar PV resources within Florida.

Q. What renewable technologies have adequate resource availability and are commercially proven?

A. The renewable technologies that potentially have adequate resource availability and are commercially proven include MSW, RDF, PV, co-fired biomass, direct-fired biomass, and anaerobic digestion.

Q. Are any advanced technologies viable from a development status or technology feasibility standpoint?

A. No. Given the needed capacity, the advanced combustion turbine, fuel cell, and coal technologies are still considered developmental stage technologies. Due to the early developmental stages of these technologies and the uncertainty relating to reliability and cost, these advanced technologies were not considered commercially viable at this time.

Q. Discuss the development status and technological feasibility of energy storage and distributed generation technologies?

A. Each of the energy storage technologies (pumped hydroelectric, lead-acid battery, and compressed air) stores energy collected during off-peak hours and then releases the energy during peak demand periods. Energy storage systems were considered commercially proven. However, because these technologies rely on storing energy during off-peak periods, they are limited to only peaking applications and, therefore, have lower availability than other conventional alternatives. As a result, energy storage technologies cannot be considered for based load capacity.

Distributed generation technologies are typically used for small demand applications. Reciprocating engines are considered commercially proven, while microturbines are in early commercial deployment. Distributed generation systems are often very small in size.

Q. Does this conclude your testimony?

A. Yes.

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Ryan Pletka
Exhibit ____ [RJP-1]
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RESUME OF

Ryan J. Pletka

Project Manager, Renewable Energy

Renewable and Advanced Energy Technologies, Strategic Planning, RPS Compliance Planning, Feasibility Studies, Government Incentives, Market Analyses

Education
BS, Mechanical Engineering, Iowa State University, 1996
MS, Mechanical Engineering, Iowa State University, 1998

Professional Registration
Professional Engineer, Kansas, 2001

Total Years Experience
9

Joined B&V
1998

Publications / Presentations
More than 30 related to advanced and renewable energy projects

Mr. Pletka is a project manager in Black & Veatch's renewable energy group and is very active in assessments of advanced, distributed, and renewable energy technologies. He has participated in Black & Veatch assessments of over 70 renewable energy projects and technologies since joining Black & Veatch in 1998. Project types have included strategic planning, policy advisory, feasibility studies, due diligence investigations, new technology evaluations, engineering and financial analyses, critical flaw reviews, market analyses, and project proposal evaluation. This experience includes evaluation of around 200 project proposals from developers of all types of renewable energy projects.

Mr. Pletka has been involved in projects representing a wide variety of generation technologies including wind, biomass and waste, energy storage (batteries, CAES, ultracapacitors), cogeneration, microturbines, fuel cells, Stirling engines, solar photovoltaic, solar thermal, geothermal, hydroelectric, ocean energy, zero-point (free energy), gasification, in addition to the various conventional technologies.

Mr. Pletka is Black & Veatch's lead analyst of government incentives and regulatory policies for renewable energy. He has evaluated projects involving the production tax credit (Sec 45), accelerated depreciation, investment tax credit, renewable energy production incentive, unconventional fuels (Sec 29) credit, net metering, green pricing, renewable energy credits, Clean Renewable Energy Bonds, renewable portfolio standards, and various state-specific grants, rebates, and other programs. A particular area of expertise is developing optimum compliance plans for meeting state renewable portfolio standards.

Mr. Pletka has a mechanical engineering background with graduate-level specialization in gasification, biomass energy, fluidized beds, and energy storage.

Representative Project Experience

Strategic Plan, American Wind Energy Association: United States. 2006
Project Manager – Recently awarded project to develop a new strategic plan for the American Wind Energy Association. The plant has a focus of assessing the potential for wind energy growth through 2030. The plan included a survey of key industry stakeholders, development of wind energy supply curves and a wind market forecast for eight regions of the country, identification of key barriers to reaching 20 percent of US energy supply, and recommendations for priorities to address the industry's key constraints.

Consulting and Engineering Services for Renewable Portfolio Standard Compliance, Sierra Pacific Power / Nevada Power: Nevada. 2006-Present
Project Manager – Coordinated and managed consulting and engineering services for Sierra Pacific Power / Nevada Power for a wide variety of projects including renewable energy business plan development, project due diligence, and wind and geothermal supply curve development.

Renewable Energy Ownership Options Study, Sacramento Municipal Utility District: California. 2004 – 2006
Project Manager – Managed study of the financial and risk aspects of different renewable energy project structures including ownership, joint ownership, PPA, PPA Transfer, "flip", lease finance, tolling, and several others. Project included detailed Monte Carlo financial analysis of wind, geothermal, solar thermal, landfill gas and biomass projects.

Renewable Energy Consulting and Engineering Services, Los Angeles Department of Water and Power: California. 2003 – 2005
Project/Study Manager – Coordinated and managed consulting and engineering services for LADWP for a wide variety of projects including wind, biomass, geothermal, solar, small hydro and other renewable sources. Services under the multi-million dollar contract include RPS least cost planning support, policy advisory services, RFP development and evaluation, project due diligence, contract negotiation support, technology evaluation, feasibility studies, and project engineering services.

California Energy Commission Renewable Energy Program Support, KEMA / California Energy Commission: California. 2005 – Present
Project Manager – Black & Veatch provides support to the California Energy Commission in implementation of the state's Renewable Portfolio Standard. Black & Veatch is the task leader for the Existing Renewable Facilities Program and New Renewable Facilities Program. Work to date has included review of renewable energy contract failure frequency, review of standards for renewable energy procurement, and assessment of credit requirements for renewable contracting.

Virginia Renewable Portfolio Standard Analysis, Virginia Tech University: Virginia. 2005-2006
Management of independent review of factors impacting development of a renewable portfolio standard in Virginia. Review included Virginia renewable energy potential, technology costs, socioeconomic impacts, and incentives and barriers.

Integrated Resource Plan Development, Kauai Island Utility Cooperative: Hawaii. 2005-2006
Technical Specialist – Assisted with development and presentation of multiple aspects of the integrated resource plan including load forecast, fuel price forecasts, technology screening, technology characterization, and resource plan development and evaluation.

Wind-Compressed Air Energy Storage Market Assessment, Iowa Association of Municipal Utilities: Iowa. 2004-2005
Project Manager – Development market, economic, and financial models of 200 MW compressed air energy storage plant integrated with 100 MW wind project in Iowa.

Renewable Development Initiative, European Bank for Reconstruction and Development: Eastern Europe & Former Soviet Union. 2005—Present
Project Manager – Project Manager for initiative is to advance the development and financing of renewable energy projects in the EBRD countries of operation. This region comprises 27 countries located throughout Central and Eastern Europe and the former Soviet Union. Developed website (www.EBRDrenwables.com) to track the latest developments in the region and serve as an information resource to project developers, policymakers, and researchers.

Biomass Cofiring Conceptual Design Study, Confidential Client: United States. 2005-2006
Project Manager – Managed consulting and engineering services to investigate cofiring fast growing energy crops in two new coal circulating fluidized beds for a confidential client. The target cofiring level was up to 20 percent (by energy) in each of the 90 MW boilers.

Geothermal Technical and Economic Characterization, Confidential Client: United States. 2005-2006
Project Manager – Investigated large-scale geothermal power systems to determine the costs associated with their development and operation. Target size was 400-500 MW. Scope included: total capital cost and lead time required for construction, lifetime of the facility, operation and maintenance costs, and capacity factor. Key risks associated with the project were identified, and Black & Veatch developed an economic model to determine the minimum power purchase price assuming project financing by an independent power producer.

Landfill Gas Technical Due Diligence, Confidential Client: United States. 2006
Project Manager – Advised confidential client on technical issues for acquisition of 29 landfill gas projects in the United States totaling nearly 150 MW. Projects employed many different technologies including reciprocating engines, steam boilers, combustion turbines, and combined cycles.

Energy Storage Enabled Renewable MicroGrid Power Network, CEC / Palmdale Water District: California. 2005-Present
Technical Specialist – Awarded contact from CEC to demonstrate a 450 kW ultracapacitor-based microgrid that will integrate wind, hydro, engine generators, and various loads at the Palmdale Water District. Currently in negotiation.

Cow Manure Burner Development Support, Panda Energy: United States. 2005
Project Manager – Provided technical support to developer pursuing project to burn/gasify up to 3,000 tons per day of cow manure for heat and power production for an adjacent ethanol plant.

Pennsylvania Renewable Portfolio Standard Impacts Analysis, Community Foundation for the Alleghenies: Pennsylvania. 2003-2004
Project Manager – Management of study of Pennsylvania renewable energy potential and evaluation of economic impacts of renewable portfolio standard. Scope includes technology assessment, resource evaluation (including development of cost curves), least cost portfolio planning, and economic impact analysis. Study was used to support passage of one of the most aggressive portfolio standards in the country.

Market Strategy Development for the Mutnovsky Geothermal Project, United Nations Development Program: Russia. 2002
Technical Specialist - Provided project support assistance including work plan development, review of reports and project deliverables, and subcontractor coordination. The overall project objective was to develop a marketing plan to highlight the UNDP/GEF/EBRD project and facilitate its replication.

Other Renewable and Advanced Energy Project Experience

- Renewable Energy Project Development Support, Colorado Springs Utilities: Colorado, 2006
- Compressed Air Energy Storage / Wind Feasibility Study, New York State Energy Research and Development Authority, 2005-Present.
- Landfill Gas Technical Due Diligence, Confidential Client: United States. 2005-2006
- Renewable Energy Development Plan, Orlando Utilities Commission: Florida. 2005-2006
- Solar Thermal Hot Water Business Plan, Lakeland Electric: Florida. 2005
- Landfill Gas Technical Due Diligence, Confidential Client: United States. 2005
- Landfill Gas Conversion, Confidential Client: United States. 2005
- Biomass Cofiring Preliminary Design Study, Arizona Public Service: United States. 2005
- Poultry Litter Gasification Project Due Diligence, Confidential Client: United States. 2005
- Conversion of 50 MW Fossil Fuel Boiler to Biomass, Confidential Client: United States. 2005
- Biomass/Waste Combustion and Gasification Technology Review, Confidential Developer: 2005.
- Landfill Gas Conversion, Confidential Client: United States. 2005
- Advanced Ethanol Technology Process Due Diligence, Confidential Client: United States. 2005
- Renewable Technologies Assessment, Kauai Island Utility Cooperative: Hawaii. 2004
- Biomass Co-firing Study, Confidential Client: United States. 2004-2005

- Biomass Resource Assessments, Confidential Client: United States. 2004
- Biomass Co-firing Study, Gainesville Regional Utilities: United States. 2004
- Biomass CHP Plant Development Support, Green Institute: United States. 2004
- Plasma Arc Gasification Technology Review and Feasibility Study, Confidential Client: United States. 2004
- RFO Technical Requirements, Pacific Gas & Electric: California. 2004
- Integrated Resource Plan Support, Hawaiian Electric Company, Inc (HECO) & Hawaiian Electric Light Company, Inc (HELCO): Hawaii. 2003 – Present
- Geothermal Project Due Diligence, Los Angeles Department of Water and Power: California. 2003
- Electrical Planning and Solar and Wind Project Implementation, Palmdale Water District: California. 2001 - Present
- On-Site Power Generation Evaluation, St. Paul Regional Water Services: Minnesota. 2002 – 2003
- Biogas Alternatives Screening, MWRDGC: United States. 2003
- Los Angeles Sludge-to-Energy Study, Internal Project: United States. 2003
- Bio-oil Co-firing Study, Confidential Client: United States. 2003
- Bull Manure Gasification Study, Confidential Client: United States. 2003
- Grain Processing Plant Biomass Power Study, Confidential Client: United States. 2003
- Green Waste Anaerobic Digestion Power Facility, Los Angeles Department of Water and Power: California. 2003
- Pyrolysis Business Plan Development, Confidential Client: United States. 2003
- Biomass IGCC Independent Review, Rabo Bank: India. 2002-2003
- Gasified Biomass Co-firing Study, Confidential Client: Southwest US. 2002-2003
- Integrated Biomass Pyrolysis Combined Cycle Study, US Department of Energy – National Energy Technology Laboratory: United States. 2002 - 2003

- Technical Support for the California Energy Research Program, California Energy Commission / ICF Consulting: California. 2002 - Present
- Renewable Energy Survey and Project Identification, Modesto Irrigation District: California. 2002
- On-Site Power Generation Evaluation, Fairfax County Water Authority: Virginia. 2002
- Due Diligence Investigation, Confidential Technology Developer: International. 2001-2002
- Independent Review of Tire Combustion Technology, Tire Energy Corporation: United States. 2001-2002
- Coal Plant Biomass Gasifier Retrofit Co-firing Study, US Department of Energy – Western Regional Biomass Energy Program: Nebraska. 2001-2002.
- Due Diligence of Gasification / Pyrolysis Technology, Confidential Client: California. 2001
- Inota Tires to Energy Feasibility Study, US Trade and Development Agency / Transelektro: Hungary. 2001
- Energy Analysis for Water Transfer Study, San Diego County Water Authority: California. 2001
- Energy Planning Advisory Services, Viejas Tribal Government: California. 2001
- Florida Alternative Energy Options Analyses, Numerous Florida Utilities: Florida. 2000
- Compressed Air Energy Storage Study, Confidential Client: United States. 1999 - 2000
- Project Development Solicitation, Tashe United Cogeneration Corporation: Taiwan. 1999
- Advanced Wind Turbine Technical Due Diligence, Ergon Energy: Australia. 1999
- Poultry Litter Gasification Review, Poultry Processor: United States. 1999
- Wood Waste Feasibility Study, Jacksonville Electric Authority: Florida. 1999
- Thailand Biomass Feasibility Studies and Project Development, National Energy Policy Office of Thailand: Thailand. 1998 - 2000
- Resort Renewable Energy Supply Study, Emerald Resorts : Mexico. 2000-2001

- Advanced Compressed Air Energy Storage Review, Confidential Client: United States. 2000
- Cycle Optimization and Cost Estimate, Kuan Yin Project, Meiya Power Corporation: Taiwan. 2000
- Compressed Air Energy Storage Study, DuPage County Department of Environmental Concerns: Illinois. 1999
- Power Plant Desktop Project, Owensboro Municipal Utility: Kentucky. 1998-2001

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^{TM} model.

A. The PRISM^{TM} model is a proprietary model developed by Hill & Associates for the purpose of forecasting coal, emission allowance, and electricity prices. PRISM^{TM} 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^{TM} 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^{TM} model. The PRISM^{TM} model assumes that CAIR and CAMR will be implemented as promulgated in 2005. The PRISM^{TM} 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^{TM} 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^{TM} 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^{TM} model. As a linear programming model, PRISM^{TM} includes constraints on SO_2, NO_x, Hg, and, in the case of the sensitivity scenario, CO_2. PRISM^{TM} 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^{TM} 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™ 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^{TM} 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.

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Taylor Energy Center
Matthew Preston
Exhibit ____ [MP-1]
Page 1 of 3

RESUME OF

MATT PRESTON

EDUCATIONAL BACKGROUND

B.S. Mining Engineering, University of Arizona, 1978

PROFESSIONAL EXPERIENCE

Current Position

Matt is currently a Vice President with Hill & Associates.

Matt has worked with a variety of clients including coal companies, utilities, unregulated generating companies, major railroads, government agencies and investment bankers. Some of these tasks include:

- Developing market analyses for domestic and off-shore coal companies.
- Developing fuel procurement strategies for generating stations including probabilistic analysis of potential outcomes.
- Providing expert opinion and subsequent deposition testimony on a coal sales contract dispute.
- Providing forecasts of generator viability.
- Providing due diligence on power plant fuel contracts for potential buyers.
- Developing studies of long term coal basin demand.

Additionally Matt participates heavily or is a principal author of the Company's annual twenty year forecast of coal and emission prices, supply and demand ("Outlook for U.S. Steam Coal"),the Quarterly Price Forecast and the Central Pennsylvania Coal Supply Study

Prior Experience

Prior to Hill & Associates Matt worked for Pennsylvania Electric Company/General Public Utilities (GPU). Matt performed a variety of administrative and analytical tasks in the Fuel Procurement Department at GPU. Some of these tasks include:

- Coal Price Forecasting and Market Analysis
- Fuel Procurement Strategic Planning
- Fuel Procurement and Contract Administration
- Environmental Emission Credit Strategic Planning
- Environmental Emission Credit Procurement
- Preparation of Testimony for Rate Cases before the Pennsylvania Public Utility Commission
- Preparation of responses to Fuel Related Interrogatories from the Pennsylvania Public Utility Commission, the Pennsylvania Consumer Advocate, The New York Public Service Commission and the Federal Energy Regulatory Commission.

Prior to Pennsylvania Electric and GPU, Matt worked for Consolidation Coal Company, where Matt was an underground Assistant Mine Foreman at the Ireland and Shoemaker mines. During this period Matt worked as a Section Foreman, a Safety Inspector, and assisted in the Labor Relations Department.

Publications and Presentations Subjects

- Fuel Related Risk Management, Or Life Without the Fuel Clause", Power Plant Performance and Reliability Conference, Denver, Colorado, December 9-10, 1999
- "Risk Management Applications and Fuel Procurement", Electricity Trading in Transition, Denver, Colorado, January 28, 2000.
- "Integrating the Physical Coal Position, Part I - Understanding and Pricing Optionality in Current Coal Contracts", Managing Coal Costs and Market Risk, Orlando, Florida, November 29, 2001
- "Prepare for the Resurgence of Coal-Fired Generation?*Climate Change Regulation*"
- Platts: Prepare for the Resurgence of Coal-Fired Generation – Platts/CBI Conference, Chicago, June 28, 2004
- "The Outlook for U.S. Coal Projects", Coal Power Project Development, Denver, Co., June 2, 2005
- "The U.S Sulfur Credit Market", McCloskey's Coal Conference of the Americas, Cartagena, Colombia, March 16, 2006

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Matthew Preston
Exhibit ____ [MP-2]
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Base Case Fuel and Corresponding Emission Allowance Price Forecasts – Constant 2005 $/Ton, Unless Otherwise Specified

SUB-REGION	FLAVOR	MODELED QUALITY Btu/lb.	MODELED QUALITY % SULFUR	MODELED QUALITY Lbs. SO2/ mmBtu	Contract Signature Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
					Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS																														
WEST. PA	MID-SULFUR	13,000	1.93	3.00		$ 52.38	$ 44.52	$ 37.75	$ 38.27	$ 37.45	$ 37.11	$ 37.70	$ 37.75	$ 37.43	$ 37.11	$ 37.58	$ 37.61	$ 39.37	$ 39.99	$ 39.32	$ 40.22	$ 40.24	$ 41.55	$ 41.70	$ 42.01	$ 42.00	$ 42.70	$ 43.10	$ 43.49	$ 43.89
WEST. PA	HIGH-SULFUR	12,200	3.34	5.48		$ 50.47	$ 44.33	$ 33.21	$ 34.32	$ 33.49	$ 32.78	$ 33.57	$ 33.62	$ 33.50	$ 33.41	$ 33.65	$ 33.72	$ 35.68	$ 36.39	$ 35.60	$ 36.20	$ 36.24	$ 37.41	$ 37.81	$ 37.96	$ 38.52	$ 39.12	$ 39.63	$ 40.14	$ 40.65
OHIO	MID-SULFUR	12,150	2.20	3.62		$ 45.58	$ 37.93	$ 32.50	$ 34.72	$ 34.56	$ 34.01	$ 34.74	$ 35.15	$ 34.71	$ 34.68	$ 35.58	$ 35.87	$ 39.17	$ 39.45	$ 38.98	$ 39.78	$ 39.63	$ 41.00	$ 42.05	$ 42.73	$ 42.54	$ 43.86	$ 44.61	$ 45.36	$ 46.12
OHIO	HIGH-SULFUR	11,750	3.60	6.13		$ 40.51	$ 33.79	$ 32.92	$ 32.88	$ 32.12	$ 31.73	$ 32.40	$ 32.74	$ 32.20	$ 32.06	$ 32.71	$ 32.94	$ 36.27	$ 36.50	$ 38.56	$ 38.50	$ 38.60	$ 40.00	$ 41.00	$ 41.00	$ 41.00	$ 42.06	$ 42.64	$ 43.22	$ 43.80
N. WV	MID-SULFUR	12,900	2.10	3.26		$ 54.17	$ 46.77	$ 39.15	$ 37.16	$ 36.54	$ 36.14	$ 36.69	$ 37.20	$ 37.22	$ 36.60	$ 37.67	$ 38.05	$ 39.47	$ 39.83	$ 39.36	$ 40.12	$ 39.97	$ 41.43	$ 41.69	$ 42.06	$ 41.76	$ 42.65	$ 43.07	$ 43.49	$ 43.91
N. WV	HIGH-SULFUR	12,350	3.60	5.83		$ 50.78	$ 43.07	$ 36.90	$ 36.41	$ 35.68	$ 35.38	$ 35.91	$ 35.87	$ 35.55	$ 35.22	$ 35.37	$ 35.33	$ 36.64	$ 37.46	$ 36.64	$ 37.46	$ 37.57	$ 38.33	$ 38.22	$ 38.24	$ 38.40	$ 38.62	$ 38.78	$ 38.94	$ 39.09
CENTRAL APPALACHIA REGION SELECTED COALS																														
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		$ 71.96	$ 60.60	$ 46.62	$ 40.44	$ 39.81	$ 39.74	$ 40.19	$ 40.53	$ 40.68	$ 41.00	$ 41.90	$ 42.02	$ 42.87	$ 42.41	$ 42.85	$ 43.95	$ 43.77	$ 44.90	$ 44.58	$ 45.89	$ 45.83	$ 46.53	$ 47.04	$ 47.55	$ 48.06
S. WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.99		$ 70.93	$ 62.14	$ 49.59	$ 40.18	$ 40.46	$ 40.19	$ 40.83	$ 41.47	$ 40.87	$ 40.69	$ 42.30	$ 42.35	$ 42.76	$ 42.22	$ 42.80	$ 43.71	$ 43.68	$ 44.52	$ 45.02	$ 45.29	$ 45.49	$ 46.12	$ 46.56	$ 47.00	$ 47.43
S. WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		$ 67.17	$ 58.63	$ 46.69	$ 36.04	$ 35.31	$ 34.99	$ 35.57	$ 35.95	$ 35.94	$ 36.35	$ 36.56	$ 36.55	$ 37.18	$ 37.35	$ 37.12	$ 37.90	$ 37.84	$ 38.82	$ 38.98	$ 39.19	$ 39.19	$ 39.73	$ 40.04	$ 40.34	$ 40.65
S. WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		$ 68.17	$ 57.25	$ 46.33	$ 37.00	$ 37.29	$ 36.53	$ 37.17	$ 37.68	$ 37.24	$ 37.15	$ 38.02	$ 37.87	$ 38.32	$ 38.32	$ 38.07	$ 39.21	$ 39.38	$ 40.53	$ 41.39	$ 41.60	$ 41.62	$ 42.57	$ 43.12	$ 43.67	$ 44.23
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		$ 58.69	$ 48.69	$ 42.38	$ 34.14	$ 33.50	$ 33.21	$ 33.71	$ 34.05	$ 33.93	$ 34.23	$ 35.09	$ 35.11	$ 35.81	$ 35.91	$ 35.70	$ 36.37	$ 36.31	$ 37.26	$ 37.41	$ 37.60	$ 37.49	$ 38.02	$ 38.29	$ 38.56	$ 38.82
S. WV-MID BTU-NS	NEAR-COMPLIANCE	12,350	0.98	1.60		$ 61.55	$ 50.08	$ 44.46	$ 34.74	$ 34.65	$ 34.86	$ 35.28	$ 36.06	$ 35.62	$ 35.38	$ 36.37	$ 36.27	$ 36.71	$ 36.67	$ 36.42	$ 37.52	$ 37.68	$ 38.79	$ 39.55	$ 39.74	$ 39.64	$ 40.54	$ 41.03	$ 41.52	$ 42.00
S. WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		$ 56.21	$ 47.92	$ 42.03	$ 35.14	$ 34.99	$ 34.85	$ 34.82	$ 35.39	$ 35.40	$ 35.73	$ 36.30	$ 36.20	$ 36.96	$ 37.05	$ 36.71	$ 37.38	$ 37.33	$ 38.48	$ 39.29	$ 39.43	$ 39.32	$ 40.25	$ 40.74	$ 41.24	$ 41.73
S. WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		$ 41.87	$ 38.96	$ 37.39	$ 37.27	$ 36.95	$ 37.57	$ 37.44	$ 38.31	$ 37.80	$ 37.62	$ 38.61	$ 38.62	$ 39.35	$ 39.30	$ 38.96	$ 40.06	$ 40.25	$ 41.42	$ 42.26	$ 42.40	$ 42.29	$ 43.24	$ 43.75	$ 44.25	$ 44.76
E. KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		$ 72.50	$ 62.53	$ 48.56	$ 40.53	$ 40.00	$ 39.93	$ 40.29	$ 40.73	$ 40.80	$ 41.13	$ 41.69	$ 41.62	$ 42.69	$ 42.42	$ 42.44	$ 43.34	$ 43.20	$ 44.30	$ 44.54	$ 45.17	$ 45.18	$ 45.93	$ 46.41	$ 46.89	$ 47.38
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		$ 55.64	$ 50.66	$ 51.80	$ 40.43	$ 40.88	$ 40.46	$ 41.08	$ 41.79	$ 41.17	$ 41.22	$ 42.65	$ 42.65	$ 43.06	$ 42.52	$ 43.10	$ 44.01	$ 43.98	$ 44.82	$ 45.32	$ 45.59	$ 45.79	$ 46.42	$ 46.86	$ 47.30	$ 47.73
E. KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		$ 65.51	$ 36.64	$ 45.23	$ 36.84	$ 36.08	$ 35.71	$ 36.05	$ 36.41	$ 36.48	$ 36.86	$ 37.11	$ 37.05	$ 37.68	$ 37.87	$ 37.66	$ 38.30	$ 38.27	$ 39.23	$ 39.51	$ 40.18	$ 39.85	$ 40.64	$ 41.05	$ 41.46	$ 41.87
E. KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		$ 67.41	$ 55.27	$ 45.19	$ 37.54	$ 37.70	$ 37.01	$ 37.65	$ 38.28	$ 37.71	$ 37.67	$ 38.51	$ 38.33	$ 38.70	$ 38.74	$ 38.48	$ 39.62	$ 39.89	$ 41.05	$ 41.88	$ 42.07	$ 42.19	$ 43.10	$ 43.67	$ 44.23	$ 44.79
E. KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		$ 56.40	$ 47.72	$ 40.09	$ 34.25	$ 34.10	$ 34.16	$ 34.55	$ 35.07	$ 35.12	$ 35.37	$ 36.14	$ 35.93	$ 36.69	$ 36.82	$ 36.55	$ 36.83	$ 36.92	$ 37.79	$ 38.30	$ 38.59	$ 38.43	$ 39.15	$ 39.53	$ 39.91	$ 40.29
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		$ 61.19	$ 50.35	$ 44.46	$ 34.76	$ 34.68	$ 34.99	$ 35.40	$ 36.17	$ 35.74	$ 35.47	$ 36.50	$ 36.36	$ 36.79	$ 36.81	$ 36.57	$ 37.66	$ 37.82	$ 38.95	$ 39.79	$ 39.99	$ 40.01	$ 40.94	$ 41.48	$ 42.02	$ 42.56
E. KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		$ 42.13	$ 38.60	$ 35.65	$ 34.82	$ 34.66	$ 34.67	$ 35.07	$ 35.60	$ 35.64	$ 35.88	$ 36.52	$ 36.32	$ 37.07	$ 37.27	$ 36.90	$ 37.10	$ 37.24	$ 38.11	$ 38.57	$ 38.82	$ 38.71	$ 39.39	$ 39.75	$ 40.12	$ 40.48
E. KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		$ 42.12	$ 38.86	$ 36.42	$ 34.46	$ 34.23	$ 34.41	$ 34.83	$ 35.61	$ 35.21	$ 34.96	$ 36.19	$ 36.15	$ 36.83	$ 36.93	$ 36.56	$ 37.58	$ 37.79	$ 38.90	$ 39.51	$ 39.63	$ 39.58	$ 40.38	$ 40.81	$ 41.24	$ 41.67
ILLINOIS BASIN SELECTED COALS																														
INDIANA	COMPLIANCE	11,100	0.58	1.05		$ 63.98	$ 54.20	$ 44.90	$ 32.24	$ 32.03	$ 31.60	$ 31.03	$ 31.71	$ 31.58	$ 31.45	$ 31.31	$ 30.90	$ 30.95	$ 30.91	$ 30.78	$ 30.85	$ 30.51	$ 31.12	$ 31.32	$ 31.07	$ 30.67	$ 31.02	$ 31.05	$ 31.07	$ 31.10
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		$ 46.18	$ 37.32	$ 32.93	$ 28.82	$ 28.20	$ 28.19	$ 27.97	$ 28.20	$ 28.06	$ 28.13	$ 28.89	$ 28.54	$ 29.12	$ 30.67	$ 30.92	$ 30.91	$ 30.25	$ 30.93	$ 31.30	$ 30.85	$ 30.41	$ 30.82	$ 30.84	$ 30.87	$ 30.89
INDIANA	MID-SULFUR	11,000	1.70	3.09		$ 44.69	$ 37.49	$ 31.38	$ 28.82	$ 28.36	$ 28.84	$ 29.38	$ 29.28	$ 28.50	$ 28.31	$ 28.98	$ 29.15	$ 29.52	$ 30.28	$ 30.11	$ 29.79	$ 29.25	$ 30.03	$ 30.20	$ 30.21	$ 30.04	$ 30.47	$ 30.65	$ 30.83	$ 31.00
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		$ 37.72	$ 32.21	$ 28.33	$ 28.21	$ 27.45	$ 27.71	$ 27.50	$ 27.49	$ 27.34	$ 26.85	$ 27.32	$ 27.14	$ 28.07	$ 28.73	$ 27.96	$ 28.17	$ 27.84	$ 28.61	$ 28.71	$ 28.59	$ 28.45	$ 28.80	$ 28.92	$ 29.04	$ 29.16
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		$ 45.51	$ 37.97	$ 33.40	$ 29.36	$ 29.00	$ 28.72	$ 28.73	$ 28.92	$ 28.91	$ 29.07	$ 29.80	$ 29.63	$ 30.78	$ 30.83	$ 30.37	$ 30.82	$ 30.81	$ 31.73	$ 31.93	$ 32.16	$ 31.97	$ 32.55	$ 32.82	$ 33.10	$ 33.37
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		$ 44.47	$ 36.82	$ 31.64	$ 29.97	$ 29.19	$ 29.18	$ 28.96	$ 29.17	$ 29.01	$ 29.01	$ 29.61	$ 29.19	$ 29.74	$ 29.86	$ 29.39	$ 29.64	$ 29.51	$ 30.41	$ 30.72	$ 30.79	$ 30.70	$ 31.25	$ 31.53	$ 31.81	$ 32.08
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		$ 40.00	$ 32.34	$ 28.91	$ 27.93	$ 27.28	$ 27.33	$ 27.16	$ 27.04	$ 26.43	$ 26.55	$ 26.73	$ 26.23	$ 26.56	$ 26.92	$ 26.18	$ 26.32	$ 26.30	$ 27.10	$ 27.47	$ 28.30	$ 27.53	$ 28.46	$ 28.83	$ 29.20	$ 29.94
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		$ 46.30	$ 41.64	$ 40.00	$ 35.45	$ 33.26	$ 33.32	$ 33.55	$ 33.10	$ 32.36	$ 32.12	$ 32.52	$ 32.33	$ 32.47	$ 32.52	$ 32.23	$ 32.94	$ 32.32	$ 33.24	$ 33.48	$ 33.55	$ 33.10	$ 33.70	$ 33.89	$ 34.07	$ 34.26
W. KY	HIGH-SULFUR	11,600	3.19	5.50		$ 37.46	$ 28.67	$ 27.76	$ 28.10	$ 27.71	$ 27.61	$ 27.52	$ 27.41	$ 27.32	$ 27.23	$ 27.12	$ 26.97	$ 27.00	$ 27.48	$ 26.72	$ 26.93	$ 26.60	$ 27.39	$ 27.40	$ 27.28	$ 27.06	$ 27.39	$ 27.48	$ 27.56	$ 27.64
WYOMING POWDER RIVER BASIN																														
PRB-N.GILLETTE	COMPLIANCE	8,350	0.44	1.05		$ 13.68	$ 11.92	$ 5.36	$ 4.92	$ 5.14	$ 4.74	$ 4.58	$ 4.78	$ 4.47	$ 4.45	$ 5.11	$ 5.13	$ 5.11	$ 5.11	$ 5.06	$ 6.53	$ 6.58	$ 8.66	$ 8.64	$ 8.78	$ 8.60	$ 9.50	$ 9.92	$ 10.33	$ 10.75
PRB-S.GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		$ 15.12	$ 13.10	$ 6.75	$ 5.57	$ 5.55	$ 5.14	$ 4.98	$ 5.07	$ 4.75	$ 4.73	$ 5.41	$ 5.39	$ 5.37	$ 5.34	$ 5.32	$ 6.82	$ 6.85	$ 8.90	$ 8.89	$ 9.06	$ 8.86	$ 9.77	$ 10.18	$ 10.60	$ 11.02
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,800	0.35	0.80		$ 16.98	$ 14.90	$ 8.17	$ 6.69	$ 6.65	$ 6.18	$ 6.02	$ 6.12	$ 5.79	$ 5.78	$ 6.50	$ 6.50	$ 6.43	$ 6.41	$ 6.39	$ 7.95	$ 7.99	$ 10.14	$ 10.14	$ 10.30	$ 10.09	$ 11.04	$ 11.48	$ 11.91	$ 12.35
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		$ 19.12	$ 17.23	$ 10.26	$ 7.50	$ 7.55	$ 6.93	$ 6.76	$ 6.96	$ 6.63	$ 6.84	$ 7.95	$ 7.98	$ 7.83	$ 7.36	$ 7.69	$ 8.38	$ 8.36	$ 10.37	$ 10.31	$ 10.48	$ 10.24	$ 11.11	$ 11.50	$ 11.89	$ 12.27
LATIN AMERICA																														
LATIN AMER-HI BTU	LATIN AMER-HI BTU	13,000	0.6	0.92		$ 50.74	$ 53.32	$ 52.52	$ 52.15	$ 51.67	$ 50.54	$ 48.66	$ 46.92	$ 45.73	$ 44.90	$ 42.76	$ 40.73	$ 38.10	$ 37.13	$ 36.74	$ 36.14	$ 35.74	$ 34.99	$ 34.10	$ 33.07	$ 33.07	$ 32.02	$ 31.29	$ 30.57	$ 29.84
LATIN AMER-MID BTU	LATIN AMER-MID BTU	12,000	1.17	1.95		$ 43.75	$ 48.17	$ 47.45	$ 47.12	$ 46.87	$ 46.51	$ 44.99	$ 43.07	$ 43.06	$ 41.56	$ 39.58	$ 37.71	$ 35.27	$ 34.38	$ 34.01	$ 33.45	$ 33.08	$ 32.39	$ 31.56	$ 30.61	$ 30.61	$ 29.64	$ 28.97	$ 28.30	$ 27.62
Pet Coke Expected Price																														
Pet Coke (Gulf Region)	Low Sulfur, High Grind	14,000	4.5	6.42		$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35
Low Grind	Low Sulfur, Low Grind	14,000	4.5	6.42		$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99
Pet Coke (Gulf Region)	High Sulfur, High Grind	14,000	6.5	9.29		$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45
Low Grind	High Sulfur, Low Grind	14,000	6.5	9.29		$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09
Emission Offset Prices																														
SO2 Emission Offsets	in $/Ton					$ 1,058.47	$ 950.01	$ 372.41	$ 407.70	$ 339.46	$ 337.98	$ 380.82	$ 381.16	$ 482.98	$ 672.05	$ 760.32	$ 831.62	$ 850.00	$ 845.48	$ 900.00	$ 958.43	$ 1,005.91	$ 1,064.87	$ 1,190.49	$ 1,190.00	$ 1,180.73	$ 1,218.05	$ 1,255.37	$ 1,292.69	$ 1,330.01
NOx Emission Offsets	in $/Ton					$ 1,828.61	$ 1,803.67	$ 1,795.94	$ 2,075.77	$ 2,824.40	$ 2,889.42	$ 2,932.71	$ 2,930.68	$ 3,096.49	$ 4,825.03	$ 5,088.85	$ 4,260.75	$ 4,302.05	$ 5,506.12	$ 6,477.05	$ 6,006.79	$ 5,599.09	$ 7,014.83	$ 10,297.86	$ 10,895.90	$ 11,493.94	$ 12,091.98	$ 12,690.02	$ 13,288.06	$ 13,886.10
Mercury Emission Offsets	in $/pound					$ -	$ -	$ -	$ -	$ 14,921.59	$ 14,825.01	$ 11,705.98	$ 14,933.16	$ 8,679.16	$ 16,352.16	$ 10,642.96	$ 9,884.05	$ 19,228.28	$ 18,259.91	$ 18,259.91	$ 19,482.35	$ 20,038.81	$ 35,536.09	$ 35,672.87	$ 55,634.85	$ 59,654.71	$ 63,674.57	$ 67,694.44	$ 71,714.30	$ 75,734.16
CO2 Emission Offsets	in $/Ton					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Henry Hub Natural Gas Price																														
Natural Gas (Henry Hub)	$/MMBtu					$ 9.02	$ 7.63	$ 7.20	$ 6.12	$ 5.36	$ 5.10	$ 5.20	$ 5.31	$ 5.41	$ 5.52	$ 5.63	$ 5.74	$ 5.86	$ 5.98	$ 6.09	$ 6.22	$ 6.34	$ 6.47	$ 6.60	$ 6.73	$ 6.86	$ 7.00	$ 7.14	$ 7.28	$ 7.43
Gulf Coast Oil Prices																														
Oil Price Forecast																														
GC #6 1%	$/Bbl					$ 45.32	$ 41.79	$ 40.26	$ 38.79	$ 37.03	$ 35.74	$ 35.50	$ 35.48	$ 35.48	$ 35.53	$ 35.88	$ 36.31	$ 36.74	$ 37.18	$ 37.61	$ 38.05	$ 38.48	$ 38.92	$ 39.36	$ 40.25	$ 40.25	$ 40.69	$ 41.14	$ 41.59	$ 42.03
GC #6 3%	$/Bbl					$ 37.32	$ 34.80	$ 33.65	$ 32.54	$ 31.17	$ 30.17	$ 29.98	$ 29.97	$ 29.97	$ 30.00	$ 30.28	$ 30.62	$ 30.96	$ 31.28	$ 31.62	$ 31.96	$ 32.29	$ 32.63	$ 32.97	$ 33.64	$ 33.64	$ 33.98	$ 34.31	$ 34.65	$ 34.98
GC #2 0.5%	$/Bbl					$ 73.31	$ 63.90	$ 60.75	$ 57.83	$ 54.48	$ 52.12	$ 51.66	$ 51.64	$ 51.64	$ 51.72	$ 52.38	$ 53.15	$ 53.95	$ 54.76	$ 55.56	$ 56.40	$ 57.23	$ 58.08	$ 58.95	$ 59.82	$ 60.71	$ 61.62	$ 62.54	$ 63.46	$ 64.40
GC #2 0.05%	$/Bbl					$ 74.63	$ 64.95	$ 61.71	$ 58.71	$ 55.25	$ 52.83	$ 52.36	$ 52.34	$ 52.34	$ 52.42	$ 53.09	$ 53.89	$ 54.70	$ 55.53	$ 56.38	$ 57.22	$ 58.09	$ 58.97	$ 59.85	$ 60.75	$ 61.67	$ 62.61	$ 63.55	$ 64.50	$ 65.47
GC #2 0.0015%	$/Bbl					$ 77.15	$ 69.13	$ 65.69	$ 62.69	$ 59.33	$ 57.90	$ 56.89	$ 56.38	$ 55.94	$ 55.64	$ 56.31	$ 57.11	$ 57.93	$ 58.75	$ 59.59	$ 60.45	$ 61.31	$ 62.19	$ 63.08	$ 63.97	$ 64.89	$ 65.83	$ 66.77	$ 67.73	$ 68.70

Docket No. ________
Taylor Energy Center
Matthew Preston
Exhibit ____ [MP-3]
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High Fuel and Corresponding Emission Allowance Price Forecasts – Constant 2005 $/Ton, Unless Otherwise Specified

SUB-REGION	FLAVOR	MODELED QUALITY Btu/lb.	% SULFUR	Lbs. SO2/ mmBtu	Contract Signature Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
					Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS																														
WEST. PA	MID-SULFUR	13,000	1.95	3.00		$ 54.41	$ 45.34	$ 37.93	$ 41.24	$ 39.45	$ 39.60	$ 40.73	$ 40.59	$ 39.95	$ 40.50	$ 41.16	$ 41.10	$ 42.70	$ 42.67	$ 42.55	$ 43.88	$ 44.24	$ 44.64	$ 45.41	$ 46.87	$ 47.63	$ 48.40	$ 49.16	$ 49.92	$ 50.68
WEST. PA	HIGH-SULFUR	12,200	3.34	5.48		$ 51.84	$ 44.33	$ 33.14	$ 37.09	$ 35.40	$ 34.95	$ 36.38	$ 36.16	$ 35.64	$ 36.20	$ 36.76	$ 37.07	$ 38.65	$ 38.69	$ 38.47	$ 39.44	$ 39.59	$ 39.98	$ 41.10	$ 41.38	$ 41.96	$ 42.54	$ 43.12	$ 43.70	$ 44.29
OHIO	MID-SULFUR	12,150	2.20	3.62		$ 47.38	$ 38.62	$ 32.41	$ 37.55	$ 36.48	$ 36.43	$ 37.65	$ 37.78	$ 37.45	$ 37.84	$ 38.75	$ 39.08	$ 42.14	$ 42.02	$ 41.88	$ 43.02	$ 43.30	$ 44.34	$ 45.07	$ 45.48	$ 46.19	$ 46.90	$ 47.61	$ 48.32	$ 49.03
OHIO	HIGH-SULFUR	11,750	3.60	6.13		$ 41.88	$ 34.36	$ 32.81	$ 35.53	$ 33.94	$ 34.07	$ 35.16	$ 35.23	$ 34.79	$ 35.03	$ 35.74	$ 36.06	$ 38.96	$ 41.47	$ 41.29	$ 41.30	$ 41.40	$ 42.80	$ 43.80	$ 43.80	$ 43.80	$ 45.77	$ 46.57	$ 47.36	$ 48.16
N. WV	MID-SULFUR	12,900	2.10	3.26		$ 56.15	$ 47.73	$ 39.24	$ 40.17	$ 38.55	$ 38.66	$ 39.69	$ 39.78	$ 39.14	$ 40.04	$ 41.14	$ 41.11	$ 42.81	$ 42.49	$ 42.39	$ 43.58	$ 43.90	$ 44.29	$ 45.14	$ 45.62	$ 46.24	$ 46.85	$ 47.46	$ 48.07	$ 48.68
N. WV	HIGH-SULFUR	12,350	3.60	5.83		$ 52.26	$ 43.72	$ 37.11	$ 39.19	$ 37.48	$ 37.59	$ 38.67	$ 38.49	$ 37.89	$ 38.32	$ 38.69	$ 38.59	$ 39.88	$ 39.83	$ 39.74	$ 41.04	$ 41.42	$ 41.35	$ 41.97	$ 42.42	$ 42.92	$ 43.42	$ 43.92	$ 44.43	$ 44.93
CENTRAL APPALACHIA REGION SELECTED COALS																														
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		$ 75.33	$ 64.03	$ 49.35	$ 42.02	$ 41.48	$ 42.06	$ 42.68	$ 43.14	$ 42.20	$ 43.56	$ 44.88	$ 44.90	$ 45.64	$ 45.41	$ 46.00	$ 47.44	$ 48.49	$ 48.21	$ 48.45	$ 49.04	$ 49.52	$ 50.00	$ 50.48	$ 50.96	$ 51.44
S. WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.99		$ 73.88	$ 65.22	$ 51.80	$ 41.44	$ 41.41	$ 42.24	$ 42.81	$ 43.30	$ 42.77	$ 43.29	$ 47.38	$ 44.37	$ 46.98	$ 45.02	$ 45.40	$ 47.21	$ 47.02	$ 48.38	$ 49.15	$ 49.41	$ 50.04	$ 50.68	$ 51.31	$ 51.94	$ 52.57
S. WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		$ 69.63	$ 60.84	$ 48.89	$ 37.47	$ 36.83	$ 37.05	$ 38.01	$ 38.37	$ 37.48	$ 38.62	$ 39.04	$ 38.99	$ 39.88	$ 40.01	$ 40.02	$ 41.48	$ 42.12	$ 42.27	$ 42.79	$ 43.46	$ 44.08	$ 44.71	$ 45.33	$ 45.96	$ 46.58
S. WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		$ 69.00	$ 59.57	$ 48.18	$ 38.26	$ 38.17	$ 38.46	$ 39.02	$ 39.50	$ 39.10	$ 39.40	$ 40.44	$ 39.99	$ 40.28	$ 40.60	$ 40.68	$ 42.71	$ 43.33	$ 44.70	$ 45.21	$ 46.43	$ 47.49	$ 48.55	$ 49.61	$ 50.66	$ 51.72
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		$ 60.30	$ 50.10	$ 43.91	$ 35.46	$ 34.92	$ 35.17	$ 35.96	$ 36.16	$ 35.53	$ 36.41	$ 37.17	$ 37.14	$ 38.36	$ 38.43	$ 38.42	$ 39.85	$ 40.45	$ 40.67	$ 40.97	$ 41.77	$ 42.37	$ 42.98	$ 43.58	$ 44.18	$ 44.79
S. WV-MID BTU-NS	NEAR-COMPLIANCE	12,250	0.98	1.60		$ 62.35	$ 51.31	$ 45.51	$ 35.64	$ 35.54	$ 36.73	$ 37.11	$ 37.35	$ 36.94	$ 37.63	$ 38.70	$ 38.30	$ 38.61	$ 38.86	$ 38.95	$ 40.91	$ 41.51	$ 42.82	$ 43.29	$ 44.42	$ 45.42	$ 46.42	$ 47.43	$ 48.43	$ 49.43
S. WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		$ 56.79	$ 47.92	$ 42.03	$ 36.39	$ 35.74	$ 36.35	$ 37.11	$ 37.29	$ 36.86	$ 38.07	$ 38.31	$ 38.26	$ 39.46	$ 39.43	$ 39.48	$ 40.91	$ 41.53	$ 41.91	$ 42.37	$ 43.22	$ 43.91	$ 44.61	$ 45.31	$ 46.01	$ 46.70
S. WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		$ 42.46	$ 39.40	$ 38.04	$ 38.40	$ 37.91	$ 38.98	$ 39.41	$ 39.67	$ 39.25	$ 40.00	$ 41.12	$ 41.01	$ 41.38	$ 41.53	$ 41.60	$ 43.65	$ 44.23	$ 45.44	$ 45.82	$ 46.96	$ 47.92	$ 48.89	$ 49.85	$ 50.82	$ 51.78
E. KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		$ 75.64	$ 65.65	$ 51.17	$ 41.82	$ 41.25	$ 41.89	$ 42.62	$ 42.90	$ 42.20	$ 43.63	$ 44.45	$ 44.45	$ 45.22	$ 45.56	$ 45.60	$ 46.81	$ 47.79	$ 47.50	$ 47.87	$ 48.41	$ 48.90	$ 49.38	$ 49.86	$ 50.34	$ 50.82
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		$ 59.36	$ 54.57	$ 54.32	$ 41.90	$ 41.87	$ 42.52	$ 43.06	$ 43.49	$ 42.94	$ 43.59	$ 44.97	$ 44.70	$ 45.16	$ 45.20	$ 45.75	$ 48.16	$ 47.45	$ 49.52	$ 49.75	$ 50.31	$ 51.06	$ 51.81	$ 52.56	$ 53.31	$ 54.06
E. KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		$ 67.94	$ 58.84	$ 47.41	$ 37.81	$ 37.22	$ 37.55	$ 38.16	$ 38.36	$ 37.72	$ 38.96	$ 39.57	$ 39.63	$ 40.34	$ 40.50	$ 40.54	$ 41.72	$ 42.50	$ 42.83	$ 43.54	$ 44.15	$ 44.83	$ 45.51	$ 46.19	$ 46.88	$ 47.56
E. KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		$ 70.00	$ 57.79	$ 47.12	$ 38.68	$ 38.58	$ 38.95	$ 39.50	$ 40.00	$ 39.58	$ 39.90	$ 40.85	$ 40.48	$ 40.75	$ 41.02	$ 41.12	$ 43.15	$ 43.85	$ 45.14	$ 45.75	$ 46.95	$ 48.03	$ 49.11	$ 50.18	$ 51.26	$ 52.34
E. KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		$ 56.64	$ 47.85	$ 40.46	$ 35.44	$ 35.22	$ 35.60	$ 36.33	$ 36.52	$ 36.18	$ 37.36	$ 38.03	$ 37.99	$ 38.59	$ 39.00	$ 38.76	$ 40.09	$ 41.17	$ 41.48	$ 42.07	$ 42.76	$ 43.45	$ 44.14	$ 44.83	$ 45.52	$ 46.21
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		$ 61.90	$ 50.92	$ 45.18	$ 35.67	$ 35.57	$ 36.86	$ 37.22	$ 37.45	$ 37.04	$ 37.72	$ 38.83	$ 38.42	$ 38.69	$ 39.00	$ 39.09	$ 41.05	$ 41.65	$ 42.98	$ 43.54	$ 44.66	$ 45.69	$ 46.71	$ 47.74	$ 48.76	$ 49.79
E. KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		$ 42.21	$ 38.56	$ 35.93	$ 36.02	$ 35.78	$ 36.12	$ 36.88	$ 37.05	$ 36.71	$ 37.87	$ 38.44	$ 38.40	$ 39.03	$ 39.38	$ 39.12	$ 40.42	$ 41.49	$ 41.80	$ 42.43	$ 43.12	$ 43.81	$ 44.51	$ 45.21	$ 45.91	$ 46.60
E. KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		$ 42.66	$ 39.24	$ 37.00	$ 35.53	$ 35.12	$ 36.29	$ 36.67	$ 36.91	$ 36.55	$ 37.23	$ 38.35	$ 38.47	$ 38.75	$ 39.00	$ 39.07	$ 40.98	$ 41.54	$ 42.50	$ 42.93	$ 43.99	$ 44.88	$ 45.77	$ 46.65	$ 47.54	$ 48.43
ILLINOIS BASIN SELECTED COALS																														
INDIANA	COMPLIANCE	11,100	0.58	1.05		$ 67.24	$ 56.86	$ 47.91	$ 34.89	$ 33.11	$ 33.16	$ 33.70	$ 34.40	$ 33.54	$ 34.21	$ 33.86	$ 33.55	$ 34.21	$ 33.80	$ 33.87	$ 35.16	$ 35.73	$ 36.12	$ 36.07	$ 37.14	$ 37.75	$ 38.37	$ 38.98	$ 39.59	$ 40.20
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		$ 46.62	$ 38.96	$ 35.27	$ 32.10	$ 30.63	$ 31.23	$ 31.81	$ 31.98	$ 31.87	$ 32.16	$ 32.71	$ 32.20	$ 33.08	$ 32.61	$ 32.32	$ 33.35	$ 35.14	$ 35.91	$ 35.92	$ 37.47	$ 38.46	$ 39.45	$ 40.44	$ 41.44	$ 42.43
INDIANA	MID-SULFUR	11,000	1.70	3.09		$ 47.06	$ 39.63	$ 32.36	$ 32.09	$ 30.59	$ 31.52	$ 31.90	$ 32.39	$ 32.04	$ 32.26	$ 34.95	$ 35.15	$ 35.60	$ 36.25	$ 34.86	$ 34.75	$ 35.07	$ 34.55	$ 34.63	$ 34.78	$ 34.79	$ 34.79	$ 34.79	$ 34.79	$ 34.79
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		$ 39.08	$ 33.07	$ 28.58	$ 31.19	$ 29.67	$ 30.34	$ 30.93	$ 31.06	$ 30.92	$ 31.05	$ 31.01	$ 30.85	$ 31.50	$ 31.17	$ 31.10	$ 31.97	$ 32.29	$ 32.13	$ 32.44	$ 32.74	$ 33.06	$ 33.38	$ 33.70	$ 34.02	$ 34.34
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		$ 45.39	$ 38.10	$ 33.21	$ 32.57	$ 30.91	$ 31.58	$ 32.28	$ 33.04	$ 32.40	$ 33.24	$ 33.56	$ 33.48	$ 34.49	$ 34.06	$ 33.86	$ 35.07	$ 36.35	$ 36.23	$ 36.14	$ 36.91	$ 37.37	$ 37.83	$ 38.28	$ 38.74	$ 39.19
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		$ 45.53	$ 38.20	$ 32.71	$ 33.31	$ 31.72	$ 32.37	$ 32.98	$ 33.11	$ 32.85	$ 33.19	$ 33.61	$ 33.04	$ 33.64	$ 32.93	$ 32.73	$ 33.97	$ 34.88	$ 34.66	$ 54.63	$ 35.51	$ 35.96	$ 36.40	$ 36.85	$ 37.29	$ 37.73
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		$ 41.00	$ 35.54	$ 29.74	$ 31.14	$ 29.54	$ 30.14	$ 30.73	$ 30.76	$ 30.02	$ 30.27	$ 30.50	$ 29.88	$ 30.28	$ 29.60	$ 29.38	$ 30.39	$ 31.16	$ 30.92	$ 31.03	$ 31.91	$ 32.34	$ 32.77	$ 33.20	$ 33.63	$ 34.06
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		$ 46.95	$ 42.59	$ 40.96	$ 38.87	$ 35.20	$ 35.80	$ 36.51	$ 36.69	$ 36.19	$ 36.59	$ 36.70	$ 36.37	$ 36.67	$ 36.53	$ 36.41	$ 37.82	$ 38.09	$ 37.84	$ 37.63	$ 38.26	$ 38.52	$ 38.77	$ 39.02	$ 39.27	$ 39.53
W. KY	HIGH-SULFUR	11,600	3.19	5.50		$ 38.94	$ 29.84	$ 28.80	$ 31.57	$ 30.10	$ 30.72	$ 31.31	$ 31.29	$ 31.11	$ 31.01	$ 30.91	$ 30.63	$ 30.71	$ 30.61	$ 30.52	$ 31.32	$ 31.43	$ 31.19	$ 31.21	$ 31.61	$ 31.81	$ 32.01	$ 32.21	$ 32.41	$ 32.61
WYOMING POWDER RIVER BASIN																														
PRB-N GILLETTE	COMPLIANCE	8,350	0.44	1.05		$ 15.87	$ 13.45	$ 7.08	$ 5.75	$ 5.27	$ 5.23	$ 5.23	$ 5.21	$ 5.18	$ 5.18	$ 5.38	$ 5.51	$ 5.55	$ 6.51	$ 8.68	$ 10.87	$ 10.94	$ 10.92	$ 10.90	$ 12.04	$ 12.57	$ 13.11	$ 13.64	$ 14.17	$ 14.70
PRB-S.GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		$ 17.47	$ 14.66	$ 8.81	$ 6.14	$ 5.55	$ 5.53	$ 5.50	$ 5.48	$ 5.46	$ 5.44	$ 5.64	$ 5.77	$ 5.81	$ 6.79	$ 8.98	$ 11.16	$ 11.24	$ 11.23	$ 11.19	$ 12.36	$ 12.90	$ 13.43	$ 13.97	$ 14.50	$ 15.04
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,600	0.35	0.80		$ 19.55	$ 16.61	$ 10.42	$ 7.29	$ 6.69	$ 6.63	$ 6.61	$ 6.59	$ 6.54	$ 6.56	$ 6.78	$ 6.91	$ 6.93	$ 7.95	$ 10.24	$ 12.51	$ 12.61	$ 12.59	$ 12.55	$ 13.79	$ 14.36	$ 14.92	$ 15.49	$ 16.05	$ 16.62
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		$ 22.27	$ 19.23	$ 12.96	$ 8.16	$ 7.64	$ 7.43	$ 7.44	$ 7.53	$ 7.50	$ 7.77	$ 8.27	$ 8.37	$ 8.35	$ 8.86	$ 10.62	$ 12.78	$ 12.81	$ 12.76	$ 12.71	$ 13.86	$ 14.36	$ 14.87	$ 15.38	$ 15.88	$ 16.39
LATIN AMERICA																														
LATIN AMER-HI BTU	LATIN AMER-HI BTU	13,000	0.6	0.92		$ 52.40	$ 54.39	$ 53.25	$ 52.67	$ 52.59	$ 51.04	$ 49.27	$ 47.92	$ 48.23	$ 48.47	$ 48.71	$ 48.96	$ 49.20	$ 49.45	$ 49.70	$ 49.94	$ 50.19	$ 50.44	$ 50.70	$ 50.95	$ 51.20	$ 51.46	$ 51.72	$ 51.98	$ 52.24
LATIN AMER-MID BTU	LATIN AMER-MID BTU	12,000	1.17	1.95		$ 44.65	$ 48.79	$ 47.83	$ 47.38	$ 47.50	$ 46.77	$ 45.27	$ 45.35	$ 45.48	$ 45.70	$ 45.93	$ 46.16	$ 46.39	$ 46.62	$ 46.86	$ 47.09	$ 47.33	$ 47.56	$ 47.80	$ 48.04	$ 48.28	$ 48.52	$ 48.77	$ 49.01	$ 49.25
Pet Coke Expected Price																														
Pet Coke (Gulf Region)	Low Sulfur, High Grind	14,000	4.5	6.42		$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71	$ 23.71
Low Grind	Low Sulfur, Low Grind	14,000	4.5	6.42		$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35
Pet Coke (Gulf Region)	High Sulfur, High Grind	14,000	6.3	9.39		$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49	$ 18.49
Low Grind	High Sulfur, Low Grind	14,000	6.5	9.29		$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27	$ 17.27
Emission Offset Prices																														
SO2 Emission Offsets	in $/Ton					$ 1,311.19	$ 1,155.35	$ 397.97	$ 434.95	$ 162.97	$ 375.95	$ 426.81	$ 434.15	$ 548.57	$ 704.29	$ 765.00	$ 845.00	$ 865.00	$ 906.84	$ 1,053.22	$ 1,157.84	$ 1,173.27	$ 1,301.82	$ 1,207.00	$ 1,245.00	$ 1,282.00	$ 1,320.00	$ 1,357.00	$ 1,395.00	$ 1,433.00
NOx Emission Offsets	in $/Ton					$ 1,875.47	$ 1,803.67	$ 2,007.97	$ 2,148.70	$ 2,895.47	$ 2,939.77	$ 3,074.99	$ 3,206.36	$ 3,428.40	$ 5,865.71	$ 5,200.00	$ 5,300.00	$ 6,408.24	$ 6,566.03	$ 8,081.58	$ 9,146.77	$ 10,024.77	$ 8,994.89	$ 11,261.96	$ 12,101.77	$ 12,941.58	$ 13,781.38	$ 14,621.19	$ 15,460.99	$ 16,300.80
Mercury Emission Offsets	in $/pound					$ -	$ -	$ -	$ -	$ 15,254.59	$ 12,779.90	$ 12,635.73	$ 11,834.36	$ 10,262.83	$ 16,535.66	$ 15,304.42	$ 10,219.85	$ 19,621.46	$ 19,706.97	$ 18,933.93	$ 19,999.77	$ 21,416.80	$ 34,323.26	$ 38,750.00	$ 57,500.00	$ 61,525.00	$ 65,831.75	$ 70,439.97	$ 75,370.77	$ 80,646.72
CO2 Emission Offsets	in $/Ton					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Henry Hub Natural Gas Price																														
Natural Gas (Henry Hub) (PI	$/MMBtu					$ 10.82	$ 9.16	$ 8.64	$ 7.34	$ 6.43	$ 6.12	$ 6.24	$ 6.37	$ 6.49	$ 6.62	$ 6.76	$ 6.89	$ 7.03	$ 7.18	$ 7.31	$ 7.46	$ 7.61	$ 7.76	$ 7.93	$ 8.08	$ 8.23	$ 8.40	$ 8.57	$ 8.74	$ 8.92
Gulf Coast Oil Prices																														
Oil Price Forecast																														
GC #6 1%	$/Bbl					$ 54.38	$ 50.15	$ 48.31	$ 46.55	$ 44.44	$ 42.89	$ 42.60	$ 42.58	$ 42.58	$ 42.64	$ 43.06	$ 43.57	$ 44.09	$ 44.62	$ 45.13	$ 45.66	$ 46.18	$ 46.70	$ 47.23	$ 48.30	$ 48.30	$ 48.83	$ 49.37	$ 49.91	$ 50.44
GC #6 3%	$/Bbl					$ 44.78	$ 41.76	$ 40.38	$ 39.05	$ 37.40	$ 36.20	$ 35.98	$ 35.96	$ 35.96	$ 36.00	$ 36.34	$ 36.74	$ 37.15	$ 37.54	$ 37.94	$ 38.35	$ 38.75	$ 39.16	$ 39.56	$ 40.37	$ 40.37	$ 40.78	$ 41.17	$ 41.58	$ 41.98
GC #2 0.5%	$/Bbl					$ 87.97	$ 76.68	$ 72.90	$ 69.40	$ 65.38	$ 62.54	$ 61.99	$ 61.97	$ 61.97	$ 62.06	$ 62.86	$ 63.78	$ 64.74	$ 65.71	$ 66.67	$ 67.67	$ 68.68	$ 69.70	$ 70.74	$ 71.78	$ 72.85	$ 73.94	$ 75.05	$ 76.15	$ 77.28
GC #2 0.05%	$/Bbl					$ 89.56	$ 77.94	$ 74.05	$ 70.45	$ 66.30	$ 63.40	$ 62.83	$ 62.81	$ 62.81	$ 62.90	$ 63.71	$ 64.67	$ 65.64	$ 66.64	$ 67.65	$ 68.66	$ 69.71	$ 70.76	$ 71.82	$ 72.90	$ 74.00	$ 75.13	$ 76.26	$ 77.40	$ 78.56
GC #2 0.0015%	$/Bbl					$ 92.58	$ 82.96	$ 78.83	$ 75.23	$ 71.20	$ 69.48	$ 68.27	$ 67.66	$ 67.13	$ 66.77	$ 67.57	$ 68.53	$ 69.52	$ 70.50	$ 71.51	$ 72.54	$ 73.57	$ 74.63	$ 75.70	$ 76.76	$ 77.87	$ 79.00	$ 80.12	$ 81.28	$ 82.44

Docket No. ________
Taylor Energy Center
Matthew Preston
Exhibit ____ [MP-4]
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Low Fuel and Corresponding Emission Allowance Price Forecasts – Constant 2005 $/Ton, Unless Otherwise Specified

SUB-REGION	FLAVOR	MODELED QUALITY			Contract Signature Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
		Btu/lb.	% SULFUR	Lbs. SO2/ mmBtu	Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS																														
WEST. PA	MID-SULFUR	13,000	1.95	3.00		$ 53.51	$ 44.51	$ 37.74	$ 38.07	$ 36.77	$ 35.99	$ 35.64	$ 35.99	$ 35.68	$ 35.41	$ 36.24	$ 36.40	$ 38.22	$ 38.90	$ 38.78	$ 38.47	$ 38.37	$ 39.45	$ 39.21	$ 39.46	$ 39.27	$ 41.01	$ 41.41	$ 41.81	$ 42.21
WEST. PA	HIGH-SULFUR	12,200	3.34	5.48		$ 51.41	$ 44.33	$ 33.32	$ 34.04	$ 32.85	$ 31.71	$ 31.89	$ 32.24	$ 31.88	$ 31.78	$ 32.30	$ 32.60	$ 34.52	$ 35.32	$ 35.01	$ 34.66	$ 34.45	$ 35.57	$ 35.51	$ 35.79	$ 35.77	$ 36.15	$ 36.41	$ 36.68	$ 36.94
OHIO	MID-SULFUR	12,150	2.20	3.62		$ 46.61	$ 37.94	$ 32.62	$ 34.50	$ 34.33	$ 33.31	$ 33.15	$ 33.87	$ 33.67	$ 33.56	$ 34.23	$ 34.73	$ 37.96	$ 38.49	$ 38.26	$ 37.91	$ 37.53	$ 39.72	$ 39.54	$ 39.94	$ 39.41	$ 40.50	$ 40.91	$ 41.33	$ 41.75
OHIO	HIGH-SULFUR	11,750	3.60	6.13		$ 41.22	$ 34.01	$ 33.09	$ 32.71	$ 31.93	$ 31.04	$ 30.90	$ 31.42	$ 31.25	$ 31.05	$ 31.49	$ 31.86	$ 35.05	$ 35.90	$ 37.98	$ 37.90	$ 38.00	$ 39.40	$ 40.43	$ 40.40	$ 40.40	$ 41.46	$ 42.04	$ 42.62	$ 43.20
N. WV	MID-SULFUR	12,900	2.10	3.26		$ 54.68	$ 46.59	$ 39.22	$ 36.93	$ 35.78	$ 34.95	$ 34.71	$ 35.45	$ 35.92	$ 35.91	$ 36.25	$ 36.70	$ 38.41	$ 38.83	$ 38.46	$ 38.05	$ 37.69	$ 39.20	$ 39.03	$ 39.49	$ 39.00	$ 39.58	$ 39.84	$ 40.10	$ 40.35
N. WV	HIGH-SULFUR	12,350	3.60	5.83		$ 51.48	$ 43.27	$ 36.81	$ 36.23	$ 35.07	$ 34.35	$ 33.92	$ 34.23	$ 33.93	$ 33.65	$ 34.26	$ 34.30	$ 35.72	$ 36.36	$ 36.39	$ 36.19	$ 36.18	$ 36.52	$ 36.15	$ 36.21	$ 36.25	$ 36.13	$ 36.10	$ 36.07	$ 36.04
CENTRAL APPALACHIA REGION SELECTED COALS																														
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		$ 68.29	$ 58.16	$ 45.77	$ 40.12	$ 38.86	$ 38.87	$ 38.87	$ 39.53	$ 39.70	$ 40.22	$ 40.92	$ 41.33	$ 41.99	$ 41.54	$ 41.72	$ 41.50	$ 42.10	$ 42.72	$ 42.85	$ 43.05	$ 43.25	$ 43.36	$ 43.54	$ 43.72	$ 43.90
S. WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.99		$ 67.78	$ 59.93	$ 48.76	$ 40.24	$ 39.90	$ 39.89	$ 39.91	$ 40.39	$ 40.24	$ 40.14	$ 41.44	$ 40.12	$ 41.83	$ 41.33	$ 41.57	$ 42.83	$ 41.95	$ 43.73	$ 43.15	$ 44.07	$ 45.34	$ 45.53	$ 46.17	$ 46.81	$ 47.44
S. WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		$ 65.30	$ 56.99	$ 45.95	$ 35.81	$ 34.81	$ 34.42	$ 34.44	$ 35.00	$ 35.11	$ 35.66	$ 35.70	$ 36.05	$ 36.51	$ 36.39	$ 36.25	$ 36.12	$ 36.44	$ 37.20	$ 37.15	$ 37.07	$ 37.12	$ 37.16	$ 37.22	$ 37.29	$ 37.35
S. WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		$ 68.00	$ 55.55	$ 45.57	$ 37.07	$ 36.79	$ 36.35	$ 36.35	$ 36.92	$ 36.75	$ 36.72	$ 37.07	$ 37.07	$ 37.44	$ 37.29	$ 37.11	$ 37.19	$ 37.68	$ 38.43	$ 38.91	$ 38.85	$ 38.67	$ 39.03	$ 39.25	$ 39.47	$ 39.69
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		$ 57.45	$ 47.74	$ 41.85	$ 33.94	$ 32.93	$ 32.66	$ 32.67	$ 33.09	$ 33.20	$ 33.69	$ 34.09	$ 34.32	$ 35.11	$ 34.95	$ 34.81	$ 34.69	$ 34.91	$ 35.72	$ 35.67	$ 35.50	$ 35.49	$ 35.63	$ 35.70	$ 35.78	$ 35.87
S. WV-MID BTU-NS	NEAR-COMPLIANCE	12,250	0.98	1.60		$ 60.94	$ 50.35	$ 44.33	$ 34.53	$ 34.32	$ 34.74	$ 34.69	$ 34.63	$ 34.48	$ 34.84	$ 35.43	$ 35.48	$ 35.85	$ 35.67	$ 35.50	$ 35.59	$ 36.04	$ 36.76	$ 37.17	$ 37.08	$ 36.79	$ 37.13	$ 37.30	$ 37.46	$ 37.63
S. WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		$ 56.22	$ 47.92	$ 42.03	$ 35.09	$ 34.29	$ 34.73	$ 34.70	$ 34.55	$ 34.66	$ 35.18	$ 35.27	$ 35.41	$ 36.23	$ 35.99	$ 35.81	$ 35.78	$ 35.94	$ 36.62	$ 37.08	$ 36.84	$ 36.65	$ 36.99	$ 37.15	$ 37.31	$ 37.47
S. WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		$ 41.87	$ 38.78	$ 37.28	$ 37.28	$ 36.60	$ 37.57	$ 37.41	$ 37.25	$ 37.09	$ 37.02	$ 37.55	$ 37.77	$ 38.47	$ 38.21	$ 38.03	$ 38.17	$ 38.60	$ 39.39	$ 39.69	$ 39.74	$ 39.54	$ 39.99	$ 40.21	$ 40.42	$ 40.64
E. KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		$ 69.37	$ 60.30	$ 47.72	$ 40.30	$ 39.23	$ 39.29	$ 39.26	$ 39.82	$ 39.91	$ 40.56	$ 41.16	$ 40.99	$ 41.88	$ 41.52	$ 41.53	$ 41.60	$ 42.25	$ 42.89	$ 42.92	$ 43.17	$ 43.34	$ 43.46	$ 43.63	$ 43.79	$ 43.96
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		$ 51.66	$ 47.91	$ 50.92	$ 40.50	$ 40.29	$ 40.24	$ 40.26	$ 40.73	$ 40.56	$ 40.44	$ 41.23	$ 41.39	$ 42.01	$ 41.73	$ 41.66	$ 41.96	$ 42.54	$ 43.27	$ 43.72	$ 43.73	$ 43.86	$ 44.11	$ 44.38	$ 44.65	$ 44.91
E. KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		$ 63.87	$ 55.03	$ 44.48	$ 36.63	$ 35.60	$ 35.14	$ 35.06	$ 35.54	$ 35.69	$ 36.47	$ 36.71	$ 36.57	$ 37.01	$ 36.88	$ 36.95	$ 37.08	$ 37.62	$ 38.26	$ 38.21	$ 38.33	$ 38.32	$ 38.43	$ 38.52	$ 38.60	$ 38.69
E. KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		$ 64.81	$ 53.45	$ 44.42	$ 37.61	$ 37.20	$ 36.87	$ 36.84	$ 37.40	$ 37.23	$ 37.18	$ 37.52	$ 37.55	$ 37.91	$ 37.82	$ 37.64	$ 37.73	$ 38.23	$ 39.04	$ 39.47	$ 39.41	$ 39.35	$ 39.70	$ 39.94	$ 40.18	$ 40.42
E. KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		$ 56.12	$ 47.83	$ 40.05	$ 34.23	$ 33.81	$ 33.70	$ 33.87	$ 34.28	$ 34.40	$ 34.85	$ 35.12	$ 35.17	$ 35.93	$ 35.84	$ 35.65	$ 35.57	$ 35.80	$ 36.08	$ 36.03	$ 35.86	$ 36.13	$ 36.08	$ 36.11	$ 36.15	$ 36.19
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		$ 60.64	$ 50.09	$ 44.31	$ 34.57	$ 34.35	$ 34.86	$ 34.80	$ 34.74	$ 34.60	$ 34.94	$ 35.55	$ 35.58	$ 35.94	$ 35.81	$ 35.64	$ 35.72	$ 36.19	$ 36.91	$ 37.39	$ 37.33	$ 37.15	$ 37.51	$ 37.72	$ 37.94	$ 38.16
E. KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		$ 41.97	$ 38.67	$ 35.65	$ 34.80	$ 34.36	$ 34.22	$ 34.39	$ 34.79	$ 34.92	$ 35.37	$ 35.51	$ 35.57	$ 36.34	$ 36.22	$ 36.02	$ 35.98	$ 36.18	$ 36.49	$ 36.35	$ 36.08	$ 36.28	$ 36.17	$ 36.15	$ 36.12	$ 36.09
E. KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		$ 42.13	$ 38.72	$ 36.32	$ 34.48	$ 33.90	$ 34.28	$ 34.23	$ 34.20	$ 34.07	$ 34.43	$ 34.98	$ 35.35	$ 36.01	$ 35.87	$ 35.69	$ 35.81	$ 36.25	$ 37.01	$ 36.90	$ 37.16	$ 37.00	$ 37.33	$ 37.49	$ 37.66	$ 37.82
ILLINOIS BASIN SELECTED COALS																														
INDIANA	COMPLIANCE	11,100	0.58	1.05		$ 61.54	$ 52.13	$ 44.16	$ 32.12	$ 31.02	$ 30.01	$ 29.71	$ 30.50	$ 30.58	$ 30.86	$ 31.31	$ 30.63	$ 30.00	$ 30.46	$ 29.71	$ 29.29	$ 29.67	$ 30.03	$ 29.65	$ 29.52	$ 29.69	$ 29.66	$ 29.60	$ 29.53	$ 29.46
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		$ 45.84	$ 37.53	$ 32.88	$ 28.76	$ 27.51	$ 26.99	$ 26.85	$ 27.38	$ 27.20	$ 27.24	$ 27.81	$ 27.62	$ 28.26	$ 30.13	$ 30.02	$ 29.16	$ 29.12	$ 29.01	$ 29.13	$ 29.31	$ 29.18	$ 29.27	$ 29.31	$ 29.34	$ 29.38
INDIANA	MID-SULFUR	11,000	1.70	3.09		$ 44.16	$ 36.99	$ 31.28	$ 28.78	$ 27.73	$ 27.76	$ 27.64	$ 28.64	$ 27.82	$ 27.40	$ 27.87	$ 27.73	$ 28.62	$ 29.58	$ 29.39	$ 28.60	$ 28.47	$ 28.42	$ 28.44	$ 28.59	$ 28.37	$ 28.47	$ 28.47	$ 28.47	$ 28.46
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		$ 37.96	$ 32.25	$ 28.33	$ 28.21	$ 26.85	$ 26.67	$ 26.57	$ 26.84	$ 26.70	$ 26.29	$ 26.54	$ 26.50	$ 27.31	$ 28.02	$ 27.72	$ 27.35	$ 27.16	$ 27.14	$ 27.07	$ 26.94	$ 26.83	$ 26.70	$ 26.60	$ 26.50	$ 26.40
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		$ 45.60	$ 37.83	$ 33.08	$ 29.35	$ 28.03	$ 28.04	$ 27.81	$ 28.04	$ 28.21	$ 28.51	$ 28.67	$ 28.83	$ 29.88	$ 29.77	$ 29.35	$ 29.43	$ 29.48	$ 29.60	$ 29.58	$ 29.38	$ 29.74	$ 29.62	$ 29.65	$ 29.67	$ 29.70
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		$ 44.22	$ 36.39	$ 31.52	$ 29.82	$ 28.48	$ 27.96	$ 27.94	$ 28.33	$ 28.14	$ 28.12	$ 28.53	$ 28.29	$ 28.90	$ 28.79	$ 28.36	$ 28.25	$ 28.28	$ 28.40	$ 28.65	$ 28.44	$ 28.39	$ 28.56	$ 28.59	$ 28.62	$ 28.66
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		$ 39.00	$ 31.82	$ 28.91	$ 27.92	$ 26.69	$ 26.11	$ 26.16	$ 25.95	$ 25.67	$ 25.58	$ 25.78	$ 25.43	$ 25.84	$ 25.82	$ 25.37	$ 25.32	$ 25.33	$ 25.50	$ 25.84	$ 26.23	$ 25.61	$ 26.26	$ 26.42	$ 26.57	$ 26.73
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		$ 45.72	$ 40.84	$ 39.73	$ 35.47	$ 32.99	$ 32.91	$ 32.55	$ 32.81	$ 33.69	$ 33.34	$ 31.96	$ 31.47	$ 31.59	$ 31.98	$ 31.71	$ 31.13	$ 31.00	$ 31.07	$ 31.12	$ 30.89	$ 30.77	$ 30.78	$ 30.73	$ 30.68	$ 30.62
W. KY	HIGH-SULFUR	11,600	3.19	5.50		$ 37.72	$ 28.15	$ 27.76	$ 28.09	$ 27.08	$ 26.49	$ 26.91	$ 26.85	$ 26.75	$ 26.65	$ 26.55	$ 26.33	$ 26.35	$ 26.80	$ 26.49	$ 26.13	$ 25.95	$ 25.93	$ 25.83	$ 25.65	$ 25.48	$ 25.41	$ 25.29	$ 25.18	$ 25.06
WYOMING POWDER RIVER BASIN																														
PRB-N.GILLETTE	COMPLIANCE	8,350	0.44	1.05		$ 12.17	$ 6.73	$ 4.62	$ 4.91	$ 4.74	$ 4.40	$ 4.39	$ 4.46	$ 4.39	$ 4.43	$ 4.47	$ 4.45	$ 4.43	$ 4.42	$ 4.46	$ 5.10	$ 5.87	$ 5.89	$ 5.89	$ 5.58	$ 5.86	$ 5.62	$ 5.36	$ 5.51	$ 5.45
PRB-S.GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		$ 13.40	$ 12.00	$ 6.13	$ 5.57	$ 5.22	$ 4.83	$ 4.79	$ 4.77	$ 4.75	$ 4.73	$ 4.74	$ 4.69	$ 4.67	$ 4.65	$ 4.69	$ 5.30	$ 6.09	$ 6.11	$ 6.11	$ 5.80	$ 6.10	$ 5.85	$ 5.79	$ 5.73	$ 5.68
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,800	0.35	0.80		$ 15.05	$ 13.70	$ 7.50	$ 6.68	$ 6.29	$ 5.83	$ 5.79	$ 5.78	$ 5.73	$ 5.75	$ 5.80	$ 5.72	$ 5.71	$ 5.70	$ 5.74	$ 6.36	$ 7.26	$ 7.27	$ 7.25	$ 6.94	$ 7.22	$ 6.97	$ 6.91	$ 6.84	$ 6.78
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		$ 16.76	$ 11.14	$ 9.45	$ 7.48	$ 7.12	$ 6.50	$ 6.46	$ 6.55	$ 6.48	$ 6.68	$ 7.13	$ 7.16	$ 7.18	$ 7.02	$ 7.17	$ 7.71	$ 8.59	$ 8.46	$ 8.43	$ 7.86	$ 7.47	$ 7.13	$ 6.85	$ 6.57	$ 6.29
LATIN AMERICA																														
LATIN AMER-HI BTU	LATIN AMER-HI BTU	13,000	0.6	0.92		$ 49.91	$ 46.23	$ 46.03	$ 38.77	$ 37.26	$ 37.26	$ 38.66	$ 41.14	$ 42.24	$ 40.63	$ 40.13	$ 40.23	$ 37.60	$ 36.63	$ 36.24	$ 35.64	$ 35.24	$ 34.49	$ 33.60	$ 32.57	$ 32.57	$ 31.52	$ 30.79	$ 30.07	$ 29.34
LATIN AMER-MID BTU	LATIN AMER-MID BTU	12,000	1.17	1.95		$ 43.37	$ 41.05	$ 39.56	$ 33.82	$ 32.37	$ 32.54	$ 34.01	$ 36.38	$ 37.48	$ 35.65	$ 35.22	$ 33.83	$ 34.77	$ 33.88	$ 33.51	$ 32.95	$ 32.58	$ 31.89	$ 31.00	$ 30.11	$ 30.11	$ 29.14	$ 28.47	$ 27.80	$ 27.12
Pet Coke Expected Price																														
Pet Coke (Gulf Region)	Low Sulfur, High Grind	14,000	4.5	6.42		$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99	$ 16.99
Low Grind	Low Sulfur, Low Grind	14,000	4.5	6.42		$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63	$ 15.63
Pet Coke (Gulf Region)	High Sulfur, High Grind	14,000	6.5	9.29		$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41	$ 12.41
Low Grind	High Sulfur, Low Grind	14,000	6.5	9.29		$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91	$ 10.91
Emission Offset Prices																														
SO2 Emission Offsets	in $/Ton					$ 844.34	$ 886.00	$ 362.96	$ 378.71	$ 305.14	$ 303.19	$ 348.49	$ 340.29	$ 423.18	$ 604.72	$ 674.85	$ 756.93	$ 692.03	$ 737.40	$ 702.23	$ 747.98	$ 717.16	$ 774.52	$ 794.27	$ 844.41	$ 836.00	$ 857.00	$ 877.00	$ 898.00	$ 918.00
NOx Emission Offsets	in $/Ton					$ 1,811.41	$ 1,803.67	$ 1,795.94	$ 2,012.29	$ 2,662.47	$ 2,696.08	$ 2,847.29	$ 2,861.81	$ 2,940.53	$ 4,403.58	$ 2,832.18	$ 3,154.57	$ 4,034.40	$ 4,384.45	$ 4,442.50	$ 4,626.90	$ 4,766.22	$ 5,140.88	$ 5,299.06	$ 5,757.57	$ 5,731.01	$ 5,947.67	$ 6,164.33	$ 6,380.99	$ 6,597.65
Mercury Emission Offsets	in $/pound					$ -	$ -	$ -	$ -	$ 14,300.55	$ 13,918.44	$ 13,271.05	$ 14,876.41	$ 10,262.83	$ 16,454.30	$ 11,985.54	$ 10,063.78	$ 18,933.93	$ 18,259.91	$ 16,352.16	$ 19,217.25	$ 19,476.32	$ 30,319.43	$ 35,672.87	$ 50,634.85	$ 53,876.76	$ 56,570.60	$ 59,399.13	$ 62,369.08	$ 65,487.54
CO2 Emission Offsets	in $/Ton					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Henry Hub Natural Gas Price																														
Natural Gas (Henry Hub) (P!	$/MMBtu					$ 7.22	$ 6.10	$ 5.76	$ 4.90	$ 4.29	$ 4.08	$ 4.16	$ 4.25	$ 4.33	$ 4.42	$ 4.50	$ 4.59	$ 4.69	$ 4.78	$ 4.87	$ 4.98	$ 5.07	$ 5.18	$ 5.28	$ 5.38	$ 5.49	$ 5.60	$ 5.71	$ 5.82	$ 5.94
Gulf Coast Oil Prices																														
Oil Price Forecast																														
GC #6 1%	$/Bbl					$ 36.26	$ 33.43	$ 32.21	$ 31.03	$ 29.62	$ 28.59	$ 28.40	$ 28.38	$ 28.38	$ 28.42	$ 28.70	$ 29.05	$ 29.39	$ 29.74	$ 30.09	$ 30.44	$ 30.78	$ 31.14	$ 31.49	$ 32.20	$ 32.20	$ 32.55	$ 32.91	$ 33.27	$ 33.62
GC #6 3%	$/Bbl					$ 29.86	$ 27.84	$ 26.92	$ 26.03	$ 24.94	$ 24.14	$ 23.98	$ 23.98	$ 23.98	$ 24.00	$ 24.22	$ 24.50	$ 24.77	$ 25.02	$ 25.30	$ 25.57	$ 25.83	$ 26.10	$ 26.38	$ 26.91	$ 26.91	$ 27.18	$ 27.45	$ 27.72	$ 27.98
GC #2 0.5%	$/Bbl					$ 58.65	$ 51.12	$ 48.60	$ 46.26	$ 43.58	$ 41.70	$ 41.33	$ 41.31	$ 41.31	$ 41.38	$ 41.90	$ 42.52	$ 43.16	$ 43.80	$ 44.45	$ 45.12	$ 45.78	$ 46.46	$ 47.16	$ 47.86	$ 48.57	$ 49.30	$ 50.03	$ 50.77	$ 51.52
GC #2 0.05%	$/Bbl					$ 59.70	$ 51.96	$ 49.37	$ 46.97	$ 44.20	$ 42.26	$ 41.89	$ 41.87	$ 41.87	$ 41.94	$ 42.47	$ 43.11	$ 43.76	$ 44.42	$ 45.10	$ 45.78	$ 46.47	$ 47.18	$ 47.88	$ 48.60	$ 49.34	$ 50.09	$ 50.84	$ 51.60	$ 52.38
GC #2 0.0015%	$/Bbl					$ 61.72	$ 55.30	$ 52.55	$ 50.15	$ 47.46	$ 46.32	$ 45.51	$ 45.10	$ 44.75	$ 44.51	$ 45.05	$ 45.69	$ 46.34	$ 47.00	$ 47.67	$ 48.36	$ 49.05	$ 49.75	$ 50.46	$ 51.18	$ 51.91	$ 52.66	$ 53.42	$ 54.18	$ 54.96

Docket No. ________
Taylor Energy Center
Matthew Preston
Exhibit ___ [MP-5]
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Regulated-CO$_2$ Fuel and Corresponding Emission Allowance Price Forecasts – Constant 2005 $/Ton, Unless Otherwise Specified

SUB-REGION	FLAVOR	MODELED QUALITY Btu/lb	MODELED QUALITY % SULFUR	MODELED QUALITY Lbs. SO2/mmBtu	Contract Signature Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
					Contract Delivery Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NORTHERN APPALACHIA REGION SELECTED COALS																														
WEST PA	MID-SULFUR	13,000	1.95	3.00		$ 52.38	$ 44.52	$ 37.75	$ 38.27	$ 36.40	$ 36.38	$ 37.14	$ 37.43	$ 36.11	$ 34.02	$ 33.05	$ 32.79	$ 34.71	$ 35.27	$ 34.34	$ 35.42	$ 35.62	$ 35.80	$ 34.94	$ 32.07	$ 29.62	$ 30.12	$ 30.40	$ 30.68	$ 30.96
WEST PA	HIGH-SULFUR	12,200	3.34	5.48		$ 50.47	$ 44.33	$ 33.21	$ 34.32	$ 32.00	$ 32.19	$ 33.18	$ 33.29	$ 32.47	$ 30.87	$ 29.92	$ 29.71	$ 31.70	$ 32.05	$ 31.35	$ 32.14	$ 32.29	$ 32.33	$ 31.55	$ 28.69	$ 27.02	$ 27.44	$ 27.80	$ 28.16	$ 28.52
OHIO	MID-SULFUR	12,150	2.20	3.62		$ 45.58	$ 37.93	$ 32.50	$ 34.72	$ 33.10	$ 33.38	$ 33.82	$ 34.63	$ 33.60	$ 32.45	$ 32.09	$ 32.47	$ 35.79	$ 35.57	$ 35.22	$ 36.12	$ 36.20	$ 36.39	$ 36.24	$ 33.40	$ 30.74	$ 31.69	$ 32.23	$ 32.78	$ 33.32
OHIO	HIGH-SULFUR	11,750	3.60	6.13		$ 40.51	$ 33.79	$ 32.92	$ 32.88	$ 30.76	$ 31.15	$ 31.90	$ 32.30	$ 31.17	$ 29.62	$ 29.14	$ 29.68	$ 33.13	$ 32.56	$ 34.63	$ 34.69	$ 34.94	$ 35.12	$ 34.91	$ 31.49	$ 29.08	$ 29.83	$ 30.25	$ 30.66	$ 31.07
N. WV	MID-SULFUR	12,900	2.10	3.26		$ 54.17	$ 46.77	$ 39.15	$ 37.16	$ 36.01	$ 35.25	$ 36.08	$ 36.97	$ 36.28	$ 33.83	$ 33.16	$ 33.19	$ 35.10	$ 35.14	$ 34.51	$ 35.59	$ 35.62	$ 35.95	$ 35.08	$ 32.25	$ 29.81	$ 30.44	$ 30.74	$ 31.04	$ 31.34
N. WV	HIGH-SULFUR	12,350	3.60	5.83		$ 50.78	$ 43.07	$ 36.90	$ 36.41	$ 34.08	$ 34.50	$ 35.34	$ 35.39	$ 34.54	$ 33.75	$ 32.90	$ 32.37	$ 33.32	$ 33.37	$ 32.85	$ 33.92	$ 34.19	$ 33.90	$ 32.69	$ 29.53	$ 27.64	$ 27.80	$ 27.91	$ 28.03	$ 28.14
CENTRAL APPALACHIA REGION SELECTED COALS																														
S. WV-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.62	0.94		$ 71.96	$ 60.60	$ 46.62	$ 40.44	$ 37.24	$ 37.73	$ 38.07	$ 37.46	$ 38.23	$ 37.97	$ 37.15	$ 37.65	$ 38.93	$ 38.20	$ 38.51	$ 39.58	$ 39.26	$ 35.65	$ 36.00	$ 36.93	$ 34.51	$ 35.04	$ 35.42	$ 35.81	$ 36.19
S. WV-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.65	0.99		$ 70.93	$ 62.14	$ 49.59	$ 40.18	$ 37.34	$ 37.73	$ 38.66	$ 38.59	$ 38.53	$ 38.28	$ 38.79	$ 38.82	$ 39.09	$ 38.00	$ 38.27	$ 39.83	$ 40.06	$ 40.51	$ 39.18	$ 36.95	$ 34.74	$ 35.22	$ 35.55	$ 35.89	$ 36.23
S. WV-MID BTU-CSX	COMPLIANCE	12,200	0.67	1.10		$ 67.17	$ 58.63	$ 46.69	$ 36.04	$ 33.05	$ 33.14	$ 33.65	$ 33.48	$ 33.69	$ 34.31	$ 33.23	$ 33.31	$ 34.14	$ 33.70	$ 33.85	$ 34.90	$ 34.74	$ 34.84	$ 34.24	$ 31.86	$ 29.77	$ 30.18	$ 30.41	$ 30.65	$ 30.88
S. WV-MID BTU-NS	COMPLIANCE	12,350	0.67	1.09		$ 68.17	$ 57.25	$ 46.33	$ 37.00	$ 34.40	$ 34.21	$ 35.14	$ 35.01	$ 34.96	$ 34.95	$ 34.86	$ 34.66	$ 34.97	$ 34.38	$ 34.23	$ 35.72	$ 36.23	$ 37.04	$ 36.12	$ 33.88	$ 31.70	$ 32.42	$ 32.84	$ 33.26	$ 33.69
S. WV-MID BTU-CSX	NEAR-COMPLIANCE	12,200	0.82	1.34		$ 58.69	$ 48.69	$ 42.38	$ 34.14	$ 31.44	$ 31.47	$ 31.88	$ 31.80	$ 31.99	$ 32.27	$ 31.98	$ 31.96	$ 32.49	$ 32.02	$ 31.90	$ 32.94	$ 32.82	$ 33.53	$ 32.42	$ 30.00	$ 28.06	$ 28.46	$ 28.66	$ 28.87	$ 29.07
S. WV-MID BTU-NS	NEAR-COMPLIANCE	12,250	0.98	1.60		$ 61.55	$ 50.68	$ 44.46	$ 34.74	$ 32.30	$ 32.64	$ 33.33	$ 33.49	$ 33.42	$ 33.27	$ 33.33	$ 33.18	$ 33.47	$ 32.89	$ 32.74	$ 34.15	$ 34.24	$ 35.03	$ 34.11	$ 31.98	$ 29.89	$ 30.57	$ 30.94	$ 31.30	$ 31.67
S. WV-MID BTU-CSX	MID-SULFUR	12,500	1.67	2.67		$ 56.21	$ 47.92	$ 42.03	$ 35.14	$ 33.30	$ 33.11	$ 32.90	$ 32.99	$ 33.27	$ 33.58	$ 33.03	$ 33.00	$ 33.59	$ 33.01	$ 32.32	$ 33.61	$ 33.66	$ 34.50	$ 34.09	$ 31.31	$ 29.21	$ 29.90	$ 30.27	$ 30.64	$ 31.00
S. WV-MID BTU-NS	MID-SULFUR	12,800	1.67	2.61		$ 41.87	$ 38.96	$ 37.39	$ 37.27	$ 34.45	$ 35.19	$ 35.39	$ 35.60	$ 35.48	$ 35.38	$ 35.40	$ 35.36	$ 35.90	$ 35.76	$ 35.45	$ 36.45	$ 36.63	$ 37.69	$ 38.46	$ 38.58	$ 38.48	$ 39.35	$ 39.81	$ 40.27	$ 40.73
E. KY-HI BTU-NS	SUPER-COMPLIANCE	13,100	0.57	0.87		$ 72.50	$ 62.53	$ 48.56	$ 40.53	$ 37.62	$ 38.07	$ 38.31	$ 37.88	$ 38.13	$ 38.09	$ 37.16	$ 37.45	$ 38.35	$ 37.65	$ 37.04	$ 38.80	$ 38.50	$ 39.09	$ 38.63	$ 36.37	$ 33.85	$ 34.41	$ 34.77	$ 35.13	$ 35.49
E. KY-HI BTU-CSX	SUPER-COMPLIANCE	13,150	0.65	0.99		$ 55.64	$ 50.66	$ 51.80	$ 40.43	$ 37.60	$ 37.94	$ 38.98	$ 38.85	$ 38.55	$ 38.27	$ 38.51	$ 38.53	$ 39.13	$ 38.33	$ 38.19	$ 39.76	$ 39.95	$ 40.45	$ 39.21	$ 37.14	$ 34.82	$ 35.30	$ 35.63	$ 35.97	$ 36.30
E. KY-MID BTU-NS	COMPLIANCE	12,700	0.67	1.06		$ 65.51	$ 56.64	$ 45.23	$ 36.84	$ 33.97	$ 33.98	$ 34.18	$ 33.80	$ 34.09	$ 34.34	$ 33.32	$ 33.40	$ 33.79	$ 33.53	$ 33.06	$ 34.50	$ 34.36	$ 34.76	$ 34.45	$ 32.16	$ 29.70	$ 30.39	$ 30.60	$ 30.90	$ 31.21
E. KY-MID BTU-CSX	COMPLIANCE	12,500	0.69	1.10		$ 67.41	$ 55.27	$ 45.19	$ 37.54	$ 34.80	$ 34.78	$ 35.65	$ 35.58	$ 35.42	$ 35.48	$ 35.32	$ 35.16	$ 35.40	$ 34.81	$ 34.34	$ 36.09	$ 36.30	$ 37.35	$ 38.11	$ 38.29	$ 38.39	$ 39.22	$ 39.74	$ 40.25	$ 40.76
E. KY-MID BTU-NS	NEAR-COMPLIANCE	12,300	1.00	1.63		$ 56.40	$ 47.72	$ 40.09	$ 34.25	$ 32.69	$ 32.81	$ 32.96	$ 32.87	$ 32.88	$ 33.03	$ 32.85	$ 32.73	$ 33.09	$ 32.58	$ 32.25	$ 32.94	$ 33.33	$ 33.53	$ 32.82	$ 30.49	$ 28.60	$ 29.14	$ 29.42	$ 29.70	$ 29.99
E. KY-MID BTU-CSX	NEAR-COMPLIANCE	12,600	1.12	1.78		$ 61.19	$ 50.35	$ 44.46	$ 34.76	$ 32.34	$ 32.86	$ 33.45	$ 33.70	$ 33.53	$ 33.38	$ 33.44	$ 33.26	$ 33.55	$ 33.01	$ 32.86	$ 34.28	$ 34.36	$ 35.16	$ 35.01	$ 33.99	$ 33.61	$ 34.39	$ 34.84	$ 35.30	$ 35.75
E. KY-MID BTU-NS	MID-SULFUR	12,100	1.74	2.88		$ 42.13	$ 38.60	$ 35.65	$ 34.82	$ 33.33	$ 33.31	$ 33.68	$ 33.39	$ 33.37	$ 33.55	$ 33.25	$ 33.14	$ 33.47	$ 32.96	$ 32.67	$ 33.17	$ 33.61	$ 33.80	$ 33.09	$ 30.66	$ 28.67	$ 29.17	$ 29.44	$ 29.71	$ 29.98
E. KY-MID BTU-CSX	MID-SULFUR	12,300	1.75	2.85		$ 42.12	$ 38.86	$ 36.42	$ 34.46	$ 31.88	$ 32.18	$ 32.90	$ 33.06	$ 33.01	$ 32.84	$ 33.12	$ 33.03	$ 33.55	$ 33.08	$ 32.69	$ 34.17	$ 34.29	$ 35.09	$ 33.84	$ 31.82	$ 29.77	$ 30.37	$ 30.69	$ 31.01	$ 31.34
ILLINOIS BASIN SELECTED COALS																														
INDIANA	COMPLIANCE	11,100	0.58	1.05		$ 63.98	$ 54.20	$ 44.90	$ 32.24	$ 29.90	$ 30.05	$ 28.61	$ 29.24	$ 29.74	$ 29.32	$ 28.77	$ 29.04	$ 29.35	$ 28.96	$ 28.03	$ 28.30	$ 28.06	$ 27.96	$ 27.05	$ 24.29	$ 21.94	$ 22.19	$ 22.21	$ 22.23	$ 22.25
INDIANA	NEAR-COMPLIANCE	10,950	1.10	2.01		$ 46.18	$ 37.32	$ 32.93	$ 28.82	$ 26.31	$ 26.71	$ 26.83	$ 26.74	$ 26.48	$ 26.19	$ 25.80	$ 25.37	$ 26.00	$ 27.03	$ 26.59	$ 26.72	$ 26.28	$ 26.54	$ 26.00	$ 23.08	$ 21.15	$ 21.43	$ 21.45	$ 21.47	$ 21.48
INDIANA	MID-SULFUR	11,000	1.70	3.09		$ 44.69	$ 37.49	$ 31.38	$ 28.82	$ 26.41	$ 27.59	$ 28.40	$ 28.09	$ 27.28	$ 26.66	$ 26.58	$ 26.67	$ 26.30	$ 26.72	$ 26.61	$ 26.61	$ 26.13	$ 26.05	$ 25.21	$ 22.90	$ 21.19	$ 21.50	$ 21.62	$ 21.74	$ 21.87
INDIANA	HIGH-SULFUR	11,100	3.05	5.50		$ 37.72	$ 32.21	$ 28.33	$ 28.21	$ 26.32	$ 27.12	$ 27.06	$ 26.95	$ 26.69	$ 25.78	$ 25.14	$ 24.91	$ 25.13	$ 25.20	$ 24.69	$ 25.14	$ 24.94	$ 24.86	$ 23.99	$ 21.50	$ 19.90	$ 20.14	$ 20.23	$ 20.31	$ 20.39
ILLINOIS	NEAR-COMPLIANCE	11,800	1.30	2.20		$ 45.51	$ 37.97	$ 33.40	$ 29.36	$ 26.44	$ 27.71	$ 27.66	$ 27.61	$ 27.68	$ 27.10	$ 26.87	$ 26.53	$ 27.42	$ 27.03	$ 26.34	$ 27.00	$ 27.11	$ 27.43	$ 26.49	$ 24.16	$ 22.26	$ 22.66	$ 22.85	$ 23.04	$ 23.23
ILLINOIS	MID-SULFUR	11,550	1.70	2.94		$ 44.47	$ 36.82	$ 31.64	$ 29.97	$ 27.00	$ 27.97	$ 28.03	$ 28.04	$ 27.96	$ 26.99	$ 26.72	$ 26.26	$ 26.49	$ 26.22	$ 25.56	$ 25.92	$ 25.96	$ 26.23	$ 25.49	$ 23.07	$ 21.40	$ 21.79	$ 21.98	$ 22.17	$ 22.36
ILLINOIS	HIGH-SULFUR	11,150	3.00	5.38		$ 40.00	$ 32.34	$ 28.91	$ 27.93	$ 25.93	$ 25.83	$ 25.76	$ 25.44	$ 24.93	$ 24.45	$ 23.69	$ 23.12	$ 23.23	$ 23.16	$ 22.29	$ 22.91	$ 22.75	$ 23.19	$ 22.58	$ 20.93	$ 18.93	$ 19.56	$ 19.81	$ 20.07	$ 20.32
W. KY	NEAR-COMPLIANCE	11,900	0.98	1.65		$ 46.30	$ 41.64	$ 40.00	$ 35.45	$ 30.17	$ 31.30	$ 32.50	$ 31.39	$ 30.88	$ 31.69	$ 30.70	$ 29.23	$ 29.03	$ 29.12	$ 28.68	$ 29.28	$ 28.96	$ 29.11	$ 28.31	$ 28.44	$ 28.14	$ 28.64	$ 28.80	$ 28.96	$ 29.12
W. KY	HIGH-SULFUR	11,600	3.19	5.50		$ 37.46	$ 28.67	$ 27.76	$ 28.10	$ 26.48	$ 26.82	$ 27.44	$ 26.91	$ 26.57	$ 25.98	$ 24.97	$ 24.60	$ 24.19	$ 23.99	$ 23.27	$ 23.85	$ 23.45	$ 23.51	$ 22.61	$ 20.23	$ 18.63	$ 18.85	$ 18.91	$ 18.97	$ 19.02
WYOMING POWDER RIVER BASIN																														
PRB-N GILLETTE	COMPLIANCE	8,350	0.44	1.05		$ 13.68	$ 11.92	$ 5.36	$ 4.92	$ 4.23	$ 3.76	$ 3.98	$ 4.07	$ 3.85	$ 3.88	$ 3.97	$ 3.83	$ 4.02	$ 3.83	$ 3.80	$ 4.90	$ 4.94	$ 6.50	$ 6.48	$ 6.59	$ 6.45	$ 7.12	$ 7.44	$ 7.75	$ 8.06
PRB-S GILLETTE	SUPER-COMPLIANCE	8,400	0.36	0.85		$ 15.12	$ 13.10	$ 6.75	$ 5.57	$ 4.53	$ 4.20	$ 4.40	$ 4.35	$ 4.19	$ 4.32	$ 4.65	$ 4.53	$ 4.66	$ 4.01	$ 3.99	$ 5.12	$ 5.14	$ 6.68	$ 6.67	$ 6.80	$ 6.65	$ 7.32	$ 7.64	$ 7.95	$ 8.27
PRB-N.WRIGHT	SUPER-COMPLIANCE	8,800	0.35	0.80		$ 16.98	$ 14.90	$ 8.17	$ 6.69	$ 5.51	$ 5.09	$ 5.34	$ 5.26	$ 5.11	$ 5.15	$ 5.30	$ 5.16	$ 5.33	$ 4.81	$ 4.79	$ 5.96	$ 5.99	$ 7.61	$ 7.61	$ 7.73	$ 7.57	$ 8.28	$ 8.61	$ 8.93	$ 9.26
PRB-S.WRIGHT	ULTRA-COMPLIANCE	8,800	0.24	0.55		$ 19.12	$ 17.23	$ 10.36	$ 7.50	$ 6.14	$ 5.69	$ 5.97	$ 5.84	$ 5.79	$ 5.75	$ 6.06	$ 5.98	$ 6.29	$ 5.62	$ 5.77	$ 6.29	$ 6.27	$ 7.78	$ 7.73	$ 7.86	$ 7.68	$ 8.33	$ 8.63	$ 8.92	$ 9.21
LATIN AMERICA																														
LATIN AMER-HI BTU	LATIN AMER-HI BTU	13,000	0.6	0.92		$ 50.74	$ 53.32	$ 52.52	$ 52.15	$ 47.62	$ 47.45	$ 45.42	$ 42.62	$ 43.66	$ 41.64	$ 38.51	$ 36.86	$ 34.29	$ 32.97	$ 31.84	$ 31.80	$ 31.58	$ 30.18	$ 28.34	$ 25.12	$ 22.81	$ 22.08	$ 21.58	$ 21.08	$ 20.58
LATIN AMER-MID BTU	LATIN AMER-MID BTU	12,000	1.17	1.95		$ 43.75	$ 48.17	$ 47.45	$ 47.12	$ 43.20	$ 43.70	$ 41.78	$ 39.22	$ 40.26	$ 38.69	$ 35.48	$ 33.80	$ 31.28	$ 30.09	$ 29.25	$ 28.89	$ 28.47	$ 27.16	$ 25.47	$ 22.48	$ 20.47	$ 19.82	$ 19.37	$ 18.92	$ 18.47
Pet Coke Expected Price																														
Pet Coke (Gulf Region)	Low Sulfur, High Grind	14,000	4.5	6.42		$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35	$ 20.35
Low Grind	Low Sulfur, Low Grind	14,000	4.5	6.42		$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99	$ 18.99
Pet Coke (Gulf Region)	High Sulfur, High Grind	14,000	6.5	9.29		$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45	$ 15.45
Low Grind	High Sulfur, Low Grind	14,000	6.5	9.29		$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09	$ 14.09
Emission Offset Prices																														
SO2 Emission Offsets	in $/Ton					$ 1,058.47	$ 950.01	$ 372.41	$ 209.04	$ 266.59	$ 278.25	$ 218.99	$ 298.72	$ 280.24	$ 339.72	$ 394.48	$ 424.13	$ 433.50	$ 429.78	$ 476.88	$ 488.36	$ 544.31	$ 575.03	$ 642.86	$ 632.23	$ 627.30	$ 647.13	$ 666.96	$ 686.78	$ 706.61
NOx Emission Offsets	in $/Ton					$ 1,828.61	$ 1,803.67	$ 1,795.94	$ 1,663.37	$ 2,075.45	$ 2,118.06	$ 1,798.31	$ 1,795.93	$ 1,550.81	$ 3,361.38	$ 3,453.89	$ 3,678.04	$ 3,102.56	$ 3,106.27	$ 3,432.12	$ 3,047.20	$ 2,966.52	$ 3,292.33	$ 6,108.11	$ 6,327.64	$ 6,674.94	$ 7,022.25	$ 7,369.55	$ 7,716.85	$ 8,064.16
Mercury Emission Offsets	in $/pound					$ -	$ -	$ -	$ -	$ 13,212.32	$ 13,913.39	$ 9,971.26	$ 13,819.32	$ 8,293.66	$ 13,437.76	$ 8,744.48	$ 8,577.09	$ 17,364.08	$ 16,896.40	$ 16,424.62	$ 16,627.97	$ 16,440.74	$ 21,707.17	$ 19,685.33	$ 36,158.38	$ 38,770.98	$ 41,383.59	$ 43,996.19	$ 46,608.79	$ 49,221.39
CO2 Emission Offsets	in $/Ton					$ -	$ -	$ -	$ -	$ -	$ -	$ 4.22	$ 8.45	$ 10.85	$ 10.01	$ 10.28	$ 8.89	$ 2.43	$ 3.46	$ 2.56	$ 2.97	$ 6.26	$ 7.92	$ 6.14	$ 6.94	$ 7.24	$ 7.81	$ 8.38	$ 8.95	$ 9.52
Henry Hub Natural Gas Price																														
Natural Gas (Henry Hub) [P]	$/MMBtu					$ 9.02	$ 7.63	$ 7.20	$ 6.12	$ 5.36	$ 5.10	$ 5.20	$ 5.31	$ 5.41	$ 5.52	$ 5.63	$ 5.74	$ 5.86	$ 5.98	$ 6.09	$ 6.22	$ 6.34	$ 6.47	$ 6.60	$ 6.73	$ 6.86	$ 7.00	$ 7.14	$ 7.28	$ 7.43
Gulf Coast Oil Prices																														
Oil Price Forecast																														
GC #6 1%	$/Bbl					$ 45.32	$ 41.79	$ 40.26	$ 38.79	$ 37.03	$ 35.74	$ 35.50	$ 35.48	$ 35.48	$ 35.53	$ 35.88	$ 36.31	$ 36.74	$ 37.18	$ 37.61	$ 38.05	$ 38.48	$ 38.92	$ 39.36	$ 40.25	$ 40.25	$ 40.69	$ 41.14	$ 41.59	$ 42.03
GC #6 3%	$/Bbl					$ 37.32	$ 34.80	$ 33.65	$ 32.54	$ 31.17	$ 30.17	$ 29.98	$ 29.97	$ 29.97	$ 30.00	$ 30.28	$ 30.62	$ 30.96	$ 31.28	$ 31.62	$ 31.96	$ 32.29	$ 32.63	$ 32.97	$ 33.64	$ 33.64	$ 33.98	$ 34.31	$ 34.65	$ 34.98
GC #2 0.5%	$/Bbl					$ 73.31	$ 63.90	$ 60.75	$ 57.83	$ 54.48	$ 52.12	$ 51.66	$ 51.64	$ 51.64	$ 51.72	$ 52.38	$ 53.15	$ 53.95	$ 54.76	$ 55.56	$ 56.40	$ 57.23	$ 58.08	$ 58.95	$ 59.82	$ 60.71	$ 61.62	$ 62.54	$ 63.46	$ 64.40
GC #2 0.05%	$/Bbl					$ 74.63	$ 64.95	$ 61.71	$ 58.71	$ 55.25	$ 52.83	$ 52.36	$ 52.34	$ 52.34	$ 52.42	$ 53.09	$ 53.89	$ 54.70	$ 55.53	$ 56.38	$ 57.22	$ 58.09	$ 58.97	$ 59.85	$ 60.75	$ 61.67	$ 62.61	$ 63.55	$ 64.50	$ 65.47
GC #2 0.0015%	$/Bbl					$ 77.15	$ 69.13	$ 65.69	$ 62.69	$ 59.33	$ 57.90	$ 56.89	$ 56.38	$ 55.94	$ 55.64	$ 56.31	$ 57.11	$ 57.93	$ 58.75	$ 59.59	$ 60.45	$ 61.31	$ 62.19	$ 53.08	$ 63.97	$ 64.89	$ 65.83	$ 66.77	$ 67.73	$ 68.70

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MYRON R. ROLLINS

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 Myron R. Rollins. 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 Project Manager.

Q. Please describe your responsibilities in that position.

A. As a project manager, I am responsible for the management of various projects for utility and nonutility clients. These projects encompass a wide variety of services for the power industry. The services include load forecasts, conservation and demand-side management, reliability criteria and evaluation, development of generating unit addition alternatives, fuel forecasts, screening evaluations, production cost simulations, optimal generation expansion modeling, economic and financial evaluation, sensitivity analysis, risk analysis, power purchase and sales evaluation, strategic considerations, analyses of the effects of environmental regulations, feasibility studies, qualifying facility and independent power producer evaluations, power market studies, and power plant financing.

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 Electrical Engineering from the University of Missouri – Columbia. I also have two years of graduate study in Nuclear Engineering at the University of Missouri – Columbia. I am a licensed professional engineer and a Senior Member of the Institute of Electrical and Electronic Engineers.

I have over thirty years of experience in the power industry specializing in generation planning and project development. In the past ten years, I have been the project manager for over 100 projects, the vast majority of which are for Florida utilities. Florida utilities for which I have worked include Lakeland – Electric, Kissimmee Utility Authority, Florida Municipal Power Agency (FMPA), Orlando Utilities Commission (OUC), JEA, City of Tallahassee (City), Reedy Creek Improvement District (RCID), City of St. Cloud, Utilities Commission of New Smyrna Beach, Sebring Utilities Commission, City of Homestead, Florida Power Corporation, and Seminole Electric Cooperative.

I was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and POWROPT optimal generation expansion program. I am also responsible for power market analysis and project feasibility studies. I have been responsible for supporting need for power petitions on a number of power plants in Florida including Stanton 1, 2, A, and B; Cedar Bay; Cane Island 3; McIntosh 5; Treasure Coast Unit 1; and the Brandy Branch Combined Cycle Conversion. I also participated in the need for power proceeding for the Hardee and Hines projects. I have presented expert testimony on several occasions before the Alaska, Indiana, Missouri, and Florida public service commissions and have presented numerous papers on strategic planning and cogeneration.

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 Taylor Energy Center (TEC) Need for Power Application, Exhibit __ [TEC-1]. In addition to this general summary, I will discuss the economic parameters used to evaluate alternatives available to meet the capacity needs of FMPA, JEA, RCID, and the City of Tallahassee (collectively referred to as the Participants). I will also discuss the environmental considerations included in the analysis of TEC. I will describe the screening analyses for all supply-side alternatives. I will analyze TEC's consistency with Peninsular Florida's capacity and reliability needs. I will conclude my testimony by discussing the consequences of delaying the addition of TEC for each of the Participants.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit __ [MRR-1] is a copy of my résumé.

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.1.0, A.2.0, A.4.1, A.4.2, A.4.3, A.4.4, A.4.5, A.5.1, A.5.2, A.5.3, A.5.4, A.5.6, A.6.6, A.10.0, B.9.0, C.9.0, D.9.0, and E.9.0, all of which were prepared by me or under my direct supervision.

Q. Please summarize the Taylor Energy Center Need for Power Application, Exhibit __ [TEC-1].

A. The TEC Need for Power Application, Exhibit TEC-1 is submitted in support of the Site Certification Application (SCA) by the Participants for the construction of the Taylor Energy Center in accordance with the Florida Electrical Power Plant Siting Act. TEC is proposed to be a 765 MW (net) supercritical power plant that will be designed to burn a blend of pulverized coal and petroleum coke (petcoke), with commercial operation planned for May 1, 2012. TEC is proposed to be developed on a site consisting of approximately 3,000 acres located approximately 5 miles southeast of Perry, in Taylor County, Florida.

The determination of need for TEC is being sought under Section 403.519 of the Florida Statutes. The joint Taylor Energy Center Need for Power Application, Exhibit __ [TEC-1], is based upon the collective needs of the Participants. The proposed ownership percentages of TEC are as follows:

- FMPA – 38.9 percent.
- JEA – 31.5 percent.
- RCID – 9.3 percent.
- City of Tallahassee – 20.3 percent.

The Participants went through a multistage evaluation process to develop the most cost-effective generation expansion plan that would meet the corresponding need for capacity for each Participant. The first step involved developing detailed cost and performance estimates for TEC.

The second step involved the development of cost and performance estimates for numerous supply-side alternatives to TEC. Supply-side alternatives were developed in the following categories: renewable technologies, conventional technologies, advanced technologies, energy storage technologies, distributed generation, and emerging technologies. Supply-side alternatives included units that are specific to each Participant, using available existing sites as well as other joint ownership alternatives.

All supply-side alternatives were screened for economics, feasibility, and reliability for use in each Participant's system. The screening process resulted in a wide range of alternatives being selected for further detailed economic evaluations and sensitivity analyses, including simple cycle combustion turbines, combined cycle, pulverized coal (including participation in TEC), circulating fluidized bed (CFB), biomass, and integrated gasification combined cycle (IGCC).

The third step in the evaluation process to determine the most cost-effective expansion plan for each Participant involved conducting a Request for Proposal (RFP) process for purchase power in lieu of participation in TEC. The RFP requested purchase power bids from 100 to 750 MW for contract terms of 10 years or more. The Participants received two bids from one bidder. Both bids were substantially higher in cost than TEC. The RFP process is described in the testimony of Paul Arsuaga.

The fourth step in the evaluation process was to conduct a detailed system evaluation of self-build and purchase power alternatives. Economic assumptions and fuel price forecasts were developed for base case and sensitivity analyses. A chronological optimal generation expansion model was used to determine the least-cost expansion plans for the self-build and purchase power alternatives. The evaluation was conducted over a 30 year planning period from 2006 through 2035. The least-cost expansion plans for each Participant determined by the optimal generation expansion model were modeled using a detailed chronological production cost model to obtain annual production costs. Fixed costs, including fixed charges on new unit additions, purchased power capacity costs, fixed operating and maintenance (O&M) costs for new unit additions, and natural gas transportation charges for firm delivery of natural gas (for any new combined cycle alternatives), were considered in the detailed system analyses described in the testimony of Bradley Kushner. In addition, environmental considerations were factored into the analyses, including the forecast cost of emissions allowances for current and potential future regulatory requirements. Conservation and demand-side management (DSM) measures were evaluated, and cost-effective conservation and DSM measures were included in the analyses. The cumulative present worth costs (CPWC) of all of these annual costs were determined and used as the basis to compare expansion plans.

The analyses performed indicate that participation in TEC represents the least-cost capacity expansion plan for each Participant when compared to the most economical alternate self-build capacity expansion plans under base case assumptions and most of the sensitivity assumptions.

Q. Please describe the economic parameters used in the Taylor Energy Center Need for Power Application, Exhibit __ [TEC-1].

A. A 2.5 percent annual general inflation rate was used. Escalation rates of 2.5 percent annually were used for capital and O&M costs. An annual rate of 5.0 percent was used for the long-term tax-exempt bond rate, interest during construction rate, and present worth discount rate. Alternatives were evaluated over a 30 year planning period from 2006 through 2035.

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year.

Simple cycle combustion turbines were assumed to have a 20 year financing term, while natural gas fired combined cycle units were assumed to be financed over 25 years. Solid fuel generating unit alternatives were assumed to have a 30 year financing term. Given the various financing terms, different levelized FCRs were developed for the alternatives considered. All levelized FCR calculations used the 5.0 percent tax exempt municipal bond interest rate, a

2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an interest rate equal to the bond interest rate of 5.0 percent. The resulting 20 year FCR (for simple cycle combustion turbine options) is 8.972 percent, the 25 year FCR (for combined cycle options) is 7.915 percent, and the 30 year FCR (for solid fuel options) is 7.254 percent.

Q. Why are different financing terms used for the different generating technologies when calculating the FCR?

A. The financing terms used in this analysis correspond to typical financing terms available from underwriters that issue municipal bonds. Thus, bonds issued to finance simple cycle combustion turbine units typically have shorter financing terms than those issued to finance solid fuel generating facilities. The use of a 30 year financing term for TEC is conservative given that TEC's expected actual service life is 35 to 50 years or more.

Q. Please describe how the 2.5 percent annual general inflation rate was established.

A. The 10 year historical inflation rate was reviewed when the analysis of TEC was begun, and found to average approximately 2.5 percent annually over that period.

Q. In your opinion, are these economic parameters appropriate for use in this Need for Power Application?

A. Yes. They are consistent with economic parameters that we have been using in similar evaluations before the Commission and more importantly, they are internally consistent across all the evaluations.

Q. Please describe the pending environmental regulations considered in the Taylor Energy Center Need for Power Application, Exhibit __ [TEC-1].

A. There were two pending environmental regulatory programs considered. These programs are the Environmental Protection Agency (EPA's) Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), both finalized in 2005. CAIR and CAMR are regulatory programs designed to reduce emissions in 28 states (including Florida) and the entire US, respectively. The former will reduce nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions, while the latter will reduce mercury (Hg) emissions. Both programs are structured to reduce emissions by imposing statewide limits or caps on the amount of pollutants that can be emitted in tons per year. It is up to each affected state to develop a method for meeting these caps, which is subject to the EPA's approval. The programs will be implemented in phases with the first phase for NO_x emission reductions under CAIR starting in 2009. The first phase for SO_2 emission reductions under CAIR and Hg emission reductions under CAMR will begin in 2010. The second phase for NO_x and SO_2 emission reductions under CAIR will start in 2015, and the second phase for Hg emission reductions under CAMR will start in 2018.

Q. Does the EPA provide any model or suggested means of meeting the statewide emission caps?

A. Yes. The EPA has developed a recommended model cap-and-trade program for meeting the emission caps for each state, which is similar to the program currently in use for meeting emission reductions in the EPA's Acid Rain Program. Under the proposed cap-and-trade program, states will receive allowances corresponding to each state's cap or emission limit. States will decide which emission sources to regulate, and distribute allowances accordingly on an annual basis. An allowance represents the ability to emit a given amount of NO_x, SO_2, or Hg. Regulated sources within the state, which are expected to consist primarily of electric generating units, will then be required to possess enough allowances to equal the amount of pollutants emitted by each regulated source every year. Under the proposed cap-and-trade program, allowances will be fully transferable and can be bought, sold, traded, or saved for future use. A utility with more than one regulated generating unit can distribute their allowances in any manner to ensure that each unit has enough allowances to cover its emissions for the year.

Q. Will the State of Florida participate in the EPA's recommended cap-and-trade program?

A. Yes, the State of Florida adopted rules to implement CAIR and CAMR using a cap-and-trade program nearly identical to EPA's recommended approach. DEP adopted its CAIR-implementation rules on August 15, 2006, and they became effective on September 4, 2006. We are also aware that DEP received a Petition challenging portions of its CAIR-implementation rules related to the formula used to distribute allowances within the state, and that these specific portions have not been adopted and will not be effective until the rule-challenge Petition is resolved. DEP has submitted the adopted rules to EPA for approval as a revision to Florida's State Implementation Plan (SIP). Ultimately, the EPA must approve Florida's SIP for it to become completely effective. If EPA does not approve Florida's rules, EPA's Federal Implementation Plan (FIP), finalized on April 28, 2006, will apply. Regarding CAMR, DEP adopted its implementation rules on August 17, 2006, and these rules became effective on September 6, 2006. DEP must also submit its CAMR-implementation rules to EPA for approval, and this deadline is November 17, 2006. DEP's CAMR rules are also nearly identical to EPA's recommended approach, except that DEP is withholding 25 percent of the available allowances for 6 years between 2012 through 2017. Also, DEP's rules for both CAIR and CAMR set aside a certain number of allowances each year for new units, such as those at TEC.

Q. How were the effects of CAIR and CAMR incorporated into the detailed economic analysis?

A. Forecasts for emission allowances were developed by Hill & Associates to reflect the cost to reduce emissions of SO_2 and NO_x by one ton per year, and Hg emissions by one ounce per year (refer to the testimony of Matthew Preston). These costs were incorporated into the fuel prices for both existing and candidate units in the economic analysis based on the emission rates of the units.

Emission rates for units in each Participant's existing system were provided by the respective Participant. Emission rates for TEC were provided by Sargent & Lundy (refer to the testimony of Paul Hoornaert). Emission rates for candidate units were developed by Black & Veatch based on each unit's fuel, uncontrolled emission rate, emission control equipment, and best available control technology (BACT) expected emission permit limits. An individual fuel price adder was calculated and applied to existing and candidate units (including TEC) based on this information. This is discussed in more detail in the testimony of Bradley Kushner.

Q. What other environmental considerations have been included in the analysis of TEC?

A. Although regulation of carbon dioxide (CO_2) is currently not required, the Participants chose to evaluate the potential impact on the economic analysis for TEC of potential future regulation of CO_2 emissions. This discussion about the analysis is provided for information purposes only, as it does not relate to an existing legal requirement.

The Senate has considered bills requiring reductions in CO_2, which is a greenhouse gas, as well as implementation of a potential tax on carbon based emissions. Hill & Associates provided a forecast of CO_2 emissions allowance prices for use in the economic analysis based on implementation of a proposed cap-and-trade program that would regulate CO_2 emissions from utility generating units. The forecast emissions allowance prices are discussed in the testimony of Matt Preston.

Black & Veatch included these projected CO_2 emissions allowances costs in a sensitivity case. These costs were added to the fuel price in the same manner that SO_2, NO_x, and Hg allowance costs were treated in the base case. As a result, one of the economic analyses presented in Sections B.6, C.6, D.6, and E.6 of the Taylor Energy Center Need for Power Application, Exhibit __ [TEC-1], and discussed in the testimony of Bradley Kushner, includes the costs for complying with current as well as potential future environmental programs.

Q. Were allowance allocations for existing units that will be granted to each Participant based on their existing generation resources considered in the economic analyses?

A. No. As stated above, the cost of purchasing allowances for all existing and candidate units was included in the economic analyses. Similar to the capital cost and fixed O&M costs for existing units, the value of the allowance allocations for each Participant's existing units would be the same for all plans and was therefore not included in the economic analyses.

Q. How were supply-side alternatives selected for detailed economic analysis?

A. A screening analysis was conducted for the conventional and emerging technologies as well as the renewable, advanced, energy storage, and distributed generation technologies. The supply-side screening considers each alternative's feasibility, levelized cost, and overall reliability to meet each Participant's capacity and energy needs. The most promising technologies were selected for further economic analyses.

Q. Please describe the methodology used in the supply-side screening.

A. The supply-side screening considered both economic and non-economic aspects of each type of technology. The non-economic aspects included the technology's developmental status, fuel or resource availability, reliability, feasibility, and the technology's overall ability to meet each Participant's forecast capacity needs. Economics for the technologies were captured in the development of a range of levelized costs for each type of technology.

Q. How were the levelized costs for each supply-side alternative developed?

A. Levelized costs are representative of an all-in cost for each type of technology. The levelized cost for each alternative is determined on a dollar per MWh basis and includes capital costs, fuel costs, and O&M costs. The levelized cost is calculated to reflect an all-in cost for energy at a given capacity factor and is used to make screening level comparisons of different technologies.

Q. Why are levelized costs used in the screening analysis?

A. Levelized costs convert varying annual costs to a single, level annual cost that has the same present value as the original varying annual costs. Levelized cost comparisons of supply-side alternatives provide a good method for screening a large number of alternatives into a smaller number of supply-side alternatives that are the most capable of providing low cost energy. The alternatives that passed the initial screening were then evaluated on a more detailed basis, as described in the testimony of Bradley Kushner.

Q. Please describe the results of the supply-side screening.

A. Before a supply-side alternative can be appropriately considered for analysis on a levelized cost basis, the technology's reliability and feasibility to meet the Participants' capacity needs must be established. Several of the renewable technologies considered are still in the research and development stage. As a result of a lack of commercial demonstration, the biomass gasification IGCC, parabolic dish, central receiver, solar chimney, ocean thermal, and marine current technologies were eliminated from further economic evaluation.

The effectiveness of renewable technologies is highly dependent on the availability and sufficiency of the various renewable resources utilized for electric power production. Based on transmission considerations, renewable technology alternatives considered in this analysis were geographically limited to the State of Florida. Therefore, wind energy, solar parabolic trough, geothermal, and hydroelectric technologies were eliminated from further economic analysis because of insufficient available resources. While landfill gas (LFG) is available at various sites throughout the state, most of the available LFG is already being utilized by other utilities, including JEA. Additionally, the amount of LFG available is not sufficient to mitigate the need for additional capacity for any of the Participants. Thus, LFG generation was not considered for further evaluation.

Advanced technologies were screened by development status and feasibility. The advanced combustion turbine, fuel cell, and coal technologies are still considered developmental stage technologies. Due to the early developmental stages of these technologies and the uncertainty relating to reliability and cost, these advanced technologies were not considered for further evaluation.

The remaining nonconventional supply-side technologies were examined on a levelized cost basis, and were evaluated against the levelized costs of the conventional technologies. As a result of this comparison, municipal solid waste mass burn, refuse derived fuel, solar photovoltaic, pumped hydroelectric energy storage, lead-acid battery energy storage, compressed air energy storage, reciprocating engine, and microturbine technologies were eliminated from further economic analyses.

A few nonconventional supply-side technologies appeared favorable when compared to conventional alternatives on a levelized cost basis, but were eliminated from further analyses for various non-economic reasons. These technologies include co-fired biomass, anaerobic digestion, and nuclear. The anaerobic digestion alternatives would not provide sufficient capacity because of limitations on biogas fuel quantities available to the Participants to defer the need for TEC. These projects are typically less than 1 MW in size because of biogas resource limitations.

Co-fired biomass was eliminated due to the lack of units that could be converted to biomass co-firing among the Participants. In addition, co-firing would not add to the existing capacity resources of a Participant, but would only alter the fuel sources.

The nuclear alternative is both too large for the Participants to undertake alone, and new designs are not considered available for commercial operation prior to 2021. In addition, while the capital costs for nuclear alternatives appear attractive, these are based primarily on vendor estimates. No new domestic nuclear units have been started in more than 25 years. While it may be possible to achieve the estimated costs, they represent a tremendous reduction from the costs of the most recently constructed US nuclear unit. For these reasons, nuclear alternatives were not considered available for the Participant capacity needs.

Q. What was the result of the screening analysis?

A. The overall result of the supply-side screening was that advanced, energy storage, and distributed generation technologies did not pass all of the criteria of the supply-side screening to merit further economic analysis. One renewable alternative, direct-fired biomass, warranted further consideration. Although adequate resources would need to be confirmed for a specific biomass project and location, a sensitivity analysis was conducted to determine the cost effectiveness of a 30 MW direct-fired biomass facility. The other technologies considered in the detailed economic analyses, presented in Sections 5 and 6 of Volumes B through E of Exhibit __ [TEC-1], included all conventional technologies, IGCC, and the General Electric LMS100 combustion turbine.

Q. In general, how did the renewable technologies compare to the conventional technologies in the levelized cost comparison?

A. Although resources for most renewable technologies are not available to meet the capacity needs of the Participants in Florida, they are competitive with conventional alternatives in other areas of the country. Because of transmission import limitations, renewable generating alternatives were limited to those available within Florida. Alternatives that can be competitive in other areas of the country include wind, parabolic trough, hydroelectric, geothermal, landfill gas, and biomass. Wind energy is intermittent and therefore cannot provide firm capacity. In addition, as discussed in the testimony of Ryan Pletka, wind resources in Florida are generally insufficient for economical wind energy generation. Biomass may be competitive on a small scale, if resources can be obtained within Florida.

Q. Are there any benefits to peninsular Florida associated with the addition of TEC?

A. Yes. As a reliable and efficient supercritical pulverized coal unit, TEC will increase reliability as well as fuel diversity in peninsular Florida. TEC will help fill Florida's need for additional generation over the next 10 years to maintain adequate reserve requirements. It will also diversify Florida's fuel mix by adding coal fired generation, and thus displace some future natural gas fired capacity, which is subject to higher price volatility than coal and potential supply disruptions. In addition, having diversity of fuel supplies can limit potential disruptions in electric service resulting from fuel supply interruptions and, thus, can increase system reliability.

Q. What are the consequences to the Participants of delaying TEC?

A. Delaying TEC would result in reduced reliability and higher costs. If TEC is delayed, the Participants' ability to meet their respective reserve margin requirements in 2012 will be affected. FMPA, JEA, RCID, and the City of Tallahassee's reserve margins will drop to approximately 2 percent, 13 percent, 15 percent, and 14 percent, respectively. RCID would need to increase their purchases under an existing contract to maintain its reserve margin. The lower reserve margins would increase the probability that each Participant would not be able to serve its member loads in the event of unforeseen circumstances.

The economic consequences of delaying TEC until May 2013 vary for each Participant. However, a 1 year delay in commercial operation of TEC will result in higher CPWCs for each Participant compared to commercial operation in May 2012. If other capacity resources were installed to meet each Participant's reserve margin, costs would increase. The economic consequences of a 1 year delay in commercial operation of TEC are approximately $25.9 million for

FMPA, $41.7 million for JEA, $25.5 million for RCID, and $4.4 million for the City of Tallahassee.

Q. **Does this conclude your pre-filed testimony?**

A. Yes.

Docket No. _________
Taylor Energy Center
Myron Rollins
Exhibit ____ [MRR-1]
Page 1 of 4

RESUME OF

MYRON R. ROLLINS

Black & Veatch

Project Manager

Project Management; Integrated Resource Planning; Permitting and Licensing; Feasibility Studies and Project Development

Education
Bachelors, Electrical, University of Missouri at Columbia, 1974

Professional Registration
Engineer (PE), Missouri, 1982

Total Years Experience
30

Joined B&V
1976

Professional Associations
MoKan American Nuclear Society – Past President
Institute of Electrical and Electronics Engineers – Senior Member

Language Capabilities
English

Mr. Rollins is a project manager in Enterprise Management Solutions. He is responsible for management of system planning and feasibility studies encompassing the areas of integrated resource planning, load forecasting, generation planning, cogeneration, site selection, and other special studies.

Mr. Rollins specializes in generation planning and project development. He is responsible for numerous power supply studies incorporating integrated planning techniques. Mr. Rollins was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and POWROPT optimal generation expansion program. He is also responsible for power market analysis and project feasibility studies. Mr. Rollins extends his expertise in generation system planning to the area of need for power certification of power plants.

Mr. Rollins has broad expertise in planning and project development that enables him to assist clients in the development of expansion plans and specific projects in a realistic manner that incorporates the required balance between engineering and cost considerations as well as sociopolitical and licensing considerations. With this experience, Mr. Rollins has successfully helped utility and developer clients add value to their systems and projects throughout his career.

Mr. Rollins has presented expert testimony on several occasions before the Alaska, Florida, Indiana and Missouri Public Service Commissions, and has published numerous papers on strategic planning and cogeneration. He is past chairman of the Mo-Kan section of the American Nuclear Society and a senior member of IEEE.

Representative Project Experience

Need for Power Certification, Orlando Utilities Commission, Florida 2005-2006
Project Manager. Managed the preparation of a Need for Power Application for Orlando Utilities Commission's Stanton Energy Center Unit B. Stanton B is a proposed IGCC unit to be constructed at Stanton Energy Center in Orlando, Florida. The application was submitted to the Florida Public Service Commission under the Electrical Power Plant siting Act. The Need for Power Application evaluated Stanton B against

other self-build alternatives and demand-side management alternatives. The Florida Public Service Commission unanimously approved the need for Stanton B.

Need for Power Certification, Florida Municipal Power Agency, Florida
2005
Project Manager. Managed the preparation of a Need for Power Application for Florida Municipal Power Agency's (FMPA's) Treasure Coast Energy Center (TCEC) Unit 1. TCEC Unit 1 is a proposed 1x1 F class combined cycle unit to be constructed on a greenfield site in Ft. Pierce, Florida. The application that was submitted to the Florida Public Service Commission under the Florida Electrical Power Plant Siting Act. The Need for Power Application evaluated TCEC Unit 1 against other self-build alternatives, purchase power from a request for proposals (RFP) process, and demand-side management alternatives. The Florida Public Service Commission unanimously approved the need for TCEC Unit 1.

Integrated Resource Plan, City of Tallahassee, Florida
2005-2006
Project Manager. Managing an integrated resource plan (IRP) for the City of Tallahassee. The IRP involves extensive evaluation of gas and coal fueled alternatives. More than 140 demand-side management (DSM) measures were evaluated. The IRP includes extensive evaluation of the impacts from the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). Biomass generation was evaluated as part of the IRP. Extensive probabilistic risk analysis was also conducted.

Integrated Resource Plan, JEA, Florida
2005-2006
Project Manager. Managing an integrated resource plan (IRP) in conjunction with JEA. The IRP involves extensive evaluation of gas and coal fueled alternatives including the development of site-specific estimates. Requirements for the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) were included in determining air quality control additions necessary for existing units. Demand-side management (DSM) evaluation made use of previous work conducted by Black & Veatch as part of JEA's Conservation Goal Docket before the Florida Public Service Commission.

Integrated Resource Plan Review, City of Lakeland, Florida
2005
Project Manager. Managed the review of the development of the City of Lakeland's integrated resource plan (IRP). The review encompasses all aspects of the IRP including load forecast, fuel forecast, development of supply side alternatives, life extension, and expansion planning. In

addition, Black & Veatch evaluated demand-side management alternatives for the City of Lakeland.

Expert Testimony, Indiana Municipal Power Agency, Indiana
2004
Project Manager. Presented expert testimony before the Indiana Utility Regulatory Commission for issuance of a Certificate of Public Convenience and Necessity. The testimony covered the technical and economic feasibility for three coal generating unit projects in which the Indiana Municipal Power Agency planned to participate.

St. Johns River Power Park Annual Report, JEA, Florida
2004
Project Manager. Managed preparation of the annual report on the operation and maintenance of St. Johns River Power Park consisting of two 675 MW pulverized coal units burning a mix of coal and petroleum coke. The units are jointly owned by Florida Power & Light Company and JEA. The annual operation and maintenance report is required to be submitted to the bond trustee under JEA's bond covenants.

Ten Year Site Plan, Orlando Utilities Commission, Florida
2004
Project Manager. Managed the preparation of the Ten Year Site Plan for Orlando Utilities Commission as required by the Florida Public Service Commission. The Ten Year Site Plan is an integrated resource expansion plan for the utility including load forecast, fuel price forecast, demand side management, and generation expansion.

Stock Island Combustion Turbine Unit 4 Development and Licensing, Florida Municipal Power Agency, Florida
2004
Project Manager. Managed development of the project description, the conceptual design, the development of lease and operating agreements, and permitting and licensing of a LM6000 simple cycle combustion turbine located at Key West, Florida. In addition, studies of the method of project execution, either EPC or traditional design and construction management, were developed along with a detailed schedule and cost estimate.

Combined Cycle Site Selection Study, Florida Municipal Power Agency, Florida
2004
Project Manager. Managed the site selection study for a 1x1 F class combined cycle for Florida Municipal Power Agency (FMPA). The site selection study initially evaluated four FMPA member generation sites. From those four sites, two were selected for detailed evaluation. The site selection study evaluated fatal flaws and permitting requirements, natural gas supply, water supply, wastewater disposal, and transmission

interconnection requirements. The study evaluated construction and operating costs differences between the two sites. The study also evaluated the ability to deliver power to the East system and the associated economic impacts of wheeling costs to get power to the East system. The study recommended selection of a site in St. Lucie County. Final permitting is currently under way for construction of the unit.

Independent Assessment, Edwards & Angell, Florida
2003
Project Manager. Managed an independent assessment of the current state and cost to complete of a partially completed combined cycle repowering project in Lake Worth, Florida for Edwards & Angell, the City of Lake Worth's bond attorney. The study involved developing an estimate to complete the project as a simple cycle combustion turbine and providing consultation on the development of a new natural gas transportation agreement and a memorandum of understanding between the existing owner, AES, and the new purchaser of the project, Florida Municipal Power Agency. The assignment also involved review and advise on numerous other project agreements.

Cane Island 4 Feasibility Study, Florida Municipal Power Agency, Florida
2002
Project Manager. Managed a feasibility study for the installation of a 1 x 1 F class combined cycle at the existing Cane Island Power Park. The study addressed site arrangement, the availability of cooling water, and the disposal of wastewater.