ORIGINAL

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Subject: Docket 060635-EU

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b. Docket No. 060635-EU

In re: Petition To Determine Need For an Electrical Power Plant in Taylor County

c. Document being filed on behalf of Florida Municipal Power Agency, JEA, Reedy Creek Improvement District and City of Tallahassee

d. There are a total of 68 pages.

e. The document attached for electronic filing is Petitioners' Post-Hearing Statement of Issues and Positions and Brief in Support of Petition to Determine Need for Electrical Power Plant in Taylor County

Thank you for your cooperation.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

ORIGINAL

In re: Petition To Determine Need For an Electrical Power Plant in Taylor County by Florida Municipal Power Agency, JEA, Reedy Creek Improvement District and City of Tallahassee.	DOCKET NO. 060635-EU FILED: January 24, 2007

PETITIONERS' POST-HEARING STATEMENT OF ISSUES AND POSITIONS AND BRIEF IN SUPPORT OF PETITION TO DETERMINE NEED FOR ELECTRICAL POWER PLANT IN TAYLOR COUNTY

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STATEMENT OF ISSUES & POSITIONS

1. **Is there a need for the proposed Taylor Energy Center (TEC) generating unit, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes?**

   Yes. TEC is needed to satisfy the Applicants' forecast capacity requirements and to maintain their respective reserve margins. Fuel diversity and supply reliability also will be increased through the capability to utilize fuel sourced from multiple international and domestic supply regions. The use of demonstrated supercritical pulverized coal technology on a new site also will increase electric system reliability for each Applicant and the State as a whole.

2. **Is there a need for the proposed TEC generating unit, taking into account the need for adequate electricity at a reasonable cost, as this criterion is used in Section 403.519, Florida Statutes?**

   Yes. Each Applicant needs its share of capacity from TEC in order to meet its minimum reserve margin(s). TEC also provides an opportunity for these municipal utilities to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant. TEC will be a highly efficient, advanced supercritical pulverized coal unit that will provide power at a reasonable cost by providing low cost, baseload, coal-fired generation. The project will have the ability to source coal and petroleum coke from both domestic and international sources. As a result, TEC will help mitigate exposure to high natural gas and fuel oil prices and will help the Applicants and the State of Florida reduce dependence on higher cost energy from natural gas and oil. Moreover, extensive economic analyses of bids received in response to an RFP as well as numerous other supply-side alternatives and demand-side management measures demonstrate that TEC is the most cost-effective alternative available to the Applicants. As a cost-effective and reliable resource, TEC will provide adequate electricity at a reasonable cost.

3. **Is there a need for the proposed TEC generating unit, taking into account the need for fuel diversity and supply reliability, as this criterion is used in Section 403.519, Florida Statutes?**

   ** Yes. The evidence shows that the baseload, coal-fired generation provided by TEC will increase fuel diversity and supply reliability for each Applicant and the State as a whole in a way that reduces overall supply and price volatility for the Applicants and their customers. The evidence also demonstrates that TEC will increase fuel supply reliability for the Applicants and the State as a whole by providing the capability to obtain fuel from multiple geographic regions in the United States and abroad. TEC also will have the capability to store coal and petcoke inventory for approximately 90 days of operation, reducing the potential supply disruptions associated with natural gas like those resulting from hurricanes in the Gulf Coast. The ability to store up to approximately 90 days of fuel also mitigates potential transportation disruption. Fuel diversity and supply reliability allows the Applicants to minimize the risks that accompany their operations.**

4. **Are there any conservation measures taken by or reasonably available to the Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and City of Tallahassee (Applicants) which might mitigate the need for the proposed TEC generating unit?**

** No. The evidence demonstrates there are no conservation measures taken by or reasonably available to the Applicants which might mitigate the need for TEC. Using the Commission-approved FIRE model, FMPA and JEA determined that no additional DSM measures were cost-effective. Tallahassee's evaluation is consistent with its recent internal evaluations. If Tallahassee's DSM portfolio fully realizes the projected maximum achievable capacity and energy savings, Tallahassee's capacity need may be delayed until 2016, but that would not affect Tallahassee's economic need for TEC. Considering RCID's substantial need for capacity in 2011/2012, its unique customer base and the significant savings RCID and its customers are achieving through DSM already, there is no basis to conclude that additional DSM would mitigate RCID's need for TEC.

There is no evidence to support departure from the Commission's established precedent regarding DSM cost-effectiveness and establishing a new, uniform methodology for evaluating DSM. Such a change would affect municipal, cooperative and investor-owned utilities throughout Florida. As such, this docket is not the appropriate forum to raise generic questions regarding how to evaluate DSM programs. Any policy change would be more appropriately addressed in a rulemaking or generic proceeding which would allow all affected parties to participate.**

5. **Have the Applicants appropriately evaluated the cost of CO_2 emission mitigation costs in their economic analyses?**

**Yes. The Applicants have appropriately evaluated potential CO_2 emission mitigation costs by submitting a sensitivity analysis for the Commission's information. That sensitivity analysis indicates that TEC remains cost-effective for all Applicants under the reasonably assumed CO_2-regulated environment. However, because there currently are no federal, state, or local regulations that impose CO_2 mitigation costs on power plants in Florida, the Commission cannot make any dispositive findings regarding potential CO_2 emission costs. The Commission previously has recognized that it cannot reach findings of fact relating to proposed or possible regulations because such findings require speculation as to what might or might not occur.

Accordingly, the Commission cannot base its decision on what, if any, CO_2 regulation and associated costs may be imposed in the future.**

6. **Does the proposed TEC generating unit include the costs for the environmental controls necessary to meet current state and federal environmental requirements, including the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and applicable regulations governing particulate matter, nitrogen oxide (NOx) and sulfur dioxide (SO2) emissions.**

Yes. The economic analyses performed for the TEC appropriately included costs for environmental controls necessary to meet current state and federal environmental requirements, including CAIR, CAMR, and applicable regulations governing mercury, NOx, SO_2 and particulate emissions. The Applicants' economic analyses appropriately included the costs of NOx, SO_2 and particulate emission controls for every hour the unit will operate. The economic analyses also included projected allowance costs for NOx, SO_2 and mercury emissions based on the national cap-and-trade programs established in the existing federal CAIR and CAMR rules. Although Florida has not yet submitted its State Implementation Plan revisions for CAIR implementation, the state implementation rules adopted by the Florida Department of Environmental Protection call for Florida to participate in the national CAIR and CAMR cap-and-trade programs. There is no basis to conclude that differences in the state and federal CAIR and CAMR rules will significantly affect the price of allowances under the national cap-and-trade programs.

7. **Have the Applicants requested available funding from DOE to construct an IGCC unit or other cleaner coal technology?.**

Yes. Significant efforts were made on behalf of the Applicants to investigate the availability of DOE funding for IGCC or other emerging advanced technologies. However, these investigations revealed no likely sources of significant funding for IGCC or other emerging advanced coal technologies. Moreover, given the size of their municipal utilities and the undemonstrated nature of IGCC technology, IGCC is not a feasible alternative to meet the Applicants' needs within the necessary time-frame.

8. **Has each Applicant secured final approval of its respective governing body for the construction of the proposed TEC generating unit?**

The governing body of each Applicant has approved participation in the project through at least the permitting and licensing phases. Like any other utility seeking a need determination, the Applicants retain the ability to explore all options pending final approval of the project under the Florida Electrical Power Plant Siting Act (PPSA) and execution of appropriate contracts for construction of the facility. It is prudent for utilities to continuously evaluate whether participating in a particular project continues to be cost-effective. In any event, final approval for *construction* is <u>not</u> one of the criteria listed in Section 403.519, F.S., and therefore, is an issue that is beyond the jurisdiction of the Commission.

9. Is the proposed TEC generating unit the most cost-effective alternative available, as this criterion is used in Section 403.519, Florida Statutes?

Yes. TEC is the most cost-effective alternative available to the Applicants. The Applicants developed reasonable estimates of capital, O&M, fuel and transmission costs, as well as performance estimates for TEC. The Applicants appropriately identified and screened numerous supply-side alternatives and, although they are not subject to the Commission's bidding rules, issued a request for proposals (RFP) that resulted in two proposals from a single bidder. The Applicants conducted comprehensive, detailed economic analyses of each Applicant's system considering the responses to the RFP, numerous other potential supply-side alternatives, including biomass and IGCC technology, and potential DSM alternatives. Based on the results of the comprehensive analyses, TEC is the most cost-effective alternative for each Applicant and will provide combined cumulative present worth cost (CPWC) savings of approximately $899 million.

10. Based on the resolution of the foregoing issues, should the Commission grant the Applicants' petition to determine the need for the proposed TEC generating unit?

Yes. The Commission should grant the petition for determination of need for TEC. TEC provides the Applicants and the Florida electric system reliability and integrity, adequate electricity at a reasonable cost, fuel diversity and supply reliability, and is the most cost-effective alternative available. There also are no conservation measures taken by or reasonably available to the Applicants which might mitigate the need for the unit. As such, TEC meets all of the pertinent statutory criteria in Section 403.519, Florida Statutes, and, therefore, should be approved.

11. Should this docket be closed?

Yes. When the Commission has issued its final order in the case and the time for reconsideration has passed, this docket should be closed.

POST-HEARING BRIEF

INTRODUCTION

Florida Municipal Power Agency, JEA, Reedy Creek Improvement District and City of Tallahassee (collectively, "Petitioners" or the "Applicants"), hereby submit their Post-Hearing Statement of Issues and Positions and Brief in support of their Petition to Determine Need For an Electrical Power Plant in Taylor County.

BACKGROUND

The Taylor Energy Center (TEC) is a proposed 765 megawatt (MW) (net) supercritical pulverized coal unit to be constructed on a 3,000 acre site located approximately 5 miles southeast of Perry, in Taylor County, Florida. [Rollins, T.319; EX.7, §A.3.2, p.A.3-1] 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. [Lawson, T.399, 404] FMPA is a wholesale supplier to 15 city-owned electric utilities throughout Florida who participate in FMPA's All Requirements Project (ARP). [Lawson, T.382, 399] JEA is a retail supplier in Jacksonville, Florida, and in parts of three adjacent counties. [Id.] RCID is a retail supplier in parts of Orange and Osceola Counties. [Id.] The City of Tallahassee is the principal retail supplier in Tallahassee, Florida. [Id.]

TEC provides an opportunity for these four municipal utilities to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant and to meet their forecast capacity requirements. [Lawson, T.383, 400] All of TEC's capacity will be fully subscribed to and owned by the four Applicants. [Lawson, T.382] FMPA will own 38.9 percent of TEC (298 MW), JEA will own 31.5 percent (245 MW), RCID will own 9.3

percent (71 MW), and the City of Tallahassee will own the remaining 20.3 percent (155.4 MW). [Id.; Rollins, T.319]

TEC will be an advanced supercritical pulverized coal unit with a higher steam pressure in comparison to subcritical boilers, resulting in improved efficiency and, therefore, reduced overall fuel consumption per unit of output. [Hoornaert, T.825; EX.24, §A.3.3, p.A.3-2] TEC will include one boiler, one steam turbine generator with efficient steam cycle, cooling system, water and wastewater treatment systems, material handling systems, air quality control systems, electrical interconnections, and other balance-of-plant systems. [Hoornaert, T.813; EX.24, §A.3.3, p. A.3-2] 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. [Hoornaert, T.813; EX.24, §A.3.3, p.A.3-4]

TEC will be electrically interconnected to the Progress Energy Florida (PEF) transmission system at 230 kilovolts (kV). [Hoornaert, T.814; EX.24, §A.3.3.7, p. A.3-8; Brinkworth, T.755] Transmission lines of approximately 5.5 miles in length will connect the plant to the Perry Substation. [Hoornaert, T.814, 829; EX.24, §A.3.3.7, p. A.3-9] An additional 230 kV transmission line will also likely be constructed by PEF to connect to the PEF system. [Brinkworth, T.758; Hoornaert, T.814]

As detailed in the discussion of Issue No. 6 below, TEC will be designed to include the most advanced pollution control systems (known as Best Available Control Technology or "BACT") to minimize plant emissions of nitrogen oxide (NO_x), sulfur dioxide (SO_2), and particulate emissions. [Hoornaert, T.814, 825; EX.24, §A.3.3, p. A.3-4, and §A.3.3.6, p. A.3-8] Mercury (Hg) emissions will be reduced through the co-benefits of these systems [Id.], and, if necessary, installation of activated carbon injection (ACI). [Hoornaert, T.823-25] Collectively, these pollution control systems will control TEC emissions to very low levels in compliance with all applicable regulatory standards. [Hoornaert, T.815] In addition, process wastewaters generated from the plant will either be recycled within the plant or processed in a zero liquid discharge (ZLD) facility to eliminate process wastewater flows from the plant. [Hoornaert, T.815; EX.24, §A.3.3.4, p.A.3-6]

TEC will be unique among solid fuel plants in its ability to burn a wide variety of fuel types. [Hoornaert, T.815] The TEC boiler, material handling, and other systems will be designed to burn up to 30 percent petroleum coke (petcoke) blended with a variety of coals. [Id.] In addition, TEC will be capable of burning coals from Latin America, the Powder River Basin (PRB) in Wyoming, and Central Appalachia regions. [Id.] This will provide fuel diversity and flexibility, producing additional benefits including the ability to competitively bid coal supply and transportation among multiple suppliers, and increased fuel supply reliability resulting from the ability to source from multiple geographic regions. [Hoornaert, T.815-816]

SUMMARY

For all of the reasons discussed below, the Commission should grant the petition for determination of need for the TEC. TEC is needed to satisfy the Applicants' forecast capacity requirements and to maintain their respective reserve margins. The use of demonstrated supercritical pulverized coal technology will also increase reliability. TEC is the most cost-effective option to meet the Applicants' capacity needs. As a reliable and cost-effective resource, TEC will provide adequate electricity at a reasonable cost. There are no conservation measures taken by or reasonably available to the Applicants which might mitigate the need for the proposed plant. Fuel diversity and supply reliability also will be increased through the capability to utilize fuel sourced from multiple international and domestic supply regions. As such, TEC meets all of the pertinent statutory criteria in Section 403.519, Florida Statutes, and, therefore, should be approved.

ISSUE-BY-ISSUE ANALYSIS

ISSUE 1: **Is there a need for the proposed Taylor Energy Center (TEC) generating unit, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes?**

POSITION: ****Yes. TEC is needed to satisfy the Applicants' forecast capacity requirements and to maintain their respective reserve margins. Fuel diversity and supply reliability also will be increased through the capability to utilize fuel sourced from multiple international and domestic supply regions. The use of demonstrated supercritical pulverized coal technology on a new site also will increase electric system reliability for each Applicant and the State as a whole.****

As further discussed below, the evidence demonstrates that all of the Applicants have need for capacity in the year 2012 to maintain their respective reserve margins based on load forecasts developed using methodologies that are commonly accepted and widely used in the utility industry. Furthermore, delay in licensing the TEC unit would require the Applicants to implement more expensive alternatives to maintain adequate reliability, and would impose increased costs. The economic consequences of a one-year delay in commercial operation of TEC are approximately $19.9 million for FMPA, $39.0 million for JEA, $24.4 million for RCID, and $2.1 million for the City of Tallahassee. [Rollins, T.334-335]

FMPA

FMPA serves the capacity and energy requirements of the ARP members through five FMPA generation projects, existing member generation resources, and various capacity and purchase power agreements. [EX.13, §B.1.1, p. B.1-1] The total summer generating capacity available to FMPA is 1,753 MW and the total available winter generating capacity is 1,827 MW. [EX.13, §B.1.1, p. B.1-1] Current projections indicate that 252 MW of ARP member generating capacity will be retired during the thirty year period of analysis. [EX.13, §B. 1.1, p. B.1-1]

Additionally, Vero Beach's 137 MW of generating resources will not be available to FMPA beginning January 1, 2010. [Id.]

FMPA's load forecast was developed using an econometric approach to project electric sales by major rate classification in the service territories of the ARP Members. [Nunes, T.542; EX.15, § B.3.4, p. B.3-2] Econometric forecasting makes use of regression analysis to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience. [Nunes, T.542; EX.15, §B.3.4, p. B.3-3] These historical models are evaluated and selected on their statistical ability to explain variations in energy consumption. [Nunes, T.543; EX.15, §B.3.4, p. B.3-3] The resulting models are then simulated using projections of the explanatory variables to produce forecasts of energy sales. [Id.] 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. [Nunes, T.543; EX.15, §B.3.7, p. B.3-7] 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. [Id.]

FMPA's 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 gigawatt hours (GWh). [Nunes, T.544; EX.15, §B.3.7, p. B.3-7] 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). [Nunes, T.544; EX.15, §B.3.7, p. B.3-7, and Table B.3-3, p. B.3-9] 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). [Id.] Net energy for load (NEL) 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). [Id.]

FMPA has established a 15 percent minimum planned reserve margin criterion for the winter period and an 18 percent reserve margin criterion for the summer period for planning purposes. [May, T.460] Based on FMPA's load forecast and the ARP capacity resources, FMPA's winter reserve margins are expected to fall below the required 15 percent minimum in the winter of 2012/13. [May, T.460; EX.13, §B.4.2, p. B.4-3, and Table B.4-1, p. B.4-4] At that 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. [May, T.461; EX.13, §B.4.2, p. B.4-3] 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. [May, T.461; EX.13, §B.4.2, p. B.4-3] Projected winter capacity deficits continue to increase beyond 2013/14. [Id.]

FMPA's summer reserve margins are forecast to fall below the 18 percent level in the summer of 2007. [May, T.461; EX.13, §B.4.2, p. B.4-3 and Table B.4-2, p. B.4-5] At that 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. [May, T.461; EX.13, §B.4.2, p. B.4-3] FMPA would likely enter into a short-term seasonal purchase to maintain its reserve margin in 2007. [Id.] The addition of the 296 MW Treasure Coast Energy Center (TCEC) combined cycle unit in June 2008 raises FMPA's projected reserve margin above 18 percent in 2008 and 2009. [Id.] The addition of simple cycle combustion turbines in the summer of 2010 will satisfy forecast capacity requirements for FMPA until the summer of 2011. [Id.] 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. [Id.] Projected summer capacity deficits continue to increase beyond 2011 to 230 MW in the summer of 2012 and 442 MW in the summer of 2014. [May, T.461; EX.13, §B.4.2, p. B.4-3, & Table B.4-2, p. B.4-5]

Although the Sierra Club alleged in the prehearing order that transmission constraints will complicate FMPA's ability to meet demand growth reliably, Order No. PSC-07-006-PHO-EU, at 8, there is no evidence in the record to support that contention. To the contrary, the evidence demonstrates that because FMPA's members are distributed across the State and as much of its load is connected to the PEF and FPL transmission systems, TEC will provide a strategic benefit to FMPA by adding much needed generation on PEF's transmission system to complement its existing generation attached to FPL's system. [EX.2, Tab 8, May Depo. at 55] In addition, the Florida Reliability Coordinating Council's (FRCC's) Transmission Working Group reviewed the recommendation for the System Impact Study performed by PEF and FPL (discussed below in connection with Issue No. 9) and determined that the proposed interconnection, along with future corrective action plans, will be reliable, adequate and will not adversely impact the reliability of the FRCC transmission system. [EX.2, Tab 12, Brinkworth Depo. at 2193-94]

JEA

JEA consists of three financially separate entities: the Electric System, the bulk power system St. Johns River Power Park (SJRPP) Units 1 and 2, and the bulk power system Robert W. Scherer Electric Generating Plant (Scherer Unit 4). [Gilbert, T.649-650; EX.17, §C.1.1, p. C.1-1; §C.2.1, p. C.2-1] The Electric System includes the Brandy Branch, Northside, and Kennedy generating stations. [Gilbert, T.650; EX.17, §C.2.1.1, p. C.2-1] JEA also has a contract with Southern Company for the purchase of 207 MW of coal-fired capacity and energy from June

1995 through May 2010. [Gilbert, T.650; EX.17, §C.2.5.1, p. C.2-6] 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. [Gilbert, T.650; EX.17, §C.1.1, p. C.1-1] For the purposes of this Need for Power Application, it has been assumed that Kennedy combustion turbines (CT) 4 and CT 5 remain in long-term reserve shutdown. [Gilbert, T.650; EX.17, §C.4.2, p. C.4-2] 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. [Gilbert, T.650; EX.17, §C.1.1, p. C.1-1]

JEA has installed significant renewable capacity under the JEA Clean Power Program Strategic Plan. [Gilbert, T.651; EX.17, §C.2.5.3, p. C.2-8] JEA currently has approximately 91 MW committed under its Clean Power Program Strategic Plan, including approximately 321 kilowatts (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 and 22 MW of proposed landfill and biomass projects. [Gilbert, T.652; EX.17, §C.2.5.3, p. C.2-8] In addition, JEA has made 43 MW of generating unit efficiency improvements under the Clean Power Action Plan. [Id.] In 2001, JEA signed a 15 year power purchase agreement with Biomass Investment Group (BIG) to purchase 70 MW of renewable energy from a proposed biomass ("e-grass") gasification plant in Florida. [Gilbert, T.652; EX.17, §C.2.5.3.2, pp. C.2-8 - C.2-9] Although JEA is committed to this project, 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. [Gilbert, T.652; EX.17, §C.2.5.3.2, p. C.2-9] JEA will continue to review this opportunity and other biomass projects as they are presented. [Gilbert, T.652]

JEA prepares forecasts of both NEL and peak demand. [Gilbert, T.653; EX.17, §C.3.1, p. C.3-1] The NEL forecast is developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. [Gilbert, T.653; EX.17, §C.3.1.4, p.C.3-8.] Inputs into the forecast include historical energy production, JEA territory sales, off-system sales (such as to Florida Public Utilities), and heating and cooling degree-days. [Id.] 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. [Id.] The temperature-dependent NEL is modeled as a function of parameter estimates for historical and projected heating and cooling degree-days. [Gilbert, T.653-654; EX.17, §C.3.1.4, p. C.3-8]

To forecast peak demand, JEA has developed a nonlinear regression analysis that utilizes Statistical Analysis Software (SAS) and Excel software. [Gilbert, T.654; EX.17, §C.3.1.2, p. C.3-1] 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. [Id.] The peak demand forecast is driven by temperature and time-series data. [Gilbert, T.654; EX.17, §C.3.1.2, p. C.3-3] The forecasting process involves the collection of historical hourly system load data and daily temperature data. [Id.] A nonlinear regression analysis is then conducted to forecast the summer and winter peaks. [Id.] The forecast temperature used in the regression analysis 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. [Id.]

Based on JEA's currently available capacity resources, JEA's projected reserve requirements for the winter base case and the summer base case demonstrate that JEA's capacity will fall below its required 15 percent reserve margin in the winter of 2011/12. [Gilbert, T.657; EX.17, §C.4.2, p. C.4.2, and Tables C.4-1 & C.4-2, pp. C.4-3- C.4-4] At that time, JEA's reserve margin is projected to fall to 13.0 percent, 67 MW short of the 15 percent required reserves. [Gilbert, T.657; EX.17, §C.4.2, p. C.4-2] 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. [Gilbert, T.657; EX.17, §C.4.2, p. C.4-2]

RCID

RCID owns, operates, and maintains facilities associated with the generation and distribution of electric power solely within RCID. [Guarriello, T.711; EX.18, §D.1.1, p. D.1-1] The current net summer generating capacity totals 60 MW. [Id.] 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. [Id.] In addition to the CEP site, the Epcot Central Energy Plant consists of two packaged diesel generating units to provide peaking and emergency backup service to vital loads. [Id.] Each diesel unit has a maximum permitted capacity limit of 2.5 MW. [Id.] RCID currently meets a major portion of its electric system requirements through power purchases from Tampa Electric Company (TECO), PEF, and Orlando Cogen Limited. [Guarriello, T.711; EX.18, §D.8.9, p. D.8-5, Table D.2-1]

RCID's primary customer is the Walt Disney World Resort Complex (WDW), which represents approximately 85 percent of its load. [Guarriello, T.712; EX.18, §D.3.0, p. D.3-1] The remaining 15 percent of RCID's load is primarily from commercial customers consisting of hotels and service businesses, and includes approximately 10 residential customers. [Id.] As such, load forecasts for RCID are generally driven by its commercial customers' baseload business models. [Id.] RCID's load growth is forecast to occur in increments due to new facilities developed as part of its customers' business models. [Guarriello, T.712; EX.18, §D.3.1, p. D.3-1] 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. [Id.] 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. [Id.] As a result, the forecast is essentially a straight-line approximation of the growth rate. [Id.]

Based on RCID's load forecast and its capacity resources, 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. [Guarriello, T.714; EX.18, §D.4.0, Table D.4-1, p. D.4-4] The need for additional capacity increases to approximately 185 MW by 2025. [Id.]

TALLAHASSEE

The City of Tallahassee currently operates three generating stations with a total summer net capacity of 746 MW and a total net winter capacity of 797 MW. [Brinkworth, T.745; EX.20, §E.1.1, p. E.1-1] 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. [Id.] 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. [Brinkworth, T.746; EX.20, §E.2.1.1, p. E.2-2] The repowering, which is expected to begin commercial operation in the summer of 2008, will provide an additional 68 MW of summer capacity and 96 MW of winter capacity while increasing the efficiency of the unit. [Brinkworth, T.746-747] The City also generates electricity at the C.H. Corn Hydroelectric Station. [Brinkworth, T.745; EX.20, §E.1.1, p. E.1-1] By 2025, the City expects to retire approximately 180 MW of summer capacity and 188 MW of winter capacity. [Brinkworth, T.746; EX.20, §E.2.1.5, Table E.2-2, p. E.2-5]

The City has no firm long-term capacity sales contracts in place. [Brinkworth, T.746; EX.20, §E.2.1.3, p. E.2-4] The City does, however, conduct short-term and intermediate sale transactions as available. [Id.] In addition, the City currently has a long-term firm capacity and energy purchase agreement with PEF, which will expire December 3, 2016. [Brinkworth, T.746; EX.20, §E.2.1.4, p. E.2-4] The City continues to evaluate other power purchase opportunities as they become available. [Brinkworth, T.746; EX.20, §E.2.1.4, p. E.2-5]

The City develops its load forecast 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. [Brinkworth, T.747; EX.20, §E.3.1, p. E.3-1] 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). [Brinkworth, T.747; EX.20, §E.3.1, p. E.3-1] The City also uses two additional regression models to separately predict summer and winter peak demand. [Id.]

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). [Brinkworth, T.748] Net energy for load (NEL) 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). [Brinkworth, T.748]

Based on the City's base case load forecast and the capacity resources, the City is forecast to initially require additional capacity in the summer of 2011, at which time approximately 22 MW will be required. [Brinkworth, T.750; EX.20, §E.4.2, Table E.4-1, p. E.4-

3] The need for summer capacity is forecast to increase to approximately 294 MW by 2025. [Id.]

Tallahassee's capacity need may be deferred until 2016 if its uniquely designed demand side management (DSM) portfolio fully realizes the assumed maximum achievable capacity reductions. [Brinkworth, T.801-02, EX.20, §E.7.2.4, p. E.7-15; Kushner, T.1121, 1133] However, such a delay would not affect the City's economic need for TEC because participation in TEC in 2012 would still provide approximately $228.8 million in CPWC savings because of the low cost, baseload, coal-fired generation that TEC would provide to diversify the City's existing natural gas-fired generation portfolio. [Kushner, T.1121; EX. 58, p. E.7-15, as revised by EX.3; Brinkworth, T.751] In addition, TEC's less expensive coal power would be available if the DSM portfolio does not perform as the City hopes it will. [Brinkworth, T.800]

The Commission has a long history of approving need determination petitions based on economic need rather than strict and immediate capacity requirements.[1] Likewise, the

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[1] See e.g., In re: for expansion of electrical cogeneration power plant in Palm Beach County by Florida Power & Light Company (FPL) and New Hope Power Partnership, PSC-04-1105A-FOF-EI, Docket Nos. 040766-EI and 040767-EI, at 2 (2004); ("Although FPL does not have a reliability need, as this criterion is used in Section 403.519, Florida Statutes, FPL and its customers have an economic need for the New Hope Project. FPL's purchase of as-available energy will provide no reliability benefit from a planning perspective, but the existence of this as-available energy source may, under certain operational circumstances, enhance FPL system reliability by increasing fuel and geographic diversity of generating resources."); In re Petitions to Determine Need for Electrical Power Plants in Martin and Manatee Counties by FPL, Order No. PSC-02-1743-FOF-EI, Docket Nos. 020262-EI and 020263-EI, at 6 (2002) ("[E]lectric system reliability would not be harmed by deferring the in-service date of Martin Unit 8 by one year to more closely meet FPL's projected load growth. It is, however, more cost-effective for FPL's ratepayers if FPL places Martin Unit 8 into commercial service in 2005, instead of deferring the unit by one year, and it is for that reason that we approve the need for both units in 2005."); In re Petition for Certification of Need for Orlando Utilities Commission (OUC), Curtis H. Stanton Energy Center Unit 1, 81 F.P.S.C. 10:18, Order No. 10320, Docket No. 810180-EU, at 3 (1981) ("Even though the Stanton Center is not required in the 1980's to meet the peninsula's capacity needs, the project will provide significant economic benefits for peninsular Florida in terms of supplying an alternative to oil-fired capacity generation."); In re JEA/FPL's Application of need for SRPP Units 1 and 2, 81 F.P.S.C. 6:220, 221-22, Order No. 10108,

Commission has recognized that it is not unusual for a utility to grow into the capacity of a large generating unit. Panda Energy Int'l v. Jacobs, 813 So.2d 46, 54 (Fla. 2002) ("The PSC appropriately considered . . . that FPC was expected to grow into the capacity provided by Hines 2."); In Re: Petition to Determine Need for Proposed Electrical Power Plant in St. Marks, Wakulla County, by City of Tallahassee, Order No. PSC-97-0659-FOF-EM, Docket No. 961512-EM, at 4 (1997) ("[W]e note that it is not unusual for a utility to grow into the capacity of a large generating unit.").

ADDITIONAL RELIABILITY BENEFITS

For all of the Applicants, and the State of Florida as a whole, TEC will provide geographic diversity because it will be constructed on a new site. [May, T.465; EX.13, §B.8.8, p. B.8-5; Gilbert, T.660; §C.8.8, p. C.8-5; Guarriello, T.718; §D.8.8, p. D.8-5; Brinkworth, T.753; §E.8.8, p. E.8-5.] The new site provides baseload generation without increasing the concentration of any Applicant's generation resources at one location. [Id.] 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. [Id.]

ISSUE 1 CONCLUSION

Based on the foregoing, the evidence demonstrates that there is a need for the proposed TEC, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes. Each of the Applicants needs its share of TEC in order

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Docket No. 810045-EU, at 2 (1981) ("We construe the 'need for power' issue to encompass several aspects of need. In our evaluation of the need for SJRPP Units 1 and 2 and related facilities, we have considered the principal areas of the electrical need for additional capacity to insure an adequate supply of bulk electrical power and energy to electric consumers and the economic need of providing this bulk power and energy at the lowest possible cost. In addition, the socio-economic need of reducing the consumption of imported oil in the State of Florida has been considered. Each of these aspects of need for SJRPP 1 and 2 was evaluated with respect to the electrical consumers of JEA, FPL, and peninsular Florida as a whole.").

to maintain its required reserve margin(s). Furthermore, the use of demonstrated supercritical pulverized coal technology at a new site will increase reliability for each Applicant and the State as a whole.

The Intervenors presented no evidence that calls into question any of the Applicants' load forecasts or reliability needs. Indeed, Sierra Club, et al., specifically recognize that the individual Applicants "do evidence demand growth and the need for additional capacity." Prehearing Order No. PSC-07-0016-PHO-EU, at 8. Nevertheless, the Intervenors apparently contend that the Applicants' needs could be met through use of DSM measures or renewable resources. As discussed in connection with Issue No. 4, however, the evidence demonstrates that there are no conservation or DSM measures taken by or reasonably available to the Applicants that might mitigate their need for TEC. Likewise, as discussed in connection with Issue No. 9 below, the Applicants have demonstrated that there are no cost-effective renewable resources available to meet the Applicants' capacity needs.

ISSUE 2: **Is there a need for the proposed TEC generating unit, taking into account the need for adequate electricity at a reasonable cost, as this criterion is used in Section 403.519, Florida Statutes?**

POSITION: ****Yes. Each applicant needs its share of capacity from TEC in order to meet its minimum reserve margin(s). TEC also provides an opportunity for these municipal utilities to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant. TEC will be a highly efficient, advanced supercritical pulverized coal unit that will provide power at a reasonable cost by providing low cost, baseload, coal-fired generation. The project will have the ability to source coal and petroleum coke from both domestic and international sources. As a result, TEC will help mitigate exposure to high natural gas and fuel oil prices and will help the Applicants and the State of Florida reduce dependence on higher cost energy from natural gas and oil. Moreover, extensive economic analyses of bids received in response to an RFP as well as numerous other supply-side alternatives and demand-side management measures demonstrate that TEC is the most cost-effective alternative available to the Applicants. As a cost-effective and reliable resource, TEC will provide adequate electricity at a reasonable cost.****

The evidence demonstrates that there is a need for TEC, taking into account the need for adequate electricity at a reasonable cost, as this criterion is used in Section 403.519, Florida Statutes. As discussed above, the evidence demonstrates that each Applicant needs its share of capacity from TEC in order to meet its minimum reserve margin(s). TEC also provides an opportunity for these municipal utilities to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant. [Lawson, T.383, 400] TEC will be a highly efficient, advanced supercritical pulverized coal unit that will provide power at a reasonable cost by providing highly reliable, low cost, baseload, coal-fired generation. [Hoornaert, T.813, Lawson, T.383] 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 (CAPP), Latin American, and other regions, as well as petcoke from the Gulf Coast region and the Caribbean. [Hoornaert, T.815; Brinkworth, T.751; Guarriello, T.716-717; Gilbert, T.658; May, T.463; EX.31, §A.3.4.2, p. A.3-14] Historically, coals from these regions and petcoke have experienced significantly lower prices on a $/MBtu basis than oil and natural gas. [Id.] As a result, TEC will help mitigate exposure to high natural gas and fuel oil prices and will help the Applicants and the State of Florida reduce dependence on higher cost energy from natural gas and oil. [Id.]

Although the Applicants, as municipal utilities, were not required to issue a request for proposals (RFP), they did so in this case. The evidence demonstrates that TEC is more cost-effective than the two bids received in response to the RFP. [Arsuaga, T.934; EX.22, §A.7.4, p. A.7-4; Lawson, T.383, 400; Kushner, T.1117, 1127-28] Moreover, as discussed below in connection with Issue Nos. 4 and 9, extensive economic analyses of numerous other supply-side alternatives and demand-side management measures demonstrate that TEC is the most cost-effective alternative available to the Applicants. As a cost-effective and reliable resource, TEC will provide adequate electricity at a reasonable cost.

ISSUE 3: **Is there a need for the proposed TEC generating unit, taking into account the need for fuel diversity and supply reliability, as this criterion is used in Section 403.519, Florida Statutes?**

POSITION: **** Yes. The evidence shows that the baseload, coal-fired generation provided by TEC will increase fuel diversity and supply reliability for each Applicant and the State as a whole in a way that reduces overall supply and price volatility for the Applicants and their customers by providing the capability to obtain fuel from multiple geographic regions in the United States and abroad. TEC also will have the capability to store coal and petcoke inventory for approximately 90 days of operation, 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. Fuel diversity and supply reliability allows the Applicants to minimize the risks that accompany their operations.****

The evidence demonstrates that there is a need for the proposed TEC, taking into account the need for fuel diversity and supply reliability, as this criterion is used in Section 403.519, Florida Statutes.

Fuel diversity refers to an electric utility's procurement of power supply encompassing a range of types of electric generation facilities, fuel sources, or purchased power agreements. [Fetter, T.621] Fuel diversification allows a utility to minimize the risks that accompany its operations and enables it to withstand the ups and downs that are unanticipated specifically, but foreseeable generally. [Id.] Such risks include fuel price and supply volatility as well as price and supply effects from international political events, regional weather patterns or unforeseen events. [Id.] 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. [Fetter, T.621-622] By dealing with future unanticipated occurrences, fuel diversity enhances a utility's ability to supply its customers with electricity in a reliable manner. [Fetter, T.622]

The TEC Fuels Committee, which includes a representative of each Applicant, is responsible for developing and implementing strategies for fuel procurement and delivery to TEC. [Myers, T.961; EX. 31, §A.3.4.1, p. A.3-13] 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. [Myers, T.961] TEC's fuel strategy is designed to take full advantage of these sourcing and transportation flexibilities by establishing a plan that creates and exploits competitive opportunities in the marketplace. [Myers, T.961; EX. 31, §A.3.4.1, p. A.3-13] 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. [Myers, T.961] For example, when it is economical to do so, oceangoing vessels may be used to provide partial delivery of coal and petcoke to TEC as an alternative to complete reliance on rail transportation. [Id.] In addition, the TEC Fuels Committee will require multiple rail carriers to compete to supply service to TEC. [Myers, T.961; EX. 31, §A.3.4.1, p. A.3-14] 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. [Myers, T.961] 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. [Id.]

A blend of Latin American coal and petcoke is expected to provide the lowest production costs. [Myers, T.962, 970; EX.31, §A.3.4.2, p. A.3-14] Powder River Basin (PRB) and Central Appalachian (CAPP) coals are also potential competitive options. [Myers, T.962, 970; EX.31,

§A.3.4.2, p. A.3-15] Petcoke and international coal supplies will be transported by vessel to one of several US terminals and trans-loaded to rail for delivery to TEC. [Myers, T.962, 970; EX.31, §A.3.4.2, p. A.3-14, §A.3.4.4, p. A.3-16] TEC Fuels has identified several potential port locations for terminaling services. [Myers, T.962; EX.31, §A.3.4.5, Table A.3-3, pp. A.3-18 – A.3-21]

Based on JEA's actual experience in successfully delivering approximately 30 million tons of Latin American coal to SJRPP since 1987, it is unlikely that supply interruptions due to international political events will impact TEC's operation. [EX.2, Tab 5, Appl. Resp. Staff Int. No. 85, p.7] Furthermore, in the event of an extended supply interruption, TEC will be capable of maintaining adequate fuel supply due to the unit's ability to utilize a wide range of coal types and the on-site 90-day fuel storage capability. [Id.]

The next lowest as-fired cost of fuel for TEC is sub-bituminous coal from the PRB blended with petcoke. [Myers, T.962; EX.31, §A.3.4.7, p. A.3-22] The PRB has enormous reserve and mining capabilities. [Id.] In addition, rail service in the PRB is provided by both the Burlington Northern Santa Fe (BNSF) and the Union Pacific (UP). [Id.] Both of these western carriers link with Norfolk Southern (NS) and CSX Transportation (CSXT) in the east. [Myers, T.962; EX.31, §A.3.4.7, p. A.3-23] The combination of very large scale and low-cost 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. [Myers, T.962; EX.31, §A.3.4.7, p. A.3-24]

The CAPP coal region presents another domestic option for coal supply to TEC. [Myers, T.962; EX.31, §A.3.4.8, p. A.3-24] It has historically been the source of the majority of domestic coal tonnages used by Florida utilities. [Myers, T.962] Both CSXT and NS provide rail service from numerous mines located with the CAPP region. [Myers, T.962; EX.31,

§A.3.4.8, p. A.3-25] Multiple existing rail routes exist to reliably provide CAPP coal to TEC, if it becomes economical to do so. [Myers, T.963; EX.31, §A.3.4.8, p. A.3-27]

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. [Myers, T.963; EX.31, §A.3.4.9, p. A.3-27] Coupled with the ability to access foreign sourced coals, these arrangements will provide a high degree of competition for fuel supply for the TEC. [Myers, T.963] This will help mitigate fuel costs and increase reliability. [Id.] Multiple rail carriers and routes exist for the reliable transportation of domestic coal supplies. [Myers, T.963, 970] The combination of abundant supply options and multiple transportation sources will allow TEC to be reliably supplied with competitively-priced fuel. [Myers, T.964, 970-71; EX.31, §A.3.4.9, p. A.3-27]

The evidence demonstrates that 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. [Fetter, T.622] TEC also will increase fuel diversity and supply reliability for each Applicant. [May, T.463-464, 476; EX.13, §B.8.1, p. B.8-1; Gilbert, T.658-659; EX.17, §C.8.1, p. C.8-1; Guarriello, T.715-717; EX.18, §D.8.1, p. D.8-1; Brinkworth, T.751-752; EX.20, §E.8.1, p. E.8-1; Lawson, T.383, 400] This factor is particularly important to the City of Tallahassee because approximately 98 percent of its generating capacity is fueled by natural gas and oil. [Brinkworth, T.745; EX.20, §E.8.1, Figures E.8-1 and E.8-2, pp. E.8-1 to E.8-2] Likewise, RCID's system currently is almost completely dependent upon natural gas, fuel oil, and purchase power contracts that will soon expire. [Guarriello, T.716; EX.18, §D.8.1, p. D.8-1] TEC will help diversify FMPA's fuel mix diversity by replacing expiring purchase power contracts for natural gas-fired generation with an energy supply source with less price volatility than natural gas. [May, T.463-464, 475-476; EX.13,

§B.1.1, p. B.1-2.]. Despite the expiration of a purchase power agreement for 207 MW of coal-fired generation, TEC will maintain JEA's capacity at approximately 50 percent solid fuel and 50 percent natural gas and fuel oil, with the ability to produce 70 to 80 percent of the system energy requirements from either fuel type. [Gilbert, T.659; EX.17, §C.8.1, p. C.8-1]

The evidence also demonstrates that TEC will increase fuel supply reliability for the Applicants and the State as a whole. [Fetter, T.622, 627; May, T.463; EX.13, §B.8.2, p. B.8-1; Gilbert, T.658; EX.17, §C.8.2, p. C.8-1; Guarriello, T.717; EX.18, §D.8.2, p. D.8-1; Brinkworth, T.752; EX.20, §E.8.2, p. E.8-1] TEC will increase fuel supply reliability by providing the capability to obtain fuel from multiple geographic regions in the United States and abroad. [Id.] TEC also will have the capability to store coal and petcoke inventory for approximately 90 days of operation, reducing the potential supply disruptions associated with natural gas like those resulting from hurricanes in the Gulf Coast. [Id.] Furthermore, the ability to store up to approximately 90 days of fuel mitigates potential transportation disruption. [Id.]

The Intervenors acknowledge the value of fuel diversity,[2] but they apparently contend that the Applicants should pursue an Integrated Gasification Combined Cycle Unit (IGCC), additional renewable fuel sources, and/or additional DSM measures. See Prehearing Order No. PSC-07-0016-PHO-EU, at 9. As discussed below in connection with Issue No. 4, however, the evidence demonstrates that there are no conservation or DSM measures taken by or reasonably available to the Applicants that might mitigate their need for TEC. Likewise, as discussed in connection with Issue No. 9 below, the Applicants have demonstrated that there are no cost-effective renewable resources available to meet the Applicants' capacity needs and that IGCC

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[2] The NRDC stated: "The NRDC, recognizes in principle the value of fuel diversity in the state's current generation mix." The Sierra Club stated: "It is acknowledged that cost effective fuel diversity has value in the state's current generation mix." Finally, Mr. Whitton stated that he "recognizes the need for fuel diversity in the State of Florida's electric power generation facilities." Prehearing Order No. PSC-07-0016-PHO-EU, at 9.

technology is neither demonstrated sufficiently nor cost-effective to meet the Applicants' needs in 2012.

<u>ISSUE 4</u>: **Are there any conservation measures taken by or reasonably available to the Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and City of Tallahassee (Applicants) which might mitigate the need for the proposed TEC generating unit?**

<u>POSITION</u>: **** No. The evidence demonstrates there are no conservation measures taken by or reasonably available to the Applicants which might mitigate the need for TEC. Using the Commission-approved FIRE model, FMPA and JEA determined that no additional DSM measures were cost-effective. Tallahassee's evaluation is consistent with its recent internal evaluations. If Tallahassee's DSM portfolio fully realizes the projected maximum achievable capacity and energy savings, Tallahassee's capacity need may be delayed until 2016, but that would not affect Tallahassee's economic need for TEC. Considering RCID's substantial need for capacity in 2011/2012, its unique customer base and the significant savings RCID and its customers are achieving through DSM already, there is no basis to conclude that additional DSM would mitigate RCID's need for TEC.**

There is no evidence to support departure from the Commission's established precedent regarding DSM cost-effectiveness and establishing a new, uniform methodology for evaluating DSM. Such a change would affect municipal, cooperative and investor-owned utilities throughout Florida. As such, this docket is not the appropriate forum to raise generic questions regarding how to evaluate DSM programs. Any policy change would be more appropriately addressed in a rulemaking or generic proceeding which would allow all affected parties to participate.**

As further discussed below, the evidence demonstrates that there are no conservation measures taken by or reasonably available to any of the Applicants which might mitigate the need for the proposed TEC unit.

<u>FMPA</u>

As noted above, FMPA is a wholesale supplier of electricity to the fifteen ARP Member cities. [Lawson, T.382; May, T.462; EX.13, §B.7.1, p. B.7-1] As such, FMPA does not directly implement demand-side management (DSM) to retail customers. [May, T.462; EX.13, §B.7.1, p. B.7-1] The individual ARP Members actually provide the DSM programs to their customers.

[May, T.462] FMPA fully supports DSM and provides assistance to ARP Members implementing DSM programs by analyzing measures for opportunities to reduce customers' cost and by providing assistance to member cities that are implementing DSM programs. [May, T.462, 476] 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; and Fix-Up Programs for the Elderly and Handicapped. [May, T.462] The load forecast for FMPA reflects the energy savings resulting from DSM and conservation measures already implemented by FMPA's member cities. [May, T.529]

FMPA presented the results of analyses using the Commission-approved Rate Impact (RIM) Test in the Commission-approved Florida Integrated Resource Evaluator (FIRE) model to evaluate the cost-effectiveness of 180 DSM measures compared to participation in the TEC. [Kushner, T.1143-44] These 180 DSM measures reflect a wide range of DSM measures pertinent to residential, commercial and industrial customer classes. [Kushner, T.1174, 1211] For purposes of the analysis, FMPA used residential rates for the City of Leesburg and commercial rates for Kissimmee Utility Authority, the lowest rates of the ARP members for the respective rate classes. [Kushner, T.1182] This approach is most favorable to finding DSM measures cost-effective and is consistent with the approach utilized for FMPA in a need determination approved by the Commission in PSC Order No. PSC-05-0781-FOF-EM issued in Docket No. 050256-EM on July 27, 2005. [Id.] None of the 180 measures evaluated passed the Commission-approved RIM test. [Kushner, T.1119; EX.58, § B.7.4, pp. B.7-16 thru B.7-24, Tables B.7-7 thru B.7-10] Although 74 measures passed the Total Resource Test for residential and commercial rate classes combined, these measures would not provide sufficient capacity reductions to displace FMPA's ownership share of TEC. [Kushner, T.1120] From a cost perspective, evaluating DSM measures at the FMPA level to reduce its coincident peak (as was done here) is optimal; if the individual ARP member cities did a similar evaluation it could only result in a higher cost for them. [May, T.497-98]

JEA

JEA is the only Applicant subject to this Commission's jurisdiction under the Florida Energy Efficiency and Conservation Act (FEECA), which is codified at Sections 366.80-366.825 and 403.519, Florida Statutes. Pursuant to FEECA, this Commission adopts and periodically reviews energy conservation goals for JEA and other jurisdictional utilities. JEA's current conservation plan was approved by the Commission on September 1, 2004. Order No. PSC-04-0768-PAA-EG, at p.2 (Aug. 9, 2004). In reviewing the Plan, the Commission concluded that there were no cost-effective conservation measures available for use by JEA. [Id.] Nevertheless, JEA has voluntarily continued its existing DSM programs. These include: Energy Audits; a Solar Incentives Program; Green Built Homes of Florida; Chilled Water Services; and interruptible load. [Gilbert, T.663; EX.17, § C.7.1] JEA's demand forecast reflects the energy savings resulting from DSM and conservation measures already taken by JEA's customers. [Gilbert, T.702-703]

When JEA's current DSM plan was approved in 2004, the Commission specifically found that "JEA appropriately evaluated the cost-effectiveness of measures using the RIM test." Order No. PSC-04-0768-PAA-EG, at p.2 (Aug. 9, 2004). Consistent with that approach, in this proceeding, JEA presented the results of analyses using the Commission-approved RIM test to evaluate the cost-effectiveness of 180 DSM measures compared to participation in the TEC. [Kushner, T. 1143-44] These 180 DSM measures reflect a wide range of DSM measures pertinent to residential, commercial and industrial customer classes. [Kushner, T.1174, 1211] None of the 180 measures evaluated passed the RIM test. [Kushner, T.1119; EX 58, § 7.4, pp.C.7-17 through C.7-25, Tables C.7-7 thru C.7-10] Although 28 passed the Total Resource Test for residential and commercial rate classes, these measures would not provide sufficient capacity reductions to displace JEA's ownership share of TEC. [Kushner, T.1120]

RCID

As noted above, RCID's primary customer is WDW, which represents approximately 85 percent of its load. [Guarriello, T.712] The remaining 15 percent of RCID's load is primarily from other commercial customers consisting of hotels and service businesses and includes approximately 10 residential customers. [Id.] As such, RCID's load forecasts are generally driven by its commercial customers' baseload business models. [Id.] RCID's load growth is forecast to occur in increments due to new facilities being developed as part of its customers' business models. [Id.]

Throughout its history, RCID has assisted and participated in numerous conservation and efficiency programs that have saved approximately 100 gigawatt hours annually, which translates to approximately an 8 percent reduction in RCID's total annual energy load and approximately a 10 percent reduction in RCID's demand. [Guarriello, T.728] Even Sierra Club's DSM witness, Hale Powell, acknowledged that a DSM program with 4 percent savings in annual energy load, half that accomplished by RCID, would characterize a "highly successful" DSM program. [Powell, T.921-22]

A vast majority of the DSM and conservation activities within the RCID service territory have been implemented for and/or by WDW. [Guarriello, T.714] The load forecast for RCID reflects the energy savings resulting from DSM and conservation measures already implemented by RCID and its customers. [Guarriello, T.715]

RCID employs a Chief Energy Management Engineer who conducts monthly meetings with RCID's customers to share best energy conservation practices in an open forum. [EX.2, Tab 10, Guarriello Depo. at 14; Guarriello, T.724, EX.18, p. D.7-3] RCID and its customers will continually evaluate opportunities for energy conservation. [Guarriello, T.715] As new facilities are built, by 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. [Id.] WDW has just instituted a goal of reducing their energy take by an additional 5 percent over the next five years; but achievement of that aggressive goal would only reduce RCID's 134 MW need by approximately 5 to 7 MW. [Guarriello, T.737]

A renewed DSM cost-effectiveness analysis for RCID was not performed because RCID's customers have already applied all reasonably available conservation measures and will continue to install conservation measures, as appropriate, in the future. [Kushner, T1133, 1171-72] Taking into consideration RCID's substantial (134 MW) need for additional capacity in the 2011/2012 time frame, coupled with its unique customer base and the significant savings RCID and its customers are achieving through DSM already, there is no basis to believe that there are additional DSM measures that could be implemented to mitigate RCID's need for TEC. [Kushner, T.1172]

TALLAHASSEE

The City of Tallahassee implemented a utility-specific DSM analysis that no other utility in Florida has utilized. [Brinkworth, T.802] The City's DSM cost-effectiveness evaluation methodology was based on projections of maximum achievable potential and the associated annual costs developed specifically for the City. [Brinkworth, T.801-02] Candidate DSM measures were initially reviewed 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. [Brinkworth, T.769; EX.20,

§E.7.2] 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. [Id.] Chronological hourly 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. [Id.] Instead of screening individual measures, the combined DSM measures were analyzed in a portfolio as a reduction to the City's annual load projections, and the resulting system was evaluated using production cost modeling. [Id.]

Based on the City's analysis, the peak demand maximum achievable savings projected for the DSM portfolio would defer the City of Tallahassee's initial capacity requirement from 2011 to 2016. [Brinkworth T.801-02, EX.20, §E.7.2.4] As noted above, 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 of approximately $228.8 million when compared to a capacity expansion plan with the DSM portfolio that does not include participation in TEC. [Kushner, T.1121; EX. 58, p. E.7-15, as revised by EX.3] In addition, TEC's less expensive coal power would be available if the DSM portfolio does not perform as the City hopes it will. [Brinkworth, T.800]

ISSUE 4 CONCLUSION

Based on the evidence discussed above, there are no conservation measures taken by or reasonably available to the Applicants that might mitigate the need for the proposed unit. Intervenors suggest that the Commission should require all of the Applicants to utilize a uniform methodology for evaluating DSM.[3] The Intervenors take issue with the Commission-approved

[3] Sierra Club witness Powell also suggested that the Applicants failed to adequately identify a full range of potentially available DSM measures. [Powell, T.916] However, the

FIRE model and associated RIM test and, although they generally applaud Tallahassee's utility-specific methodology, they criticize Tallahassee for nevertheless concluding that TEC is the City's most cost-effective alternative for meeting its needs notwithstanding the maximum achievable energy savings projected to result from the City's DSM portfolio. For its part, NRDC argues that the Commission should adopt an incipient policy rejecting the FIRE model and associated RIM test in favor of a new methodology comparing the levelized costs of DSM measures against the levelized costs of the proposed unit on a $/MWh basis. [T.299] As discussed below, however, the Intervenors have failed to adequately explain any proposed change in Commission policy, and they failed to provide competent, substantial evidence supporting any such policy change as required in established precedent under Florida's Administrative Procedure Act. See Southern States Utilities v. Public Serv. Comm'n, 714 So.2d 1046, 1055 (Fla. 1st DCA 1999) (Change in Commission policy requires adequate explanation or supporting evidence); Florida Power & Light Co. v. State, 693 So.2d 1025, 1027-28 (Fla. 1st DCA 1997) ("[P]olicy must be established by expert testimony, documentary opinion, or other evidence appropriate to the nature of the issues involved and the agency must expose and elucidate its reasons for its discretionary action.") (citation omitted); In re Mid-County Services, Inc., Docket No. 030446-SU, Order No. PSC-99-1912-FOF-SU, at 18 (1999) ("Chapter 120,

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evidence demonstrates that the 180 DSM measures evaluated by Mr. Kushner using the FIRE model represent a wide range of various end-use measures across residential, commercial and industrial customer classes, and also differentiate between existing and new construction. [Kushner, T.1136, 1174] The DSM measures also are consistent with those evaluated in previous need for power dockets. [Kushner, T.1136] Furthermore, the list of DSM measures utilized is reviewed prior to being used in proceedings such as this and is updated as more DSM programs become available or if the costs associated with the DSM programs included in the Black & Veatch database have changed. [Kushner, T.1180] Although Mr. Powell also questions the level of detail presented in the application for the DSM analysis, the level of detail is consistent with, if not greater than, that presented in the need for power applications for FMPA's TCEC Unit 1 in Docket No. 050256-EM and OUC's Stanton Unit B in Docket No. 060155-EM, which the Commission found to be appropriate. [Kushner, T.1136]

Florida Statutes, requires us to explain deviations from prior policy, and that such deviations be supported by the record.").

The Commission repeatedly has relied on the FIRE model and associated RIM test in evaluating DSM measures in numerous need determination cases.[4] As recently as May, 2006, when it approved OUC's need for its Stanton Unit B IGCC project, the Commission found that OUC evaluated the cost-effectiveness of over 180 DSM measures by using the FIRE model "which the Commission has found to be appropriate for evaluating conservation and DSM measures." In re: Petition for determination of need for proposed Stanton Energy Center Combined Cycle Unit B electrical power plant in Orange County, by OUC, Order No. PSC-06-0457-FOF-EM, Docket No. 060155-EM, at 3 (2006). Similarly, when the Commission approved the need for FMPA's Treasure Coast Energy Center (TCEC) Unit 1 in July, 2005, the Commission found that, although FMPA is not directly responsible for DSM programs, FMPA "used the [FIRE] model, which the Commission has found to be appropriate for evaluating conservation and DSM measures." In re: Petition to determine need for TCEC Unit 1, proposed electrical power plant in St. Lucie County, by FMPA, Order No. PSC-05-0781-FOF-EM, Docket No. 050256-EM, at 3 (2005). Based on these findings, the Commission concluded that FMPA

[4] Other need determination orders in which the Commission has relied on use of the FIRE model and associated RIM test include: In re: Joint petition for determination of need for proposed Stanton Energy Center Combined Cycle Unit A by OUC, Kissimmee Utility Authority, FMPA, and Southern Company-Florida, LLC., Order No. PSC-01-1103-FOF-EM, Docket No. 010142-EM (2001); In re: Petition to determine need for Treasure Coast Energy Center Unit 1, proposed electrical power plant in St. Lucie County, by FMPA, Order No. PSC-05-0781-FOF-EM, Docket No. 050256-EM (2005); In re: Petition for Determination of Need for Polk County Units 1-4 by Florida Power Corporation, Order No. 25805, Docket No. 910759-EI (1992); In re: Petition for Determination of Need for a Proposed Electrical Power Plant and Related Facilities in Polk County by TECO, Order No. PSC-92-0002-FOF-EI, Docket No. 910883-EI (1992); and In re: Joint Petition to Determine Need for Electric Power Plant in Okeechobee County by FPL and Cypress Energy Partners, Order No. PSC-92-1355-FOF-EQ, Docket No. 920520-EQ (1992).

"adequately demonstrated that there are no cost-effective conservation measures reasonably available that would avoid or defer the need for TCEC Unit 1." [Id. at 4]

Moreover, in past proceedings in which the Commission approved DSM goals for electric utilities under FEECA, the Commission has determined that the RIM test is appropriate for evaluating cost-effectiveness of DSM measures. [Para, T.616; Order No. PSC-04-0768-PAA-EG, at p.2 (Aug. 9, 2004); Order No. PSC-94-1313-FOF-EG, at p.22 (Oct. 25, 1994)] This finding of appropriateness of the RIM test for evaluating cost-effectiveness of DSM measures is justified because the RIM test results in lower rates and ensures that customers who participate in a utility DSM measure are not subsidized by customers who do not participate. [Id.]

No competent substantial evidence supports departure from this established policy in favor of NRDC's proposed levelized cost comparison test. To the contrary, the evidence demonstrates that NRDC's proposed test is inappropriate because it fails to account for differences in the duty cycles of DSM measures versus TEC. [Brinkworth, T.786; Kushner, T.1167] As the Applicants' expert Bradley Kushner explained, most DSM measures provide savings during peak periods; whereas, TEC will operate as a baseload unit at a 90 percent availability factor.[5] [Kushner, T.1167] So in that sense the duty cycles are drastically different. [Kushner, T.1167-68] For that reason, it would be inappropriate to simply compare the levelized costs of DSM measures to the TEC's levelized costs and then automatically accept each and every program that appeared to score a levelized cost below TEC's. [Brinkworth, T.786]

Based on the foregoing, there is no legal or evidentiary basis to depart from the Commission's established precedent regarding evaluation of DSM cost-effectiveness, particularly in this case which involves municipal utilities over which the Commission does not have rate-

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[5] For example, the City of Tallahassee new DSM portfolio is projected to have a duty cycle of approximately 38% by 2025. [Kushner, T.1223]

setting authority. In that regard, when the Commission originally approved conservation goals for municipalities subject to FEECA in 1995, the Commission specifically recognized that all the municipal and cooperative utilities, with the exception of Tallahassee, used the RIM test to evaluate DSM cost-effectiveness. Order No. PSC-95-0461-FOF-EG, at p.2 (Apr. 10, 1995). While Tallahassee proposed more measures than were cost-effective under the RIM test, the Commission recognized that because it does not have rate-setting authority over municipal and cooperative utilities, those utilities should have the latitude to adopt goals they deem appropriate regardless of cost-effectiveness. [Id.]

Furthermore, departing from this Commission's long-standing approach and establishing a new, uniform methodology for evaluating DSM cost-effectiveness would have broad ramifications for municipal, cooperative and investor-owned utilities throughout Florida in setting numeric DSM goals and in need determination proceedings. [Para, T.618] For that reason, this docket is not the appropriate forum to raise generic questions regarding how to evaluate the cost-effectiveness of DSM programs. [Id.] Any revisions to the Commission's established methodology would be more appropriately addressed in a rulemaking or other generic proceeding in which all affected parties would have the opportunity to participate. [Id.]

ISSUE 5: **Have the Applicants appropriately evaluated the cost of CO_2 emission mitigation costs in their economic analyses?**

POSITION: ****Yes. The Applicants have appropriately evaluated potential CO_2 emission mitigation costs by submitting a sensitivity analysis for the Commission's information. That sensitivity analysis indicates that TEC remains cost-effective for all Applicants under the reasonably assumed CO_2-regulated environment. However, because there currently are no federal, state, or local regulations that impose CO_2 mitigation costs on power plants in Florida, the Commission cannot make any dispositive findings regarding potential CO_2 emission costs. The Commission previously has recognized that it cannot reach findings of fact relating to proposed or possible regulations because such findings require speculation as to what might or might not occur.**

Accordingly, the Commission cannot base its decision on what, if any, CO_2 regulation and associated costs may be imposed in the future.**

Despite the fact that there is no regulation of carbon dioxide (CO_2) emissions in Florida, the Applicants appropriately evaluated potential CO_2 emission mitigation costs by submitting a sensitivity analysis for the Commission's information. That sensitivity, which appropriately accounted for the interrelationship between emission allowance costs and fuel prices, demonstrated that TEC would still be the most cost-effective alternative for each Applicant even under the reasonably assumed CO_2 regulatory environment. [Kushner, T.1116, 1127-28]

The Applicants' CO_2 sensitivity analysis was based on a specific fuel price forecast that included corresponding emission allowance prices for SO_2, NO_x, Hg, as well as CO_2, based on assumptions generally analogous to the proposed McCain/Liebermann *Climate Stewardship Act of 2005* (S.342). [Preston, T.1011; EX.41, §A.5.5, p. A.5-18; §A.4.7.3, p.A.4-39] More specifically, the following aspects of S.342 were adopted by Mr. Preston of 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.

[Id.] 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*. [Preston, T.1011-12] Mr. Preston developed such a cap based on CO_2 emissions from EGUs as reported by the US Environmental Protection Agency (USEPA) for the year 2000 in the preliminary *Summary Emissions Report (Quarter 4: Year-To-Date Values.* [Preston, T.1012]

The preliminary *Summary Emissions Report (Quarter 4: Year-To-Date Values)* reported year 2000 EGU CO_2 emissions as 2.45 billion tons. [Id.] 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. [Id.] 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.). [Id.]
- The potential for low cost CO_2 emissions offsets from other industries. [Id.]
- Additional CO_2 emissions offsets/credits assigned to EGUs out of political expediency in an effort to buffer electricity customers from higher electricity costs. [Id.]

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. [Preston, T.1013]
- 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. [Id.]

- 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. [Id.]

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 would trend lower than the base case. [Preston, T.1014] Additionally, a CO_2 emissions cap would reduce the rate of growth in demand for fossil fuel generation and would influence reversion in the long-term towards a buyers' market for coal (i.e., lower prices). [Id.] Lower coal prices in the United States would cause Latin American suppliers to reduce prices to maintain market share. [Id.] Petcoke demand for electric generation would remain generally unchanged. [Id.] Petcoke supply would 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*. [Id.] However, as utilities burn only a fraction of the petcoke produced, prices would be less likely to be affected. [Id.]

Whitton's witness Dian Deevey questioned Mr. Preston's assumptions regarding the functional cap for EGU emissions, limitation on demand growth, increased renewable and other non-emitting sources, and increased nuclear generation. [Deevey, T.560-562] As Mr. Preston explained, however, because there is no existing CO_2 regulatory regime, he had to develop a plausible scenario. [Preston, T.1025, 1065] Considering the long lead time to make large scale changes in demand, supply and distribution of electricity, he appropriately increased the functional limit for electric generation units by 10 percent over 2000 emission levels to avoid potential shock on electricity rates. [Preston, T.1025-26, 1055] Furthermore, in a carbon constrained environment, many actions will need to be taken in order for the economy as a whole to meet the new emission targets. [EX.2, Tab 14, Preston Depo. at 59] Indeed, many of the bills that have been presented include strong renewable and DSM standards and support. [Preston, T.1054] It is also logical that if there were a regulated-CO_2 fuel and corresponding emission allowance price scenario, it would cause downward pressure on electricity demand growth. [Rollins, T.1248] Moreover, other CO_2 emission allowance forecasters have made comparable assumptions regarding limited demand growth, increased renewable and efficiency efforts, and increased renewable generation in the fairly short term. [Preston, T.1058-59]

Ms. Deevey also opined that CO_2 allowance estimates provided in a publication by Synapse Energy Economics are among the best available. [Deevey, T.562; EX.79] On a levelized basis, Mr. Preston's CO_2 allowance price estimate is $13.78 per ton. [Kushner, T.1224] This value falls between the low-case ($8.50 per ton) and the mid-case ($19.60 per ton) estimates provided in the Synapse publication. [Preston, T.1061; Kushner, T.1224; EX.79 at 41] Significantly, Synapse states in that publication:

> We think the most likely scenario is that as policymakers commit to taking serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complimentary energy policies that lead to lower cost scenarios, and that technology innovation will reduce the price of low-carbon technologies, *making the most likely scenario closer to (though not equal to) low case scenarios rather than the high case scenario.* The probability of this path increases over time, as society learns more about optimal carbon reduction technologies.

[EX.79 at 42 (emphasis added)] Thus, the Synapse publication corroborates the reasonableness of Mr. Preston's CO_2 allowance forecast.[6]

NRDC witness Daniel Lashof questioned the reasonableness of Mr. Preston's CO_2 allowance price forecast based on his opinion that reasonable estimates for CO_2 costs range from $8 to about $40 ton. [Lashof, T.861] This range is based on allowance prices in Europe and allowance price estimates used by utilities in other jurisdictions. [Id.] Other than this general range of potential CO_2 allowance prices, however, Mr. Lashof provided no specific testimony to support his view that Mr. Preston's estimates were unreasonable. Furthermore, one of the utilities he referenced, which used a CO_2 allowance cost of $14 per ton for its 2006 integrated resource plan, actually expects to add 250 MW of pulverized coal-fired generation by 2013. [Lashof, T.879-880] This indicates that CO_2 regulation does not necessarily make pulverized coal units uneconomical even at allowance costs within Mr. Lashof's expected range.

Based on the evidence and the uncertainty concerning potential CO_2 regulation, Mr. Preston's CO_2 allowance forecast is reasonable and appropriate. As discussed above, the CO_2 allowance price forecast was developed using a comprehensive model which accounts for the interplay of fundamental market factors such as electricity demand and fuel supply/price relationships as well as the cost of actions potentially necessary to meet environmental goals. [Preston, T.1023] Intervenors' criticisms primarily relate to assumptions concerning the

[6] As shown in Exhibit No. 107, the City of Tallahassee conducted numerous sensitivity analyses with and without consideration of various CO_2 allowance price scenarios. At hearing, Intervenors pointed out that one of the 46 scenarios conducted showed that TEC was not the least cost alternative using the Synapse high case scenario. [Brinkworth, T.781, 802] As noted above, however, even Synapse does not believe the high case scenario is most likely. [EX.79 at 42] Moreover, as also shown in Exhibit No. 107, TEC was the least cost alternative under the Synapse base-case scenario and under a scenario that utilized a CO_2 allowance price forecast that was integrated with the City's fuel price forecast, much like Mr. Preston's approach. [Brinkworth, T.802]

components of a CO_2 regulatory program that has not been adopted. [Id.] This simply underscores the high degree of uncertainty inherent in developing CO_2 allowance price forecasts unless and until a specific regulatory program is enacted and the regulators determine how such a program would be implemented. [Id.]

Because there is no existing federal or state CO_2 regulatory program, the Commission cannot make any dispositive findings or conclusions regarding CO_2 mitigation costs.[7] Potential future environmental regulation is speculative and beyond the scope of cognizable issues in this proceeding. The Commission has previously recognized that it cannot reach findings of fact relating to proposed or possible regulations because such findings of fact require speculation as to what might or might not occur. See In re Gulf Power Company, Docket No. 921155-EI, Order No. PSC-93-1376-FOF-EI at 28-29 (1993) (rejecting proposed findings regarding prospective air toxics regulations which had not been promulgated by Florida or the EPA); In re Gulf Power Company, Docket No. 921155-ET, Order No. PSC-94-0264-FOF-EI (1994) (order denying motion for reconsideration); see also Duval County School Bd. v. Spruell, 665 So. 2d. 262 (Fla. 1st DCA 1996) (Court refused to speculate as to results of future agency action).

[7] The cases previously cited by NRDC on this point are inapposite. In the FPL Martin Expansion need proceeding, for example, the Commission considered whether FPL had appropriately considered the potential costs of SCR if the then-Department of Environmental Regulation (DER) ultimately required it under its then-*existing* BACT regulations, not under "the Clean Air Act making its way through Congress at the time" as suggested in NRDC's response to the Applicants' motion to strike portions of the NRDC's testimony and exhibits (Docket Filing No. 11801-06). See In re: Petition of Florida Power and Light Company for determination of need for proposed electrical power plant and related facilities - Martin Expansion Project (Martin Units 3 and 4), Order No. 23080, 90 FPSC 6:268, 280-81 (1990). Similarly, the Cypress need case cited by NRDC dealt with potential costs for mercury controls that might be required under the *existing* Site Certification process in which mercury limits were, at the time, "*currently* set[ting] on a case-by-case review . . . ." In re: Joint Petition to determine need for electric power plant to be located in Okeechobee County by FPL and Cypress Energy, LLP , Order PSC-92-1355-FOF-EQ, 92 FPSC 11:363, 376-77 (1992) (emphasis added). Even there, the Commission stated that "it would not be prudent to base our determination of need for a power plant on *guesswork* as to action or inaction of the Siting Board." Id. at 377 (emphasis added).

ISSUE 6: **Does the proposed TEC generating unit include the costs for the environmental controls necessary to meet current state and federal environmental requirements, including mercury, NOx, SO_2, and particulate emissions?**

POSITION: ****Yes. The economic analyses performed for the TEC appropriately included costs for environmental controls necessary to meet current state and federal environmental requirements, including CAIR, CAMR, and applicable regulations governing mercury, NOx, SO_2 and particulate emissions. The Applicants' economic analyses appropriately included the costs of NOx, SO_2 and particulate emission controls for every hour the unit will operate. The economic analyses also included projected allowance costs for NOx, SO_2, and mercury emissions based on the national cap-and-trade programs established in the existing federal CAIR and CAMR rules. Although Florida has not yet submitted its State Implementation Plan revisions for CAIR implementation, the state implementation rules adopted by the Florida Department of Environmental Protection call for Florida to participate in the national CAIR and CAMR cap-and-trade programs. There is no basis to conclude that differences in the state and federal CAIR and CAMR rules will significantly affect the price of allowances under the national cap-and-trade programs.****

The evidence demonstrates that TEC will be designed to include Best Available Control Technology (BACT) to minimize plant emissions of nitrogen oxide (NO_x), sulfur dioxide (SO_2), and particulate matter in accordance with Prevention of Significant Deterioration requirements in Rule 62-212.400, F.A.C. [EX. 2, Tab 1, Appl. Resp. Staff Int. No. 9] Low nitrogen oxide (NO_x) burners, over-fire air ports, and selective catalytic reduction (SCR) will be used to limit NO_x emissions. [Hoornaert, T.814, EX. 24, §A.3.3, p.A.3-4] A wet flue gas desulfurization (FGD) system will be utilized to reduce SO_2 emissions, and a reverse air baghouse will be used to control particulate emissions. [Id.] A wet electrostatic precipitator (WESP) will further reduce particulate matter, hazardous air pollutants in particulate form, and acid mists. [Id.] Mercury emissions will be reduced through the co-benefits of these systems, [Hoornaert, T.815; EX.24, §A.3.3, p. A.3-4] and, if necessary, installation of activated carbon injection (ACI). [Hoornaert, T.823-824] Collectively, these pollution control systems will control TEC emissions to very low levels in compliance with all applicable regulatory standards. [Hoornaert, T.815, EX. 24, §A.3.3, p.A.3-4] Furthermore, the Applicants' economic analyses assume that the pollution controls will operate whenever the unit operates. [EX. 108, Appl. Resp. NRDC Int. Nos. 18, 19] The capital costs for all of these emission controls were accounted for in the TEC economic analyses, as were O&M costs for FGD reagent, ammonia for the SCR, an allocation for SCR catalyst replacement, and an allocation for baghouse bag replacements. [Hoornaert, 815, 817-818; EX. 24, §A.3.6.2, p. A.3-29, §A.3.5, p. A.3-27, as revised by EX. 3]

The Intervenors presented no evidence to support their apparent contention that the Applicants have not appropriately considered the costs of particulate emission controls. Rather, their focus appears to be on costs for complying with the Clean Air Interstate Rule (CAIR), which applies to NO_x and SO_2, and the Clean Air Mercury Rule (CAMR), which applies to mercury. The U.S. Environmental Protection Agency (USEPA) adopted the final CAIR and CAMR programs in 2005. [Rollins, T.324; EX. 2, Tab 3, Appl. Resp. Staff Int. No. 76] 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. [Rollins, T.324] The programs will be implemented in phases with the first phase for NO_x emission reductions under CAIR starting in 2009. [Id.] The first phase for SO_2 emission reductions under CAIR and Hg emission reductions under CAMR will begin in 2010. [Id.] 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. [Id.]

Subject to USEPA approval, it is up to each affected state to develop a method for meeting the CAIR and CAMR caps. [Id.] The Florida Department of Environmental Protection (FDEP) has adopted CAIR and CAMR implementation rules which call for Florida to participate in the federal cap-and-trade programs. [Rollins, T.325] See also, Rule 62-296.470, F.A.C. ("Implementation of Federal Clean Air Interstate Rule"); Rule 62-296.480, F.A.C.

("Implementation of Federal Clean Air Mercury Rule"). Under these cap-and-trade programs, source owners will be able to comply by installing emission controls and/or purchasing allowances so long as the total emissions of all their affected units do not exceed the total number of allowances they hold in any year. [Id.]

FDEP adopted its CAIR-implementation rules on August 15, 2006, with an effective date of September 4, 2006. [Rollins, T.325-326] However, portions of the rule related to the formula used to distribute allowances have been challenged under Chapter 120, F.S. [Rollins, T.326] As a result, the challenged portions will not be effective until the rule-challenge is resolved. [Id.] Ultimately, FDEP must submit its CAIR implementation rules for USEPA approval as part of Florida's State Implementation Plan (SIP). [Id.] Upon USEPA approval, FDEP will be responsible for administering CAIR in Florida. [Id.] Until USEPA approves Florida's SIP, USEPA's Federal Implementation Plan (FIP) will govern implementation of the cap-and-trade program in Florida. [Id. at 326, 347]

In the economic analyses for TEC, the costs of complying with CAIR and CAMR were appropriately accounted for by including emission allowance forecasts developed by Hill & Associates to reflect the cost to reduce emissions of SO_2 and NO_x on a dollars per ton basis, and Hg emissions on a dollars per pound basis. [Preston, EX. 37, 38, 39, 40] 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. [Rollins, T.326] Emission rates for units in each Applicant's existing system were provided by the respective Applicants. [Rollins, T.327] Emission rates for TEC were provided by Sargent & Lundy in Section A.3.3.6 of the Need for Power Application. [EX.24, p.A.3-8] Emission rates for candidate units were developed by Black & Veatch based on each unit's fuel, uncontrolled emission rate, emission control equipment, and BACT expected emission permit limits. [Rollins, T.327] Based on this information, an individual fuel price adder was calculated and applied to existing and candidate units (including TEC) on a $/MBtu basis. [Rollins, T.327; Kushner, T.1111] 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. [Kushner, T.1111]

The Intervenors presented no specific evidence that the Applicants inappropriately addressed the costs associated with CAIR and CAMR compliance. Instead, they apparently seek to call the Applicants' analyses into question because the Hill & Associates' allowance forecasts assumed implementation of the federal cap-and-trade programs and because there are minor differences between the state and federal rules. As noted above, however, FDEP's CAIR and CAMR implementation rules call for Florida to participate in the federal cap-and-trade programs. [Rollins, T.325-327] Unless and until EPA approves Florida's SIP submittal, the EPA's FIP will govern CAIR implementation in Florida. [Id.] Moreover, there is no basis to conclude that the minor differences in the state and federal rules would affect allowance prices. [Rollins, T.349-350; EX.2, Tab 14, Preston Depo. at 32]

Based on the evidence discussed above, the Applicants have appropriately accounted for the costs of environmental controls necessary to meet current state and federal environmental requirements, including mercury, NOx, SO_2, and particulate emissions.

ISSUE 7: **Have the Applicants requested available funding from DOE to construct an IGCC unit or other cleaner coal technology?**

POSITION: ****Yes. Significant efforts were made on behalf of the Applicants to investigate the availability of DOE funding for IGCC or other emerging advanced technologies. However, these investigations revealed no likely sources of significant funding for IGCC or other emerging advanced coal**

technologies. Moreover, as discussed below, given the size of their municipal utilities and the undemonstrated nature of IGCC technology, IGCC is not a feasible alternative to meet the Applicants' needs within the necessary time-frame.**

The evidence demonstrates that the Applicants made significant efforts to seek out federal financial assistance for potential alternative technologies for the TEC. Such investigations included the following activities:

- Meetings with investment bankers [Lawson, T.394; EX.8, T.396]
- Meeting with a consortium including a power plant developer and IGCC technology supplier [Id.]
- Meetings with staff members of both the U.S. Senate and House of Representatives [Id.]
- Meetings with investor-owned utilities (IOUs), and public power entities. [Id.]
- Participation in the February 2006 Coal Utilization Research Council conference on clean coal incentives in Washington, D.C. [Id.] Senator Robert Byrd, U.S. Representative Ralph Hall, and senior staff members from the US Department of Energy (DOE), US Department of Treasury, Internal Revenue Service, and the USEPA attended this conference. [Id.]
- Exploration of applicable incentives in the Energy Policy Act of 2005. [Id.]
- Consideration of the Clean Air Coal Program. [Id.]
- Participation in the 2nd Annual IGCC Symposium in May 2006. [Id., Lawson, T.395]

The Applicants ultimately concluded that there were no likely sources of significant funding for IGCC or other emerging advanced coal technologies. [Lawson, T.395; Letter to Taylor County Commission, EX.8, T.396] Although the Applicants did not officially submit an application for federal funding, they did make a diligent search. Nothing requires them to perform a futile act such as filing an application lacking any prospect of success. Moreover, as discussed below in connection with Issue No. 9, given the size of their municipal utilities and the undemonstrated nature of IGCC technology, IGCC is not a feasible alternative to meet the Applicants' needs within the necessary time-frame. [Rollins, T.338-339]

ISSUE 8: **Has each Applicant secured final approval of its respective governing body for the construction of the proposed TEC generating unit?**

POSITION: ****The governing body of each Applicant has approved participation in the project through at least the permitting and licensing phases. Like any other utility seeking a need determination, the Applicants retain the ability to explore all options pending final approval of the project under the Florida Electrical Power Plant Siting Act (PPSA) and execution of appropriate contracts for construction of the facility. It is prudent for utilities to continuously evaluate whether participating in a particular project continues to be cost-effective. In any event, final approval for *construction* is not one of the criteria listed in Section 403.519, F.S., and therefore, is an issue that is beyond the jurisdiction of the Commission.****

The governing body of each Applicant has approved participation in the project through at least the permitting and licensing phases pursuant to what has been termed the "Phase II-B" Agreement. [May, T.526; EX.2, Tab 8, Depo. at 5-6; Gilbert, T.701; Guarriello, T.738; EX.2, Tab 10, Depo. at 7; Brinkworth, T.800] Like any other utility seeking a need determination, the Applicants retain the ability to explore all options pending final approval of the project under the Florida Electrical Power Plant Siting Act (PPSA) and execution of appropriate contracts for construction of the facility. [May, T.526; Guarriello, T.738; Gilbert, T.701; Brinkworth, T.800] This will enable the Applicants to evaluate any changed circumstances that might affect the cost-effectiveness of the TEC project. [May, T.527; Gilbert, T.701; Guarriello, T.738; Brinkworth, T.800-801] It is prudent for utilities to continuously evaluate whether participating in a particular project continues to be cost-effective. [Id.]

Final approval for *construction* is not one of the criteria listed in Section 403.519, Florida Statutes, and therefore, is an issue that is beyond the jurisdiction of the Commission. See Panda Energy International v. Jacobs, 813 So.2d 46, 54 n.10 (Fla. 2002), quoting Tampa Electric Co. v. Garcia, 767 So.2d 428, 435 (Fla. 2000). In Panda Energy, when the Court was asked to expand the Commission's needs analysis to include a criterion not included in Section 403.519, the Florida Supreme Court refused to do so, stating:

> [T]he solution for the PSC or other interested entities if they desire to expand the PSC's authority is to seek an amendment to the statute. ... We find that the Legislature must enact express statutory criteria if it intends such authority for the PSC. Pursuant only to such legislative action will the PSC be authorized to consider [a new criterion].

Id. Nothing in the governing statute authorizes or requires the Commission to consider whether final approval for *construction* has been secured. As the Supreme Court stated in Panda Energy, if Intervenors wish to add a new criterion to the Commission's needs analysis, they should approach the Legislature to adopt that criterion by statute. Panda Energy, 813 So.2d 46, 54 n.10.

ISSUE 9: **Is the proposed TEC generating unit the most cost-effective alternative available, as this criterion is used in Section 403.519, Florida Statutes?**

POSITION: ****Yes. TEC is the most cost-effective alternative available to the Applicants. The Applicants developed reasonable estimates of capital, O&M, fuel and transmission costs, as well as performance estimates for TEC. The Applicants appropriately identified and screened numerous supply-side alternatives and, although they are not subject to the Commission's bidding rules, issued a request for proposals (RFP) that resulted in two proposals from a single bidder. The Applicants conducted comprehensive, detailed economic analyses of each Applicant's system considering the responses to the RFP, numerous other potential supply-side alternatives, including biomass and IGCC technology, and potential DSM alternatives. Based on the results of the comprehensive analyses, TEC is the most cost-effective alternative for each Applicant and will provide combined cumulative present worth cost (CPWC) savings of approximately $899 million.****

The Applicants conducted a multistage evaluation process to develop the most cost-effective generation expansion plan that would meet the corresponding need for capacity for each Applicant. [Rollins, T.319; EX.5, §A.2.2, p. A.2-2]

TEC COST ESTIMATES

The first step in the economic analysis involved developing detailed cost estimates, including estimates for capital, O&M, fuel and transmission costs, as well as performance estimates for TEC. [Rollins, T.319; EX.5, §A.2.2, p. A.2-2]

Capital Cost Estimates

The Applicants have presented reasonable estimates of the capital costs of TEC. The base estimate includes, among other things, the supercritical pulverized coal unit and associated facilities, pollution control equipment, construction labor, contingency and various owners' costs. [Hoornaert, T.815-817; EX.24, §A.3.5, p. A.3-27] The TEC cost estimate also includes $5 million that the Applicants have committed to provide the City of Perry to mitigate rail traffic impacts.[8] [Lawson, T.411-12, 415; EX.87, Ltr. from Lawson dated 10/5/06]

Originally, the total capital cost for TEC was estimated to be $1,713,399,000 in 2012 dollars. [Hoornaert, T.817, 822-823; EX.24, §A.3.6, Table A.3-5, p. A.3-28, as revised by EX.3] In light of changing market conditions observed nationwide, however, the Applicants submitted updated capital cost estimates to account for market impacts on the costs of major equipment and

[8] Typically, addressing such train traffic issues are the responsibility of the rail company and are reflected in their transportation charges. [Lawson, T.438, 448-49] In most areas, the trains delivering fuel to TEC will cross roads in no more than two minutes, resulting in minimal traffic impacts. [Lawson, T.434] The situation in Perry is somewhat different because trains must slow to 10 miles/hour to negotiate a curve before entering the TEC site, resulting in an 8-minute road crossing. [Id. at 416, 445] To mitigate the potential public safety implications of such a traffic delay at rail/road crossing, the TEC Applicants have committed $5 million to the City of Perry that can be used to help fund a rail bypass around the City, or fund a rail overpass, signaling, safety awareness programs, or possibly satellite stations on each side of the rail track. [Lawson, T.411-12, 415; EX.87, Ltr. from Lawson dated 10/5/06]

labor. [Hoornaert, T.822] The updated estimates also include cost estimates for certain additional items that the TEC Applicants selected after the filing of the original application, as well as a contingency for installation of activated carbon injection in the event that it is determined necessary for mercury emission control, and an adjustment to the initial Community Contribution to account for changes in the structure of the contribution that were agreed upon with Taylor County after the original filing.[9] [Hoornaert, T.822-824] The updated capital cost estimate is $2,039,074,000, which reflects an increase of approximately 19.01 percent from the original estimate. [Hoornaert, T.823; EX.24, §A.3.6, Table A.3-5, p. A.3-28, as amended by EX.3; EX. 25]

The Intervenors attempted to call the updated TEC capital cost estimates into question by pointing out that two other utilities have recently updated their capital costs estimates for proposed pulverized coal projects. In particular, the Intervenors noted that Duke Energy recently submitted updated capital cost estimates with the State Commission in North Carolina. [Hoornaert, T.837] In that case, however, Duke Energy originally estimated the costs for *two* 800 MW units to be $2 billion and it now estimates the costs for the two units to be $3 billion. [Hoornaert, T.842] By comparison, as noted above, the costs for TEC, which consists of *one* 765 MW unit, were originally estimated to be approximately $1.7 billion, which is considerably more conservative than the original Duke Energy estimates. [Id.] Likewise, the new $2 billion estimate for TEC is still much more conservative than the revised Duke Energy estimates. [Id.]

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[9] In that regard, the updated capital costs reflect an initial community contribution of $17 million rather than the $20 million. [Hoornaert, T.822; EX.24, §A.3.6.1.1, p.A.3-28, as revised by EX.3; EX.25] The annual contribution was increased from $2.5 million to $3 million. [EX.2, Tab 2, Appl. Resp. Staff Int. No. 19] The cumulative effect of the change in the Community Contribution was to increase the CPWC by only approximately $1.3 million for 2006 through 2035 (i.e., from $52,550,875 to $53,830,436). [Id.] Although the estimated O&M costs were not revised to reflect this increase in the annual contribution, the annual contribution is a very minor component of the overall project costs and this level of change would not have a significant impact on the TEC analyses. [EX.2, Tab 13, Kushner Depo. at 2212]

Furthermore, there are indications in the market that capital costs are stabilizing for coal-fired plants. [Klausner, T.1098-99] For these reasons, the capital costs estimates for TEC are reasonable.

Operation & Maintenance (O&M) Costs

Based on full-time staffing, fixed O&M costs are estimated to be $17,710,227 in 2005 dollars, and are assumed to escalate at the assumed rate of inflation. [Hoornaert, T.817] Ongoing capitalized expenditures are an additional aspect of fixed O&M expenses that have been included in the TEC estimates. [Id.] These are estimated to be $2.50/kW-yr in 2005 dollars. [Id.] 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. [Id.] Variable O&M expenses, which include costs for FGD reagent, water treatment chemicals, ammonia for the SCR, an allocation for SCR catalyst replacement, allocation for baghouse bag replacements, and other costs, vary depending on the fuel blend being used and the amount of MW produced.[10] [Hoornaert, T.817-818] The variable O&M estimates in 2005 dollars are $1.36/MWh for the Latin American coal blend (28.7% petcoke), $1.38/MWh for the PRB coal blend (26.3% petcoke), and $1.37/MWh for the CAPP coal blend (22.6% petcoke). [EX.2, Tab 5, Appl. Resp. Staff Int. No. 82] Variable O&M is also assumed to escalate at the assumed inflation rate. [Id.]

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[10] As discussed above, the capital cost for ACI equipment has been included as a contingency in the event it is needed to achieve a 90 percent level of Hg emission reduction by 2018. However, the O&M costs have not been included because it is anticipated that the synergistic effect of the other pollution controls may be able to achieve the 90 percent reduction level. [Hoornaert, T.824; EX.2, Tab 11, Depo. at 31] It is not definite whether ACI is going to be needed or not or when that would be needed throughout the plant life. [Hoornaert, T.841] Thus, it was not appropriate to reflect ACI in O&M costs. [Hoornaert, T.841; EX.2, Tab 11, Depo. at 11]

Fuel Cost Projections

The Applicants have appropriately evaluated fuel commodity and transportation costs. Fuel price projections for coal (including Latin American, CAPP and PRB), petcoke, natural gas, and fuel oil were developed by Hill & Associates for 2006 through 2030. [Preston, T.996-998; EX.41, § A.4.6, p.A.4-2] The fuel price forecasts provided by Hill & Associates were developed based in part on the expertise of several companies. [Preston, T.998; EX.41, §A.4.6, p. A.4-2] Natural gas and fuel oil price forecasts were provided by Pace Global Energy Services. [Id.] Forecasts for coal were developed by Hill & Associates, using its proprietary PRISM forecasting model, which integrates aspects of all fossil fuel markets as they relate to electricity demand. [Preston, T.998-999; EX.41, §A.4.6.1, p. A.4-3] The forecast for petcoke was based on historical averages. [Preston, T.1004] The TEC coal price forecasts were compared to several independent coal price forecasts including forecasts developed by the Energy Information Agency (EIA) in its Annual Energy Outlook, those presented in Seminole Electric Cooperative's need for power application for Seminole Generating Station Unit 3, and those presented in the OUC's recent need for power application for Stanton Energy Center Unit B. [EX.2, Tab 5, Resp. to Staff Int. No. 84(b)] The comparison demonstrates that the TEC forecasts of coal prices are reasonable compared to alternative forecasts. [Id.]

The TEC Fuels Committee developed overall delivered fuel price forecasts for various grades of coals, pet coke, natural gas, and fuel oils (distillate and residual) based on the commodity price forecasts provided by Hill & Associates and Pace Global, as well as rail transportation rates provided by Hellerworx, Inc., and ocean vessel rates provided by Simpson, Spence & Young Consultancy & Research Ltd. (SSY). [Myers, T.964-965; EX.31, §A.4.6.8, p.A.4-27]

Hellerworx provided the forecast of rail transportation rates from the various coal producing regions in the United States to the TEC site assuming a competitive rail environment between CSXT and NS. [Myers, T.964; EX.31, §A.4.6.8, p. A.4-27] For PRB coals, Hellerworx based its forecast on a competitive environment between the Union Pacific (UP) and Burlington Northern Santa Fe (BNSF) railroads for deliveries to interconnections with both CSXT and NS. [Myers, T.962; EX.31, §A.4.6.8, p. A.4-27] Hellerworx also provided a rate forecast for a short haul from a potential water terminal to be constructed in the Jacksonville, Florida area to the TEC to accommodate delivery of imported coals. [Id.] The Hellerworx estimates include reasonable cost estimates for leasing and maintaining railcars, although the Applicants may ultimately elect to purchase railcars if purchasing is determined to be more cost-effective. [Myers, T.979-81]

SSY provided the forecasted shipping rates from a common point in Bolivar, Colombia to Jacksonville, Florida for two different sized vessels (Handymax and Panamax). [Myers, T.965; EX.31, §A.4.6.8, pp. A.4-27 - A.4-28] 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. [Myers, T.965; EX.31, §A.4.6.8, pp. A.4-27 – A.4-28]

To develop the forecast of delivered coal prices, TEC Fuels combined the commodity and rail and vessel transportation cost components, in real 2005 $/ton. [Myers, T.965; EX.31, §A.4.6.8.1, p. A.4-28] For domestic coals, the Hellerworx rail forecasts were added to the Hill & Associates coal price forecasts. [Id.] For Latin American coals (Colombian and Venezuelan), the commodity price forecasts from Hill & Associates were added to the shipping rates from Bolivar to Jacksonville provided by SSY, which were then combined with the transloading rates developed by TEC Fuels and the short haul rates from Jacksonville to the TEC site provided by

Hellerworx. [Myers, T.966; EX.31, §A.4.6.8.1, p. A.4-28] The resulting delivered coal price forecasts were converted from a real 2005 $/ton basis to a real 2005 $/MBtu basis using the heating content of each coal type, and the real 2005 $/MBtu forecasts were then converted to nominal (current year) $/MBtu, based on an annual inflation rate of 2.5 percent. [Myers, T.966; EX.31, §A.4.6.8.1, p. A.4-28]

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 real 2005 $/ton. [Myers, T.966; EX.31, §A.4.6.8.2, p. A.4-28] TEC Fuels estimated a barge freight rate from the US Gulf Coast region to the Jacksonville, Florida area in real 2005 $/ton. [Id.] To develop the forecast of delivered petcoke prices, TEC Fuels combined the commodity and barge transportation cost components in real 2005 $/ton. [Id.] The transloading rates projected by TEC Fuels and the short haul rates from Jacksonville to the TEC site provided by Hellerworx were then added. [Id.] The resulting delivered coal price forecasts were converted from real 2005 $/ton basis to real 2005 $/MBtu basis using the heating content of the petcoke, and the real 2005 $/MBtu forecasts were then converted to nominal (current year) $/MBtu, based on an annual inflation rate of 2.5 percent. [Myers, T.966-967; EX.31, §A.4.6.8.2, p. A.4-28]

Pace Global provided the forecasted natural gas prices at the Henry Hub in Louisiana through 2030 in real 2005 $/MBtu. [Myers, T.967; EX.31, §A.4.6.8.3, p. A.4-28] TEC Fuels estimated a long-term variable charge for delivery of natural gas from Louisiana to the TEC site, which was added to the Henry Hub forecasts provided by Pace Global. [Id.] The variable charge developed 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. [Myers, T.967; EX.31, §A.4.6.8.3, p. A.4-28] The variable delivered natural gas cost in real 2005 $/MBtu was then converted to nominal (current year) $/MBtu, based on an annual inflation rate of 2.5 percent. [Myers, T.967; EX.31, §A.4.6.8.3, p. A.4-28]

To address fuel price uncertainty, high and low fuel price sensitivities and a fuel sensitivity that considers the potential impact of the regulation of CO_2 emissions in the United States were provided for use in the economic analyses discussed below. [Preston, T.997; EX.31, §A.4.6, p. A.4-2]

Transmission-related Costs

As noted above The TEC site is located within the PEF transmission system and will be connected to it. [Brinkworth, T.755; EX.20, §A.3.3.7, p. A.3-8] 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. [Brinkworth, T.756] These rules prescribe a set of studies that PEF must conduct to determine if the project can be reliably connected to the transmission grid and to identify the extent of the facilities that will be required. These studies include: a feasibility study, a system impact study, and a facilities study. [Brinkworth, T.756; EX.20, §A.3.3.7, p. A.3-8] The feasibility and system impact studies have been completed, and the facilities study is expected to be finished in early 2007. [Brinkworth, T.757] 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. [Id.] The system impact study evaluated three power transfer scenarios for four different interconnection alternatives and concluded there are no significant impacts to the regional transmission grid or the Southern-Florida Interface due to the interconnection of the TEC project. [Id. at 757-58]

For evaluation purposes, the Applicants assumed the direct interconnection costs to be based on three 5.5 mile 230 kV transmission lines from TEC to the Perry substation.

[Brinkworth, T.758; EX.20, §A.3.3.7, p. A.3-12] The estimated cost for these lines, which is projected to be about $17 million, has been included in the updated TEC capital cost estimate discussed above. [Brinkworth, T.758; EX.2, Tab 2, Appl. Resp. Staff Int. No. 26] 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. [Brinkworth, T.758-59] This is a conceptual cost estimate and will be refined in the next stage of the interconnection analysis. [Id. at 759]

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. [Id.] All interconnection costs will be initially funded by the Applicants, and then the costs of all network improvements will be credited to the Applicants as offsets to their respective transmission service charges for delivery of the power from TEC. [Id.]

In addition to the $17 million included in the project's updated capital cost, the TEC economic analyses include the transmission service charges for TEC as costs to the project for each Applicant as appropriate to deliver their capacity and energy under the presumption that the interconnection facilities will be classified as network improvements. [Id.] This presumption is reasonable because the Wilcox line will effectively create a triangular 230 kV loop in the transmission grid connecting the Perry, Fort White and Wilcox substations. [EX 2, Tab 12, Brinkworth Depo. at 70-71] This loop will strengthen the grid and improve transmission reliability in North Florida. [Id.] 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. [Kushner, T.1115] The results of this analysis indicate that participation in TEC is still the most cost-effective alternative available to each Participant. [Id.] Under such a scenario, participation in TEC will result in combined CPWC savings of approximately $823 million. [Id.]

Plant Performance

Actual plant performance (including net plant output and net plant heat rate) will be a function of ambient conditions, fuel characteristics, and other factors. [Hoornaert, T.818] Estimated performance was developed for a summer condition, winter condition, and average annual condition. [Id.] Part load performance was also developed for 35 percent load, 50 percent load, and 75 percent load. [Id.] These performance points were developed with three fuel blends consisting of up to 28 percent petcoke and 72 percent coal for each of the three coals, including Latin American, PRB, and CAPP. [Hoornaert, T.819] 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. [Id.] The heat rate has been increased by a 1.5 percent allowance for degradation. [Id.] The unit is expected to have a forced outage rate of 5.23 percent and a scheduled outage rate of 4.38 percent. [Hoornaert, T.818]

IDENTIFICATION OF SUPPLY-SIDE ALTERNATIVES

The second step of the multistage evaluation conducted by Black & Veatch involved the development of cost and performance estimates for numerous supply-side alternatives to TEC. [Rollins, T.320; EX.5, §A.2.2, p. A.2-2] Supply-side alternatives were developed in the following categories: renewable technologies, conventional technologies, advanced technologies, energy storage technologies, distributed generation, and emerging technologies. [Id.] Supply-side alternatives included units that are specific to each Applicant, using available existing sites as well as other joint ownership alternatives. [Rollins, T.320; EX.5, §A.2.2, p. A.2-3] In light of the changing market conditions discussed above, the Applicants also provided updated cost estimates for the coal-fired and natural gas-fired supply-side alternatives. [Klausner, T.1083] Because of the same market influences that have led to the updated capital cost estimate for TEC, a supercritical pulverized coal unit, estimates for coal-fired alternatives, including IGCC, were increased by approximately 20 percent.[11] [Klausner, T.1083] However, because there are proportionally less commodities in natural gas fired generation compared to coal generation as well as proportionally less construction labor required, the estimated percentage increase in the capital cost of natural gas fired generation alternatives was approximately 12 percent. [Klausner, T.1084]

SCREENING OF SUPPLY-SIDE ALTERNATIVES

All supply-side alternatives were screened for economics, feasibility, and reliability for use in each Applicant's system. [Rollins, T.320] 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 IGCC. [Id.]

Intervenor Whitton's witness Dian Deevey questioned the Applicants' evaluation of biomass technology, alleging that the Applicants inappropriately assumed that fuel availability problems would limit the size of biomass units to a practical maximum of 50 MW. [Deevey, T.557] However, the totality of the evidence supports the Applicants' assumption. Applicants' witness Pletka, who has extensive experience with biomass technology,[12] explained that the

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[11] As the Applicants' expert Klausner explained, this is likely a conservative (i.e., favorable) assumption for IGCC technology in light of recent press releases in which AEP has indicated that the cost difference of IGCC above pulverized coal is going to be substantially greater than the 20 percent differential previously estimated. [Klausner, T.1094]

[12] Mr. Pletka has been involved in projects utilizing a variety of biomass fuels, including wood, energy crops, animal manure, municipal waste, agricultural residues, and industrial wastes. [Pletka, T.607] Areas of emphasis include combustion, gasification, pyrolysis, biogas,

appropriate size for a biomass plant must consider numerous factors including site constraints, emissions caps, risk, need for capacity, fuel supply and technology issues. [Pletka, T.609] Of these, the most important is fuel supply. [Id.] Historically most direct-fired biomass plants have relied on local waste biomass from sources such as sawmills, pulp and paper production, and urban wood waste. [Id.] These resources have typically been low cost and local. [Id.] Their limited supply has often resulted in relatively small scale biomass facilities, usually less than 50 MW. [Pletka, T. 609-610] Although the average unit size is increasing somewhat, it is still much smaller than coal-fired plants and a plant size of 30 MW is considered typical and representative of direct-fired combustion biomass alternatives. [Id. at 610] There is no experience with biomass plants of the scale of TEC. [Id. at 610] Meeting the annual fuel requirement of such a utility-scale biomass power plant would require the purchase of thousands of acres of timberland, the cost of which would be similar to, if not higher than, the total capital cost of the biomass power plant. [Id. at 611-612] For these and other reasons discussed by Mr. Pletka, it is not practical or economically viable with current biomass technologies to develop a biomass power plant to the same scale as TEC. [Id. at 611]

Based primarily on public testimony of Steven Furman, the Intervenors allege that IGCC is a preferable alternative to the proposed supercriticial pulverized coal unit. However, the evidence demonstrates that IGCC is still an emerging technology. [Rollins, T.338; Klausner, T.1073; Kushner, T.1117] Only two coal-fired IGCC units are currently operating in the United States, including TECO's Polk County facility which has demonstrated availability

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and production of alternative fuels (e.g., ethanol, biodiesel, and bio-oil). [Id.] In Florida, he has worked on biomass related projects for the Florida Department of Environment Protection, OUC, Gainesville Regional Utilities, JEA, Lakeland Electric, and other clients. [Id.] He has a mechanical engineering background with graduate-level specialization in gasification, biomass energy, fluidized beds, and energy storage. [Pletka, T.607-608] His master's thesis was based on a novel pyrolytic gasification process for biomass fuels and included design, construction, and testing of a pilot scale biomass gasifier. [Pletka, T.608] factors of only 69 percent since it began commercial operation and only 74 percent over the past five years. [Klausner, T.1095] In recent years, the TECO facility has achieved availability factors in the range of 80 percent, but despite considerable efforts it has not achieved the 90 percent availability factor anticipated for TEC. [Klausner, T.1096] Nor has the other IGCC unit operating in the U.S. achieved a 90 percent availability factor firing petcoke and coal. [Furman, T.40-41] Given the size of their municipal utilities and the potential reliability risk associated with IGCC technology, the Applicants appropriately assumed, for purposes of the base-case economic analyses, that IGCC technology would not be available until 2018. [Rollins, T.338-339] This would allow for three years of operational data from the OUC Stanton B demonstration project scheduled to commence operation in 2010, as well as two years to permit and license an IGCC unit and then three additional years to construct it.[13] [Rollins, T.338-339; Klausner, T.1074] Nevertheless, as discussed below, the Applicants did conduct a sensitivity analysis assuming that a joint-development three train 1x1 IGCC alternative would be available in May 2012. [Kushner, T.1116-1117] That sensitivity analysis shows that TEC is more cost-effective than the joint development IGCC alternative even under the favorable assumption, promoted by Mr. Furman, that the IGCC unit would burn 100 percent petcoke. [Furman, T.26-27; Kushner, T.1218-20, 1139]

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[13] Mr. Furman and NRDC witness Lashof also opined that it would be less expensive to capture and sequester carbon from IGCC units than for supercritical pulverized coal units in the event such technology becomes necessary if CO_2 regulation is adopted and implemented in Florida. [Lashof, T.881] However, although carbon capture and sequestration may be technically feasible for both IGCC and pulverized coal units [Lashof, T.881], it has not been demonstrated on any large scale power plant project, be it IGCC, pulverized coal, or even natural gas-fired combined cycle. [Klausner, T.1090] Indeed, as Dr. Lashof admitted, there currently are no IGCC units in current operation that capture or sequester carbon dioxide. [Lashof, T.881, Klausner, T.1090-91] In any event, as discussed above, the Applicants' CO_2 sensitivity analysis demonstrates that TEC is still cost-effective under the assumed CO_2 regulatory regime.

REQUEST FOR PROPOSALS

The third step in the multistage evaluation process to determine the most cost-effective expansion plan for each Applicant involved conducting a Request for Proposal (RFP) process for purchase power in lieu of participation in TEC. [Rollins, T.320; EX.5, §A.2.2, p. A.2-3] Although the Applicants are not subject to the Commission's "bidding rule" contained in Rule 25-22.082, Florida Administrative Code, they issued an RFP requesting purchase power bids from 100 to 750 MW for contract terms of 10 years or more. [Arsuaga, T.931; Rollins, T.320] The RFP served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the Applicants beginning on June 1, 2012, and continuing over a period of at least 10 years. [Arsuaga, T.931] The RFP requested a minimum of 100 MW (up to a maximum of 750 MW) to be allocated among the Applicants and required that the proposed capacity and energy be delivered into each Applicant's system on a firm, first-call, non-recallable basis. [Id.] The RFP was distributed to more than 40 potential bidders and submitted to six industry publications. [Arsuaga, T.925, 931]

The Applicants received two bids from a single potential supplier: one bid provided indicative pricing for a pulverized coal-fired unit and the other provided a firm bid for a natural gas-fired combined cycle unit. [Arsuaga, T.932] Although compliance with the four minimum requirements of the RFP was questionable for both bids, a busbar analysis for the two bids and TEC 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 O&M expenses. [Arsuaga, T.932-933] Because there were differences between the proposals and the self-build alternative, certain adjustments were made to ensure consistency in the evaluation. [Id. at 933] The evaluation concluded that the TEC projected delivered cost was lower than both the proposed coal resource and the proposed combined cycle resource over a range of evaluation scenarios. [Id. at 934] This conclusion did not change when the bids were compared with the updated capital costs for TEC. [Arsuaga, T.942]

ECONOMIC ANALYSES

The fourth step in the evaluation process was to conduct a detailed system evaluation of self-build and purchase power alternatives. [Rollins, T.321, EX.5, §A.2.2, p. A.2-4] Economic assumptions and fuel price forecasts were developed for base case and sensitivity analyses. [Id.] A chronological optimal generation expansion model was used to determine the least-cost expansion plans for the self-build and purchase power alternatives. [Id.] The evaluation was conducted over a 30 year planning period from 2006 through 2035. [Id.] The least-cost expansion plans for each Applicant determined by the optimal generation expansion model were modeled using a detailed chronological production cost model to obtain annual production costs. [Id.] Fixed costs, including fixed charges on new unit additions, purchased power capacity costs, fixed 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. [Id.] In addition, as discussed above, environmental considerations were factored into the analyses, including the forecast cost of emissions allowances for current regulatory requirements. [Id.] Conservation and DSM measures were evaluated, and cost-effective conservation and DSM measures were included in the analyses. [Id.] The cumulative present worth costs (CPWC) of all of these annual costs were determined and used as the basis to compare expansion plans. [Id.; Kushner, T.1107-1108]

Using the updated capital cost estimates, the base-case analyses show that participation in TEC represents the least-cost capacity expansion plan for each Applicant when compared to the most economical alternate self-build capacity expansion plans under base case assumptions and most of the sensitivity assumptions. [Rollins, T.322; Kushner, T.1114, 1125; EX.56] The base-case analyses demonstrate that the least-cost expansion plan with TEC will result in CPWC savings of approximately $417.1 for FMPA, approximately $38.1 million for JEA, approximately $255.6 million for RCID, and approximately $188.6 million for the City of Tallahassee, for a combined CPWC savings of approximately $899.3 million. [Kushner, T.1126-1127]

In addition to the base case analyses, over 70 sensitivity analyses were conducted using the updated capital cost estimates. [Kushner, T.1143] 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.[14] [Kushner, T.1116] In response to Staff Interrogatories, the Applicants also performed sensitivity analyses under "acid tests" which assumed constant natural gas/coal price differentials over the thirty year period of analysis. [EX. 2, Tab 3, Appl. Resp. to Staff Int. No. 74] In addition, as noted above, although the Applicants remain confident that the majority of the costs identified in the transmission system impact study report will be classified as network improvements, the Applicants performed a sensitivity analysis that increased the capital cost of the project by approximately $100 million to capture the upper end of the project's transmission interconnection cost exposure based on the conceptual estimates provided in the system impact study report. [Kushner, T.1115] As previously noted, the results of this analysis indicate that participation in TEC is still the most cost-effective alternative available to each

[14] In response to an NRDC interrogatory, the Applicants also performed a sensitivity analysis assuming low load and energy growth along with the CO_2 allowance prices forecasted by Hill & Associates. [EX.108, Appl. Resp. to NRDC Int. No. 26] That sensitivity analysis showed that TEC was still the most cost-effective alternative for all of the Applicants. [Id.]

Participant. [Id.] Under such a scenario, participation in TEC will result in combined CPWC savings of approximately $823 million. [Id.]

External parameter sensitivity analyses also were 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 PRB coal instead of Latin American coal. [Kushner, T.1116-1117] The joint development three train 1x1 IGCC alternative was assumed available in May 2012 to allow for a comparable evaluation of these options versus participation in TEC. [Id. at 1117] This is a favorable assumption for the IGCC because, as discussed above, it is considered an emerging technology that the Applicants would likely not commit to for commercial operation until 2018. [Id.] In addition, as noted above, the joint development three train 1x1 IGCC alternative was assumed to operate with 100 percent petcoke, which is another favorable assumption because 100 percent petcoke would be less expensive than a petcoke/coal blend and because there are reliability concerns regarding the availability of 100 percent petoke. [Kushner, T.1218-20]

The results of the over 70 sensitivity analyses indicate that participation in TEC is included in each Applicant's least-cost capacity expansion plan under all but one sensitivity scenario. [Kushner, T.1127] The lone exception is JEA's low fuel price sensitivity, which indicates the least-cost expansion plan not including participation in TEC would be approximately $12.7 million lower in CPWC than participation in TEC. [Kushner, T.1128] Under that scenario, the least-cost expansion plan for JEA under the low fuel price sensitivity includes a petcoke-fired CFB alternative in lieu of participation in TEC. [Id.]

Although economic evaluations were conducted through 2035, 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. [Gilbert, T.660; May, T.464; Guarriello, T.718; Brinkworth, T.752-753] 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 the Applicants. [Id.] Therefore, the total cost savings and benefits of TEC are understated in the economic analysis. [Id.]

ISSUE 9 CONCLUSION

Based on the evidence discussed above, the Applicants' economic analyses appropriately accounted for anticipated costs and plant performance. Contrary to Intervenors' assertions, the Applicants appropriately considered biomass and IGCC technology and concluded that neither is a viable or cost-effective alternative to TEC. The results of the base case analysis, coupled with the results of the sensitivity analyses, demonstrate that the capacity expansion plan including participation in TEC is a robust plan for each Applicant, and is sufficiently flexible to overcome variations and deviations from the base case assumptions, even in light of the updated capital cost estimates. Moreover, the detailed economic analyses demonstrate that the proposed TEC generating unit is the most cost-effective alternative available, as this criterion is used in Section 403.519, Florida Statutes.

ISSUE 10: **Based on the resolution of the foregoing issues, should the Commission grant the Applicants' petition to determine the need for the proposed TEC generating unit?**

POSITION: ****Yes. The Commission should grant the petition for determination of need for TEC. TEC provides the Applicants and the Florida electric system reliability and integrity, adequate electricity at a reasonable cost, fuel diversity and supply reliability, and is the most cost-effective alternative available. There also are no conservation measures taken by or reasonably available to the Applicants which might mitigate the need for the unit. As**

such, TEC meets all of the pertinent statutory criteria in Section 403.519, Florida Statutes, and, therefore, should be approved.**

For all of the reasons discussed above, the Commission should grant the petition for determination of need for the TEC. TEC is needed to satisfy each Applicant's forecast capacity requirements and to maintain their respective reserve margins. TEC is the most cost-effective option to meet the Applicants' capacity needs. As a cost-effective and reliable resource, TEC will provide adequate electricity at a reasonable cost. There are no conservation measures taken by or reasonably available to the Applicants which would mitigate the need for the proposed plant. Fuel diversity and supply reliability also will be increased through the capability to utilize fuel sourced from multiple international and domestic supply regions. The use of demonstrated supercritical pulverized coal technology will also increase reliability. As such, TEC meets all of the pertinent statutory criteria in Section 403.519, Florida Statutes, and, therefore, should be approved.

While the Applicants presented overwhelming evidence in support of their Need for Power Application, the Intervenors failed to offer "contrary evidence of equivalent quality" to show why the application should be denied. <u>See</u> <u>Department of Transportation v. J.W.C. Co</u>., Inc. 396 So. 2d 778, 788-89 (Fla. 1st DCA 1981). Likewise, nothing in the public comments refutes the Applicants' case. In that regard, the majority of the public comment focused on matters, such as environmental, health, and rail traffic impacts, that are beyond the Commission's jurisdiction in this proceeding. Those matters are appropriately addressed by the agencies with relevant jurisdiction and, ultimately, by the Governor and Cabinet in the subsequent certification proceeding under the Florida Electric Power Plant Siting Act (PPSA). <u>See</u> <u>In re: Petition of Florida Power and Light Company for determination of need for proposed electrical power plant and related facilities - Martin Expansion Project</u>, Order No. 23080, at p.

22, 90 FPSC 6:268, 289 (1990) ("The forum in which the Legislature intended the record to be developed on the environmental impacts of proposed power plants is the forum in which the agencies charged with environmental matters have the greatest input: the final certification hearing."). Accordingly, those matters are not addressed in this filing.

ISSUE 11: **Should this docket be closed?**

POSITION: ****Yes. When the Commission has issued its final order in the case and the time for reconsideration has passed, this docket should be closed.****

Consistent with established Commission practice, this docket should be closed when the Commission has issued its final order in the case and the time for reconsideration has passed.

CONCLUSION

Based on the foregoing, Florida Municipal Power Agency, JEA, Reedy Creek Improvement District and City of Tallahassee respectfully request that the Florida Public Service Commission grant their Petition to Determine Need for the Taylor Energy Center.

Respectfully submitted, this 24th day of January, 2007.

//s//Gary V. Perko

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Petitioners' Post-Hearing Statement of Issues and Positions and Brief in Support of Petition to Determine Need For Electrical Power Plant in Taylor County in Docket No. 060635-EU have been furnished by hand-delivery (*) or U.S. Mail on this 24th day of January, 2007:

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