State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 8, 2007

TO: Director, Division of the Commission Clerk & Administrative Services (Bayó)

FROM: Division of Economic Regulation (Harlow, Breman, Brown, Lester, Matlock, McRoy, Springer, Stallcup, VonFossen)
Office of the General Counsel (Brubaker, Fleming, Holley)

RE: Docket No. 060635-EU – Petition for determination of need for electrical power plant in Taylor County by Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and City of Tallahassee

AGENDA: 02/13/07 – Regular Agenda – Posthearing Decision – Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: McMurrian

CRITICAL DATES: 02/13/07 (Applicants waived rule requirement for a vote within 135 days until 2/13/2007)

SPECIAL INSTRUCTIONS: None

FILE NAME AND LOCATION: S:\PSC\ECR\WP\060635.RCM.DOC

Case Background

On September 19, 2006, Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and City of Tallahassee (the City) (collectively Applicants) filed a petition for a need determination for the proposed Taylor Energy Center (TEC), a 765 megawatt supercritical pulverized coal plant. The TEC is expected to be placed in service in May 2012, and will be located on a 3,000 acre greenfield site in Taylor County. The Applicants also pre-filed testimony on September 19, 2006.

The Applicants consist of three municipal electric utilities, JEA, RCID, and the City of Tallahassee, along with FMPA, a wholesale power company composed of 30 municipal electric utilities. Fifteen of FMPA's members participate in the All Requirements Project, under which FMPA meets all of these members' power requirements.

All of TEC's 765 megawatt capacity will be fully subscribed by the Applicants, and will serve retail customers of the municipal utilities. According to the current agreement between the Applicants, the ownership and costs for TEC will be allocated 38.9 percent to FMPA, 31.5 percent to JEA, 9.3 percent to RCID, and 20.3 percent to the City of Tallahassee. The capacity from the proposed generating unit will be allocated to each Applicant as follows: 297.8 megawatts to FMPA, 241.1 megawatts to JEA, 71.2 megawatts to RCID, and 155.4 megawatts to the City of Tallahassee.

Intervention was granted to the Sierra Club, Inc., John Hedrick, Brian Lupiani, Rebecca J. Armstrong and Anthony Viebesie (collectively, Sierra Club), the Natural Resources Defense Council, Inc. (NRDC), and John Carl Whitton, Jr. (Whitton).[1] Intervenor testimony was filed on November 2, 2007. The Applicants filed rebuttal testimony on November 21, 2007; supplemental testimony on December 12, 2007; and supplemental, revised supplemental, and supplemental testimony on December 26, 2007.

A formal administrative hearing was held on January 10 through 12, and 18, 2007. The Applicants, the NRDC, and Whitton timely filed post-hearing briefs on January 24, 2007. The Sierra Club filed its post-hearing brief on January 25, 2007.

Public Testimony: In addition to the pre-filed testimony submitted by the applicants and intervenors, the Commission also considered live testimony from concerned citizens. On January 10, 2007, a full day of the hearing was dedicated to public testimony from 35 witnesses. Most represented themselves as residents of the city of Tallahassee or nearby Madison and Taylor counties. Others represented themselves in their professional capacity, i.e. the Mayor of Tallahassee, a County Commissioner from Baker County, and the president of the First Coast Manufacturers Association. The public testimony touched on many issues previously identified at the pre-hearing conference. The associated concerns and where they will be addressed in staff's recommendation are shown below:

Fuel Diversity – Issues 3 and 9
Reasonable Rates – Issues 2, 3, 4, 5, 6, and 9
Reliable Service – Issues 1, 2, and 3
Generation Alternatives – Issues 2, 3, 4, and 9
Increased Capital Costs – Issues 2, 8, and 9
The Use of Demand-Side Management – Issues 4, 8, and 9
Environmental Compliance Costs – Issues 5, 6, 8, and 9

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[1] Intervention was granted by Order No. PSC-06-0867-PCO-EU, issued October 20, 2006 with respect to Rebecca J. Armstrong; by Order No. PSC-06-0898-PCO-EU, issued October 26, 2006, with respect to the Sierra Club, John Hedrick, and Brian Lupiani; by Order No. PSC-06-0954-PCO-EU, issued November 15, 2006, with respect to Anthony Viegbesie; by Order No. PSC-06-0957-PCO-EU, issued November 16, 2006, with respect to John Carl Whitton, Jr.; and by Order No. PSC-06-0971-PCO-EU, issued November 21, 2006, with respect to the NRDC.

Some concerns discussed during the public testimony phase of the hearing were broad in nature, and in staff's opinion, touched on subjects which are beyond the scope of this proceeding under Section 403.519, Florida Statutes, or this Commission's jurisdiction under its authorizing statutes. A summary of these concerns is shown below:

Impact of Existing and Future Pollution Sources – This concern was twofold. Some citizens raised concerns about pollution, such as mercury, particulates, and carbon dioxide, that a coal fired power plant would add to the air and water in Perry, Florida. Concerns were also raised regarding pollution from an existing paper mill also located in Perry, Florida.[2]

Impact of Increased Railroad Traffic – Some citizens raised concerns about how the increased rail traffic to deliver coal to the TEC site would impact local communities in areas such as emergency vehicle response, noise, and general automobile traffic congestion.[3]

Cost Recovery for Municipal Utilities – Although the Commission does not have rate making authority over municipal and cooperative utilities, several witnesses requested the Commission to limit or re-visit the cost-recovery of the proposed facility because of the risk of future environmental requirements. Some witnesses wanted the Commission to direct the participating utilities on how to allocate their financial resources, i.e. research renewable generation, preserve canopy roads, and improve mass transit.[4]

Staff believes that the extent of public testimony on these matters demonstrates a very strong concern on the part of the public regarding potential issues of pollution, railroad traffic, and cost recovery in association with this project. Staff also notes its concerns regarding these issues; however, as stated above, we believe that the Commission's ability to address these matters in the context of this proceeding is limited by the legislative scope of the Commission's authority under Section 403.519, Florida Statutes.

For instance, the Commission can address whether the Applicants have appropriately addressed costs associated with rail traffic as a component of the infrastructure improvements associated with the TEC project (see TR 415; Issue 9). However, the ultimate resolution of those issues would most appropriately take place before the Department of Transportation, the Department of Environmental Protection, the Division of Administrative Hearings, the Governor and Cabinet, sitting as the Siting Board or in proceedings before the applicable municipal bodies who may address future rate issues associated with the proposed TEC project. Staff does note, however, that Applicant Witness Lawson testified that the Applicants would be willing to serve as a conduit between the affected municipalities and railroads to facilitate resolution of the concerns regarding the impact of rail traffic associated with the TEC project. (TR 433-434, 449)

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[2] Witnesses Saff, Cavros, Thompson, Poppell, Parker, Bellamy, J. Dickert, G. Dickert, Taitt, Monroe, Reynolds, Kelynack, Johnson, Blair, Liles, Fullington, O'Connor, Lupiani, Ezell. TR 45-55; 74-83; 83-89; 125-155; 158-176; 178-190; 208-220; 222-248

[3] Witnesses Robinson, Parsons, Perkins, Johnson. TR 66-74; 102-109; 176-190

[4] Witnesses Cavros, Lloyd, Reynolds, Fullington, Lupiani, Ezell. TR 74-83; 89-93; 163-168; 222-225; 229-248

Similarly, while Section 403.519, Florida Statutes, authorizes the Commission to examine TEC's projected costs for environmental controls necessary to meet current state and federal environmental requirements (see Issue 6), some of the concerns raised during the public testimony fall under the Department of Environmental Protection's jurisdiction.

While staff believes that the Commission's ability to address all issues raised in the public testimony is limited by the scope of Section 403.519, Florida Statutes, and other statutes which set the Commission's legislative authority, staff urges that those entities and forums in which these additional issues may be addressed take particular note of the strong public opinion expressed during the January 10, 2007, public testimony portion of the hearing in this matter. These concerns may be relevant in the certification proceedings before the Department of Environmental Protection, the Division of Administrative Hearings, and the Governor and Cabinet, sitting as the Siting Board or in proceedings before the applicable municipal bodies who may address future rate issues associated with the proposed TEC project.

The Commission has jurisdiction in this matter pursuant to Section 403.519, Florida Statutes.

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Executive Summary

Under Florida law, the Commission's need determination is the first step in the certification process required for all major power plant additions in Florida. In its entirety, the Florida Power Plant Siting Act requires that decisions be made not only by the Commission but also the Department of Environmental Protection, other affected state and local agencies, and ultimately the Governor and Cabinet sitting as the Siting Board relating to each agency's area of expertise. The power plant siting process is designed, however, to be a "one-stop" process with final decisions rendered within certain statutory time frames based on the best information and evidence available at the time. The Commission's decision on a need determination petition must be based on the facts as they exist at the time of filing with underlying assumptions tested for reasonableness, certainty, and prudence. However, it is prudent for each utility to continue to analyze whether it is in the best interests of its ratepayers to participate in a proposed power plant before, during, and after construction of a generating unit.

The evidence presented during the four days of hearing support the approval of the need for the Taylor Energy Center. The four Applicants demonstrated a reliability need for additional generating capacity (MW need) in the year 2012 based upon reasonable load forecasts, the expiration of existing purchased power contracts, and the retirement of older generating units. Even an aggressive demand-side management effort by the co-owners, similar to the City of Tallahassee's proposed plan, would not overcome the reliability need for additional generation by the year 2012. The Taylor Energy Center was also shown to be a proven technology and the most cost-effective alternative with savings of approximately $899 million (economic need). Such savings, based on most likely forecasts, were tested using approximately 70 different scenarios including changes in fuel price forecasts, increased capital costs, and the cost impacts of potential CO_2 regulations. Based on the record in this case, staff recommends that the Taylor Energy Center is the most cost-effective alternative at this time to meet the electrical needs of the Applicants. At the hearing, four main areas were addressed and are discussed in more detail below.

<u>Cost of Future Environmental Regulations</u>

As discussed in Issue 5, the cost of future environmental regulations, especially for carbon emissions, are unknown and largely unquantified at this time. The Applicants performed numerous sensitivity analyses to verify the reasonableness of the cost-effectiveness of the Taylor Energy Center. For example, a conventional natural gas-fired combined cycle unit produces lower CO_2 emissions than the proposed Taylor Energy Center. While natural gas technology may reduce the impact of future CO_2 regulations, it would not contribute to fuel diversity for the Applicants or the State and, based on the evidence presented, the ratepayers of the four Applicant utilities would experience an increase in costs of approximately $1.3 billion. In other words, the TEC's projected costs can increase approximately $1.3 billion due to potential CO_2 regulation and still remain cost-effective when compared to a natural gas-fired combined cycle unit.

Another sensitivity analysis conducted by the Applicants examined the feasibility and costs of constructing similarly sized Integrated Gas Combined Cycle (IGCC) technology as a substitute for the Taylor Energy Center. An IGCC unit converts coal to gas prior to combustion and is therefore better capable of removing and reducing carbon emissions. However, IGCC technology is relatively new and untested particularly in larger unit sizes such as 765 MW. IGCC technology is also more expensive to construct and operate than more conventional advanced technology coal-fired generation such as being proposed for the Taylor Energy Center. The Applicants' analysis showed that an IGCC unit would increase costs by approximately $464 million over the costs of the Taylor Energy Center.

As discussed in Issue 8, however, while staff recommends a determination of need for the Taylor Energy Center be granted at this time pursuant to the record in this case and the provisions of the Florida Power Plant Siting Act, that does not mean that the Applicants should not continue to examine the ongoing cost-effectiveness of the unit. Prudent utility practice is to continue to analyze a generation project before, during, and after construction to ensure continued benefits to the utility's general body of ratepayers.

Demand-Side Management

The City of Tallahassee presented evidence of their commitment to an aggressive demand-side management program that could defer the City's reliability need from 2012 to 2016. However, because of the lower energy cost associated with the Taylor Energy Center, the City of Tallahassee was able to demonstrate an economic need for the Taylor Energy Center beginning in 2012. Even if the other Applicants (JEA, FMPA, and Reedy Creek Improvement District) were to deploy a similar demand-side management effort, the resulting reduction in peak demand would not overcome the utilities load growth and a reliability need for additional coal-fired generation would still exist during the 2012 to 2013 time period. The ownership share for these three utilities is approximately 80% of the total output from the Taylor Energy Center. In other words, the evidence supports that, at a minimum, 80% of the generating capacity from the Taylor Energy Center is needed for reliability purposes by the year 2012 even if aggressive demand-side management measures were implemented.

This does not mean, however, that the Applicants should be allowed to relax their efforts to pursue aggressive demand-side management efforts. Rather, the Applicants should continue their individual and collective efforts to develop and implement prudent and affordable demand-side management programs. In order to ensure that the Applicants do all within their ability to promote conservation among their constituent ratepayers, each Applicant utility should continue to report on its conservation initiatives and achievements annually in their Ten-Year Site Plan filings.

Transmission System Impacts

Even though the proposed Taylor Energy Center will be owned by four different utilities, the footprint of the generating unit does not reside in any of the Applicant's service territories. To actually get the power from the Taylor Energy Center to the Applicants' service territories will require the use of the transmission systems of Progress Energy Florida and Florida Power & Light Company. No adverse transmission reliability impacts were identified by Progress Energy Florida and Florida Power and Light Company and this conclusion was confirmed by the Florida

Reliability Coordinating Council. Such findings appear consistent with other transmission studies that have been reviewed by the Commission.

Issues Outside the Commission's Jurisdiction

The public testimony phase of the hearing identified strong concerns regarding issues beyond the Commission's jurisdiction, such as the local impacts due to increased rail traffic. While these issues are outside the Commission's jurisdiction, these concerns are significant and may be considered in the certification proceedings before the Department of Environmental Protection, the Department of Administrative Hearings, the Governor and Cabinet sitting as the Siting Board, or in proceedings before the applicable municipal bodies who are responsible for addressing retail rate issues that arise from participation in the Taylor Energy Center. One issue has been addressed by the Applicants with their $5 million contribution to the City of Perry to mitigate adverse rail traffic impacts. The full record of the Commission's proceeding is available to these other entities for their review and deliberation at future proceedings.

While staff believes that the Commission's ability to address all issues raised in the public testimony is limited by the scope of Section 403.519, Florida Statutes, and other statutes which set the Commission's legislative authority, staff urges that those entities and forums in which these additional issues may be addressed take particular note of the strong public opinion expressed during the January 10, 2007, public testimony portion of the hearing in this matter.

Discussion of Issues

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?

Recommendation: Yes. Based upon reasonable projections of load growth, the expiration of existing purchased power contracts, and the retirement of existing generating units, the Applicants have demonstrated a reliability need for the TEC. (Brown)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: The Applicants have not demonstrated that TEC is needed or appropriate taking into account the need for electric system reliability and integrity because they have not adequately addressed issues, such as the availability of DSM options and the likely regulatory costs associated with future CO_2 emission limitations, that may have significant implications for system reliability and integrity.

Whitton: No. While there is evidence of growth in the Applicants' need for capacity requirements, the Applicants have not proved, by a preponderance of the evidence, that the proposed TEC will enhance the reliability and integrity of each Applicant. For example, the details and costs of interconnecting the TEC have yet to be determined.

Sierra Club: No. While the individual Participants do evidence demand growth and the need for additional capacity, they have elected to meet their needs by the addition of a large, base-load, coal-fired plant which brings with it substantial economic and operational risk. The application fails to demonstrate adequate measures to manage this risk over the life of the proposed plant addition, instead asserting that super-critical pulverized coal plants generically manage the risk of volatility in global fossil fuel markets. The City of Tallahassee has benefited from expert advice which demonstrates that with the implementation of a well-managed portfolio of energy resources, it can reliably serve its growth in energy needs without the risk and cost of TEC. Additionally, FMPA is dramatically affected by transmission constraints in Florida in serving its dispersed members. The addition of TEC will require FMPA to take energy from North Florida and distribute to several of its members in Central Florida and South Florida, thereby increasing its operating costs, and complicating its ability to meet growth in demand reliably.

Staff Analysis: After considering the evidence in the record, staff believes the Applicants demonstrated that in order to continue to provide reliable electric service, additional capacity from the TEC will be needed in 2012. The capacity need results from the retirement of existing generating units, expiration of purchased power contracts, and expected load growth. Below is a discussion of each Applicant's need assessment in regards to participation in the TEC.

JEA

Load Forecast: The load forecast for JEA was sponsored by Witness Gilbert. Mr. Gilbert offered direct testimony and exhibits summarizing the forecasts used to create the projected system peaks. (TR 653-655, EXH 2, EXH 17) Witness Gilbert testified that JEA's summer peak demand is forecasted to increase at an average annual growth rate of 1.9 percent, while JEA's winter peak demand is forecasted to increase at an average annual growth of 2.7 percent. JEA's summer peak demand is projected to increase from 2,716 MW in 2007 to 3,729 MW in 2024, while JEA's winter peak demand is projected to increase from 2,924 MW in 2007 to 4,630 MW in 2024. (EXH 17) The NRDC agrees with the forecast methodology used by the Applicants to forecast capacity and energy. (NRDC BR 8) The NRDC's argument pertains to whether costs are reasonable and whether need could be more cost-effectively met by demand-side management programs. (NRDC BR 6-7) These matters will be discussed in Issues 4 and 9. None of the other intervenors questioned JEA's load forecast methodology.

Reserve Margin: JEA's reserve requirements are determined by comparing net system capacity and system peak demand plus reserves for the summer and winter peaks. JEA's reserve margin criteria in both the summer and winter seasons is 15 percent. (TR 659) Based on JEA's load forecast, without the TEC, JEA's 2012 summer reserve margin is approximately 12.4 percent. (EXH 2) JEA's reserve margin after adding capacity from the TEC would improve to approximately 20.2 percent. When analyzing JEA's original low and high peak demand forecast, staff realized that the additional 100 MW of load from the recently extended purchased power agreement with Florida Public Utilities Company was not included in the analysis. Therefore, when reviewing JEA's need for capacity under its high and low load growth scenarios, staff added the additional demand from the extended Florida Public Utilities Company contract to the low and high load case. The result of doing so revealed that in the low load case, JEA's need would shift to 2014. In the high load case, JEA's need advanced to 2010.

Based on current available capacity resources and projected reserve requirements, JEA has demonstrated that it has a need for capacity in order to meet its established reliability criteria of 15 percent reserve margin. (Applicant BR 13) JEA will need 83 MW of additional capacity beginning in winter 2010/2011. This capacity need results from unit retirements, expected load growth and expiration of purchased power contracts. In particular, an existing contract for unit purchased power of 207 MW of coal-fired capacity with Southern Company is due to expire May 2010. (TR 659, Applicant BR 11-12) The purchased power contract has no provisions for extension, but JEA has discussed entering into a new contract with new terms. JEA decided that it was not in its best interest to pursue a new contract with Southern Company, under the terms offered by Southern Company. (EXH 2) JEA will need capacity between 2010 and the 2012 in-service date of the TEC. JEA potentially will fulfill this excess capacity need between 2010 and 2012 with natural gas or by entering into short term capacity contracts. (TR 659)

REEDY CREEK IMPROVEMENT DISTRICT (RCID)

Load Forecast: The load forecast for RCID was sponsored by Witness Guarriello. Witness Guarriello offered direct testimony and exhibits summarizing the forecasts used to create the projected system peak. RCID's firm summer peak demand is forecasted to increase from 191 MW in 2006 to 213 MW in 2025 (an average annual growth rate of approximately 0.6 percent). (TR 712, 713, EXH 18) The NRDC agrees with the forecast methodology used by the Applicants to forecast capacity and energy. (NRDC BR 8) The NRDC's argument pertains to whether costs are reasonable and whether need could be most cost-effectively met by demand-side management programs. (NRDC BR 7) These matters will be discussed in Issues 4 and 9. None of the other intervenors questioned RCID's load forecast methodology.

Reserve Margin: RCID plans to maintain a 15 percent reserve margin criteria in both the summer and winter seasons for capacity planning purposes. (TR 714) Based on RCID's load forecast, without the TEC capacity, RCID's 2012 reserve margin is negative 52.5 percent. After including capacity gained from the TEC, RCID's reserve margin improves to negative 17 percent. When conducting the low and high peak demand forecast, the results revealed that the period for need would not shift in the low and high forecast. Witness Guarriello testified that RCID relies heavily on the purchased power contracts with Progress Energy Florida, Tampa Electric Company and Orlando Co-Gen, to meet approximately 70 percent of its load. (TR 715, 735; EXH 2) The witness also testified that any additional need beyond that gained from participating in the TEC would be satisfied by purchased power contracts with Orlando Cogen Limited (35 MW) and Tampa Electric Company (up to 75 MW). (TR 736) RCID's capacity need results primarily from the scheduled 2010 expiration of a 124 MW purchased power contract with Progress Energy Florida, which will not be renewed, and load growth. (TR 714, EXH 18, Applicant BR 15)

CITY OF TALLAHASSEE (The City)

Load Forecast: The City's load forecast was sponsored by Witness Brinkworth through testimony and Exhibit 20. The City's 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. Winter peak demand is projected to grow at an average annual rate of approximately 1.8 percent over the same period from 570 MW to 779 MW. (TR 748, EXH 20, Applicant BR 16) The NRDC agrees with the forecast methodology used by the Applicants to forecast capacity and energy. (NRDC BR 8) The Natural Resources Defense Council argument pertains to whether costs are reasonable and whether need could be most cost effectively met by demand-side management programs. (NRDC BR 7-8) These matters will be discussed in Issues 4 and 9. None of the other intervenors questioned the City's load forecast methodology.

Reserve Margin: The City uses a 17 percent reserve margin criteria for both the summer and winter seasons. (TR 749) Based on its load forecast, the City's need for additional capacity would occur in the summer of 2011, with a need for 22 MW. (TR 750, EXH 20, Applicant BR 16) When conducting the low and high peak demand forecast, the results revealed that the period for need would not shift in the either the low or high peak demand forecast. The capacity need results from the 2011 retirement of generating units Purdom CT-1 (10 MW), Purdom CT-2

(10 MW), Purdom 7 (48 MW) and load growth. Without the TEC capacity, the City's 2012 reserve margin is approximately 12 percent. With the TEC capacity, the City's reserve margin increases to approximately 34.9 percent. If the City's expected demand-side management savings are achieved, the additional need for summer capacity could be deferred from 2011 until 2016. (TR 765, EXH 2, Applicant BR 17) However, as discussed further in Issues 4 and 9, the City will still have an economic need for the TEC in 2012.

FLORIDA MUNICIPAL POWER AGENCY (FMPA)

Load Forecast: The load forecast for FMPA was sponsored by Witness Nunes. Witness Nunes offered testimony and exhibits summarizing the forecasts used to create the projected system peak demands. (TR 544, EXH 15) FMPA's summer peak demand is forecasted to increase at an average annual growth rate of 2.5 percent from 2007 through 2009 and 2.1 percent from 2010 through 2024. The average annual growth rate in winter peak demand is projected to increase at an average annual rate of 2.6 percent from 2007 through 2009 and 2.1 from 2010 through 2024. FMPA's summer peak demand over the 2007 through 2024 period is projected to increase from 1,499 MW to 1,909 MW. The winter peak demand over the 2007 through 2024 period is projected to increase 1,458 MW to 1,821 MW. (TR 544, EXH 15) The NRDC agrees with the forecast methodology used by the Applicants to forecast capacity and energy. (NRDC BR 8) The NRDC argument pertains to whether costs are reasonable and whether need could be most cost effectively met by demand-side management programs. (NRDC BR 5-6) These matters will be discussed in Issues 4 and 9. None of the other intervenors questioned FMPA's load forecast methodology.

Reserve Margin: For planning purposes, FMPA established an 18 percent reserve margin criteria for the summer period. (TR 460, Applicant BR 10) Summer reserve margins are expected to fall below the required 18 percent minimum in the summer of 2007. FMPA's reserve margin will exceed the required 18 percent requirement during the 2008 through 2010 period before going below the reserve requirement in the year 2011. (TR 460-1, Applicant BR 10) Without the TEC capacity, the FMPA's 2012 reserve margin is approximately 2.3 percent. With the TEC capacity, FMPA's reserve margin would increase to 22.6 percent. When conducting the low and high peak demand forecast, the results revealed that in the low load case, FMPA's need would shift from 2011 to 2012. In the high load case, FMPA's need would shift from 2011 to 2009.

FMPA's summer capacity requirement projects a need of 20 MW in 2007. FMPA states that the company would likely enter into a short term seasonal purchase to make up for the need in 2007. In 2008 and 2009, Treasure Coast Energy Center would bring 296 MW of additional capacity to FMPA's system to alleviate any need for those time periods. The addition of simple cycle combustion turbines is projected to satisfy capacity requirements identified for 2010. (TR 461) Beginning in 2011, FMPA is projected to have a need of 59 MW of additional capacity. (TR 461) These capacity needs result from unit retirements (Hansel Combined Cycle: 48 MW, Lake Worth Unit 3: 22 MW, Lake Worth Unit 5: 8 MW, Lake Worth Gas Turbine 1: 26 MW, Lake Worth Gas Turbine 2: 20 MW, Lake Worth D1-5: 10 MW), expected load growth, and expiration of purchased power contracts. In his testimony, Witness May discussed the expiration of FMPA's purchased power contract with the Southern Company in 2013. The witness testified that because of the cost of extending the Southern Company contract, FMPA has decided to not extend the contract. (EXH 2)

PARTIES POSITIONS

The NRDC, Sierra Club, and Whitton have contested the need for the proposed TEC based on inadequate DSM, inadequate estimates of potential CO_2 costs associated with the proposed unit, and overall cost-effectiveness of the project. (NRDC BR 2-4, Whitton BR 4) These issues are more appropriately addressed in Issues 4, 5, and 9, respectively.

Conclusion: Staff recommends that there is a need for the TEC to maintain electric system reliability and integrity. Staff reviewed the Applicants' load forecast assumptions, methodologies, and results and believes they are appropriate for use in this docket. The forecast assumptions were drawn from independent sources on which the Commission has relied in prior cases. The Applicants followed their most recent Ten Year Site Plans which have detailed analyses of projected growth and been deemed suitable by the Commission. Staff also believes that the projected peak demands and net energy for load growth appear to be a reasonable extension of historical trends. No parties offered alternative load forecasts to those filed by the Applicants. NRDC agreed that the methodology used to forecast the Applicants' demand and energy needs is appropriate. Furthermore, NRDC stated that it does not question the resulting forecasts. (NRDC BR 8)

Staff recommends the reserve margin criteria used by each Applicant is reasonable. Each Applicant stated that its reserve margin criteria has not been changed in recent years. (EXH 2) Each Applicant has demonstrated a need for additional capacity by 2012, the in-service date of the TEC, when their available capacity will fall below their established reserve margin criteria.

<u>Issue 2</u>: 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?

<u>Recommendation</u>: Yes. The proposed TEC is a proven technology and the estimated costs provided by the Applicants appear to be reasonable. Based on current projections, the TEC is expected to provide the Applicants adequate electricity at a reasonable cost. (McRoy)

<u>Position of the Parties (Taken Directly from Briefs)</u>

Applicants: 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.

NRDC: The forecasting methodology used by the Applicants to forecast the capacity and energy demand needs necessary to meet the Applicants' respective operating and reserve margin requirements is appropriate. NRDC does not question the validity of the capacity and energy demand forecasts. As discussed in Issues 1, 3 and 4, NRDC questions whether these projected capacity and energy needs could have been substantially reduced, deferred or most cost-effectively met by demand side management (DSM) programs rather than by building any individual or collective supply side option analyzed by the Applicants. The Applicants have failed to perform meaningful and adequate assessments of the potential for cost-effective demand side management programs and thus have failed to prove that TEC will provide adequate electricity at a reasonable cost.

Whitton: No.

Sierra Club: No. Section 403.519, Florida Statutes, clearly discusses the physical need for capacity in the context of cost effectiveness. Each of the Participants is electing to invest in a large, base-load coal-fired plant essentially as an economic hedge in volatile fossil fuel markets. These Participants are presently facing the reality of escalating capital costs, of uncertain operating and maintenance costs, and of shifting financing costs. Until the full impact of these cost increases are known, the Participants cannot understand if they are reasonable, or if there are reasonable alternatives.

The Participants have grossly miscalculated the risk of adverse economic impact caused by shifts in air qualify regulation for coal-fired electric power plants. The Participants, with one noteworthy exception, apparently intend to forego this important opportunity to implement demand-side alternatives to address growth in demand, and to insulate themselves from the risk of more stringent air quality regulation.

Staff Analysis: The TEC will be a 765 MW (net) pulverized coal, balanced draft unit employing supercritical steam pressure and temperature with a mechanical draft cooling tower for condenser cooling water. The primary advantage of a technology employing a supercritical steam cycle is the improved plant efficiency due to elevated operating pressure and temperature, lower emissions and lower fuel consumption. (TR 813) Witness Hoornaert indicated that the proposed TEC plant will be designed to burn up to 30 percent petcoke blended with a variety of grades of coals. The TEC will be capable of burning coals from Latin America, the Powder River Basin region in Wyoming, and Central Appalachia regions. (TR 815) The ability to burn a blend of fuel, including various grades of coal and petcoke, will reduce risk and lower the overall operating costs of the TEC

Capital Costs

The TEC will also employ state-of-the-art emission control equipment to further reduce emissions. The list of emission control equipment is provided in the direct testimony of Witness Hoornaert. (TR 814-815) Witness Hoornaert testified that as a result of the emission-reduction measures that are planned for TEC the combined NOx, SO_2 and mercury emissions should meet current regulation standards. (TR 814-815) The total installed cost of the TEC is estimated to be \$2,039,074,000. This represents a 19.01 percent increase from the original estimate of \$1,713,399,000 in 2012 dollars. (TR 822-823) Included in the updated total installed cost is approximately \$40,000,000 for an Activated Carbon Injection system to be installed as a contingency plan for additional mercury reduction if needed to meet requirements of the second phase of the Clean Air Mercury Rule. (TR 823) These updated costs are discussed further in Issue 9.

Comparison to IGCC

Public Witness Furman raised an issue of whether the Applicants had appropriately considered building an Integrated Gasification Combined Cycle (IGCC) unit for the TEC project instead of the proposed pulverized coal unit. (TR 25, EXH 82) Witness Klausner testified that the performance characteristics of IGCC technology are not comparable to the proposed TEC. (TR 1095-1096) Witness Kushner testified that due to availability concerns, fueling an IGCC unit the size of TEC with 100 percent petcoke would cause reliability concerns. (TR 1219) Further, Witness Hoornaert characterized petcoke as an opportunity fuel, because although it is typically lower in cost than coal, its availability varies. (TR 840) However, the Applicants performed a sensitivity analysis based on an IGCC unit with an in-service date of 2012 fueled with 100 percent petcoke which showed that an IGCC unit would not be cost-effective when compared to the TEC. (TR 1116) Staff has reviewed the assumptions used in this sensitivity analysis and they appear to be reasonable. The results of the sensitivity are discussed in Issue 9.

Transmission Requirements

According to Applicant's Witness Brinkworth, the Applicants assumed that three 230 kV transmission lines will be constructed from TEC to Progress Energy Florida's Perry substation. The $11.7 million expected costs for these transmission upgrades was included in the capital cost for the TEC. (TR 758-759) To actually get the power from the TEC to the Applicants' service territories will require the use of the transmission system of Progress Energy and Florida Power & Light Company. Progress Energy and Florida Power & Light Company have identified additional transmission improvements necessary to ensure that there will be no adverse transmission impacts caused by interconnecting the TEC to the transmission grid. The Florida Reliability Coordinating Council (FRCC) Planning Committee "has 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." (EXH 2) The projected costs of needed facilities identified by Progress Energy and Florida Power & Light Company will be classified as either direct connection facilities or network improvements. (TR 759, 774) The Applicants believe the majority of the additional costs identified will be classified as network improvements. All network improvement costs will be initially paid for by the Applicants but will be credited back as offsets for the Applicants respective transmission service charges for delivery of power from the TEC. (TR 759, 775-777) However, the Applicants did perform a sensitivity analysis that increased the capital cost of the project by approximately $100.3 million to capture the upper end of the project's transmission interconnection cost exposure based on the conceptual estimates provided by Progress Energy and Florida Power & Light Company. (TR 759) Witness Kushner conducted a sensitivity analysis for this condition. (TR 760) This sensitivity analysis is discussed in Issue 9.

Parties' Positions

The intervenors contest the need for the TEC based primarily on the availability of cost-effective DSM, estimates of potential CO_2 mitigation costs, and overall cost-effectiveness of the project. These arguments are more appropriately addressed in Issues 4, 5, and 9, respectively.

Conclusion: Staff recommends that the TEC is a proven technology and the estimated costs provided by the Applicants appear to be reasonable. The Applicants' analyses show a large portion of the proposed 765 MW (net) capacity will be needed in 2012, which should be a base load type capacity for reasons of economics. Based on current projections, the TEC is expected to provide the Applicants 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?

Recommendation: Yes. The addition of baseload coal-fired generation from the TEC will improve each Applicant's fuel diversity and supply reliability. The addition of TEC will also mitigate the impact of supply disruptions caused by an overdependence on natural gas. (Brown)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: The Applicants have not demonstrated a need for TEC taking into account the need for fuel diversity and supply reliability. First, as to JEA, the TEC unit will have no significant impact with respect to fuel diversity - in fact, JEA's alternative expansion plan without TEC would result in greater coal-based generating capacity in the long run. As to each Applicant, to the extent that fuel diversity is an important objective, that objective would be better served by construction and operation of an IGCC facility. Because the Applicants failed to adequately and accurately assess the costs associated with IGCC, the Application does not appropriately address fuel diversity.

Whitton: Whitton recognizes the need for fuel diversity in the State of Florida's electric power generation facilities. However, fuel diversity should include renewable sources of fuel, which have not been seriously considered by the Applicants in this proceeding. The addition of the proposed TEC coal power plant also will not serve to further JEA's fuel diversity, as it will maintain its existing fuel diversity at approximately 50 percent coal and 50 percent natural gas. The primary fuel diversity benefits of TEC are that it will be able to utilize three types of the same fuel source – coal. In addition, since the Applicants have failed to identify specific modes and routes for the transportation of coal, the Commission cannot adequately assess the supply reliability for TEC.

Sierra Club: Sierra notes that there is a need for a formal definition of the term "fuel diversity" as used in Section 403.519, Florida Statutes. It is acknowledged that cost effective fuel diversity has value in the state's current generation mix. However, cost effective fuel diversity would be better served by an appropriate portfolio of energy efficiency measures, conservation, demand-side management (DSM) and renewables.

Staff Analysis: In 2006, the Legislature amended Section 403.519, Florida Statutes, to require the Commission to review the need for fuel diversity and supply reliability in need determination proceedings. The purpose of fuel diversity is to provide a balanced mix of generating resources. Staff agrees with Witness Fetter that fuel diversity reduces the risk of supply interruptions and lessens price volatility. (TR 627-628)

With the exception of JEA, the Applicants' current generation mix relies heavily on natural gas and purchased power. The ownership of a solid fuel generating unit, such as the TEC, would provide a more diverse fuel mix and improve fuel diversity for the Applicants. Alternatively, JEA is replacing coal-by-wire purchased power, with coal capacity from the TEC.

The solid fuel generating alternatives considered by the Applicants included nuclear, renewables, and coal. Because of the construction lead time, nuclear generation would not be available to meet the Applicants' 2012 reliability need.

The Applicants also reviewed the feasibility and cost-effectiveness of various renewable generating technologies. The only renewable technology that passed an initial screening was direct fired biomass generation. The Applicants performed a sensitivity of a generation plan that included ownership of a 30 MW direct fired biomass plant by each Applicant with an in-service date of 2012. The biomass alternative was found not to be cost-effective. The Applicants review of renewable alternatives is discussed in more detail in Issue 9.

Staff believes that the analyses presented shows that each Applicant's fuel diversity and supply reliability will benefit from participation in the TEC. Below is a discussion of each Applicant's fuel mix in 2006 without the TEC, and in 2013, with the TEC.

JEA

In 2010, JEA is terminating a purchased power contract with Southern Company consisting of 207 MW of coal-fired capacity. (TR 650, 659, EXH 2) Therefore, the TEC project is replacing purchased power coal capacity with coal capacity that will be owned by JEA. The table below displays JEA's current and future capacity mix by fuel type. (EXH 17)

JEA - Capacity by Fuel Type (%)		
	2006	**2013**
Coal	47.3	50.0
Natural Gas	38.9	44.0
Oil	8.3	5.5
Purchased Power	5.5	0.5

REEDY CREEK IMPROVEMENT DISTRICT (RCID)

Currently, RCID relies heavily on purchased power contracts to meet its capacity needs. (TR 715, 735) Witness Guarriello indicated that RCID probably gets about 70 percent of its generation from purchased power contracts. (EXH 2) Much like JEA, RCID is replacing purchased power, but also adding significant solid fuel capacity to its system. The table below displays RCID's current and future capacity mix by fuel type. (EXH 18)

RCID - Capacity by Fuel Type (%)		
	2006	**2013**
Coal	0	30.0
Natural Gas	26.3	46.3
Oil	2.4	2.2
Purchased Power	71.3	21.4

CITY OF TALLAHASSEE (The City)

The City has the least diverse fuel mix of the four Applicants, with over 98 percent of its capacity provided by natural gas-fired units. (EXH 20) The addition of the TEC will help the City displace existing gas fired generation. The table below displays the City's current and future capacity mix by fuel type. (EXH 20)

Tallahassee - Capacity by Fuel Type (%)		
	2006	**2013**
Coal	0	16.7
Natural Gas	98.2	81.8
Hydro	0.3	0.2
Purchased Power	1.5	1.3

FLORIDA MUNICIPAL POWER AUTHORITY (FMPA)

FMPA will be replacing purchased power contracts with additional solid fuel capacity. The table below displays FMPA's current capacity mix by fuel type (2006) and after the addition of the TEC (2013): (EXH 13)

FMPA - Capacity by Fuel Type (%)		
	2006	**2013**
Coal	12.8	25.4
Natural Gas	53.1	52.0
Oil	8.8	10.5
Purchased Power	20.5	8.3
Nuclear	4.8	3.8

Both the NRDC and Whitton raise the issue that the proposed plant will not improve JEA's fuel diversity. (NRDC BR 17 , Whitton BR 5) As shown above, while the percentage of coal in JEA's fuel mix does not change dramatically, the shift is from purchased power coal capacity to utility owned coal generation. Staff believes this shift offers a benefit for JEA associated with the greater degree of operational and cost control of self-owned capacity. Whitton also contends that the Commission cannot adequately assess the fuel supply reliability for the TEC because the Applicants did not identify modes and routes for transporting coal. However, as discussed further in Issue 9, staff agrees with the Applicants that it is premature to have fuel commodity and transportation contracts for the TEC in place at this time prior to receiving regulatory approvals. Furthermore, the TEC's ability to burn various grades of coal as well as petcoke will allow the Applicants more options in obtaining fuel and fuel transportation than for a more typical pulverized coal plant that burns a single grade of fuel. (TR 961) The ability to burn a variety fuels will also provide flexibility for the Applicants to competitively bid fuel and transportation sources for the TEC, resulting in reduced risks and operating costs. The remaining issues brought up by the intervenors, DSM, IGCC and renewables, are addressed in Issues 4 and 9.

Conclusion: Staff recommends that there is a need for the TEC when taking into account fuel diversity and supply reliability. Each of the Applicants' witnesses testified that the purchased power market in Florida is currently very tight, with little or no baseload capacity available for purchase. (TR 681-682, 723, 766; EXH 2) The TEC will allow the Applicants the opportunity to add additional solid fuel capacity to replace expiring purchased power contracts or displace natural gas capacity. The TEC will allow the Applicants to use various grades of coal, as well as petcoke, from both domestic and international sources. (TR 716, 751; EXH 2) The low cost baseload energy from the TEC will also help the Applicants reduce their dependence on volatile higher cost natural gas.

The design of the TEC includes the potential for up to 90 days storage of coal and petcoke. (TR 463, 658-659, 717, 752; EXH 2) The benefits from this on-site storage include minimizing short-term disruptions of fuel transportation systems as compared to natural gas where disruptions have occurred as a result of hurricanes. Therefore, staff recommends that the addition of the TEC will improve supply reliability for the Applicants.

Issue 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?

Recommendation: No. Even if the City of Tallahassee's ambitious DSM savings are applied to the other Applicants' peak demands, it would not relieve JEA's, FMPA's and RCID's reliability need. The Applicants' first priority should be maintaining reliability. Each Applicant utility should continue to report its conservation initiatives and achievements annually in their Ten-Year Site Plan filings. (Harlow)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: The Applicants, except for the City of Tallahassee, have not conducted (individually or collectively) an adequate assessment of existing or potentially available DSM measures. Each of the TEC Participants has acknowledged its obligation to consider DSM, however not Participant except for COT has actually performed an assessment that specifically evaluates DSM for technical potential, economic potential, and achievable potential, in a manner that appropriately compares the cost of DSM measures to the benefit that those measures will provide. Moreover, the DSM analysis performed to identify potentially available DSM measures for FMPA and JEA was woefully inadequate, and inappropriately rejected DSM measures that would have been identified as cost-effective under an analysis similar to the one used by COT. Finally, RCID failed entirely to perform any meaningful assessment of DSM. As a result, the Applicants have not demonstrated that DSM has been fully considered, and have not shown that DSM measures that might mitigate the need for the proposed TED facility are available.

Whitton: Yes. The total benefits of DSM opportunities have not been adequately evaluated in the analyses conducted by each Applicant. The four Applicants utilized three different methods for determining which DSM and conservation measures were cost-effective are indicative of this. JEA and FMPA relied on the Rate Impact Test for their determination of cost-effectiveness of

DSM and conservation measures. On the other hand, Tallahassee evaluated the cost-effectiveness of DSM measures based on projections of total achievable energy and capacity reductions and their associated annual costs utilizing a methodology developed specifically for Tallahassee. As a result, Tallahassee is acquiring 100 MW of DSM, despite the fact that Tallahassee believed there were no new cost-effective DSM measures available before making this more detailed analyses. Meanwhile, RCID did not conduct any tests to determine if there are any potential additional DSM measures available, and instead relied on conclusory statements that RCID's unique customer base is doing all they can for cost-effective conservation measures.

Sierra Club: Yes. The Participants generally have undervalued the economic benefits of energy efficiency, conservation and DSM opportunities, especially when it is considered that these directives insulate them from the risk of more stringent air quality regulation.

Staff Analysis: The DSM methodology and assumptions used by both JEA and FMPA are reasonable and consistent with Commission policy. The results of JEA's and FMPA's analysis found no cost-effective DSM measures which could avoid or defer the capacity of the TEC. Furthermore, given RCID's need for 134 MW beginning in 2011, approximately 67 percent of its peak demand, coupled with its unique customer base, it is reasonable to expect that RCID's need can not be deferred with additional DSM. There is some uncertainty about whether the City's DSM savings will be as high as expected, as DSM savings are less certain than generation capacity. Even if the City's ambitious DSM savings are applied to the other Applicants' peak demands, it does not mitigate JEA's, FMPA's and RCID's reliability need. The Applicants' first priority should be maintaining reliability. Staff notes that JEA, FMPA and RCID each committed to implementing cost-effective DSM measures on a going forward basis. (TR 702, 738, 478, 488) DSM programs should play a vital role in reducing customer energy needs. Staff also believes there are potential economies of scale in DSM program development, just as for generation projects. To the extent the Applicants cooperate and share information on potential DSM measures, staff believes DSM program development costs can be reduced, to the benefit of the utilities' customers. Each Applicant's DSM efforts are discussed below.

JEA and FMPA

JEA is the only Applicant for which the Commission has the authority to set DSM goals pursuant to the Florida Energy Efficiency and Conservation Act, because JEA is the only Applicant that meets the required sales threshold. (TR 496, EXH 17, EXH 20) The Commission most recently established JEA's DSM goals by Order No. PSC-04-0768-PAA-EG, issued August 9, 2004, in Docket No. 040030-EG. By its order, the Commission approved demand and energy goals for JEA set at zero because no programs were found to be cost-effective. (EXH 17) Nevertheless, JEA currently offers a number of DSM programs, including energy audits, solar incentives, Green Built homes, chilled water service, and interruptible load. (TR 663, EXH 17) While these programs were not found to be cost-effective, JEA believes that offering the programs is in the best interest of its customers. (EXH 17) Witness Gilbert stated that JEA is committed to implementing cost-effective DSM programs on a going forward basis. (TR 702)

As a wholesale power provider, FMPA does not directly implement DSM programs for its members' retail customers; rather, FMPA's member utilities provide DSM programs for their retail customers. (TR 462) FMPA does, however, have a member services department that provides information and coordinates the member cities' DSM efforts. (TR 481) Witness May stated that FMPA's "member cities encourage conservation through energy audits, lighting conversions, Energy Star and other programs." (TR 462, 475) All programs are not offered by each member due to the small size of some member utilities, which range in size from less than 20 MW to just over 200 MW. (TR 478-479) Witness May also testified that some DSM programs, such as load control programs, that may be beneficial to a retail utility, may actually increase costs for a power wholesaler such as FMPA. FMPA aggregates the peak demands of its individual members and provides service at the coincident peak. (TR 499) An individual member may actually increase the peak demand for FMPA by implementing a load control program, since an individual member's peak may differ from the coincident peak of FMPA as a whole. (TR 482-483, TR 499) To the extent that JEA and FMPA and the utility's customers are implementing DSM measures, the demand savings are reflected in each utility's load forecast. (TR 509, 1176)

Black and Veatch performed a demand-side management (DSM) analysis for JEA and FMPA which tested the cost-effectiveness of 180 DSM measures using Black and Veatch's proprietary FIRE model. (TR 1170, 1174, EXH 58) The FIRE model evaluates the cost-effectiveness of DSM measures by comparing the measure against the costs of a utility's next avoided unit, in this case, the TEC. The model calculates results for three cost-effectiveness tests: the Ratepayer Impact Measure (RIM), Participants, and Total Resource Costs (TRC) tests. (EXH 58) Witness Kushner stated that the 180 DSM measures that were evaluated for JEA and FMPA "represent a wide range of end uses and are pertinent to residential, commercial and industrial customers." (TR 1174, 1211, EXH 58)

Witness Kushner testified that no DSM measures were found to be cost-effective for JEA or FMPA under the RIM test. (TR 497, 1173-1174, 1186-1187, EXH 58) A passing value on the RIM test indicates that a program is beneficial to both a DSM program's participant and the utility's general body of ratepayers. A failing value on the RIM test indicates that there would be upward pressure on rates if the program were to be implemented in lieu of investing in planned capacity. (EXH 58) Staff agrees with Witness Kushner that the results of the FIRE model -- the RIM, Participants, and TRC tests -- are consistent with the Commission's policy in previous need determinations and in setting DSM goals. Staff also agrees with the Applicants that Black and Veatch's DSM analyses for JEA and FMPA are consistent with the DSM analysis performed in FMPA's recent need determination. (Applicants BR 32) The Commission approved FMPA's need determination for the Treasure Coast combined cycle generating unit by Order No. PSC-05-0781-FOF-EM, issued July 27, 2005, in Docket No. 050256-EM.

Witness Kushner testified that FMPA's DSM measures were tested for FMPA as a whole, rather than for FMPA's individual members. (TR 1182, EXH 58) Witness Kushner also stated that his analysis for FMPA included the least cost retail rates of FMPA's members. (TR 1182, EXH 2) Staff believes that these two assumptions are conservative in that they tend to favor DSM programs relative to planned capacity. (TR 497, 1182, EXH 2) No cost-effectiveness analysis was performed for FMPA's individual member utilities. (TR 1182, EXH 58) Witness May, however, believes that an analysis on individual members "would likely have shown that it was even more costly for the individual member than it would be for FMPA." (TR 485, 497)

Staff disagrees with the arguments set forth by NRDC, Whitton, and the Sierra Club that the Applicants have not adequately evaluated cost-effective DSM opportunities. (NRDC BR 25, Whitton BR 8, Sierra BR 21) As noted above, JEA and FMPA provided a sufficient analysis using the Commission approved cost-effectiveness tests. Staff agrees with the Applicants that this analysis contained the same level of detail as those approved by the Commission in previous need determinations. (Applicants BR 32) Staff further disagrees with the Sierra Club that the Applicants have undervalued DSM because they did not account for potential CO_2 costs. (Sierra BR 24) As discussed in Issue 5, no current regulations exist regarding CO_2. However, the Applicants performed a sensitivity to JEA's and FMPA's DSM analysis with included estimated CO_2 allowance costs. In this scenario, no DSM programs were found to be cost-effective. (TR 1187, EXH 2) The Applicants also performed a sensitivity analysis with high fuel costs, in which no DSM measures were found to be cost-effective for JEA or FMPA. (TR 1187, EXH 2)

RCID

RCID has a unique customer base with over 85 percent of its load from Walt Disney World, and the vast majority of its remaining load from commercial hotels and other commercial customers. RCID only has ten residential customers. (TR 712, 721, 724, EXH 2, EXH 18) As such, RCID views its efforts in DSM as a partnership between RCID and its major customers. Witness Guarriello stated that RCID works "very closely with its customers, including Walt Disney World and the hotels." (TR 724, EXH 18) RCID can control certain equipment, such as heating, ventilating, and air conditioning equipment at Walt Disney World, to set points which have been agreed upon by Walt Disney World and RCID. (TR 726, EX 2, EXH 18) RCID currently also offers several DSM programs, consisting of an energy audit program, a thermal storage program, and an efficient lighting program. (TR 715, 727, 729, EXH 18) RCID provides information and assistance to its commercial customers through energy audits and monthly meetings between RCID's chief senior energy management engineer and interested customers. (TR 726-727) Witness Guarriello testified that through the combined conservation efforts of RCID and its customers, "they are saving 100 gigawatt hours annually, which is about 8 percent of their energy … and that translates probably to about 10 percent of their demand." (TR 728, 737) In addition, Walt Disney World has recently set the goal to reduce its energy usage by an additional 5 percent over the next 5 years. (TR 737)

RCID did not perform an updated DSM analysis of potential DSM measures. (TR 1170) Witness Guarriello, however, testified that RCID and its customers would continually evaluate potential DSM measures. (TR 715, EXH 18) RCID gave several reasons for not performing an analysis of potential DSM measures. According to Witness Kushner, "taking into consideration Reedy Creek has a substantial need for additional capacity in the 2011/2012 time frame, coupled with their unique customer bases and the significant savings they're achieving already, there's no basis to believe that there are additional DSM measures that could be implemented and, therefore, none were evaluated." (TR 1172) The load forecast for RCID reflects the DSM measures implemented by RCID and its customers. (TR 715)

Staff initially shared NRDC's and Whitton's concern that RCID did not present an analysis of potential DSM measures according to Commission approved methodology. (TR 1170, NRDC BR 34, Whitton BR 13) However, staff disagrees with NRDC and Whitton that

RCID did not provide sufficient evidence that there were no DSM programs that could avoid or defer RCID's need for capacity. (NRDC BR 34, Whitton BR 13) According to Witness Guarriello, due to the efforts of RCID and its customers, RCID's energy has been reduced by 8 percent. (TR 728, 737) NRDC and Whitton did not dispute RCID's current energy savings. Furthermore, Sierra Club's Witness Powell characterized a utility DSM program with energy savings of 4 percent or greater as successful. (TR 921-922) Most importantly, due to the expiration of purchased power agreements, RCID has a need for 134 MW in 2011, or over 67 percent of its peak demand. (TR 1172) Staff therefore agrees with Witness Guarriello that it is not probable that RCID's need for capacity could be met with additional DSM savings, regardless of cost. (TR 737)

The City

The City currently offers a number of DSM programs, including energy audits, low interest energy efficiency loans, natural gas rebates, low-income ceiling insulation and retrofit grants, and customer information programs. (EXH 20) The City's DSM programs are primarily based on providing low interest loans. (EXH 2, EXH 20) The City recently analyzed the results of its existing programs, and found that over the past 10 years these existing programs have reduced peak demand by 20 MW and annual energy use by 80 gigawatt hours. (TR 751) These savings are reflected in the City's load forecast. (TR 1176)

The City used its own methodology, which was developed in concert with Navigant Consulting, for testing the cost-effectiveness of potential DSM measures. (TR 769) The multi-stage methodology begins with a busbar analysis in which the levelized cost of each DSM measure was calculated and compared to the levelized cost of a comparable supply-side resource. (EXH 58) In contrast to the FIRE model, DSM measures were compared to various supply-side alternatives, rather than a single avoided unit. Each DSM measure was compared to a supply-side alternative (or alternatives) with a similar duty cycle over the life of the DSM measure. (TR 769, EXH 58) As stated by Witness Brinkworth, "if you had a DSM measure that clipped your peak in the summer, for example, you'd compare that cost to the cost of a combustion turbine that would be a peaking unit." (TR 769) Next, the measures that passed the initial busbar screening were combined into bundles, which were assigned a chronological load shape based on the impact of that bundle on the City's hourly load for a year's time. The load shapes of all DSM bundles were then combined and applied to the City's demand and energy forecast. The City's generation expansion plan was then re-evaluated with the revised load shape as an input. (TR 769-770, EXH 58)

Black and Veatch did not run the FIRE model on the City's proposed DSM measures. (TR 795, 1170-1171) Therefore there are no RIM, Participants, or TRC test results for the programs in the record. Witness Brinkworth stated, however, that the City's "original screening of measures in our internal IRP did not show any measures that passed the rate impact test." (TR 770) There is conflicting evidence in the record regarding whether the City's planned DSM measures will increase customer rates. Witness Brinkworth testified that the City's expansion plan which included the DSM measures and associated reduced production costs could translate into downward pressure on rates. (EXH 2) However, Witness Kushner testified that programs that fail the RIM test would tend to put upward pressure on rates. (EXH 58) Staff agrees with

Witness Kushner that the costs of DSM programs that fail the RIM test would tend to increase rates.

The City has committed to implementing the DSM measures that it found to be cost-effective using the busbar analysis. (TR 765, EXH 2, EXH 58) If the measures are implemented as planned, the City expects savings of 7 MW summer peak reduction in 2007, growing to 161 MW of summer peak reduction in 2025, and 162 MW of winter peak demand reduction by 2025. (EXH 58) This 162 MW of expected peak demand savings was mentioned frequently at hearing, in particular, by NRDC Witness Urse. (TR 1223, 1234, 1236, 1238) Staff believes, however, that the savings the City expects to achieve by 2025 is irrelevant in determining the need for the TEC. In determining the need for the TEC, the focus should be placed on the City's expected demand savings by 2012, the in-service date of the TEC. By 2012, the City expects a summer peak reduction of 59 MW, or 8.7 percent, of the City's expected 676 MW peak demand. (EXH 58) Witness Kushner testified that if these savings materialize, the City's capacity need could be shifted from 2011 to 2016. (TR 1121) Regardless of the results of the programs, it appears that the City would still have an economic need for the low-cost baseload energy from the TEC. The Applicants' estimated that there would be additional savings of $228.8 million for an expansion plan that includes the City's expanded DSM measures and the TEC, as compared to a plan that does not include the TEC. (TR 1121; EXH 58, EXH 3)

Staff applauds the City's plans to significantly expand its DSM programs. Like the City, some of Florida's municipal utilities, including JEA and FMPA, have chosen a policy to implement DSM programs even though no programs were found to pass the RIM test. (EXH 13, EXH 17, EXH 20) However, staff agrees with Witness Kushner that the City's plans are ambitious, and there is uncertainty that the savings will be achieved to the extent predicted. The City is expecting savings to begin in 2007, (7 MW), yet at deposition, Witness Brinkworth stated that the City had not developed a plan for its specific programs. (EXH 2) The programs will be incentive-based, yet according to Witness Brinkworth, the City has not set a budget for these incentives. (TR 772-773; EXH 2) Over the next five years, the City expects to triple the demand that it has achieved in 10 years with its existing DSM programs. Witness Rollins testified that the savings from DSM programs are less certain than generating capacity because DSM programs depend on the actions of customers. (TR 1263-1265) Staff agrees with the Sierra Club's Witness Powell that some of this uncertainty can be resolved through program design. (TR 918-919) Witness Brinkworth testified that if the City's DSM savings do not materialize as expected, the capacity from the TEC could be used to meet the City's higher than expected load. (TR 800)

Staff disagrees with NRDC that additional cost-effective DSM measures could be found for JEA and FMPA by simply comparing the levelized cost of the TEC to the City's calculation of levelized costs for potential DSM measures. The levelized costs provided by the City appear to be lower than those for the TEC for several DSM measures. (TR 1169; EXH 105) However, staff agrees with Witness Brinkworth that it is inappropriate to make such a comparison because the duty cycle of the DSM measures is not the same as for the TEC, a baseload generating unit with an expected capacity factor of 90 percent. (TR 786, 1167) Staff also recommends that the City may have overstated the level of DSM savings by calculating the levelized costs of generation alternatives over the expected life of each potential DSM measure, rather than the expected life of the generators. (TR 769; EXH 58) Staff also notes that the City calculated the levelized costs for DSM measures according to the expected life of each DSM measure. (TR 769) The City then used these levelized costs in developing the total demand and energy reduction that could be achieved from its DSM measures over the life of the measures. As discussed above, the City expects demand savings from its new DSM measures beginning with 7 MW in 2007, growing to 59 MW in 2012, the in-service date of the TEC, and up to 161 MW in 2025. (EXH 58) DSM savings are achieved over time, with the demand and energy savings increasing gradually as program participation grows. (TR 1223) Therefore, staff cautions that the City's total expected DSM savings by 2025 cannot be used as an argument that the Applicants can avoid or defer the need for the TEC's capacity. What is important in determining the need for the TEC is the level of cost-effective DSM savings that could be achieved by 2012, the in-service date of the TEC.

Sierra Witness Powell testified that each Applicant should have used the same DSM analysis methodology. (TR 900) However, staff disagrees because Witness Powell did not offer a preferred methodology, but merely stated that the City "appears to have conducted the most through analysis of available DSM measures." (TR 899) As discussed above, the City expects a 59 MW reduction in peak demand, or 8.7 percent, from its new DSM measures by 2012. As a sensitivity, staff applied this 8.7 percent peak demand reduction to each Applicant's 2012 peak demand to determine if the reliability need for the TEC would shift significantly. As displayed below, even if the City's ambitious expected demand savings are applied across all Applicants, the reliability need remains in 2012 for RCID and FMPA, and moves to 2013 for JEA. This conclusion was echoed by FMPA's Witness May, who testified "[o]ur need is so significant in 2012 and 2014 that the feasible DSM programs that could be implemented, cost aside, doesn't appear that it would achieve in the time frame that we're talking about our need, sufficient reductions in load even if it were done at the individual city level." (TR 497) Of course, staff's DSM sensitivity analysis should carry the caveat that the City's planned DSM measures would not translate directly onto JEA, FMPA and RCID, as each utility has a different customer base and various levels of existing DSM programs.

	2012 Peak (MW)	**Assume 8.7% Savings (MW)**	**2012 Need (MW)**	**2013 Need (MW)**	**Reliability Need After 8.7% MW Savings (YEAR)**
The City	676	59	34	45	2016
JEA	3,307	288	182	304	2013
FMPA	1,497	130	230	322	2012
RCID	200	17	135	136	2012

Conclusion: Staff recommends the DSM methodology and assumptions used by both JEA and FMPA are reasonable and consistent with Commission policy. The results of JEA's and FMPA's analysis found no cost-effective DSM measures which could avoid or defer the capacity of the TEC. Furthermore, given RCID's need for 134 MW beginning in 2011, approximately 67 percent of its peak demand, coupled with its unique customer base, it is reasonable to expect that RCID's need can not be deferred with additional DSM. Therefore, staff believes it was reasonable in this particular instance for RCID to not submit a revised DSM analysis. Staff also applauds the City's plan to expand its DSM efforts. Even if the City's ambitious DSM savings are applied to the other Applicants' peak demands, it does not appear to relieve JEA's, FMPA's, and RCID's reliability need. Furthermore, there is some uncertainty about whether the City's DSM savings will be as high as expected, as demand savings are less certain than generation capacity. In this case, the City will need capacity from TEC to maintain its reserve margin. The Applicants' first priority should be maintaining reliability. Staff notes that JEA, FMPA, and RCID each committed to implementing cost-effective DSM measures on a going forward basis. (TR 702, 738, 478, 488) DSM programs should play a vital role in reducing customer energy needs. Staff also believes there are potential economies of scale in DSM program development, just as for generation projects. To the extent the Applicants cooperate and share information on potential DSM measures, staff believes DSM program development costs can be reduced, to the benefit of the utilities' customers. Each Applicant utility should continue to report its conservation initiatives and achievements annually in their Ten-Year Site Plan filings.

Issue 5: Have the Applicants appropriately evaluated the cost of CO_2 emission mitigation costs in their economic analysis?

Recommendation: Yes. Estimating CO_2 emission mitigation costs for the proposed TEC facility is highly speculative because there is no current CO_2 regulation and no consensus regarding potential regulatory requirements. However, the Applicants have performed a reasonable sensitivity analysis based on potential CO_2 regulation, the results of which support the TEC as cost-effective. The Applicants' sensitivity analysis comparing TEC to natural gas fired options showed significant savings for TEC. (Breman)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: No. While the PRISM model appears to be an excellent tool for forecasting mercury, SO2, Nox and CO2 emission allowance costs and associated fuel costs, the assumptions which form the parameters of the CO2 emission allowance cost study in this case are specious. Allowing CO2 emissions to increase over the study period rather than be capped or reduced is contrary to virtually all proposed legislation. Capping electric demand growth rates at 1 % is inconsistent with Florida's historic, and the Applicants' projected, growth rates. Modeling 12 new nuclear power plants between 2016 to 2020 in light of permitting and waste disposal barriers as well as renewable energy generation which increased from 12 to 20 % is simply unrealistic where many states, including Florida have no renewable energy requirements. The "full blown" CO2 emission multiclient study, which does accurately reflect the provisions of the McCain-Lieberman bill, would have given a more accurate forecast of a CO2 regulated environment. These results are consistent with Dr. Lashof's testimony of reasonable CO2 emission allowance costs and could have been used to produce a CO2 regulated sensitivity study that truly evaluated the impact of CO2 regulation. Without a valid CO2 sensitivity study and associated IRP, the Applicants have not demonstrated that TEC is the most cost-effective alternative available.

Whitton: No. The Applicants have underestimated the cost of carbon dioxide allowances which will be required to operate the proposed pulverized coal power plant. Instead of relying on existing estimates from credible sources, the Applicants relied upon the cost projects made by Hill & Associates specifically for TEC, which are dramatically less than those made in Hill & Associates commercially available projections. In order for the CO2 cost projections used by the Applicants to be reasonable, the following assumptions must be realized: (1) Demand increases for some EGUs will not exceed 1 percent per year; (2) EGUs in states which do not currently have any renewable energy standards are projected to aggressively shift to carbon-free energy sources; (3) 12 nuclear plants will come on line between 2016 and 2020, and that these will be considered non-emitters; (4) non-EGUs will aggressively reduce their emission; by non-electric generating industries; and, (5) EGUs will receive further economic relief based on political pressure.

Sierra Club: No. In the face of existing best practices, of standing carbon trading markets and clear public policy initiatives, the sensitivity analyses submitted by Participants consistently underestimate the costs that would be incurred to operate TEC in the more stringent air quality regulatory structure that will certainly be in place before TEC becomes operational.

Staff Analysis: The Applicants argue that at this time there is uncertainty regarding competing legislative initiatives purported to limit, cap, or reduce CO_2 air emissions. (TR 1042, 1043, 1055-1057, 1063-1066, 1256-1258, 1270) Witness Rollins noted while that it is impossible to mitigate all risks, it is important to identify and evaluate risks that have significant impacts on customers. (TR 1253) The Applicants prepared sensitivities based specific assumptions of what, in Witness Preston's opinion, was a plausible future outcome of pending legislation. (TR 1024, 1025, 1034-1035, 1037-1043, 1039, 1256-1258) For example, Witness Preston assumed that integrated gasification combined cycle (IGCC) facilities could partially sequester CO_2, and that there is no available technology to remove CO_2 from standard pulverized coal facilities. Witness Preston also assumed that a nationwide fungible CO_2 allowance trading system would be established. Furthermore, Witness Preston assumed (1) the addition of 12 nuclear power plants nationwide, (2) a cap on annual growth in electric demand to one percent nationwide, (3) compliance with the federal Clean Air Interstate Rule and the federal Clean Air Mercury Rule, and (4) an increase in renewable resources to 12 percent by 2010 and increasing to 20 percent on a national basis. (TR 1000, 1012-1014, 1020, 1031, 1037, 1039, 1043, 1056, 1065) These assumptions, together with fuel price, supply, and demand data, were used in a proprietary model to develop nationwide allowance prices for SO_2, NOx, mercury, and CO_2 emissions. The proprietary model allows for fuel switching, adding emissions controls, buying or selling of allowances, and determines the least cost option to meet electric demand of the United States and Canada while meeting all environmental constraints. (TR 1010, 1024) The nationwide modeling provides an estimated price of an allowance to emit a ton of CO_2.

The Applicants' overall cost-effectiveness analysis and CO_2 sensitivity analysis was presented by Witness Kushner in Exhibit 57. A summary table appears below showing the estimated cumulative present worth costs for each Applicant with and without CO_2 regulation assumptions. (TR 1034, 1036, 1038, 1039, 1042, 1043, 1055, 1056, 1063-1066, 1133, EXH 57) On a total basis, the table below shows savings for the joint expansion plan scenarios including the TEC compared to expansion plans without the TEC, even when including potential costs associated with CO_2 regulation.

Expansion Plan Sensitivities
Cumulative Present Worth Costs in Billions ($)

	Existing CO_2 Regulations (None)	**Future CO_2 Regulations**	
	With the TEC	With the TEC	Without the TEC
FMPA	9.2	9.7	10.1
JEA	14.4	15.9	16.0
RCID	1.8	1.9	2.1
The City	4.4	4.5	4.6
Total	**29.8**	**32.0**	**32.8**

NRDC, Whitton, and the Sierra Club assert that the Applicants have under estimated the potential cost of CO_2 allowances, made "industry-friendly" assumptions, and that the unknowns make the TEC project a risky proposition. (Sierra BR at 27-28; NRDC BR at 1, 38-43; Whitton BR at 15-17; TR 557, 561-564, 566, 862, 864) Whitton Witness Deevey provided alternative CO_2 allowance price forecasts developed by Synapse Energy Economics Inc. (EXH 79) Witness Deevey advocated large emission reductions of as much as 80 percent, and believes that the adoption of federal policies as proposed by the Applicants is unlikely. (TR 566) Witness Deevey further notes that there is no commercial or economical method for post-combustion removal of carbon dioxide from a supercritical pulverized coal plant. Witness Deevey believes that if the plant is approved and future regulations greatly reduce allowable carbon emissions, then the new regulations on carbon emissions will have a particularly dramatic economic effect on consumers. (TR 566-567) In addition, Witness Deevey testified regarding studies related to CO_2 concerns associated with future coal additions at Gainesville Regional Utilities. Those studies concluded that large investment in coal-based generation was too risky for municipal utilities in the present energy environment given the extreme regulatory and technological uncertainties. (TR 556, 557; EXH 75)

NRDC Witness Lashof suggested there are more efficient technologies, such as IGCC, which allow for the capture and permanent disposal of CO_2. Permanently capturing and sequestering carbon dioxide from a pulverized coal facility is more expensive and requires approximately 30 percent of the energy produced by the power plant. Witness Lashof suggested CO_2 allowance prices should range between $8 and $40 per ton. He also stated that he was not aware of any formally approved methodology by either the EPA or the DEP expressly for the purpose of evaluating source-specific costs associated with controlling CO_2 air emissions. (TR 874, 880-881)

Both the Applicants and the Intervenors support efforts to assess potential cost impacts of future CO_2. However, there is considerable uncertainty regarding estimating what future CO_2 regulations may require. NRDC Witness Deevey's exhibit DD-1, at page 11, states "[i]t is impossible to predict when the regulatory programs will affect Florida, or exactly how they will regulate emissions." (EXH 75) The executive summary of the Synapse Energy Economics Inc. report supported by Witness Deevey states "[w]e recognize that there is considerable uncertainty inherent in projecting long-term carbon emission costs, not least of which concerns the timing and form of future emission regulation in the United States." (EXH 79) Applicant Witness Fetter notes that is hard to tell what the future holds with regard to legislative activity. (TR 631) Applicant Witness Gilbert notes that there is a lot of discussion about CO_2 and greenhouse gas constrained economics and much speculation. (TR 675)

Staff believes that given the uncertainty regarding the timing and form of future CO_2 emission regulation, any effort to resolve differences in CO_2 allowance price forecasts at this time is futile. More focus can be given to resolving which CO_2 allowance price forecast is reasonable for planning purposes once a consensus federal bill exists or CO_2 air emissions requirements are established for Florida. Until such time, it is reasonable for electric utility management to continue assessing the potential long term costs associated with potential CO_2 regulations.

Nevertheless, staff believes it is necessary to test whether the Applicants have presented a project that is the most likely to be cost effective over the long term, given what is known today about CO_2 regulation. In this instance, there are only three generation technology alternatives that can address the foreseeable baseload need: the TEC, a natural gas fired combined cycle project, and an IGCC project. The uncontrolled CO_2 emission from a natural gas fired combined cycle facility is lower than either the TEC or an IGCC project. The uncontrolled CO_2 emissions from the TEC and an IGCC project are comparable. (TR 343, 566, 677, 839, 1043) Thus, the cost differential between the TEC and alternative power plant alternatives will show how much risk the TEC proposal can address in terms of increased costs due to CO_2 regulation and still remain cost-effective.

Witness Kushner's Exhibit 57 contains various cumulative present worth calculations for each of the Applicants assuming possible joint alternative projects that do not include potential CO_2 regulations. The Applicant's analysis is summarized in the table below.

Alternative Joint Project Sensitivities Without Future CO_2 Regulation
Cumulative Present Worth Costs for Joint Projects in Billions ($)

	With the TEC	Natural Gas-Fired Combined Cycle Joint Project	IGCC Joint Project
FMPA	9.2	9.8	9.4
JEA	14.4	14.7	14.5
RCID	1.8	1.9	1.9
The City	4.4	4.7	4.5
Total	29.8	31.1	30.3
Diff. increase from the TEC		**1.3**	**0.5**

As shown in the table, the TEC can absorb approximately $1.3 billion in cost increases due to potential CO_2 regulation and still remain cost-effective when compared to alternative IGCC or natural gas-fired combined cycle alternatives.

Conclusion The Applicants reasonably estimated potential cost consequences due to possible future CO_2 emission regulation. Estimating CO_2 emission mitigation costs for the proposed TEC facility is highly speculative because there is no consensus regarding regulatory requirements. However, the Applicants have performed a reasonable sensitivity analysis based on potential CO_2 regulation, the results of which support the TEC as cost-effective. Furthermore, the Applicants' comparison of the TEC to a natural gas-fired option showed significant savings for TEC. Based on the evidence presented, the cost of the TEC could increase approximately $1.3 billion due to future CO_2 regulations and still remain cost-effective when compared to a natural gas-fired combined cycle alternative.

As discussed in Issue 8 and elsewhere, a need determination decision is not the only evaluation to which a project such as the Taylor Energy Center is subject. Prudent utility practice is to analyze participation in a generation project before, during and after construction to insure continued benefits to the utility's general body of ratepayers.

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, NO_2, SO_2, and particulate emissions?

Recommendation: Yes. The Applicants appropriately included the costs for current state and federal environmental controls. The Applicants were reasonable to rely on the federal requirements of the Clean Air Interstate Rule and the Clean Air Mercury Rule instead of speculating on the outcome of ongoing rule development and litigation regarding Florida's State Implementation Plan and federal court cases. Cost risks associated with evolving environmental regulations are normal costs that power plant owners and operators incur to address their customer's electrical needs. (Breman)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: No. The Applicants used federal emission control standards for mercury, Nox and SO2 which do not reflect the standards proposed to be implemented by the Florida Department of Environmental Regulation (DEP). Further, DEP does not have final CAIR or CAMR regulations in place. Without having final DEP CAIR and CAMR standards, mercury, NO2, and SO2 emissions can not be accurately modeled in the Applicants' base case or sensitivity study integrated resource plans.

Whitton: It appears that the Applicants have evaluated the costs for the controls necessary to meet the current and reasonably anticipated state and environmental controls associated with SO2 and NOx. However, it seems that the Applicants have not fully evaluated the impacts of Florida's proposed State Implementation Plan ("SIP") with regards to mercury (Hg).

Sierra Club: No.

Staff Analysis: Applicant Witnesses Rollins and Hoornaert testified that cost estimates for environmental controls necessary to meet state and federal environmental requirements, including mercury, NOx, SO_2, and particulate emissions were included in the Applicants' cost estimates. The revised cost estimate includes an additional $40 million capital expense as a contingency for activated carbon injection to remove additional amounts of mercury. (TR 324-328, 337, 815-816, 824-825, 829, 841, 1231)

The TEC will include a wet flue gas desulfurization system to control SO_2 air emissions. NOx air emissions will be controlled using three systems which are low nitrogen oxide burners, selective catalytic reduction system, and over-fire air ports. Particulate air emission will be controlled primarily using a baghouse and a wet electrostatic precipitator. The use of these air emission controls also removes some level of mercury from the post-combustion gases. As a contingency to achieve even lower mercury emissions, if deemed necessary by the DEP, the design includes an activated carbon injection system. (TR 815, 824)

Whitton asserts that the Applicants have not fully evaluated the impacts of Florida's proposed State Implementation Plan with respect to mercury. Whitton also asserts that the Applicants have not indicated that they considered the potential impacts of the litigation against the federal Environmental Protection Agency (EPA) challenging the Clean Air Mercury Rule. (Whitton BR 18). The Sierra Club did not provide any reasoning to support its position for this issue.

NRDC asserts that the Applicants have not used the appropriate regulatory standards concerning the Clean Air Interstate Rule and the Clean Air Mercury Rule because the Applicants relied on the federal program rather than the standards proposed by the Florida Department of Environmental Protection. The NRDC also notes that the Applicants did not include operational expenses associated with the proposed activated carbon injection system. These annual costs range from $2 to $4 million. (TR 829) The NRDC concludes that the Applicants' analyses do not reflect the true cost of these regulations because the Applicants did not analyze Florida's actual implementation. (NRDC BR 13, 44-45)

At this time, there is no final Florida State Implementation Plan addressing the Clean Air Interstate Rule and the Clean Air Mercury Rule. (TR 326, 347, 348-349; EXH 2) Until the EPA approves the State Implementation Plan proposed by the Florida Department of Environmental Protection, the EPA's Federal Implementation Plan will govern implementation of the programs in Florida. (TR 326, 347)

No evidence was provided showing that the Applicants failed to include cost estimates for the environmental controls necessary to meet state and federal environmental requirements, including mercury, NOx, SO_2, and particulate emissions. While concerns were raised regarding the Applicants' omission of $2 to $4 million a year for operating a carbon injection system, no party provided evidence that an activated carbon injection system would be necessary to meet future mercury emission limits.

Staff notes that the potential cost risk of $2 to $4 million a year for 30 years would equate to $60 to $120 million, without considering the time value of money. Considering the time value of money would only decrease the estimated 30 year totals. Staff believes this level of cost risk is not significant compared to the risk associated with fuel price volatility. Witness Kushner's Exhibit 57 provides tables showing the cumulative present worth of the TEC under a base case scenario and a high fuel price scenario for each of the Applicants. The total amount for all

Applicants under the base case and high fuel price scenarios are $29,840,600 and $33,054,100, respectively. The difference between the base case and high fuel price scenarios, $3,213,500, is a measure of the potential fuel price volatility associated with the TEC. Since the TEC is cost-effective even considering high fuel prices, staff concludes that the estimated operation expenses associated with activated carbon injection is not substantive. Thus, not including operation expenses associated with activated carbon injection in the cost-effectiveness analyses is not a fatal flaw because the cost impacts are not substantive, and because there is no requirement to implement a carbon injection system at the TEC.

Staff believes that the Applicants appropriately included the costs for current state and federal environmental controls. The Applicants were reasonable to rely on the federal requirements of the Clean Air Interstate Rule and the Clean Air Mercury Rule instead of speculating on the outcome of ongoing rule development and litigation regarding Florida's State Implementation Plan and federal court cases.

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

Recommendation: No. The Applicants did not formally request funding from DOE for IGCC technology. However, the Applicants do appear to have made reasonable efforts to determine whether funding was available in the timeframe required to meet their reliability needs. A formal request of DOE funding for IGCC development is not one of the criteria listed in Section 403.519, Florida Statutes. (McRoy)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: No. The Department of Energy records reflect that the Applicants have not made a formal, written request for DOE funding to construct an IGCC unit in lieu of TEC.

Whitton: No. The Applicants have not made, nor has DOE not received, any formal requests for funding from the Applicants to construct a coal power plant utilizing IGCC technology.

Sierra Club: No.

Staff Analysis: Several of the Intervenors argue that the Applicants failed to make a formal written request to the federal Department of Energy (DOE) for funding to construct an IGCC unit or other cleaner coal technology. (NRDC BR 45, Whitton BR 19) The Applicants did not formally request funding from the DOE; however, the Applicants contend that they have made reasonable efforts to determine that no federal funding was available for an IGCC unit in the time frame needed. (TR 408; Applicant BR 46-47)

The Applicants verbally inquired into the availability of DOE funding for an IGCC. (TR 407) The DOE makes available at times demonstration grant money to assist in the constructing of an IGCC and other emerging advanced technologies units. (TR 340) At the time the Applicants inquired, the only available DOE funding was for an IGCC unit being constructed at an elevation of 4,000 feet or greater. (TR 408) Furthermore, Witness Lawson stated that the Applicants performed the following other activities in an effort to pursue the development of an IGCC unit (TR 396-397, EXH 8, Applicant BR 46):

1. Met with investment bankers, a consortium including a power plant developer and IGCC technology supplier, staff members of both the United States Senate and House, investor-owned utilities (IOUs), and public power entities.

2. Participated in the February 2006 Coal Utilization Research Council conference on clean coal incentives in Washington, D.C.

3. Explored any applicable incentives in the Energy Policy Act of 2005.

4. Considered the requirements of the Clean Air Coal Program.

5. Participated in the 2nd Annual IGCC Symposium in May 2006.

Whitton argues in his brief that, although it is highly unlikely that DOE funding would pay for an entire IGCC power plant, some funding might have made an IGCC plant cost-effective, as was the case with the Orlando Utility Commission's Stanton B plant.[5] (Whitton BR 19) However, Applicants' witnesses testified that verbal inquiries were made as to the availability of DOE funding, and no funding was available in the timeframe necessary to meet the Applicants' need for capacity. Therefore, no written request for federal funding was made. (TR 340-341, 407)

In addition to the discussion regarding DOE funding, staff notes there was testimony concerning the 2005 Federal Energy Policy Act, pursuant to which developers of clean coal technology could be eligible for federal tax credits. (TR 353) These tax credits are used to encourage the development of Clean Coal technology but are only available to taxable entities. (TR 601) The federal tax credit for IGCC development is not available to the Applicants because as municipal utilities they are exempt from federal taxes. (TR 601)

After reviewing their options, the Applicants concluded there were no likely sources of significant funding available for an IGCC unit during the time frame proposed by the Applicants. (TR 340) Moreover, the Applicants argue that nothing requires them to perform a futile act such as filing an application lacking any prospect of success. (Applicants BR 47)

Staff believes the Applicants have properly investigated the availability of DOE funding for IGCC and other emerging advanced technologies.

[5] See Order No. PSC-06-0319-CFO-EM, issued April 20, 2006, in Docket No. 06155-EM, In re: Petition for Determination of need for proposed Stanton Energy Center Combined Cycle Unit B electrical power plant in Orange County, by Orlando Utilities Commission

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

Recommendation: No. Each Applicant has received approval from its respective governing body only through the siting phase for the TEC, which is sufficient for the need proceeding. Each Applicant will have the opportunity to obtain final approval from its respective board prior to the construction phase, and each Applicant plans to reevaluate participation in the TEC with updated data prior to requesting final approval. It is prudent for each Applicant to analyze whether participating in the TEC is in the best interests of its ratepayers before, during and after construction of the unit. (Harlow)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: No. All Applicants have the contractual ability under the Phase II-B Agreement to relinquish all of their allocated capacity or to completely withdraw from TEC. All Applicants also have the ability to make a "go, no-go" decision once all permits have been secured for the construction of TEC. Tallahassee's City Commission has not approved an IRP which includes TEC. Absent such final approvals, and in light of the fact that relinquished TEC baseload capacity could be readily sold on the Florida wholesale electric market, if the Commission issues a need determination for TEC it should be with the condition that the Applicants return to the Commission when the Participation Agreement is executed and reaffirm their individual need for their share of TEC capacity and energy. To do otherwise would be to grant a need determination which has the potential to satisfy statewide, but not individual utility, capacity and energy needs contrary to past Commission decisions and §403.519, F.S., statutory authority.

Whitton: No. Each Applicant has the contractual right to withdraw from the TEC once all permitting has been secured necessary to construct the TEC generating unit and the final construction costs are known, pursuant to the Phase II-B Development Agreement between the Applicants.

Sierra Club: No. All Participants have the contractual right to withdraw once all permitting has been secured necessary to construct the TEC generating unit and the final construction costs are known. At this time the Participants predict that this "go or no go" vote will occur in 2008.

Staff Analysis: The Applicants have each received approval from its respective governing body to participate in the TEC only through completion of the permitting phase. (TR 422, 527; EXH 2) The permitting phase includes the need determination proceeding at the Commission, the certification process at the Florida Department of Environmental Protection, and a final vote by the Siting Board. (TR 422, 425) The Phase IIB agreement between the parties outlines each Applicant's obligations only through the completion of the permitting phase. The Applicants expect to finalize the permitting phase in 2008. (EXH 2) The Applicants do not currently have their governing bodies' approval to participate in the TEC through construction of the unit. (TR 422, 527; EXH 2)

After permitting is completed, the terms of the Phase IIB agreement will have been fulfilled and each Applicant will have no further obligation. (TR 425) According to the Phase IIB agreement, each Applicant will have an opportunity to make a final decision on whether to participate through the construction of the unit. (TR 425, 526, EXH 2) Witness Lawson agreed that at the end of the Phase IIB activities, each Applicant will have the opportunity to "make a final go, no-go decision." (TR 425) The Applicants expect to have a subsequent contract in place prior to the end of the permitting process. This contract would be executed between the parties that wish to continue through construction. Witness Lawson agreed that the rights and responsibilities of the participants would be "dictated in that final operating agreement." (TR 425-426)

The Phase IIB agreement provides three options for an Applicant who wishes to reduce its ownership share or completely withdraw from the project. The first option would give the remaining Applicants a right of first refusal to redistribute the capacity. The second option would allow the Applicant to find an acceptable replacement partner to take all or a portion of the capacity. If the capacity is not absorbed by the remaining Applicants, or by a new participant, the final option would be to resize the generating unit. (TR 417, 425) The Phase IIB agreement also allows any two Applicants to reallocate their ownership shares between themselves as long as the total capacity remains allocated among the Applicants. (TR 423)

Whitton argues that the existing agreement between the Applicants is problematic, in that it allows the Applicants to "opt out" of construction of the TEC after the Commission's need determination, and it allows the Applicants to reallocate their respective percentage shares of participation. (Whitton BR 20-21) Whitton contends that this constitutes an "end-around" of the Commission's authority and statutory obligations. (Whitton BR 21)

The Sierra Club argues that if parties "drop out" of participation in the TEC, capacity formerly committed to an Applicant would be sold on the wholesale market, essentially converting the TEC to an independent wholesale generator. (Sierra Club BR 18)

NRDC also expresses concern regarding the anticipation that bulk power sales will be made from the TEC to the wholesale market once constructed. (NRDC BR 47)

Staff disagrees with NRDC, Whitton, and the Sierra Club and notes that there is nothing unique about the Applicants in this proceeding with respect to their ability to withdraw from the proposed TEC project. Any utility in a need determination proceeding may make a subsequent decision not to construct a planned generating unit. Furthermore, Section 403.519, Florida Statutes, does not specify that applicants in a need proceeding must have approval through construction. Finally, no party provided evidence in the record that it is necessary for the Applicants to have approval beyond the permitting stage in order to obtain a need determination.

In its brief, NRDC also argued that the City does not have approval to include the TEC in its integrated resource plan. (NRDC BR 47) At hearing, Witness Brinkworth testified that this is technically correct. However, he qualified his response by explaining that the City Commission's vote addressed a resource plan that included the TEC. Witness Brinkworth stated, "technically the five-year approval they gave us, which would cover the period 2007 through 2012, actually includes roughly six months of the Taylor Energy Center." (TR 764) Staff does not believe NRDC's concern is relevant to the issue at hand. As stated above, staff believes the City has sufficient approval from its governing board to receive a need determination for the TEC.

Staff further disagrees with NRDC that if the Commission approves the need for TEC, the Commission should require the Applicants to return to the Commission for a subsequent approval after permitting is completed. (NRDC BR 47) This "second bite at the apple" is not contemplated by Section 403.519, Florida Statutes. NRDC and Sierra Club raise the concern that excess capacity from the TEC could be "readily sold" on the wholesale market in Florida. (NRDC BR 47, Sierra Club BR 18) Several of the Applicants' witnesses testified that there would be a market for the TEC's baseload energy if all of the capacity was not initially needed. (TR 490-491, 679-81, 766-767, 723-724) The Applicant's partnership has provided the opportunity to build a large baseload generating unit with economies of scale. (TR 383) As is typical, the Applicants will not need 100 percent of the TEC's capacity on the in-service date, but rather will grow into the capacity over time. It is prudent for utilities to sell excess capacity on the wholesale market until a unit's total capacity is needed.

Each Applicant stated that they would reevaluate the costs and other variables associated with the TEC prior to obtaining approval to participate through construction from their respective governing bodies. Staff recommends that this reevaluation is appropriate. Witness May noted that FMPA does an integrated resource plan every two years under which FMPA will evaluate all options, including participation in the TEC, on a going forward basis with the most current information. (TR 527) Witness Gilbert stated that prior to construction, JEA "will look at all factors that have changed significantly or even insignificantly. We'll build a whole other analysis." (TR 701) Witness Guarriello stated that RCID would "consider any new information that's available related to TEC, relating to other options they have…and then make a recommendation to the board of directors of Reedy Creek Improvement District." (TR 738) Witness Brinkworth expects that the City's staff would do a revised analysis, and that the City's Commission would want to "look at all the economic factors as well as weigh any other issues related to permitting…" (TR 800) Witness Lawson stated that the Applicants "would be developing a more accurate final cost dynamically as we move forward." Staff believes it is prudent for utilities to continuously evaluate whether the decision to participate in a proposed power plant project is appropriate for its ratepayers. Witnesses Gilbert, Brinkworth, May, and Guarriello affirmed their respective utility's commitment to continue to evaluate the availability of cost-effective DSM and purchased power agreements. (TR 478, 488, 702, 738, EXH 2) Witnesses Gilbert, Brinkworth, May, and Guarriello also agreed that it is prudent practice for utilities to continuously evaluate whether it is cost-effective to participate in a proposed generating plant up to the point of construction. (TR 527, 701, 738, 800)

In summary, the Applicants have approval only through the permitting phase for the TEC which is sufficient for the need proceeding. Each Applicant will have the opportunity to obtain final approval prior to the construction phase. Each Applicant intends to reevaluate its participation in the TEC with any updated information prior to construction. It is prudent for each utility to continuously analyze whether it is in the best interests of its ratepayers to participate in a proposed power plant up before, during, and after construction.

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?

Recommendation: Yes. Combined cumulative present worth cost savings from the TEC are estimated to be $899 million for the Applicants compared to the next least cost expansion plan for each Applicant, and appear to be robust under changing circumstances. The Applicants provided approximately 70 sensitivities, including changes in fuel prices, capital costs, and potential CO_2 regulation. The TEC provided savings in all but one sensitivity. The Applicants appropriately tested the TEC against other supply-side alternatives, including IGCC and biomass capacity. Further, the Applicants' analysis showed significant savings when the TEC was compared to a joint owned natural gas combined cycle, as well as an all natural gas expansion plan. (Harlow, Breman, Lester, Springer, Stallcup)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: The Applicants have not produced a record that supports TEC as the least cost alternative for the capacity and energy needs of any of the Applicants separately or the Applicants collectively. The cost of CO_2 regulation has not been properly evaluated which directly affects the fuel, SO2 and NOx allowance forecasts used by the Applicants in the POWROPT and POWRPRO models to produce their proposed least cost IRP containing TEC. Even if one assumes that the Applicants have modeled the cost of CO_2 regulation correctly, other errors in the Applicants' analysis produce an IRP which is flawed: limiting IGCC as a supply side option until 2018; unrealistically high availability factors for the TEC unit under a CO_2 regulatory scenario; use of the federal, not state, standards for mercury, NO2 and SO2 emissions; failure to include the variable costs necessary to operate the activated carbon injection system for the removal of mercury in Phase II of CAMR; and failure to properly evaluate the Southern Company bids. For these reasons, the Applicants have failed to prove that TEC is the most cost-effective alternative available to meet their identified capacity and energy needs.

Whitton: No. The Applicants could meet their needs through conservation and DSM measures, as well as invest in smaller-scale renewable energy sources such as biomass, in a more cost-effective manner than the proposed TEC. Given the current instability of the fossil-fuel markets as well as the uncertainties and potential dramatic economic impacts of CO2 regulation, deferring the need through these other alternatives would be more prudent and cost-effective.

Sierra Club: No. In the present market for electricity, the Participants could effectively meet their needs using cost effective alternatives to diversify away from fossil fuels until these markets demonstrate a period of stability. Economic and technological advances surrounding demand-side management measures, including energy efficiency and conservation measures, along with renewables, present Participants with an excellent opportunity to manage the cost of their capacity needs in this period.

Staff Analysis The Applicants performed a multi-stage analysis to compare the costs of an expansion plan with the TEC to alternative expansion plans. First, the Applicants developed the costs and performance factors for the TEC unit. Second, the Applicants developed cost and performance estimates for supply-side alternatives of various technologies. Third, the Applicants conducted a request for proposals for purchased power as an alternative to the TEC. Finally, the Applicants performed a detailed system base case analysis of various expansion plans with the self-build and purchased power alternatives. As a part of this final step, the Applicants prepared a number of sensitivities which tested the robustness of the expected the TEC savings against changed inputs and additional supply-side alternatives. Each of these steps, along with the assumptions, are discussed in detail below.

Cost and Performance Factors for the TEC: As discussed in Issue 2, TEC will be a 765 MW supercritical pulverized coal plant, and is expected to be built on a greenfield site. The steam pressure of a pulverized coal unit determines if the unit is considered supercritical or subcritical. (EXH 2, TR 813) According to Witness Hoornaert, the TEC was designed as a supercritical unit with higher steam pressure to increase the unit's fuel efficiency. (TR 813) Witness Hoornaert testified that the "difference is usually about a percent and a half improvement in efficiency for supercritical." (EXH 2) The Applicants expect the TEC's higher fuel efficiency to result in lower fuel costs and emissions per unit of energy produced as compared to subcritical technology. (TR 813) The TEC is expected to have an annual forced outage rate of 5.23 percent, and capacity factor of 90 percent. (EXH 24, TR 1167)

TEC is designed to burn various grades of coal from both national and international sources, as well as up to 30 percent petcoke, a byproduct of the petroleum refining industry. Witness Hoornaert testified that that "[t]ypically, a unit will be designed for a specific coal." (EXH 2) Witness Hoornaert further testified that the Applicants designed the TEC to burn various grades of coal and petcoke to provide fuel diversity and flexibility, in order to allow the Applicants to "competitively bid coal suppliers and transportation among multiple suppliers." The Applicants expect that the flexibility to purchase fuel from various regions within the United States and outside the country will result in increased fuel supply reliability. (TR 815)

In his pre-filed direct testimony, Witness Hoornaert provided a total capital cost estimate for the TEC of $1.713 billion in 2012 dollars. (TR 817) In response to staff's interrogatory number 58, Witness Hoornaert revised the expected total capital cost of TEC to $2.039 billion in 2012 dollars, an increase of approximately 19.01 percent. (EXH 2) Witness Hoornaert indicated that the increased capital cost estimated was caused by three primary changes in the initial assumptions. First, the Applicants increased the expected costs for major equipment and construction labor. Witness Hoornaert stated costs have increased because "[t]here is a high interest in new plants, and the suppliers are becoming busy, and as a result, their pricing is reflective of that." (TR 822, EXH 2) Second, the Applicants increased expected costs due to added equipment selected as the preliminary engineering and design work progressed. For example, $40 million was added to account for an activated carbon injection system, which was described by Witness Hoornaert as "the only currently available mercury-specific control." (TR 823) Activated carbon injection is included as a contingency to be installed if TEC's planned emission control systems cannot achieve the 90 percent mercury reduction required by the Clean Air Mercury Rule in 2018. Witness Kushner testified that because activated carbon injection is a contingency plan, he did not include the estimated $2 to $4 million per year associated O&M cost increase in modeling TEC's costs. (EXH 2) Finally, the Applicants revised the initial assumption on the up-front community contribution for Taylor County, because the community contribution agreement has been finalized. Witness Hoornaert testified that the $17 million up-front community contribution is now included in TEC's capital costs. (EXH 2)

The capital cost estimate for TEC includes approximately $11.7 million for transmission upgrades of two 230 kV transmission lines constructed from TEC to Progress Energy's Perry substation. It is unlikely that these transmission upgrades will be determined to be "network improvements," in that they will benefit solely the Applicants rather than users of the transmission network in general. The cost will therefore most likely be borne by the Applicants. (TR 756-758, EXH 2) In addition, the Applicants have chosen an intergration alternative, referred to as the "Wilcox Alternative," from among four alternatives identified by Progress Energy in its System Impact Study. Progress Energy estimated that the transmission upgrade costs associated with the Wilcox alternative will be $98 million. (EXH 2) The Applicants expect that Progress Energy will find these transmission upgrades to be network improvements. If so, the Applicants will pay the $98 million in transmission upgrade costs up-front, and be refunded the full costs over time through credited wheeling charges. (TR 776) Because the Applicants believe these costs will be credited back through reduced wheeling charges, Witness Hoornaert did not include the $98 million in costs for the Wilcox transmission upgrades in TEC's capital costs. (EXH 2) Witness Kushner testified, however, that a sensitivity analysis was performed in which the capital costs of TEC were increased by $100.3 million to determine the total cost of the project in the event that the transmission upgrades must be paid by the Applicants. TEC was found to provide $823 million in savings even if the transmission upgrades must be borne solely by the Applicants. (TR 1115, EXH 2)

Staff has reviewed the capital costs and performance characteristics of TEC and finds them to be reasonable. As discussed in more detail below, staff believes the fuel commodity and transportation price forecasts, load forecasts, and financial assumptions used by the Applicants are reasonable for planning purposes. In its Brief, NRDC argued that the costs of TEC were understated because the Applicants did not include the O&M costs associated with the activated carbon injection system. (NRDC BR 12) As discussed in Issue 6, staff disagrees; the activated carbon injection system is a contingency only if existing emission controls can not meet the Phase II CAMR standards.

Sierra Club contends that the TEC's projected costs are in flux and are not final. (Sierra Club BR 14) Sierra Club cites Applicant witnesses who indicated that labor costs for construction and other capital costs are subject to increase due to market forces which may drive capital costs for pulverized coal plants higher. (Sierra Club BR 15) Therefore, Sierra Club contends there are no guarantees of the final costs that will guide construction of the TEC. (Sierra Club BR 15) However, as discussed in Issue 8, the capital cost associated with any proposed power plant is an estimate at the time of a need proceeding and may change prior to construction. Therefore, staff believes that the expected cost savings from a proposed power plant should be reviewed in terms of the robustness of the savings under changed market conditions. The Applicants stated that they would reevaluate the costs and other variables associated with the TEC prior to obtaining final approval to participate through construction from their respective governing bodies. (TR 527, 701, 738, 800) Staff believes this action is prudent. Further, as discussed below, the Applicants performed over 70 sensitivity analyses which show that the estimated savings associated with the TEC are robust under changing circumstances. In particular, the Applicants performed a sensitivity with a 20 percent increase in the revised capital costs, under which an expansion plan with the TEC was found to provide cost savings for each Applicant. (EXH 3, EXH 57)

Cost and Performance Estimates for Supply-Side Alternatives: The Applicants developed costs and performance factors for numerous supply-side alternatives from the following categories: renewable technologies, conventional technologies, advanced technologies, energy storage technologies, distributed generation, and emerging technologies. These alternatives included units specifically designed for each Applicant to be placed on existing and greenfield sites, as well as jointly owned facilities. The Applicants performed an initial screening of each potential supply-side alternatives based on economics, feasibility, and reliability impacts for each Applicant's system. More detailed analysis was performed on those alternatives which passed the initial screening, including natural gas fired combustion turbine and combined cycle units, pulverized coal (including participation in the TEC), circulating fluidized bed coal units, biomass, and integrated coal gasification combined cycle units (IGCC). (TR 320)

Staff disagrees with NRDC that the Applicants did not appropriately compare an IGCC alternative to the TEC.[6] (NRDC BR 9) NRDC is correct that the Applicants restricted the selection of IGCC in its base case analysis to 2018. Witness Kushner stated that the Applicants consider IGCC to be an emerging technology at this time. The 2018 date allows several years to evaluate the performance of OUC's planned Stanton B IGCC unit, as well as additional time for the Applicants to site and build an IGCC. (TR 338-340, 354, 1275, EXH 2)

Staff was initially concerned about the restriction of IGCC technology until 2018. However, staff agrees with Witness Rollins that building an IGCC unit or units of the same size as the TEC in 2012 could pose risk for the Applicants. According to Witness Rollins, there are currently only 2 coal-fired IGCC units in operation to produce electricity in the United States, including Tampa Electric Company's Polk unit. (TR 353-355, 1095) Witness Rollins also testified that OUC's Stanton B IGCC unit would not have been cost-effective if it had not received $235 million in federal cost sharing. Furthermore, OUC was able to negotiate favorable contract provisions with Southern to protect its ratepayers in the event that the gasifier does not perform as expected. (TR 341, EXH 2) Staff notes that the Applicants performed a sensitivity

6 Staff notes that NRDC relied heavily on Exhibit 82 in making its argument that the Applicants did not appropriately consider IGCC technology. Exhibit 82 was provided by a member of the public, Witness Furman. The Applicants objected to this exhibit on the grounds of hearsay. Chairman Edgar noted the objection and ruled that Exhibit 82 would be entered into the record and given the weight it is deemed due. (TR 263-271)

analysis which compared an expansion plan with a jointly owned IGCC unit with an in-service date of May 2012 on the TEC site to an expansion plan which included the TEC. (TR 1217-1218) The Applicants also evaluated an IGCC alternative for each of the Applicants. (TR 1139) Participation in the TEC compared to a jointly owned 2012 IGCC unit was estimated to provide $464 million in total cumulative present worth cost savings, as well as provide benefits to each Applicant, as shown on the table below. (EXH 3, EXH 57) Public Witness Furman raised a concern that an IGCC unit fueled by 100 percent petcoke would be more cost-effective than TEC. (TR 26, EXH 82) Witness Kushner, however, testified that in the Applicants' sensitivity analysis, which showed $464.0 million in CPWC savings for participation in TEC versus a 2012 IGCC unit, 100 percent petcoke was assumed as the fuel for the IGCC unit. (TR 1218) Witness Hoornaert characterized petcoke as an opportunity fuel, because although it is typically lower in cost than coal, its availability varies. (TR 840) Witness Kushner stated that due to availability concerns, fueling an IGCC unit the size of TEC with 100 percent petcoke would cause reliability concerns. (TR 1219) The table below displays the Applicants' expected cumulative present worth cost (CPWC) savings from an expansion plan that includes the TEC, compared to an expansion plan with a 2012 IGCC unit. (EXH 3, EXH 57)

	CPWC Savings for Expansion Plan with TEC versus 2012 IGCC ($ million)
FMPA	241.1
JEA	40.3
RCID	54.4
The City	128.2
Total:	**464.0**

Whitton contends that the Applicants did not appropriately consider a biomass alternative to the TEC. (Whitton BR 5) However, the record indicated that the Applicants compared an expansion plan that includes participation in the TEC to an expansion plan that includes a 30 MW conventional direct fired biomass generating plant for each Applicant. (TR 1138) Whitton's Witness Deevey testified that the Applicants' "consultants appear wrongly to have assumed that woody biomass supplies are too limited in the locations of interest to support more than about 50 MW of capacity in any suitable location." (TR 557) There is conflicting evidence in the record on the appropriate size of a biomass alternative. Sierra Club's Witness Deevey estimates that enough biomass is available to fuel a 100 MW unit for the City and up to 150 MW for JEA at a fuel cost of 2 cents per kWh. (TR 557-558) The Applicants, however, stated that biomass plants are typically less than 50 MW "because of the dispersed nature of the feedstock and the large quantities of fuel required." (EXH 50) The Applicants further explain that due to the low heating values of biomass fuels, transportation costs are a significant consideration. Therefore, biomass units are typically limited to the use of "inexpensive or waste biomass sources." (EXH 50) Staff finds the Applicants' arguments for limiting the biomass alternative to 30 MW persuasive. Staff notes that the City's recently signed contract with BG&E is an energy-only contract from a planned 38 MW biomass facility. (EXH 2)

Request for Proposals: The Applicants further investigated supply-side alternatives by issuing a request for proposals (RFP) on November 28, 2005. The RFP solicited proposals for 100 to 750 MW for a term of at least 10 years. Witness Arsuaga testified that while the RFP expressed a preference for solid fuel alternatives, the RFP was not limited by fuel type. (TR 937) The Applicants received two bids from one bidder, the Southern Company (Southern), in response to the RFP. (TR 320) The bids consisted of a 797 MW supercritical pulverized coal unit to be constructed on the TEC site, and a 784 MW natural gas fired combined cycle unit to be constructed in St. Lucie County. (TR 935) R.W. Beck evaluated the Southern bids under a variety of scenarios and determined that the TEC "is projected to have a lower delivered cost to the Participants than Southern's proposed coal resource or the combined cycle resource." (TR 934) Witness Arsuaga testified that he made several adjustments to both the Southern bids and the TEC costs so that the alternatives could be compared on a consistent basis. (TR 933, EXH 2) Staff reviewed these adjustments and believes they are reasonable. Black and Veatch performed an additional analysis of Southern's bids. This production cost model compared a least cost expansion plan for each Applicant, which included TEC expansion plans for each Applicant that included Southern's bids. Witness Kushner testified that the analysis was revised to include the higher expected capital costs for the TEC. (TR 1127) As shown in the table below, the Applicants' analysis showed significant CPWC savings for each Applicant associated with participating in the TEC compared to the Southern alternatives. (EXH 3, EXH 57)

	CPWC Savings for Expansion Plan with TEC versus Southern's PC Coal Bid ($ million)	CPWC Savings for Expansion Plan with TEC versus Southern's Gas CC Bid ($ million)
FMPA	472.2	588.4
JEA	401.2	280.3
RCID	92.5	193.9
The City	207.6	415.8
Total:	**1,173.5**	**1,478.4**

Base Case and Sensitivity Results: The Applicants performed a detailed system evaluation of each supply-side alternative that passed the initial screening, including participation in the TEC, and Southern Company's RFP responses. This analysis used as inputs the economic assumptions and fuel price forecasts discussed in more detail below. As described by Witness Rollins, "[a] chronological optimal generation expansion model was used to determine the least-cost expansion plans for the self-build and purchased power alternatives," over a 30-year planning period from 2006 through 2035. (TR 321) The least cost 30 year expansion plan that included the TEC in 2012 was compared to the next least cost expansion plan for each Applicant under base case assumptions. Witness Kushner testified that the base case analysis was revised to account for the higher expected capital costs for the TEC. (TR 1125) The Applicants estimated that under base case conditions, the combined cumulative present worth cost savings from TEC are estimated to be $899.3 million when compared to the next least cost expansion plan for each Applicant. (TR 1127, EXH 57) As shown in the table below, the Applicants' analysis showed estimated CPWC savings for each Applicant compared to the Applicant's next best generation plan. (EXH 3, EXH 57)

	CPWC Savings for Expansion Plan with TEC versus Each Applicant's Next Best Expansion Plan ($ million)
FMPA	417.1
JEA	38.1
RCID	255.6
The City	188.6
Total:	**899.4**

In addition to the Black and Veatch analysis, the City performed its own integrated resource plan that included a base case analysis and sensitivities. Witness Brinkworth testified that the City's analysis was consistent with the results of the Black and Veatch analysis. (TR 753)

Fuel Commodity and Transportation Price Forecasts Forecasted fuel prices for various types of fuel are a necessary part of the evaluation of supply-side resources. (TR 1107, 1109) In this case, the TEC evaluated the power supply options using a fuel forecast that included the delivered prices of coal, petroleum coke (petcoke), natural gas, and No. 2 and No. 6 fuel oil. The period covered by the fuel price forecasts was from 2006 to 2030. (TR 959, 973, EXHs 26, 27, 28, & 29)

Applicant Witnesses Preston and Breton provided forecasts of the commodity prices of coal, petcoke, natural gas and fuel oil. (TR 996-997, 999) TEC Witnesses Norfolk and Heller provided forecasts of transportation rates for waterborne transportation and rail transportation, respectively. (TR 580-581, 589) TEC Witness Myers tied the forecasted commodity and transportation prices into delivered fuel prices, which the applicants used to model the costs of power supply alternatives. (TR 959) TEC Witness Myers used the commodity fuel price forecasts for coal, petcoke, natural gas, and fuel oil from Witness Preston to develop delivered fuel prices. (TR 986-987) The fuel price forecasts from Witnesses Preston and Breton and transportation rate forecasts were in constant 2005 dollars. (TR 964-967) Witness Myers converted these to nominal prices using a 2.5 percent annual escalation rate. (TR 964-967)

Witness Myers used forecasted rail transportation rates for coal from TEC Witness Heller and forecasted shipping rates from TEC Witness Norfolk to develop the delivered prices. (TR 966-967) Witness Myers assumes that railcars will be leased and railcar maintenance is also included in the base price. (TR 977, 989) For natural gas and distillate and residual fuel oil, Witness Myers added transportation costs to arrive at a delivered price. (TR 964-968)

At pages 11 and 12 of its brief, the NRDC states the following:

> Because Florida's actual implementations of the CAIR and CAMR rules were not modeled by Witness Preston, the actual projections for fuel and emissions prices provided by Witness Preston and used throughout all IRP analyses do not reflect the true cost of these items.

The NRDC and other intervenors did not provide specific testimony regarding the forecasted prices of the various types of fuel. The intervenors did provide testimony on the potential effects of future CO_2 regulation, which is addressed in the staff analysis for Issues 5 and 6. Staff notes that Florida's State Implementation Plan is currently being litigated. Furthermore, Witness Preston's fuel price forecast considers environmental regulations such as CAIR and CAMR. (TR 999-1000) Staff believes the fuel price forecast appropriately considers CAIR and CAMR. This issue is discussed further in the staff analysis for Issues 5 and 6.

Whitton asserts that supply routes have not been thoroughly identified to adequately assess supply reliability. He specifically asserts that the applicants do not have contracts for the supply and delivery of coal and petcoke, that the TEC has not identified a specific port, and transportation route, and that improvements would be needed at the Jacksonville Port Authority. (Whitton BR 6-7)

Staff notes that, for a need determination, an applicant should use reasonable estimates in its analysis. Staff believes it would be premature and impractical to require an applicant in a need determination to negotiate contracts for fuel supply and delivery ahead of regulatory approvals. Staff addresses the reasonableness of the TEC's fuel price forecasts below.

Whitton also asserts that the Applicants have not included all the potential transportation costs of delivering coal to the TEC. (Whitton BR 17) Staff disagrees, because the TEC has used delivered prices in its analysis of power supply alternatives, the reasonableness of which is discussed below. The issue of potential traffic problems caused by delivering coal by rail is also discussed below.

Staff believes the natural gas price forecast allowed for the appropriate drivers such as industrial and power sector demand and LNG imports. (TR 572-574) Staff notes the delivered price on natural gas in nominal dollars for the base case is below \$10 per MMBtu for the period 2006 through 2021. After that, the forecasted delivered price of gas trends up to approximately \$14 per MMBtu. (EXH 27) Staff believes the delivered natural gas price forecast provided by the Applicants is reasonable for the economic evaluation of the TEC and the alternatives. (TR 572-574) Staff also believes the delivered fuel oil price forecasts considered the appropriate price drivers and are reasonable for the evaluation of the TEC and the alternatives. (TR 576-577)

Regarding coal and petcoke, staff believes the forecasted delivered prices are reasonable for the evaluation of the TEC and the alternatives. Witness Preston tested the coal price forecast for reasonableness by comparing it to coal price forecasts prepared for the need determinations for Seminole Electric Cooperative's Seminole Generating Station Unit 3 and for the Orlando Utilities Commission's Stanton Energy Center Unit B. (EXH 2) The coal price forecast was also compared to the price forecast in EIA's Annual Energy Outlook. (EXH 2) According to Witness Preston, the PRISM forecasting model he used has forecasted prices close to the eventual actual prices. (EXH 2) Staff notes that petcoke prices are typically priced at a discount to the coal market due to supply outstripping demand in the domestic U.S. markets and due to higher material handling costs at plants not originally designed to burn a blend of coal and petcoke. (TR 1004, EXH 2)

As referenced in the case background, in the public testimony phase of the hearing, Baker County Commissioner Alex Robinson raised a concern with rail cars blocking traffic on U.S. Highway 90 in the Town of Sanderson. Currently, highway traffic can be blocked by trains causing inconvenience and impairing fire, police, emergency and rescue vehicles. Commissioner Robinson is concerned that the addition of coal trains to supply the TEC will make the problem worse. He reported traffic delays of up to one hour and 45 minutes. (TR 67-68) Commissioner Robinson said meeting with CSX Railroad officials regarding this problem had not been fruitful. He stated that CSX claimed the extension of the rail siding, allowing more rail cars so that the highway is not blocked, would be too expensive. (TR 73)

In addition to Commissioner Robinson's testimony, Public Witness Barry Parsons provided testimony stating concerns from local governments about increased rail traffic. The delivery of coal by rail from Jacksonville to the TEC could affect services provided by these local governments. (TR 103-106; EXH 87)

TEC Witness Lawson noted that the exact rail routes for coal and petcoke delivery to the TEC have not been established. Witness Lawson believes the trains supplying the TEC would only cause delays of less than two minutes when crossing highways. He acknowledges that extended delays, to the extent they occur, would be a problem and should be solved by the railroad. Witness Lawson does not believe the TEC can make the railroad solve traffic problems. The railroad's rates, paid by TEC and others, would have allowances for solving such problems. (TR 434-436, 438-439, 441-442, 444, 448-450) Witness Lawson offers that the TEC would be willing to meet with Baker County and the railroad to try to work out a solution. (TR 433-434, 449)

Regarding rail crossing traffic problems, Witness Lawson stated that there would be a significant impact in Perry. The TEC has agreed to contribute $5 million toward the mitigation of this impact if the TEC is approved. The $5 million contribution is included in the capital costs for the TEC. (TR 412-414) Staff notes that the Applicants also performed a sensitivity in which the updated capital costs for the TEC were increased by 20 percent, and the TEC remained cost-effective. (EXH 3, EXH 57) This indicates that if the Applicants determine that additional community contributions are necessary to alleviate rail crossing traffic problems, the TEC will remain cost-effective.

Staff notes that the Applicants are not responsible for all traffic problems along the proposed routes for its coal trains. The railroad is regulated by the Surface Transportation Board, and its rates have allowances for capital improvements, including extensions of rail sidings. (TR 435, 436-437, 441-442) Issues regarding impacts caused by increased rail traffic may be addressed by the Department of Transportation, the Department of Environmental Protection, the Division of Administrative Hearings, the Governor and Cabinet, sitting as the Siting Board or in proceedings before the applicable municipal bodies who may address future rate issues associated with the proposed TEC project. Furthermore, because the traffic problems currently exist, the TEC cannot currently be the cause, although the addition of coal trains could exacerbate the existing problems.

Financial Assumptions The Applicants' financial assumptions include an anticipated capital structure consisting of 100 percent debt financing using primarily long-term tax-exempt municipal bonds. (EXH 2) The Applicants state that they may utilize multiple bond issues and other financial vehicles to take advantage of favorable financial conditions during the construction and operation of the TEC. (EXH 2) FMPA Witness May stated that several sources of debt may be used to finance the development and construction of TEC including internal funds, pooled loans, and new long-term debt issuances. (TR 465-466) JEA Witness Gilbert stated that JEA typically finances large generation capital projects using fixed and floating rate subordinate long-term debt, but may use internal funds from operations or from prior issuances to fund early project costs. (TR 661-662)

The Applicants' other financial assumptions include an annual rate of 5 percent for the long-term tax-exempt bond rate, interest during construction rate, and present worth discount rate. (TR 322) Additionally, a 2.5 percent annual percentage rate was used for both the general inflation rate and the escalation rates that were applied to both capital costs and O&M costs. (EXH 2) These financial assumptions as applied are consistent and comparable with other recent need determinations that were approved by the Commission.[7] (EXH 2) There was no evidence presented in the record that disputes the reasonableness of these financial assumptions. Based on this review, staff concludes that the financial assumptions used for this evaluation are reasonable.

Sensitivity Analysis and Results The Applicants provided approximately 70 sensitivities to the base case analysis. (TR 1143) Witness Kushner testified that all sensitivities were revised to account for the higher expected capital costs for the TEC. (TR 1127) The sensitivity analyses included changes in the base case input assumptions, such as high and low fuel prices, high and low load and energy growth, high and low capital cost, high and low emission allowance prices, and a potential CO_2 regulation scenario. (TR 1116) The sensitivity analyses also included changed external parameters, such as other jointly owned supply-side alternatives (IGCC and natural gas fired combined cycle), participation in a second jointly owned pulverized coal unit, an all natural gas fired expansion plan, a biomass alternative, and a scenario in which the TEC uses Powder River Basin coal instead of Latin American coal. (TR 1116-1117)

Witness Kushner testified that participation in TEC provided savings to each Applicant in all but one sensitivity, the low fuel price scenario for JEA. (TR 1143) Under JEA's low fuel price forecast scenario, participation in TEC resulted in $12.7 higher cumulative present worth costs than an alternative plan because JEA's least cost alternative expansion plan in this case includes a circulating fluidized bed coal unit in lieu of participation in the TEC. (TR 1128)

To a large extent, the intervenors' arguments have focused on a comparison of the TEC's supercritical pulverized coal technology to IGCC technology, and to the effect of potential CO_2

[7] Order No. PSC-05-0781-FOF-EM, issued July 27, 2005, in Docket No. 050256-EM, In re: Petition to determine need for Treasure Coast Energy Center Unit 1, proposed electrical power plant in St. Lucie County, by Florida Municipal Power Agency (5 percent cost rate) and Order No. PSC-06-0457-FOF-EM, issued May 24, 2006, in Docket No. 060155-EM, In re: Petition for determination of need for proposed Stanton Energy Center Combined Cycle Unit B electrical power plant in Orange County, by Orlando Utilities Commission (5.25 percent cost rate including insurance costs and issuance fees).

regulation on TEC's costs. However, as discussed above, the Applicants sensitivity analysis showed that the TEC will provide economic savings relative to a 2012 jointly owned IGCC unit. As discussed in Issue 5, the expected savings in the Applicant's jointly owned natural gas-fired combined cycle sensitivity, as well as the all natural gas expansion plan sensitivity, adds weight to the Applicants' argument that TEC's savings are robust under a potential CO_2 regulation scenario. As such, staff agrees with Witness Kushner that "[t]he results of the sensitivity analyses, coupled with the results of the base case analysis, demonstrate that the capacity expansion plan including participation in TEC is a robust plan for each Participant, and is sufficiently flexible to overcome variations and deviations from the base case assumptions." (TR 1117-1118, 1128, 1143) As shown in the table, the Applicants' analysis determined that there would be significant expected CPWC savings for each Applicant of participating in the TEC compared to a jointly owned natural gas combined cycle or an all gas expansion plan. (EXH 57)

	CPWC Savings for Expansion Plan with TEC versus Joint Natural Gas CC ($ million)	CPWC Savings for Expansion Plan with TEC versus All Natural Gas Plan ($ million)
FMPA	$ 564.4	$873.3
JEA	275.2	715.1
RCID	124.4	255.6
The City	314.0	262.7
Total:	1,278.0	2,106.7

<u>Consequences of Delay</u> Witness Rollins testified that a one year delay in the in-service date of the TEC will result in higher total cumulative present worth costs of approximately $85.4 million, and higher costs for each Applicant. Witness Rollins revised these estimates to account for the higher expected capital costs of the TEC. (TR 345) The consequences of a one year delay were estimated to be $19.9 million for FMPA, $39.0 million for JEA, $24.4 million for RCID, and $2.1 million for the City. (TR 335) Witness Rollins testified that he did not account for the City's planned DSM expansion, which the City projects will defer its need for capacity from 2011 to 2016. (TR 345, EXH 2) Staff therefore believes that the estimated economic consequences of delay for the City may be overstated.

Conclusion: Staff believes that the preponderance of the evidence indicates that participation in the TEC is cost-effective for each of the Applicants. Combined cumulative present worth cost savings from the TEC are estimated to be $899 million for the Applicants compared to the next least cost expansion plan for each Applicant, and appear to be robust under changing circumstances. The TEC cost estimates, including fuel commodity and transportation costs, appear to be reasonable for planning purposes. The Applicants provided approximately 70 sensitivities, including changes in fuel prices, capital costs, and potential CO_2 regulation. The TEC provided savings in all but one sensitivity test. The Applicants appropriately tested the TEC against other supply-side alternatives, including IGCC and biomass capacity. Furthermore, the Applicants' analysis showed significant savings when TEC was compared to a jointly owned natural gas combined cycle, as well as an all natural gas expansion plan. The Applicants expect that a one year delay in commercial operation of the TEC will result in higher total cumulative present worth costs of approximately $85.4 million, as well as higher costs for each Applicant.

Staff therefore recommends that the Commission find that the proposed TEC generating unit is the most cost-effective alternative available, as this criteria is used in Section 413.519, 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?

Recommendation: Yes. As discussed in Issues 1 through 9, the record evidence indicates that the Applicants have met the criteria set forth in Section 403.519, Florida Statutes. Therefore, the Applicants' petition to determine the need for the proposed TEC unit should be approved. (Harlow, Brown, McRoy, Breman, Lester, Springer, Stallcup)

Position of the Parties (Taken Directly from Briefs)

Applicants: 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.

NRDC: No. As discussed in detail in Issues 2- 9 above, the Applicants have failed to prove that there are no demand side management measures that could reduce or eliminate the need for TEC and due to faulty assumptions in its IRP models and fuel and emission forecast models have failed to prove that TEC is the least cost alternative available to meet the Applicants' demonstrated needs.

Whitton: No.

Sierra Club: No.

Staff Analysis: As discussed in Issues 1 through 9, the capacity from TEC will add to electric system reliability and integrity and appears to be cost-effective. TEC will also provide much needed fuel diversity for the Applicants and Florida. Cumulative savings from TEC are estimated to be $899 million for the Applicants, and appear to be robust under changing circumstances. The Applicants provided approximately 70 sensitivities, including changes in fuel prices, capital costs, and potential CO_2 regulation. The Applicants appropriately tested TEC against other supply-side alternatives, including biomass and IGCC. Further, the Applicants' analysis showed significant savings when TEC was compared to a joint owned natural gas combined cycle. While the City of Tallahassee (the City) believes that its demand-side management plan could shift its need for capacity from 2011 to 2016, the City still has an economic need for TEC's low-cost baseload energy to reduce its exposure to natural gas prices. The record evidence indicates that the Applicants have met the criteria set forth in Section 403.519, Florida Statutes. Therefore, the Applicants' petition to determine the need for the proposed TEC unit should be approved.

Issue 11: Should this docket be closed?

Recommendation: The docket should be closed 32 days after issuance of the order, to allow the time for filing an appeal to run. (Brubaker, Fleming, Holley)

Position of the Parties (Taken Directly from Briefs)

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

NRDC: This docket should be closed when the Commission has issued its final order and all motions for reconsideration have been disposed of.

Whitton: This docket should be closed when the Commission has issued its final order and all motions for reconsideration have been disposed of.

Sierra Club: This docket should be closed when the Commission has issued its final order and all motions for reconsideration have been disposed of.

Staff Analysis: The docket should be closed 32 days after issuance of the order, to allow the time for filing an appeal to run.